CREW ENERGY INC.

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2007

March 25, 2008

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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

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. Liquid petroleum with a specified gravity of 28 API or higher is generally referred to as light crude oil.
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 productive capacity of wells and capital expenditures and the timing 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 provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements. 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 March 3, 2008 evaluating the crude oil, natural gas liquids and natural gas reserves of the Corporation as at December 31, 2007;

"**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:

(d) 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;

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

(f) 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

"**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, 2007.

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

CORPORATE STRUCTURE

Crew was originally incorporated pursuant to the provisions of the ABCA as 1046546 Alberta Ltd. on May 12, 2003. On June 27, 2003, Crew filed Articles of Amendment to change its name to "Crew Energy Inc." On January 1, 2008 Crew completed a short form amalgamation with its wholly-owned subsidiary, ENCO Gas, Ltd. ("**Enco**"), to form "Crew Energy Inc.".

As at December 31, 2007 Crew had two wholly-owned subsidiaries, Crew Resources and Enco. 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 Enco were, as at December 31, 2007, the only partners in the Crew Energy Partnership and, as at that date, respectively owned 40.81%, 33.235% and 25.955% of the Crew Energy Partnership.

Crew's principal 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 acquiring crude oil and natural gas properties and exploring for, developing and producing 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. The former shareholders of Baytex Energy Ltd. became shareholders of Crew and each such shareholder received one (1) Common Share for every three (3) common shares of Baytex Energy Ltd. held. 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 2007 production averaged 9,641 boe/d a 543% increase since its inception.

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 central 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 to 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:

(a) the risk capital required to secure or evaluate the investment opportunity;

(b) the potential return on the project, if successful;

(c) the likelihood of success; and

(d) the risked return versus cost of capital.

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 the following equity financings:

On May 13, 2004, the Corporation 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 $16,050,000.

On December 2, 2004, the Corporation 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 gross proceeds of $8,800,000.

On December 20, 2005, the Corporation completed a 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 total gross proceeds of approximately $35 million.

On August 17, 2006, the Corporation completed a 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 total 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. All of the outstanding 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 5,318,998 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 total 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, 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. See "*Significant Acquisitions*" below.

On October 25, 2007, the Corporation completed a 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 total gross proceeds of approximately $54.5 million.

Significant Acquisitions

Acquisition of ENCO Gas, Ltd.

On May 3, 2007 Crew completed the acquisition of all of the outstanding shares of ENCO, a private oil and gas company pursuant to a purchase and sale agreement dated April 15, 2007 (the "**Enco Acquisition Agreement**"). 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.

The Business Acquisition Report dated May 8, 2007 in respect of the Enco Acquisition is filed and can be located on SEDAR at www.sedar.com.

Recent Developments

On October 25, 2007, the Alberta government released the New Royalty Framework pertaining to royalties on oil and gas resources including oil sands, conventional oil and gas and coal bed methane. The NRF is scheduled to take effect on January 1, 2009. The NRF was the Alberta government's response to the recommendations put forth by the Alberta Royalty Review Panel. Given the methodology used in the proposed royalty regime, the effect on Crew's cash flow will be affected by depths and productivity of wells. The actual effect of the Alberta royalty rate changes on Crew will be determined based on, among other things, the actual legislation enacted, the production rates, commodity prices, foreign exchange rates, production mix, service costs and the percentage of production from Alberta after January 1, 2009. See Note 8 under "Statement of Reserves Data and Other Oil and Gas Information – Disclosure of Reserves Data – Reserves Data (Forecast Prices and Costs)" for information relating to sensitivities relating to the possible impact of the NRF.

The Corporation's Board of Directors has approved a $120 million exploration and development program for 2008. Plans include the drilling of approximately 50 wells during the year of which approximately 38 wells will be directed toward development initiatives in its core areas of Edson and Ferrier, in Alberta and Inga and Sierra in British Columbia. In addition, the Corporation plans to drill up to 12 exploratory wells in 2008, generally targeting gas/condensate reservoirs in the deeper regions of the basin and in the Corporation's newly emerging resource plays in north east B.C.

