CREW ENERGY INC.

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2008

March 30, 2009

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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.
ARTC	Alberta Royalty Tax Credit
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 (this conversion factor is an industry accepted norm)
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

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 and re-completion plans, timing of drilling, re-completion and tie in of wells, productive capacity of wells and capital expenditures and the timing 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, expected commodity prices, exchange rates, production expenses, transportations costs and other costs and expenses, maintenance of productive capacity and capital expenditures and methods of financing thereof, 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 and resources provided herein are estimates only and there is no guarantee that the estimated reserves and resources 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);

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

"**Crew Resources**" means Crew Resources Inc., a corporation incorporated pursuant to the ABCA;

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

"**GLJ Report**" means the report of GLJ dated February 25, 2009 evaluating the crude oil, natural gas liquids and natural gas reserves of the Corporation as at December 31, 2008;

"**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;

"**NRF**" means the New Royalty Framework announced by the Alberta government on October 25, 2007 and made effective January 1, 2009; 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, 2008.

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."

As at December 31, 2008 Crew had two wholly-owned subsidiaries, Crew Resources and Gentry Resources Ltd. ("**Gentry**"), both of which are organized under the ABCA. Crew is also the managing partner of the Crew Energy Partnership, which owns substantially all of Crew's producing oil and gas properties. Crew and its wholly owned subsidiaries, Crew Resources and Gentry, were, as at December 31, 2008, the only partners in the Crew Energy Partnership and, as at that date, respectively owned 53.019%, 23.018% and 23.963% of the Crew Energy Partnership.

On January 1, 2009 Crew completed a short form amalgamation with its wholly-owned subsidiary, Gentry, to form "Crew Energy Inc.",

Crew's head office is located at Suite 1400, 425 - 1st Street SW, Calgary, Alberta T2P 3L8 and its registered office is located at Suite 1400, 350 – 7th Avenue SW, Calgary, Alberta T2P 3N9.

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 wholly-owned subsidiaries and the Crew Energy Partnership.

DESCRIPTION AND GENERAL DEVELOPMENT OF THE BUSINESS

Corporate History

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 "**Baytex Arrangement**").

Pursuant to the Baytex Arrangement, Crew acquired certain oil and gas properties and undeveloped land from Baytex Energy Ltd. and the Baytex Energy Partnership. Crew did not carry on any active business until completion of the Baytex Arrangement.

At the effective date of the Baytex Arrangement, production from the properties acquired by Crew was approximately 1,500 Boe/d comprised of 7.8 Mmcf/d of natural gas production and 200 bbl/d of oil and natural gas liquids production. The properties acquired by Crew also included approximately 227,008 net acres of undeveloped land. Crew's fourth quarter 2008 production averaged 14,869 Boe/d, representing a 891% increase since Crew's inception and the Corporation owned 626,861 net acres of undeveloped land at December 31, 2008.

The business plan of Crew has been to create sustainable and profitable growth in the oil and gas industry in western Canada. To accomplish this, Crew has focused on enhancing its asset base through land acquisition and exploratory and development drilling within its core project areas in Alberta 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.

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; and (v) the strategic benefits to Crew.

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.

Funding for Crew's growth has come from a combination of cash flow from on-going operations, the Corporation's bank facility and equity financings undertaken from time to time as noted herein. Crew has also completed several material acquisitions since its inception as described below.

On May 13, 2004, Crew completed a bought deal private placement of 3,000,000 Common Shares at a price of $5.35 per share, for aggregate gross proceeds of approximately $16 million.

On December 2, 2004, Crew completed a bought deal private placement of 800,000 Common Shares, issued on a "flow-through" basis, at a price of $11.00 per share for aggregate gross proceeds of approximately $8 million.

On December 20, 2005, Crew completed a bought deal short form prospectus offering of 1,373,900 Common Shares at an issue price of $18.20 per share, and 416,700 Common Shares issued on a "flow-through" basis at an issue price of $24.00 per share, for aggregate gross proceeds of approximately $35 million.

On August 17, 2006, the Corporation completed a bought deal short form prospectus offering of 1,666,800 Common Shares at an issue price of $15.00 per share, and 759,500 Common Shares issued on a "flow-through" basis at an issue price of $19.75 per share, for aggregate gross proceeds of approximately $40 million.

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 Gentry Resources Ltd. See "*Significant Acquisitions – Acquisition of Gentry Resources Ltd.*"

Crew commenced a normal course issuer bid on October 15, 2008 pursuant to which Crew may, from time to time, purchase for cancellation up to a maximum of 5,587,988 Common Shares through the open market, subject to a maximum daily purchase limitation of 151,372 Common Shares. The bid will expire on October 14, 2009 or such earlier time as Crew may determine in its discretion. For the period from commencement of the bid through December 31, 2008, Crew purchased an aggregate of 110,000 Common Shares at an average purchase price of $4.67 per Common Share. As at March 30, 2009, the Corporation has not purchased any additional shares.

Significant Acquisitions

Acquisition of Gentry Resources Ltd.

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.

Immediately following completion of the Gentry Acquisition, Crew's $195 million revolving line of credit was increased to $270 million which, together with a $15 million operating line of credit, represented aggregate available credit facilities of $285 million. Gentry's credit facilities in the aggregate amount of $61.4 million were paid out by Crew in conjunction with the increase in Crew's credit facilities.

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.

The Corporation's Business Acquisition Report dated October 31, 2008 in respect of the Gentry 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 30, 2009. The effective date of the Statement is December 31, 2008 and the preparation date of the Statement was February 25, 2009.

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, 2008 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 and the Report on Reserves Data by the Independent Qualified Reserves Evaluator are attached at Appendices A and B hereto, respectively.

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

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 liquid 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, 2008
FORECAST PRICES AND COSTS

	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	2,972	2,489	671	552	3,043	2,160	98,590	80,334	1,293	1,259	23,333	18,799
Developed Non-Producing	529	406	7	6	374	285	23,710	18,388	886	819	5,009	3,899
Undeveloped	1,278	933	120	92	585	463	25,869	19,392	6,490	5,671	7,376	5,665
TOTAL PROVED	4,779	3,828	797	650	4,003	2,909	148,169	118,114	8,669	7,749	35,719	28,363
TOTAL PROBABLE	3,243	2,569	263	210	2,518	1,899	95,148	73,897	7,344	6,269	23,106	18,039
TOTAL PROVED PLUS PROBABLE	8,022	6,396	1,060	860	6,521	4,808	243,317	192,010	16,013	14,018	58,825	46,402

RESERVES CATEGORY	NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAXES DISCOUNTED AT (%/year) 0% (M$)	5% (M$)	10% (M$)	15% (M$)	20% (M$)	AFTER INCOME TAXES DISCOUNTED AT (%/year) 0% (M$)	5% (M$)	10% (M$)	15% (M$)	20% (M$)
PROVED										
Developed Producing	771,068	597,025	494,589	426,269	377,035	708,506	555,464	464,736	403,730	359,421
Developed Non-Producing	151,779	122,212	102,169	87,503	76,290	110,766	88,756	73,998	63,299	55,186
Undeveloped	183,592	128,897	95,330	72,923	57,025	133,848	90,837	64,526	47,068	34,778
TOTAL PROVED	1,106,439	848,134	692,088	586,696	510,351	953,120	735,056	603,260	514,097	449,386
TOTAL PROBABLE	879,347	510,584	346,964	256,170	198,634	653,121	374,977	251,527	183,093	139,824
TOTAL PROVED PLUS PROBABLE	1,985,786	1,358,718	1,039,052	842,866	708,985	1,606,241	1,110,033	854,787	697,190	589,210

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
as of December 31, 2008
FORECAST PRICES AND COSTS

RESERVES CATEGORY	REVENUE (M$)	ROYALTIES (M$)	OPERATING COSTS (M$)	DEVELOPMENT COSTS (M$)	ABANDONMENT AND RECLAMATION COSTS (M$)	FUTURE NET REVENUE BEFORE INCOME TAXES (M$)	INCOME TAXES (M$)	FUTURE NET REVENUE AFTER INCOME TAXES (M$)
Total Proved	2,128,821	399,172	493,790	108,258	21,161	1,106,439	153,320	953,120
Total Proved Plus Probable	3,769,292	735,615	829,152	191,709	27,031	1,985,786	379,545	1,606,241

FUTURE NET REVENUE
BY PRODUCTION GROUP
as of December 31, 2008
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES[3] (discounted at 10%/year) (M$)	UNIT VALUE BEFORE INCOME TAXES (discounted at 10%/year) (Units as noted)
Proved Producing	Light and Medium Crude Oil [1]	79,016	25.75 per bbl
	Heavy Oil[1]	114	16.03 per bbl
	Natural Gas [2]	410,830	4.41 per mcf
	Coal Bed Methane	4,629	3.68 per mcf
Total Proved	Light and Medium Crude Oil [1]	114,825	25.31 per bbl
	Heavy Oil[1]	142	9.19 per bbl
	Natural Gas [2]	562,139	4.16 per mcf
	Coal Bed Methane	14,981	1.93 per mcf
Total Proved Plus Probable	Light and Medium Crude Oil [1]	181,812	24.77 per bbl
	Heavy Oil[1]	220	11.50 per bbl
	Natural Gas [2]	836,121	3.80 per mcf
	Coal Bed Methane	20,899	1.49 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.

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 (see the discussion of "Economic Assumptions" below) which are generally accepted as reasonable and shall be disclosed.

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 effective aggregation is provided in the COGE Handbook.

3. Forecast Prices and Costs

GLJ has prepared its January 1, 2009, 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.

Forecast prices and costs are those:

(a) generally acceptable as being a reasonable outlook of the future; and

(b) if and only to the extent that, there are fixed or presently determinable future prices or costs to which the Corporation is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

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, 2009, 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, 2009
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)	MEDIUM CRUDE OIL @ Cromer (29 API, 2.0% S) ($Cdn/bbl)	EDMONTON PROPANE ($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 RATES[1] %/Year	EXCHANGE RATE[2] ($US/$Cdn)
Forecast										
2009	57.50	68.61	59.00	43.22	52.14	69.98	7.58	7.38	2%	0.825
2010	68.00	78.94	68.68	49.73	61.57	80.52	7.94	7.74	2%	0.850
2011	74.00	83.54	73.52	52.63	65.16	85.21	8.34	8.14	2%	0.875
2012	85.00	90.92	80.01	57.28	70.92	92.74	8.70	8.50	2%	0.925
2013	92.01	95.91	84.40	60.42	74.81	97.82	8.95	8.75	2%	0.950
2014	93.85	97.84	86.10	61.64	76.32	99.80	9.14	8.94	2%	0.950
2015	95.73	99.82	87.84	62.89	77.86	101.81	9.34	9.14	2%	0.950
2016	97.64	101.83	89.61	64.15	79.43	103.87	9.54	9.34	2%	0.950
2017	99.59	103.89	91.42	65.45	81.03	105.97	9.75	9.55	2%	0.950
2018	101.59	105.99	93.27	66.77	82.67	108.10	9.95	9.75	2%	0.950
2019	103.62	108.11	95.14	68.11	84.32	110.26	10.15	9.95	2%	0.950
There after	+2%	+2%	+2%	+2%	+2%	+2%	+2%	+2%	2%	0.950

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, 2008, were $8.37/mcf for natural gas, $74.89/bbl for crude oil and $62.32/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 Alberta government has announced, but not yet enacted, provisions that allow for transitional royalties ("**Transitional Royalties**") to the NRF for certain elected wells. For the purposes of the GLJ Report, Alberta Crown Royalties have been determined in accordance with the NRF. Reserves and net present values reflected in the above tables do not reflect the potential effect of Transitional Royalties and no sensitivities were provided by GLJ as to the potential impact of same.

8. On March 3, 2009 the Alberta government announced a 3-point incentive program to stimulate new and continued economic activity in Alberta which included a drilling royalty credit for new conventional oil and natural gas wells and a new well royalty incentive program. Reserves and net present values reflected in the above tables do not reflect the potential effect of this new program and no sensitivities were provided by GLJ as to the potential impact of same.

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, 2007	486	224	710	0	0	0	3,041	1,382	4,423
Discoveries	0	0	0	0	0	0	73	36	110
Extensions and Improved Recovery	348	479	827	181	40	221	865	1,072	1,937
Infill Drilling	0	0	0	120	30	150	0	0	0
Technical Revisions	204	(11)	194	34	9	43	287	(36)	251
Acquisitions	4,159	2,543	6,701	548	184	731	331	98	429
Dispositions	0	0	0	0	0	0	(3)	(2)	(5)
Economic Factors	5	8	13	0	0	0	(60)	(32)	(92)
Production	(422)	0	(422)	(86)	0	(86)	(531)	0	(531)
December 31, 2008	4,779	3,243	8,022	797	263	1,060	4,003	2,518	6,521

	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, 2007	106,462	47,164	153,626	7,630	8,121	15,751	22,542	10,821	33,363
Discoveries	3,960	1,869	5,829	0	0	0	733	348	1,081
Extensions and Improved Recovery	37,725	48,976	86,701	1,320	(607)	713	7,901	9,653	17,554
Infill Drilling	113	28	141	0	0	0	139	35	174
Technical Revisions	(3,880)	(9,472)	(13,352)	(365)	(230)	(595)	(181)	(1,656)	(1,837)
Acquisitions	23,631	6,940	30,571	245	60	305	9,017	3,990	13,007
Dispositions	(40)	(20)	(60)	0	0	0	(10)	(5)	(15)
Economic Factors	(797)	(338)	(1,135)	0	0	0	(188)	(80)	(268)
Production	(19,004)	0	(19,004)	(161)	0	(161)	(4,234)	0	(4,234)
December 31, 2008	148,170	95,148	243,317	8,669	7,344	16,013	35,719	23,106	58,825

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, 2008, 2007 and 2006 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 4.

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	0	0	0	0	3,585	3,585	1,327	1,327	143	143
2006	0	90	0	0	0	1,988	2,493	4,236	0	53
2007	0	0	0	0	1,796	2,595	2,537	5,899	58	78
2008	1,278	1,278	120	120	24,800	25,870	1,111	6,490	517	585

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	87	87	0	0	1,980	1,980	4,565	4,565	80	80
2006	25	134	0	0	3,391	5,767	2,679	8,806	151	258
2007	0	25	0	0	4,857	8,649	1,246	7,319	118	279
2008	2,108	2,133	30	30	40,127	47,006	1,726	6,710	848	1,238

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.

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 accelerated depletion));
- multi-zone developments (such as 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 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$)**	**Proved Plus Probable Reserves (M$)**
2009	38,843	59,269
2010	43,233	90,061
2011	9,660	14,771
2012	7,337	9,880
2013	1,027	1,002
Thereafter	8,157	16,725
Total Undiscounted	108,258	191,709

The Corporation currently expects that the capital listed in the preceding table will be funded through internally generated cash flows and will not have any associated funding costs. We do not expect that the costs of funding, if any, will have an 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, 2008. Production stated is production before deduction of royalties and includes royalty interests to Crew and, unless otherwise stated, is average production for 2008. 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, 2008 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, 2008.

Overview

Crew's operations are divided into two core areas, the 'North Core' which includes all operations in northeast British Columbia and northwest Alberta, and the 'Plains Core' which includes all operations in central Alberta. These core areas include five main operating areas: Ferrier, Edson and Princess in Alberta and Inga and Sierra in northeast British Columbia. Crew's 2008 operations focused on exploration and development of these main operating areas along with the acquisition of Gentry Resources Ltd.

Crew will continue the development of its main operating areas in 2009. The Corporation has currently budgeted approximately $70 million towards the continued growth and development of these core areas. This development will be the foundation upon which the Corporation will continue to grow its base production and will include the drilling of an estimated ten development wells in 2009.

In 2009, Crew plans to drill up to three exploration wells on the Corporation's undeveloped lands. These wells will expose the Corporation to opportunities that have the potential to significantly increase natural gas and light oil reserves and production. Currently the Corporation plans to direct between $8 million and $10 million of its 2009 drilling program toward these opportunities.

PLAINS CORE

Ferrier, Alberta

Ferrier is in the Corporation's Plains Core, located in central Alberta, approximately 80 kilometers west of Red Deer. At December 31, 2008, the Corporation had 40 (17.2 net) producing gas wells and 12 (7.9 net) producing oil wells in the area and in 2008 produced an average of 533 bbl/d of oil and ngls along with 8.8 Mmcf/d of natural gas. This area's production is mainly liquids rich natural gas production from the Ellerslie, Rock Creek and Nisku formations. In the western part of Ferrier, Crew has a 58% working interest in a gas plant and has an interest in two compression facilities. In eastern Ferrier, production is gathered and shipped to third party facilities.

Crew drilled 2 (1.3 net) wells in the Ferrier area in 2008 resulting in 2 (1.3 net) cased gas wells.

As at December 31, 2008 the GLJ Report showed Ferrier to have total reserves of 1,251 Mbbl of light oil and ngls and 18,078 Mmcf of natural gas. At year-end, the Corporation owned 79,289 net acres of land with an average working interest of 65% in this area.

Edson, Alberta

The Edson area is in west central Alberta, approximately 160 kilometers 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 and Jurassic sandstone formations. At December 31, 2008 the Corporation had 50 (40.5 net) producing gas wells and 5 (4.3 net) producing oil wells in the area. Production averaged 593 bbl/d of oil and ngls along with 14.6 Mmcf/d of natural gas in 2008. Crew owns facilities at Edson, Pine Creek, and Carrot Creek where a significant amount of the area’s gas production is gathered into these 100% owned facilities. Crew also has a 15% interest in a 90 Mmcf/d sour gas processing facility in the area. In 2008, Crew drilled 14 (13.0 net) wells in this area resulting in 14 (13.0 net) gas wells.

As at December 31, 2008, the GLJ Report showed the greater Edson area to have reserves of 1,752 Mbbl of oil and ngls and 52,496 Mmcf of natural gas. At year end, the Corporation owned 97,086 net acres of land with an average working interest of 76% in the area.