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 3, 2008. The effective date of the Statement is December 31, 2007 and the preparation date of the Statement was February 21, 2008.

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, 2007 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 and British Columbia.

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 constant prices and costs assumptions and forecast prices and costs 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, 2007
FORECAST PRICES AND COSTS

	RESERVES SUMMARY									
	LIGHT AND MEDIUM OIL		NATURAL GAS LIQUIDS		CONVENTIONAL NATURAL GAS		COAL BED METHANE		TOTAL OIL EQUIVALENT	
RESERVES CATEGORY	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (Mmcf)	Net (Mmcf)	Gross (Mmcf)	Net (Mmcf)	Gross (Mbbl)	Net (Mbbl)
PROVED										
Developed Producing	441	383	2,610	1,824	79,008	61,790	697	639	16,335	12,612
Developed Non-Producing	45	42	354	254	24,859	19,096	1,034	917	4,715	3,632
Undeveloped	0	0	78	59	2,595	2,079	5,899	5,221	1,493	1,276
TOTAL PROVED	486	426	3,041	2,137	106,462	82,965	7,630	6,777	22,543	17,519
TOTAL PROBABLE	224	199	1,382	975	47,164	36,961	8,121	6,907	10,820	8,485
TOTAL PROVED PLUS PROBABLE	710	625	4,423	3,112	153,626	119,926	15,751	13,684	33,363	26,005

	NET PRESENT VALUES OF FUTURE NET REVENUE									
	BEFORE INCOME TAXES DISCOUNTED AT (%/year)					AFTER INCOME TAXES DISCOUNTED AT (%/year)				
RESERVES CATEGORY	0% (M$)	5% (M$)	10% (M$)	15% (M$)	20% (M$)	0% (M$)	5% (M$)	10% (M$)	15% (M$)	20% (M$)
PROVED										
Developed Producing	491,690	400,595	341,997	300,872	270,222	417,784	342,952	294,682	260,691	235,271
Developed Non-Producing	127,609	102,776	85,792	73,423	64,016	90,163	72,029	59,670	50,701	43,904
Undeveloped	27,075	16,211	10,024	6,281	3,898	19,067	10,895	6,252	3,459	1,698
TOTAL PROVED	646,374	519,582	437,813	380,575	338,136	527,014	425,876	360,604	314,851	280,873
TOTAL PROBABLE	316,286	198,447	139,434	105,230	83,313	224,892	139,903	97,334	72,679	56,905
TOTAL PROVED PLUS PROBABLE	962,660	718,082	577,247	485,806	421,449	751,906	565,779	457,938	387,530	337,778

TOTAL FUTURE NET REVENUE (UNDISCOUNTED) as of December 31, 2007 FORECAST PRICES AND COSTS

RESERVES CATEGORY	REVENUE (M$)	ROYALTIES (M$)	OPERATING COSTS (M$)	CAPITAL DEVELOPMENT COSTS (M$)	ABANDONMENT AND RECLAMATION COSTS (M$)	FUTURE NET REVENUE BEFORE INCOME TAXES (M$)	INCOME TAXES (M$)	FUTURE NET REVENUE AFTER INCOME TAXES (M$)
Total Proved	1,132,575	211,925	232,474	31,057	10,745	646,374	119,360	527,014
Total Proved Plus Probable	1,725,796	323,663	364,364	61,307	13,802	962,660	210,754	751,906