Princess, Alberta

The Princess area is on a 444 section controlled contiguous block of freehold 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 over 100 drilling locations identified. A third party reservoir simulation study conducted on two of Crew's Tilley oil pools estimated the ultimate recovery of oil to be approximately three times greater under waterflood compared to primary recovery. The Corporation has submitted a waterflood application for the Tilley oil pools to the ERCB. Princess was acquired as part of the the Gentry Acquisition on August 22, 2008 and, therefore, the production numbers are from August 22 to December 31, 2008 only. In 2008, production from this area averaged 1.6 Mmcf/d of natural gas and 695 bbl/d of oil and ngls. At December 31, 2008 the Corporation owned 11 (8.1 net) producing gas wells, 96 (95.4 net) producing oil wells and 12 (12 net) service wells in the area along with three 100% owned oil batteries. From August to December 2008, Crew drilled seven (7.0 net) wells in this area resulting in five (5.0 net) oil wells, one (1.0 net) service well and one (1.0 net) dry and abandoned well.

As at December 31, 2008, the GLJ Report showed the Princess area to have reserves of 6,788 Mbbl of oil and ngls and 7,718 Mmcf of natural gas. At year end, the Corporation owned 199,051 net acres of land with an average working interest of 89% in the area.

NORTH CORE

Inga, British Columbia

The greater Inga area includes Crew's operations situated near Fort St. John, British Columbia. At December 31, 2008 the Corporation had an interest in 102 (43.9 net) producing gas wells and 9 (5.3 net) producing oil wells in this area. The Corporation's operations at Inga include natural gas production from several Triassic and Cretaceous natural gas pools acquired as part of the Corporation's acquisition of Enco in May 2007. The Corporation drilled a total of 13 (11.4 net) wells in the greater Inga area in 2008. The Corporation owns an interest in sixteen natural gas facilities in the Inga area which compress and dehydrate natural gas production in preparation for delivery into the McMahon gas processing facility.

In addition, over the past year the Corporation has successfully accumulated control of a net 184 sections of land prospective for Triassic Montney natural gas in the greater Inga area. The Corporation to date has drilled or re-completed 12 wells targeting the Montney. Crew continues to concentrate its drilling efforts in the Septimus area experiencing exceptional results with wells testing at rates as high as 17.8 mmcf per day. Crew is currently producing at a restricted rate of seven mmcf per day from the Montney at Septimus and has an estimated seven to eight mmcf per day of additional production capacity. Based on Crew's evaluation of the economics of the Septimus play, rates of return are attractive at current gas prices with a $4.40 per gj price yielding a 25% to 35% rate of return and a recycle ratio of 1.6. With roads and pipelines already built, the economies of scale are expected to improve with well costs targeted to decrease to $4.5 million per well. Equipment has been ordered and applications have been submitted for approval to the British Columbia regulatory authorities for construction of a 25 mmcf per day natural gas processing facility. The gas plant has been designed to be expanded in stages with construction expected to start after spring breakup and commissioning currently planned for late in the third quarter. Current plans are to drill four to seven wells targeting the Montney in 2009 and evaluate the gas plant expansion in late 2009.

As at December 31, 2008, the GLJ Report showed Crew's greater Inga area to have total Proved plus Probable reserves of 3,600 Mbbl of oil and ngls along with 103,869 Mmcf of natural gas. At year end, the Corporation owned 160,721 net acres of land with an average working interest of 63% in this area.

Crew engaged GLJ to prepare a best estimate of the Discovered Petroleum Initially in Place ("DPIP"), as such term is defined in the COGE Handbook, on 52 (50 net) sections of Crew's Montney lands at Septimus in the Inga area. GLJ's report is dated February 24, 2009 and has an effective date of November 30, 2008. Unless noted otherwise, the DPIP estimates and reserve information are presented on a company interest basis.

Based on the independent evaluation by GLJ, it is estimated that the DPIP for 50 net sections of Montney rights owned in Crew's Septimus area is a net 2.4 Tcf, of which 0.72 Tcf is on sections to which reserves have been assigned. In the GLJ Report, GLJ have assigned proved plus probable non-associated gas reserves of 81.5 bcf to the Septimus area, which includes 35 bcf of proved reserves. The assigned proved reserves are booked based on three wells per section and will require an additional 11 wells to be drilled with future development capital of $58.36

million including the completion and tie in of two additional wells. This reserve assignment represents a 5.2% recovery on proved reserves and a 12.1% recovery on proved plus probable reserves.

GLJ has estimated that there exists 1.7 Tcf of DPIP (of the 2.4 Tcf in total DPIP) on sections of Crew's lands at Septimus that do not currently have any reserves assigned in the GLJ Report and that there are additional Crew interest lands adjacent to these lands that have not yet been assigned any DPIP. Continued step-out drilling into the future will provide information to help assess the potential of these lands.

GLJ has provided a best estimate of the DPIP for the upper Montney on 50 out of 184 controlled net sections or 27% of Crew's prospective Montney land base. It should be noted that, given the current early stage of development, the best estimate of DPIP might change significantly in the future with further development activity and the amount of Contingent Resources as defined in the COGE Handbook has yet to be estimated. Crew is in the early stages of development of this Montney asset. Additional drilling and testing is required to confirm deliverability potential and commercial economic development. The resource estimates provided herein are estimates only and the actual resources may be greater than or less than the estimates provided herein. A recovery project cannot be defined for these volumes of DPIP at this time. There is no certainty that it will be commercially viable or technically feasible to produce any portion of this natural gas currently classified as DPIP.

Sierra, British Columbia

The greater Sierra area includes Crew's operations situated near Fort Nelson, British Columbia. At December 31, 2008, the Corporation had an interest in 13 (7.3 net) producing gas wells in this area. In 2008, Crew produced an average of 8.4 Mmcf/d of natural gas from the Sierra area. Natural gas production from this area comes predominantly from a Pine Point natural gas well. Production from this well is tied into a Crew owned compression facility that compresses the gas for delivery to the Fort Nelson natural gas processing facility. Natural gas production from this well has a level of H2S which yields a large sulphur recovery upon processing. Improved sulphur pricing during 2008 resulted in Crew generating net revenue from sulphur recovered during the year.

Crew lands in the Sierra area include 15 net sections of land that have been identified as prospective for the Horn River Basin's Muskwa Shale natural gas resource play. The Muskwa Shale is approximately 500 feet thick and appears to be prospective over a large area in a relatively homogeneous geologic environmentc environment. Crew does not have any drilling plans for the Muskwa Shales in 2009. The Corporation continues to monitor the evolution of this prospect and gain knowledge that will aid in the future development of Crew's lands.

As at December 31, 2008, the GLJ Report showed Sierra to have total reserves of 22,144 Mmcf of natural gas. At year end, the Corporation owned 22,063 net acres of land with an average working interest of 57% in this area.

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, 2008.

	Oil Wells				**Natural Gas Wells**			
	Producing		**Non-Producing**		**Producing**		**Non-Producing**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Alberta	176	131.3	316	183.3	477	248.0	205	146.1
British Columbia	8	4.3	4	3.5	92	43.3	52	16.4
Saskatchewan	112	15.0	-	-	-	-	-	-
Total	296	150.6	320	186.8	569	291.3	257	162.5

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, 2008.

	Developed Acres		Undeveloped Acres	
	Gross	**Net**	**Gross**	**Net**
Alberta	419,645	228,063	514,071	433,960
British Columbia	108,497	47,520	213,969	155,010
Other Canada	6,601	2,440	377,599	37,891
Total	534,743	278,023	1,105,639	626,861

The Corporation has a commitment to complete a 3D seismic program and drill two wells in northeastern British Columbia in 2009. The Corporation estimates that the total cost for this commitment is $9.1 million. Of the Corporation's undeveloped land, the rights to explore, develop and exploit 59,882 net acres may expire by December 31, 2009 if the Corporation takes no action to retain the land. Crew plans to drill or submit applications to continue selected portions of this acreage.

Forward Contracts and Marketing

Except as described below, the Corporation does not have any material commitments to buy or sell natural gas or crude oil production.

	Volume (GJ/d)	**Term**	**Index**	**Floor (Cdn $/GJ)**	**Ceiling (Cdn $/GJ)**
AECO	2,500	January 1, 2009 – December 31, 2009	AECO C Monthly Index less $0.09	6.50	8.30
AECO	2,500	January 1, 2009 – December 31, 2009	AECO C Monthly Index	6.60	8.50

	Volume (GJ/d)	**Term**	**Index**	**Put (Cdn $/GJ)**	**Call (Cdn $/GJ)**
AECO	15,000	April 1, 2009 – October 31, 2009	AECO C Monthly Index	6.00	
AECO	5,000	January 1, 2010 – December 31, 2010	AECO C Monthly Index		8.00
AECO	10,000	January 1, 2010 – December 31, 2010	AECO C Monthly Index		7.75

	Volume	**Term**	**Index**	**Fixed Price (Cdn $)**
WTI	250 bbl/d	January 1, 2010 – December 31, 2010	Nymex Cdn $ WTI Calendar Average	$78.50/bbl
AECO	2,500 GJ/d	January 1, 2010 – December 31, 2010	AECO C Monthly Index	$6.20/GJ

A portion of the Corporation's natural gas reserves in central Alberta was committed to aggregator sales contracts. Previous owners of these properties had committed to these contracts. The sales contracts were dedicated to specific reserves and extend for the life of the reserves. In 2008, approximately 2.3 Mmcf/d of the Corporation's total natural gas sales were sold to aggregators. As of January 1, 2009, these aggregator contracts were collapsed at no cost to the Corporation resulting in no further obligation to Crew.

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, 2008, management expected to incur abandonment and reclamation costs on 791.2 net wells. The total of such costs, net of estimated salvage value, was $29.1 million ($15.7 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 $38.5 million ($13.8 million discounted at 10%) and salvage values of $38.5 million ($7.9 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 will total approximately $2.6 million ($2.0 million discounted at 10%).

Tax Horizon

The Corporation was not required to pay any cash income taxes for the period ended December 31, 2008. 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 until 2011 or later.

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, 2008:

	($ thousands)
Property acquisition costs	
Proved properties	6,822
Undeveloped properties	88,909
Exploration costs	39,128
Development costs	127,232
Corporate acquisition - Gentry	283,731
Total	545,822

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, 2008. This table does not include wells drilled in Gentry prior to its acquisition on August 22, 2008:

	Gross			**Net**		
	Exploration	**Development**	**Total**	**Exploration**	**Development**	**Total**
Crude Oil	4	5	9	4.0	5.0	9.0
Natural Gas	16	25	41	14.0	17.3	31.3
Dry(1)	-	2	2	-	2.0	2.0
Service(2)	-	1	1	-	1.0	1.0
Total:	20	33	53	18.0	25.3	43.3

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.

The Corporation intends to continue to develop its principal properties in central Alberta and northeastern British Columbia. The Corporation is currently budgeting for an $80 million exploration and development expenditure program in 2009, which is currently planned to be financed through cash flow from operations. See "*Principal Properties*" for a description of the Corporation's exploration and development plans.

Production Estimates

The following table sets out the volume of the Corporation's average estimated daily production for the year ended December 31, 2009 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(2)		**HEAVY OIL(2)**		**NATURAL GAS LIQUIDS**		**NATURAL GAS(3)**		**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 (Boe/d)**	**Net (Boe/d)**
Total Proved										
Princess	2,066	1,494	369	284	28	20	4,434	3,173	3,202	2,326
Other Properties	668	552	202	159	1,530	1,101	58,964	45,309	12,228	9,363
	2,734	2,046	571	443	1,558	1,121	63,398	48,482	15,430	11,689
Total Proved plus probable										
Princess	2,165	1,562	382	293	29	20	4,552	3,253	3,334	2,417
Other Properties	691	567	207	161	1,635	1,197	62,317	47,899	12,919	9,908
	2,856	2,128	588	454	1,664	1,217	66,869	51,152	16,253	12,325

Notes:

(1) The Corporation's Princess field is the only field that has greater than 20% or more of the Corporation's estimated 2009 production in the December 31, 2008 GLJ Report.

(2) For the year ended December 31, 2008 all of the Corporation's oil production was classified as light and medium oil. As result of changes implemented under the NRF regarding its classification of heavy oil for royalty purposes, as of January 1, 2009 approximately 12% of the Corporation's 2008 oil production would now be classified as heavy oil.

(3) Estimated 2009 average daily natural gas production includes coal bed methane production of 1% or less in each reserve category.

Production History

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

	Quarter Ended 2008			
	Dec. 31	**Sept. 30**	**June 30**	**Mar. 31**
Average Daily Production[1]				
Light and Medium Crude Oil (bbl/d) [5]	3,123	1,515	531	384
Natural Gas (Mcf/d)[3]	60,464	52,523	45,599	51,707
NGLs (bbl/d)	1,669	1,236	1,314	1,612
Combined (BOE/d)	14,869	11,505	9,445	10,614
Average Price Received				
Light and Medium Crude Oil ($/bbl) [4]	50.21	104.68	120.17	96.40
Natural Gas ($/Mcf)[3] [4]	6.93	8.30	10.60	8.19
NGLs ($/bbl)	37.24	76.93	77.83	64.59
Combined ($/BOE) [4]	42.99	61.74	70.18	53.20
Transportation Expenses				
Light and Medium Crude Oil ($/bbl)	1.53	2.18	2.71	3.09
Natural Gas ($/Mcf)[3]	0.39	0.42	0.43	0.42
NGLs ($/bbl)	0.04	0.02	0.04	0.03
Combined ($/BOE)	1.91	2.20	2.23	2.14
Royalties Paid				
Light and Medium Crude Oil ($/bbl)	15.32	16.48	17.68	12.47
Natural Gas ($/Mcf)[3]	1.08	1.93	2.24	1.84
NGLs ($/bbl)	11.37	18.47	23.17	17.82
Combined ($/BOE)	8.80	13.38	15.30	11.00
Operating Expenses				
Light and Medium Crude Oil ($/bbl)	12.86	12.96	9.07	8.69
Natural Gas ($/Mcf)[3]	1.61	1.57	1.27	1.18
NGLs ($/bbl)	8.58	8.51	7.00	5.67
Combined ($/BOE)	10.20	9.79	7.60	6.91
Netback Received [2]				
Light and Medium Crude Oil ($/bbl)	20.50	73.06	90.71	72.15
Natural Gas ($/Mcf)[3]	3.85	4.38	6.66	4.98
NGLs ($/bbl)	17.25	49.93	47.62	41.06
Combined ($/BOE)	22.08	36.37	45.05	33.15

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 daily coal bed methane production in 2008 was less than 1% of the total natural gas production and, therefore, was not considered material.
(4) Average price received does not include the impact of the Corporation's realized gains and losses on financial instruments.
(5) For the year ended December 31, 2008, all of the Corporation's oil production was classified as light and medium oil. As result of changes implemented under NRF regarding its classification of heavy oil for royalty purposes, as of January 1, 2009, approximately 12% of the Corporation's 2008 oil production would now be classified as heavy oil.

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, 2008:

	Light and Medium Crude Oil[(1)] (bbl/d)	Natural Gas[(2)] (Mcf/d)	NGLS (bbl/d)	Oil Equivalent (BOE/d)
Edson	124	14,588	469	3,024
Ferrier	149	8,825	384	2,004
Princess	691	1,571	4	957
Other	223	11,987	138	2,358
Total Alberta	1,187	36,971	995	8,343
Inga	206	7,260	463	1,880
Greater Sierra	-	8,364	-	1,394
Total British Columbia	206	15,624	463	3,274
Total	1,393	52,595	1,458	11,617

Notes:

(1) For the year ended December 31, 2008, all of the Corporation's oil production was classified as light and medium oil. As result of changes implemented under the NRF regarding its classification of heavy oil for royalty purposes, as of January 1, 2009, approximately 12% of the Corporation's 2008 oil production would now be classified as heavy oil.

(2) Average daily coal bed methane production in 2008 was less than 1% of the total natural gas production and, therefore, was not considered material.

For the year ended December 31, 2008, approximately 30% of Crew's gross revenue was derived from crude oil and natural gas liquids production, 68% was derived from natural gas production and 2% was derived from sulphur 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 conditions 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 the price range and trading volume of the Common Shares on the TSX (as reported by the TSX) for the periods indicated.

	Price Range		
	High	**Low**	**Volume**
2008			
January	9.38	6.76	7,838,884
February	12.59	8.75	9,938,779
March	13.70	11.18	8,509,231
April	15.25	12.76	12,822,937
May	17.02	13.74	10,653,796
June	19.94	15.68	17,914,448
July	19.40	13.96	14,997,635
August	15.20	11.67	9,709,549
September	14.42	9.24	10,798,998
October	10.15	4.81	18,580,943
November	7.95	3.52	13,680,054
December	5.53	4.10	12,127,503
2009			
January	6.15	3.32	9,781,245
February	4.20	2.38	13,333,989
March (1-27)	5.00	2.60	13,792,576

ESCROWED SECURITIES

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

DIRECTORS AND OFFICERS

The names, province and country of residence, positions with the Corporation and principal occupation of the directors and officers of the Corporation 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	Principal Occupation	Director Since
John A. Brussa(2)(3)(4)(8) Alberta, Canada Age: 52	Chairman	Partner, Burnet, Duckworth & Palmer LLP (a law firm).	September, 2003
Jeffery E. Errico(1)(2)(3) Alberta, Canada Age: 58	Director	Chairman of Insignia Energy Ltd., a public energy company since 2007; prior thereto President and Chief Executive Officer of Petro Fund Corp. from 2003 to June 2007; prior thereto, various executive officer positions with NCE Resources Group since 1995.	September, 2008
Dennis L. Nerland(1)(3)(4)(7) Alberta, Canada Age: 56	Director	Partner, Shea Nerland Calnan (a law firm).	September, 2003
David G. Smith(1)(2)(4) Alberta, Canada Age: 51	Director	Executive Vice President, Liquids Business Unit, 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.	January, 2009
Dale O. Shwed(6) Alberta, Canada Age: 50	President, Chief Executive Officer and Director	President and Chief Executive Officer of the Corporation since June, 2003; prior thereto President and Chief Executive Officer of Baytex.	June, 2003
John A. Thomson, CA(9) Alberta, Canada Age: 59	Director	Independent businessman since 2001; prior thereto Vice President of Avid Oil & Gas Ltd. from 2000 and as Director of the same from 1999; prior thereto Senior Vice President and Chief Financial Officer of Renaissance Energy Ltd.	September, 2006
John G. Leach, CA Alberta, Canada Age: 44	Senior Vice-President and Chief Financial Officer	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.	N/A