FUTURE NET REVENUE BY PRODUCTION GROUP as of December 31, 2007 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)	10,988	35.84 per Bbl
	Natural Gas (2)	328,835	4.49 per Mcf
	Coal Bed Methane	2,174	3.40 per Mcf
Total Proved	Light and Medium Crude Oil (1)	11,835	34.10 per Bbl
	Natural Gas (2)	416,280	4.32 per Mcf
	Coal Bed Methane	9,697	1.43 per Mcf
Total Proved Plus Probable	Light and Medium Crude Oil (1)	14,807	33.01 per Bbl
	Natural Gas (2)	544,845	3.90 per Mcf
	Coal Bed Methane	17,595	1.29 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 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, 2008, 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, 2008, 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, 2008
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										
2008	92.00	91.10	79.26	58.30	72.88	92.92	6.75	6.55	2%	1.000
2009	88.00	87.10	75.78	55.74	69.68	88.84	7.55	7.35	2%	1.000
2010	84.00	83.10	72.30	53.18	66.48	84.76	7.60	7.40	2%	1.000
2011	82.00	81.10	70.56	51.90	64.88	82.72	7.60	7.40	2%	1.000
2012	82.00	81.10	70.56	51.90	64.88	82.72	7.60	7.40	2%	1.000
2013	82.00	81.10	70.56	51.90	64.88	82.72	7.60	7.40	2%	1.000
2014	82.00	81.10	70.56	51.90	64.88	82.72	7.80	7.60	2%	1.000
2015	82.00	81.10	70.56	51.90	64.88	82.72	7.97	7.77	2%	1.000
2016	82.02	81.12	70.57	51.91	64.89	82.74	8.14	7.94	2%	1.000
2017	83.66	82.76	72.00	52.97	66.21	84.42	8.31	8.11	2%	1.000
2018	85.33	84.42	73.44	54.03	67.53	86.11	8.48	8.27	2%	1.000
Thereafter	+2%	+2%	+2%	+2%	+2%	+2%	+2%	+2%	2%	1.000

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, 2007, were $6.75/mcf for natural gas, $71.90/bbl for crude oil and $57.02/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. Net present values reflected in the above table have been determined under the existing Alberta royalty regime as the NRF has not yet been enacted.

8. Corporate total economic forecasts were rerun to examine the impact of the NRF. The government has not yet clarified certain aspects of the new royalty calculations. Accordingly, high and low sensitivities to the NRF were conducted using the Consultant's Consensus Methodology recommended by the Society of Petroleum Evaluation Engineers, Calgary Chapter. The "NRF High" scenario represents a more optimistic or high value sensitivity of the NRF impact, and the "NRF Low" scenario represents the low value sensitivity. The following table summarizes the potential impact of the NRF. The government has stated its intention to consult with industry and review the NRF for unintended consequences. The following analysis does not take into account any potential changes to the NRF prior to its implementation that may result from such consultations. Crew will continue to monitor government announcements and proposed revisions as they become available.

POTENTIAL IMPACT OF THE NEW ALBERTA ROYALTY FRAMEWORK

	NRF Low (percent change)	**NRF High (percent change)**
Proved plus Probable Reserves		
Gross	0%	0%
Net	-1%	2%
Net Present Value of Future Net Revenue before income tax deducted discounted at 10%/year (total proved plus probable)	-1%	1%

Reconciliation of Changes in Reserves

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

	LIGHT AND MEDIUM OIL			NATURAL GAS LIQUIDS		
FACTORS	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)
December 31, 2006	509	312	821	2,535	1,150	3,685
Discoveries	0	0	0	60	36	97
Extensions and Improved Recovery	0	0	0	614	330	943
Infill Drilling	0	0	0	0	0	0
Technical Revisions	69	(124)	(55)	(719)	(423)	(1,142)
Acquisitions	105	33	138	901	245	1,145
Dispositions	0	0	0	0	0	0
Economic Factors	2	3	5	(3)	44	41
Production	(199)	0	(199)	(346)	0	(346)
December 31, 2007	486	224	710	3,041	1,382	4,423

	ASSOCIATED AND NON-ASSOCIATED GAS			COAL BED METHANE		
FACTORS	Proved (Mmcf)	Probable (Mmcf)	Proved Plus Probable (Mmcf)	Proved (Mmcf)	Probable (Mmcf)	Proved Plus Probable (Mmcf)
December 31, 2006	55,955	27,962	83,917	5,527	9,604	15,131
Discoveries	4,724	2,652	7,376	0	0	0
Extensions and Improved Recovery	13,315	7,682	20,997	2,740	(282)	2,458
Infill Drilling	0	0	0	0	0	0
Technical Revisions	3,732	(4,852)	(1,121)	(509)	(1,201)	(1,710)
Acquisitions	44,336	13,529	57,865	0	0	0
Dispositions	0	0	0	0	0	0
Economic Factors	(65)	192	127	0	0	0
Production	(15,534)	0	(15,534)	(128)	0	(128)
December 31, 2007	106,462	47,164	153,626	7,630	8,121	15,751