Name, Age, Province and Country of Residence	Office Held	Principal Occupation	Director Since
Gary Smith Alberta, Canada Age: 50	Vice-President, Exploration	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.	N/A
Ken Truscott Alberta, Canada Age: 50	Senior Vice-President, Business Development and Land	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.	N/A
Dean Tucker Alberta, Canada Age: 47	Vice-President, Production & Operations	Vice-President, Production & Operations since March, 2009; prior thereto, Vice-President, Operations of Pearl Exploration and Development since March, 2008; prior thereto, Vice President, Canadian Business Unit, Pearl Exploration and Development since August, 2007; prior thereto, Vice-President, Operations of Real Resources Inc.	N/A
Shawn A. Van Spankeren Alberta, Canada Age: 36	Vice-President, Finance and Controller	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.	N/A
Michael D. Sandrelli Alberta, Canada Age: 40	Corporate Secretary	Partner, Burnet, Duckworth & Palmer LLP (a law firm).	N/A

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.
(6) Mr. Shwed was a director of Echelon Energy Inc., a private company incorporated under the ABCA. In September 1999, a receiver-manager was appointed over the assets of Echelon.
(7) Mr. Nerland was a director of Samsports.com Inc., a public company incorporated under the ABCA. In April 2001, a receiver-manager was appointed over the assets of Samsports.

(8) Mr. Brussa was a director of Imperial Metals Limited, a corporation engaged in both oil and gas and mining operations, in the year prior to that corporation implementing a plan of arrangement under the *Company Act* (British Columbia) and under the *Companies' Creditors Arrangement Act* (Canada) which resulted in the separation of its two businesses and the creation of two public corporations: Imperial Metals Corporation and IEI Energy Inc. (now Rider Resources Ltd.). The plan of arrangement was completed in April 2002.

(9) Mr. Thomson served as Chair of the Audit Committee for the year ended December 31, 2008. Mr. Smith replaced Mr. Thomson as Chair of the Audit Committee on March 9, 2009.

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, 2008, the directors and officers of Crew, as a group, beneficially owned, directly or indirectly, 4,520,025 Common Shares or approximately 6% 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, our 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 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 Executive Vice President, Liquids Business Unit with Keyera Facilities Income Fund, a public energy infrastructure company. Prior to that he was Chief Financial Officer and Corporate Secretary of Keyera Facilities Income Fund and its predecessor companies from June 1998 until November 2008. 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.

Name	Independent	Financially Literate	Relevant Education and Experience
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 2007. 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 us and our subsidiaries for professional services rendered by KPMG LLP, our external auditors, during fiscal 2008 and 2007:

	Aggregate fees billed	
	2008	2007
Audit fees	159,000	130,000
Audit-related fees	81,500	92,000
Tax fees	18,350	66,205
All other fees	-	-
	258,850	288,205

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

Audit-Related Fees. Audit-related services including audit and review of certain subsidiaries and financial aspects of Crew and its subsidiary and partnership.

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

All Other Fees. Other services provided by our external auditor other than audit, audit-related and tax services.

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

HUMAN RESOURCES

Crew currently employs 70 full-time employees, of which 65 are located in the head office and 5 are field employees, and 3 part-time consultants. Crew intends to add additional professional and administrative staff as the need arises.

INDUSTRY CONDITIONS

The oil and natural gas industry is subject to extensive controls and regulations governing its operations (including land tenure, exploration, development, production, refining, transportation, and marketing) imposed by legislation enacted by various levels of government and with respect to pricing and taxation of oil and natural gas by 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 controls or regulations will affect the Corporation's operations in a manner materially different than they would affect other oil and 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.

Pricing and Marketing - Oil and Natural Gas

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 the markets, the value of refined products, the supply/demand balance, and other contractual terms. 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 and the issuance of such licence requires a public hearing and the approval of the Governor in Council.

The price of natural gas is determined by 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 a larger quantity requires an exporter to obtain an export licence from the NEB and the issuance of such licence requires a public hearing and the approval of the Governor in Council.

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.

Pipeline Capacity

Although pipeline expansions are ongoing, the lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to produce and to market natural gas production. In addition, the pro-rationing of capacity on the inter-provincial pipeline systems also continues to affect the ability to export oil and natural gas.

The North American Free Trade Agreement

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, United States of America, and Mexico became effective on January 1, 1994. NAFTA carries forward most of the material energy terms that are contained in the Canada United States Free Trade Agreement. 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 domestic use (based upon 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 voluntary measures which only restrict the volume of exports; and (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum or maximum export or import price requirements, provided, in the case of export price requirements, any prohibition in any circumstances in which any other form of quantitative restriction is prohibited, and in the case of import-price requirements, such requirements do not apply with respect to enforcement of countervailing and anti-dumping orders and undertakings.

NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector by 2010 and prohibits discriminatory border restrictions and export taxes. NAFTA also contemplates clearer disciplines on regulators to ensure fair implementation of any regulatory changes and to minimize disruption of contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, which is important for Canadian natural gas exports.

Provincial Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations which govern land tenure, royalties, production rates, environmental protection, and other matters. The royalty regime is a significant factor in the profitability of 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. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the 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, and tax credits, and are generally introduced when commodity prices are low. The programs are designed to encourage exploration and development activity by improving earnings and cash flow within the industry. Royalty holidays and reductions would reduce the amount of Crown royalties paid by oil and gas producers to the provincial governments and would increase the net income and funds from operations of such producers. However, the trend in recent years has been for provincial governments to eliminate, amend or allow such incentive programs to expire without renewal, and consequently few such incentive programs are currently operative.

The Canadian federal corporate income tax rate levied on taxable income is 19.5% effective January 1, 2008 for active business income including resource income. With the elimination of the corporate surtax effective January 1, 2008 and other rate reductions introduced in the October 2007 Economic Statement and Notice of Ways and Means Motion, 2006 Federal Budget, the federal corporate income tax rate will decrease to 15% in four additional steps: 19% on January 1, 2009, 18% on January 1, 2010, 16.5% on January 1, 2011 and 15% on January 1, 2012.

Alberta

In Alberta, companies are granted the right to explore, produce and develop petroleum and natural gas resources in exchange for royalties, bonus bid payments and rents. On October 25, 2007, the Government of Alberta released a report entitled "The New Royalty Framework" (the "**NRF**") containing the Government's proposals for Alberta's new royalty regime, which was followed by the Mines and Minerals (New Royalty Framework) Amendment Act, 2008, which was given Royal Assent on December 2, 2008. The NRF and the applicable new legislation became effective on January 1, 2009. Prior to the NRF, the amount of royalties that were payable was influenced by the oil production, density of the oil, and the vintage of the oil. Originally, the vintage classified oil was "new oil" and "old oil" depending on when the oil pools were discovered. If the pool was discovered prior to March 31, 1974 it was considered "old oil", if it was discovered after March 31, 1974 and before September 1, 1992, it was considered "new oil". The Alberta Government introduced in 1992 a Third Tier Royalty with a base rate of 10% and a rate cap of 25% for oil pools discovered after September 1, 1992. The new oil royalty reserved to the Crown had a base rate of 10% and a rate cap of 30%. The old oil royalty reserved to the Crown had a base rate of 10% and a rate cap of 35%. The NRF eliminates this classification and establishes new royalty rates for conventional oil, natural gas and oil sands. The new royalty rates for conventional oil are set by a single sliding rate formula which is applied monthly and increases the old royalty from 30% to 35% applied to the old and new tiers, to up to 50% and with rate caps once the price of conventional oil reaches $120 per barrel. The sliding rate formula includes in its calculation the price of oil and well production.

With respect to natural gas, and similar to the conventional oil framework, the royalties outlined in the NRF are set by a single sliding rate formula ranging from 5% to 50% with a rate cap once the price of natural gas reaches $16.59/GJ. Prior to the NRF, the royalty reserved to the Crown in respect of natural gas production, subject to various incentives, was between 15% and 30%, in the case of new natural gas, and between 15% and 35%, in the case of old natural gas, depending upon a prescribed or corporate average reference price. In response to the drop in commodity prices experienced during the second half of 2008, the Government of Alberta announced on November 19, 2008, the introduction of a five year program of transitional royalty rates with the intent of promoting new drilling. Under this new program companies drilling new natural gas or conventional oil deep wells (between 1,000 and 3,500 metres) will be given a one-time option, on a well by well basis, to adopt either the new transitional royalty rates or those outlined in the NRF. In order to qualify for this program wells must be drilled during the period starting on November 19, 2008 and ending on December 31, 2013. Following this period all new wells drilled will automatically be subject to the NRF.

On April 10, 2008, the Government of Alberta introduced two new royalty programs that will encourage the development of deep oil and gas reserves, and these are: (a) a five-year oil program for exploration wells over 2,000 metres that will provide royalty adjustments to offset higher drilling costs and provide a greater incentive for producers to continue to pursue new, deeper oil plays (these oil wells will qualify for up to a $1 million or 12 months of royalty offsets, whichever comes first); and (b) a five-year natural gas deep drilling program that will replace the existing program in order to encourage continued deep gas exploration for wells deeper than 2,500 metres (the program will create a sliding scale of royalty credit according to depth, of up to $3,750 per metre). These new programs were implemented along with the NRF.

Regulations made pursuant to the *Mines and Minerals Act* (Alberta) provided various incentives for exploring and developing oil reserves in Alberta. However, the Alberta Government announced in August of 2006 that four royalty programs were to be amended, a new program was to be introduced and the Alberta Royalty Tax Credit Program was to be eliminated, effective January 1, 2007. The programs affected by this announcement were: (i) Deep Gas Royalty Holiday; (ii) Low Productivity Well Royalty Reduction; (iii) Reactivated Well Royalty Exemption; and (iv) Horizontal Re-Entry Royalty Reduction. The program introduced was the Innovative Energy Technologies Program (the "**IETP**") which has a stated objective of promoting the producers' investment in research, technology and innovation for the purposes of improving environmental performance while creating commercial value. The IETP provides royalty reductions which are presumed to reduce financial risk. Alberta Energy decides which projects qualify and the level of support that will be provided. The deadline for the IETP's final round of applications was September 20, 2008. The successful applicants for the first two rounds have been announced, and those for the third round selection are scheduled to be announced in the first half of 2009. The technical information gathered from this program is to be made public once a two-year confidentiality period expires.

The NRF includes a policy of "shallow rights reversion". The Government of Alberta started to implement this policy on January 1, 2009, and its intent is to maximize the development of currently undeveloped resources that is consistent with the Government of Alberta's objective of maximizing recovery of known gas resources, while increasing royalty revenues. The policy's stated objective is for the mineral rights to shallow gas geological formations that are not being developed to revert back to the Government and be made available for resale, and in the event of non-productive shallow wells, to sever the rights from shallow zones and encourage increased production from up-hole zones. The shallow rights reversion policy affects all petroleum and natural gas agreements; however, the timing of the reversion will differ depending on whether the leases and licenses were acquired prior to January 1, 2009 or subsequent to January 1, 2009. Leases granted after January 1, 2009 will be subject to shallow rights reversion at the expiry of the primary term, and in the event of a licence the policy will apply at the expiry of the intermediate term. 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. The lease or licence holder can make a request to extend this period. The order in which these agreements will receive the reversion notice will depend on the vintage of their term, with the older leases and licenses receiving a reversion notice first. Leases or licences that were granted prior January 1, 2009 but have not yet been continued will have a grace period until they are continued under section 15 of the *P&G Tenure Regulation* and be subject to deeper rights reversion prior to receiving a shallow rights reversion notice.

On March 3, 2009, the Government of Alberta announced a three-point incentive program to stimulate new and continued economic activity in Alberta which included a drilling royalty credit for new conventional oil and natural gas wells and a new well royalty incentive program. Under the drilling royalty credit program a $200 per meter royalty credit will be available on new conventional oil and natural gas wells drilled between April 1, 2009 and March 31, 2010, subject to certain maximum amounts. The maximum credits available will be determined by the company's production level in 2008 and its drilling activity between April 1, 2009 and March 31, 2010. The new well incentive program will apply to wells beginning production of conventional oil and natural gas between April 1, 2009 and March 31, 2010 and provides for a maximum 5% royalty rate for the first 12 months of production, up to a maximum of 50,000 barrels or 500 Mmcf of natural gas.

The three-point incentive program also includes an investment of $30,000,000 by the Government of Alberta in abandonment and reclamation projects for orphan wells. The stated objective of this investment is to encourage the cleanup of inactive oil and gas wells and to stimulate new activity within the services sector.

British Columbia

Producers of oil and natural gas in British Columbia are required to pay annual rental payments with respect to the Crown leases and royalties and freehold production taxes in respect of oil and gas produced from Crown and freehold lands. The amount payable as a royalty in respect of oil depends on the type of oil, the value of the oil, the quantity of oil produced in a month, and the vintage of the oil. Generally, 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 rates are calculated in three stages, which take into account the vintage of the oil, if the oil produced has already been sold and any royalty exempt value applicable (exempt wells). Oil produced from newly discovered pools may be exempt from the payment of a royalty for the first 36 months of production or $11{,}450m^3$ produced, whichever comes first; and the royalties for third-tier oil are the lowest reflecting the higher costs of exploration and extraction that the producers would incur. The royalty payable on natural gas is determined by a sliding scale based on a reference price, which is the greater of the price obtained by the producer, and a prescribed minimum price. However, when the reference price is below the select price (a parameter used in the royalty rate formula), the royalty rate is fixed. As an incentive for the production and marketing of natural gas, which may have been flared, natural gas produced in association with oil has a lower royalty then the royalty payable on non-conservation gas.

On May 30, 2003, the Ministry of Energy and Mines for British Columbia announced an Oil and Gas Development Strategy for the Heartlands ("**Strategy**"). The Strategy is a comprehensive program to address road infrastructure, targeted royalties and regulatory reduction, and British Columbia service sector opportunities. In addition, the Strategy will result in economic and employment opportunities for communities in British Columbia's heartlands.

Some of the financial incentives in the Strategy include:

- Royalty credits towards the construction, upgrading, and maintenance of road infrastructure in support of resource exploration and development. Funding will be contingent upon an equal contribution from industry. This program has evolved over past years as a result of the Province's stated objective to increase competitiveness, and on March 2, 2009 the Government of British Columbia announced the 2009 Infrastructure Royalty Credit Program ("**Program**") which allocates $120 million in royalty credits for oil and gas companies. The Program provides access to royalty credits to oil and gas companies with respect to certain approved road construction or pipeline infrastructure projects intended to improve, or make possible, the access to new and underdeveloped oil and gas areas. Companies must apply to the Ministry of Energy and Mines for British Columbia prior to 2:00 p.m. on April 30, 2009 to be considered for approval under the program.

- Changes to provincial royalties: new royalty rates for low productivity natural gas to enhance marginally economic resources plays, royalty credits for deep gas exploration to locate new sources of natural gas, and royalty credits for summer drilling to expand the drilling season.

The British Columbia Energy Plan announced on February 27, 2007 outlines the requirements for the development of goals for conservation, energy efficiency and clean energy. In addition, its stated goal is to promote competitiveness through the implementation of a Net Profit Royalty Program ("**NPRP**") among others, and facilitate the development of the oil and gas industry. The NPRP's objective is to share the capital risk of successful developments. Pursuant to the Net Profit Royalty Regulation, the holder of a lease can apply to pay monthly net profit royalties on production of oil and for natural gas wells within a proposed project. The amount paid is calculated on the producer's interest in the project, and it ranges from 2% to 5% of the gross revenue and 15% to 35% of the net revenues received. In addition, it depends at which stage the well is, which may be either pre-payout, after-payout or already producing marketable gas.

The Government of British Columbia has introduced a few more royalty programs, in addition to the ones previously mentioned, including a royalty program for deep discovery wells, royalty programs with a stated goal of attracting investment to less productive shallow gas wells (Ultra-Marginal Royalty Program), and the implementation of royalty credits to assist the development of the coalbed gas reserves found in the Province of British Columbia.

Saskatchewan

In Saskatchewan, the amount payable as a royalty in respect of oil depends on the vintage of the oil, the type of oil, the quantity of oil produced in a month, and the value of the oil. For Crown royalty and freehold production tax purposes, crude oil is considered "heavy oil", "southwest designated oil", or "non-heavy oil other than southwest designated oil". The conventional royalty and production tax classifications ("fourth tier oil" introduced October 1, 2002, "third tier oil", "new oil" and "old oil") of oil production are applicable to each of the three crude oil types. The Crown royalty and freehold production tax structure for crude oil is price sensitive and varies between the base royalty rates of 5% for all "fourth tier oil" to 20% for "old oil". Marginal royalty rates are 30% for all "fourth tier oil" to 45% for "old oil".

The amount payable as a royalty in respect of natural gas is determined by a sliding scale based on a reference price (which is the greater of the amount obtained by the producer and a prescribed minimum price), the quantity produced in a given month, the type of natural gas, and the vintage of the natural gas. 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. The royalty and production tax classifications of gas production are "fourth tier gas" introduced October 1, 2002, "third tier gas", "new gas", and "old gas". The Crown royalty and freehold production tax for gas is price sensitive and varies between the base royalty rate of 5% for "fourth tier gas" and 20% for "old gas". The marginal royalty rates are between 30% for "fourth tier gas" and 45% for "old gas".

On October 1, 2002, the following changes were made to the royalty and tax regime in Saskatchewan:

- A new Crown royalty and freehold production tax regime applicable to associated natural gas (gas produced from oil wells) that is gathered for use or sale and is produced from: (a) oil wells with a finished drilling date on or after October 1, 2002, and (b) 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 cubic metres of gas for every cubic metre of oil. The royalty/tax will be payable on associated natural gas produced from an oil well that exceeds approximately 65,000 cubic metres in a month. The associated natural gas royalty/tax regime will apply to gas produced from oil wells affected by concurrent production approvals after October 1, 2002 if the oil wells meet (a) or (b) above.

- A modified system of incentive volumes and maximum royalty/tax rates applicable to the initial production from oil wells and gas wells with a finished drilling date on or after October 1, 2002, was introduced. The incentive volumes are applicable to various well types and are subject to a maximum royalty rate of 2.5% and a freehold production tax rate of zero per cent.

- The elimination of the re-entry and short section horizontal oil well royalty/tax categories. All horizontal oil wells with a finished drilling date on or after October 1, 2002, will receive the "fourth tier" royalty/ tax rates and new incentive volumes.

- A horizontal oil well, with a finished drilling date on or after October 1, 2002, that is a non-deep oil well qualifies for a 6,000 cubic metre incentive volume.

- A horizontal oil well, with a finished drilling date on or after October 1, 2002, that is a deep oil well qualifies for a 16,000 cubic metre incentive volume.

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.

On June 19, 2007, the Government of Saskatchewan introduced the Orphan Well and Facility Liability Management Program pursuant to the amendment of the Oil and Gas Conservation *Act* and the *Oil and Gas Conservation Regulations*, 1985. The program includes a security deposit, which has two purposes: (i) preventing any person with insufficient financial capability from acquiring oil and gas wells or facilities; and (ii) in the case of a bankrupt company, the funds cover the decommissioning and reclaiming of orphan properties. An additional change introduced is the mandatory licensing of all upstream oil and gas facilities in Saskatchewan.

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 from two years, 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.

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation. 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. 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.

Environmental legislation in Alberta has been consolidated into the *Environmental Protection and Enhancement Act* (Alberta) (the "**EPEA**"), which came into force on September 1, 1993, and the *Oil and Gas Conservation Act*

(Alberta) (the "**OGCA**"). The EPEA and OGCA impose stricter environmental standards, require more stringent compliance, reporting and monitoring obligations, and significantly increased penalties in comparison with historical legislation. In 2006, the Alberta Government enacted regulations pursuant to the EPEA to specifically target sulphur oxide and nitrous oxide emissions from industrial operations including the oil and gas industry. In addition, the emission reduction guidelines outlined in the *Climate Change and Emissions Management Amendment Act* came into effect on July 1, 2007 ("**CCEMAA**"). Under this legislation, Alberta facilities emitting more than 100,000 tonnes of greenhouse gases a year must reduce their emissions intensity by 12%. Industries have three options to choose from in order to meet the reduction requirements outlined in this legislation, and these are: (i) by making improvement to operations that result in reductions; (ii) by purchasing emission credits from other sectors or facilities that have emissions below the 100,000 tonne threshold and are voluntarily reducing their emission; or (iii) by contributing to the Climate Change and Emissions Management Fund (the "**Fund**"). Industries can either choose one of these options or a combination thereof. Pursuant to CCEMAA and the *Specified Gas Emitters Regulation*, companies were obliged to reduce their emission intensity by 12% by March 31, 2008. Alberta industries have achieved 2.6 million tonnes of actual reduction, due to changes in operations and investing on verified offset projects. In addition, certain companies contributed $40 million to the Fund. It is reasonably likely that the trend towards stricter standards in environmental legislation and regulation will continue.

On January 24, 2008, the Alberta Government announced a new climate change action plan that will cut Alberta's projected 400 million tonnes of emissions in half by 2050. This plan is based on three areas: (i) carbon capture and storage, which will be mandatory for *in situ* oil sand facilities that use heavy fuels for steam generation; (ii) energy conservation and efficiency; and (iii) greening production through increased investment in clean energy technology, including supporting research on new oil sands extraction processes, as well as the funding of projects that reduce the cost of separating carbon dioxide from other emissions supporting carbon capture and storage. In addition to this action plan, the Provincial Energy Strategy unveiled on December 11, 2008 is expected to, among other things, support the upgrading, refining and petrochemical clusters existing in the Province, market Alberta's energy internationally, review the emission targets and carbon charges applied to large facilities, and promote the innovation of energy technology by encouraging investment in research and development.

British Columbia's Environmental Assessment Act became effective June 30, 1995. This legislation rolls the previous processes for the review of major energy projects into a single environmental assessment process with public participation in the environmental review process. On February 27, 2007 the Government of British Columbia unveiled the Energy Plan outlining its strategy towards the environment and which includes targeting for zero net greenhouse gas emissions, promoting new investments in innovation, and becoming the world's leader in sustainable environmental management. For this purpose, on December 18, 2007 proposals were sought for applications to the Innovative Clean Energy Fund, in order to attract new technologies that will help solve energy and environmental issues. With regards to the oil and natural gas industry the objective is to achieve clean energy through conservation and energy efficient practices, whilst competitiveness is advocated in order to attract investment for the development of the oil and natural gas sector. Among the changes to be implemented are: (i) a new of Net Profit Royalty Program; (ii) the creation of a Petroleum Registry; (iii) the establishment of an infrastructure royalty program (combining roads and pipelines); (iv) the elimination of routine flaring at producing wells; (v) the creation of policies and measures for the reduction of emissions; (vi) the development of unconventional resources such as tight gas and coalbed gas; and (vii) new the Oil and Gas Technology Transfer Incentive Program that encourages the research, development and use of innovative technologies to increase recoveries from existing reserves and promotes responsible development of new oil and gas reserves. Furthering these initiatives, the Government of British Columbia introduced on July 1, 2008, revenue-neutral carbon tax legislation that is applied to all fossil fuels used in the Province of British Columbia. The tax would be phased in, and the initial rate would be based on CO2e of $10 per tonne for the first six months of 2009 and $15 per tonne for the last six months of 2009, following $5 per tonne increases on July of every year until 2012. Tax credits and reductions will be used in order to offset the tax revenues that the Government of British Columbia would receive otherwise. On April 3, 2008, the Government of British Columbia introduced the Greenhouse Gas Reduction (Cap and Trade) Act which will allow participation in the Western Climate Initiative cap and trade systems being developed. The system establishes a limit on emissions, and allows regulated emitters to buy/sell emission allowances or offset emits. The emitter is obliged to obtain emission allowances (compliance units) equal to the amount of greenhouse gases emitted within a certain period of time, and that are supposed to be surrendered to the Government of British Columbia as compliance proof.

In December 2002, the Government of Canada ratified the Kyoto Protocol ("**Kyoto Protocol**"). The Kyoto Protocol calls for Canada to reduce its greenhouse gas emissions to 6% below 1990 "business-as-usual" levels between 2008 and 2012. Given revised estimates of Canada's normal emissions levels, this target translates into an approximately 40% gross reduction in Canada's current emissions. It is questionable, based on the Updated Action Plan announced by the Federal Government (see below), that the Kyoto Protocol target of 6% below 1990 emission levels will be enforced in Canada. Bill C-288, which is intended to ensure that Canada meets its global climate change obligations under the Kyoto Protocol, was passed by the House of Commons on February 14, 2007. On April 26, 2007, the Federal Government released its Action Plan to Reduce Greenhouse Gases and Air Pollution (the "**Action Plan**") also known as ecoACTION which includes the regulatory framework for air emissions. This Action Plan covers not only large industry, but regulates the fuel efficiency of vehicles and the strengthening of energy standards for a number of energy using products.

The Government of Canada and the Province of Alberta released on January 31, 2008 the final report of the Canada-Alberta ecoENERGY Carbon Capture and Storage Task Force, which recommends among others: (i) incorporating carbon capture and storage into Canada's clean air regulations; (ii) allocating new funding into projects through competitive process; and (iii) targeting research to lower the cost of technology.

In order to strengthen the Action Plan, on March 10, 2008, the Government of Canada released "Turning the Corner – Taking Action to Fight Climate Change" (the "**Updated Action Plan**") which provides some additional guidance with respect to the Government's plan to reduce greenhouse gas emissions by 20% by 2020 and by 60% to 70% by 2050.

The Updated Action Plan is primarily directed towards industrial emissions from certain specified industries including the oil sands, oil and gas and refining. The Updated Action Plan is intended to create a carbon emissions trading market, including an offset system, to provide incentive to reduce greenhouse gas emission and establish a market price for carbon. There are mandatory reductions of 18% from the 2006 baseline starting in 2010 and an additional 2% in subsequent years for existing facilities. This target will be applied to regulated sectors on a facility-specific, sector-wide or corporate basis; in the case of oil sands production, petroleum refining, natural gas pipelines and upstream oil and gas the target will be considered facility-specific (sectors in which the facilities are complex and diverse, or where emissions are affected by factors beyond the control of the facility operator). Emissions from new facilities, which are those built between 2004 and 2011, will be based on a cleaner fuel standard to encourage continuous emissions intensity reductions over time, and will be granted a 3-year grace period during which no emissions intensity targets will apply. Targets will begin to apply on the fourth year of commercial operation and the baseline will be the third year's emissions intensity, with a 2% continuous annual emission intensity improvement required. The definition of new facility also includes greenfield facilities, major expansions constituting more than a 25% increase in a facility's physical capacity, as well as transformations to a facility that involve significant changes to its processes. For upstream oil and gas and natural gas pipelines, it will be applied using a sector-specific approach. For the oil sands, its application will be process-specific; as such, oil sands plants built in 2012 and later, those which use heavier hydrocarbons, up-graders and *in-situ* production will have mandatory standards in 2018 that will be based on carbon capture and storage.

In the following regulated sectors, the Updated Action Plan will apply only to facilities exceeding a minimum annual emissions threshold: (i) 50,000 tonnes of CO_2 equivalent per year for natural gas pipelines; (ii) 3,000 tonnes of CO_2 equivalent per year per upstream oil and gas facility; and (iii) 10,000 boe/d/company. These proposed thresholds are significantly stricter than the current Alberta regulatory threshold of 100,000 tonnes of CO_2 equivalent per year per facility.

Four separate compliance mechanisms are provided in respect of the above targets: Technology Fund contributions, offset credits, clean development credits and credits for early action. The most significant of these compliance mechanisms, at least initially, will be the Technology Fund and for which regulated entities will be able to contribute in order to comply with emissions intensity reductions. The contribution rate will increase over time, beginning at $15 per tonne for the 2010-12 period, rising to $20 per tonne in 2013, and thereafter increasing at the nominal rate of GDP growth. Contribution limits will correspondingly 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 greenhouse gas 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 mentioned above.

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 cancel the offset credits or bank them for future use or sale.

Under the Updated Action Plan, regulated entities will also be able to purchase credits created through the Clean Development Mechanism of the Kyoto Protocol. 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.

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**.**

Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not currently possible to predict either the nature of those requirements or the impact on the Corporation and its operations and financial condition at this time.

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. 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, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, 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 hazards such as fire, explosion, blowouts, cratering, sour gas releases and spills, 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. In accordance with industry practice, the Corporation is not fully insured against all of these risks, nor are all such risks insurable. Although the Corporation maintains liability insurance in an amount that it considers consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits, in which event the Corporation could incur significant costs. 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.

Global Financial Crisis

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions, have caused significant volatility to commodity prices. These conditions worsened in 2008 and are continuing in 2009, causing a loss of confidence in the broader U.S. and global credit and financial markets and resulting in the collapse of, and government intervention in, major banks, financial institutions and insurers and creating 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. These factors have negatively impacted company valuations and will impact the performance of the global economy going forward.

Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and demand of these commodities due to the current state of the world economies, OPEC actions and the ongoing global credit and liquidity concerns.

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 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 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 gas acquisition, development and exploration activities. Prices for oil and gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond the control of the Corporation. These factors include economic conditions, in the United States and Canada, the actions of OPEC, governmental regulation, political stability in the Middle East and elsewhere, the foreign supply of oil and 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 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.

Petroleum 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 the ongoing credit and liquidity concerns. Volatile oil and gas prices make it difficult to estimate the value of producing properties for acquisition and often cause disruption in the market for oil and 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.

In addition, bank borrowings available to the Corporation are determined by the Corporation's borrowing base. A sustained material decline in prices from historical average prices could reduce the Corporation's borrowing base, therefore reducing the bank credit available to the Corporation which could require that a portion, or all, of the Corporation's bank debt be repaid.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The Corporation makes 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 are 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 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.

Competition

The petroleum industry is competitive in all its phases. The Corporation competes with numerous other organizations 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 price, 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 natural gas and crude oil and increase the Corporation's costs, any 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 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.

Kyoto Protocol

Canada is a signatory to the United Nations Framework Convention on Climate Change and has ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nationwide emissions of carbon dioxide, methane, nitrous oxide and other so-called "greenhouse gases". The Corporation's exploration and production facilities and other operations and activities emit greenhouse gases which will require the Corporation to comply with the new regulatory framework announced on March 10, 2008 by the Federal Government which is intended to force large industries to reduce emissions of greenhouse gases, in addition to the proposed *Clean Air Act* (Canada) of 2006 and Alberta's recently enacted *Climate Change and Emissions Management Act* and *Specified Gas Emitters Regulation*. 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. See "Industry Conditions – Environmental Regulation".

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. There has been much public debate with respect to Canada's ability to meet these targets and the Government's strategy or alternative strategies with respect to climate change and the control of greenhouse gases. Implementation of strategies for reducing greenhouse gases whether to meet the limits required by the Kyoto Protocol 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 – Environmental Regulation".

Variations in Foreign Exchange Rates and Interest Rates

World oil and gas prices are quoted in United States dollars and the price received by Canadian producers is therefore effected 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 although the Canadian dollar has recently decreased from such levels. 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. If the Corporation's revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future drilling programs. In addition, uncertain levels of near term industry activity coupled with the present global credit crisis exposes the Corporation to additional access to capital risk. 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. From time to time, the Corporation may require additional financing in order to carry out its oil and gas acquisition, exploration and development activities. 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. If the Corporation's cash flow from operations is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or, if available, on terms acceptable to the Corporation. The Corporation’s bank facility consists of a revolving line of credit and an operating line of credit and is funded by a syndicate of banks. The available lending limits of the facility are reviewed semi-annually and are based on the bank syndicate’s interpretation of the Corporation’s reserves and future commodity prices. There can be no assurance that the amount of the available facility will not be adjusted. Continued uncertainty in domestic and international credit markets could materially affect the Corporation's ability to access sufficient capital for its capital expenditures and acquisitions, and as a result, may have a material adverse effect on the Corporation's ability to execute its business strategy and on its business, financial condition, results of operations and prospects.

Issuance of Debt

From time to time the Corporation may enter into transactions to acquire assets or the 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 equity and/or 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, if commodity prices increase beyond the levels set in such agreements, the Corporation will not benefit from such increases and the Corporation may nevertheless be obligated to pay royalties on such higher prices, even though not received by it, after giving effect to such agreements. 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. The Corporation may also enter into contracts to fix the interest rate on a portion of its outstanding debt in order to offset the risk of an increased cost of borrowing resulting from an increase in future interest rates.

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.

Reserve and Resource 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, resource and associated cash flow information set forth herein are estimates only. In general, estimates of economically recoverable oil and natural gas reserves and resources 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 and resource recovery, timing and amount of capital expenditures, marketability of oil and gas, royalty rates, the assumed effects of regulation by governmental agencies, transportation costs 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 and resources attributable to any particular group of properties, classification of such reserves and resources 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, and transportation costs 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 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.

Resource Estimate

The estimates of gas contained herein classified as Discovered Petroleum Initially in Place ("**DPIP**") are not, and should not be confused with oil and gas reserves. "Discovered Petroleum Initially in Place" is defined in the COGE Handbook as the quantity of hydrocarbons that are estimated, as of a given date, to be contained in known accumulations. DPIP is divided into recoverable and unrecoverable portions, with the estimated future recoverable portion classified as reserves and contingent resources. The remainder is unrecoverable. There is no certainty that it will be commercially viable or technically feasible to produce any portion of this DPIP except to the extent identified as proved or probable reserves. Resources do not constitute, and should not be confused with reserves.

There are a number of assumptions associated with the development of the Corporation's lands at Septimus relating to performance from new and existing wells, future drilling programs, the lack of infrastructure, well density per section, recovery factors and development necessarily involves known and unknown risks and uncertainties, including those risks identified herein.

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, such 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, 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 will 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 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 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 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, 2008, 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, 2008, 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, neither the Corporation or its subsidiaries have entered into any material contracts within the most recently completed financial year, or before the most recently completed financial year that are still in effect, other than the Gentry Acquisition Agreement, a copy of which has been filed on SEDAR at www.sedar.com. See "*Significant Acquisitions*".

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 our 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 most recent annual meeting of securityholders to be held on May 25, 2009. 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 our information circular, our comparative consolidated financial statements, including any interim consolidated comparative financial statements and additional copies of the Annual Information Form please contact:

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Calgary, Alberta T2P 3L8
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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, 2008 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. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

(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 30, 2009

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, 2008. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2008 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, 2008, 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	February 20, 2009	Canada	-	$1,039,052	-	$1,039,052

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.

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. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

(signed) "GLJ Petroleum Consultants"
GLJ Petroleum Consultants

Calgary, Alberta
February 25, 2009

Originally signed by:
Ken B. Gregory, P. Eng.
Manager, Engineering

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 ceiling test calculation;
   - 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 advise 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.