FACTORS	OIL EQUIVALENT Proved (Mboe)	Probable (Mboe)	Proved Plus Probable (Mboe)
December 31, 2006	13,290	7,723	21,013
Discoveries	848	478	1,326
Extensions and Improved Recovery	3,289	1,564	4,853
Infill Drilling	0	0	0
Technical Revisions	(113)	(1,555)	(1,668)
Acquisitions	8,395	2,532	10,927
Dispositions	0	0	0
Economic Factors	(12)	79	67
Production	(3,155)	0	(3,155)
December 31, 2007	22,542	10,821	33,363

Notes:

(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, 2007, 2006 and 2005 and, in the aggregate, before that time based on forecast prices and costs.

Proved Undeveloped Reserves

Year	Light and Medium Oil (Mbbl)		Natural Gas (Mmcf)		Coal Bed Methane (Mmcf)		NGLs (Mbbl)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
Prior thereto	0	0	0	0	0	0	0	0
2005	0	0	799	799	869	869	19	19
2006	0	0	0	799	2,493	3,362	0	19
2007	0	0	1,796	2,595	2,537	5,899	58	79

Probable Undeveloped Reserves

Year	Light and Medium Oil (Mbbl)		Natural Gas (Mmcf)		Coal Bed Methane (Mmcf)		NGLs (Mbbl)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
Prior thereto	0	0	0	0	0	0	0	0
2005	0	0	400	400	3,394	3,394	10	10
2006	25	25	3,391	3,791	2,679	6,073	151	161
2007	0	25	4,857	8,648	1,246	7,319	118	279

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. However, the Corporation has areas where multiple zones have been assigned reserves in a well. Once the currently producing zones are depleted, capital will be spent re-completing the well in another zone. Some of these expenditures are planned to occur in 2010 and beyond, the timing to be dictated by the predicted reserve life for the currently producing zones. In addition, a significant capital program is required for the development of the Corporation's coal bed methane reserves in the Wimborne-Drumheller area. We currently plan to develop proved and probable undeveloped coal bed methane reserves over a period of five years. This phasing will allow us to optimize capital allocation and facility utilization.

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.

Year	Forecast Prices and Costs Proved Reserves (M$)	 Proved Plus Probable Reserves (M$)
2008	11,924	20,531
2009	6,452	17,699
2010	4,550	6,132
2011	2,268	5,921
2012	2,898	4,225
2013	1,175	3,014
2014	1,194	2,856
2015	0	0
2016	0	0
2017	264	268
2018	0	0
2019	0	0
Thereafter	331	660
Total Undiscounted	31,057	61,307

The Corporation 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. Therefore, the capital commitments will not affect the disclosed reserves or future net revenue.

Other Oil and Gas Information

Principal Properties

The following is a description of Crew's major oil and natural gas properties as at December 31, 2007. Production stated is production before deduction of royalties and includes royalty interests to Crew and, unless otherwise stated, is average production for 2007. 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, 2007 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, 2007.

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 Wimborne-Drumheller in Alberta and Inga and Sierra in northeast British Columbia. Crew's 2007 operations focused on exploration and development of these main operating areas along with the acquisition of new operations in northeast B.C.

Crew will continue the development of its main operating areas in 2008. The Corporation has currently budgeted approximately $80 to $90 million towards the continued 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 35 wells.

In 2008, Crew also plans to drill up to 15 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 $30 and $40 million of its 2008 drilling program toward these opportunities.

NORTH CORE

Inga, British Columbia

The greater Inga area includes Crew's operations in a 50 mile radius around Fort St. John, British Columbia. The majority of the Company's existing operations in this area were acquired as part of Crew's acquisition of Enco (see "Significant Acquisitions" for details) in May 2007. At December 31, 2007 the Corporation had an interest in 92 (33.9 net) producing gas wells and 9 (5.3 net) producing oil wells in this area. In 2007, Crew produced an average of 299 bbl/d of light oil and ngls along with 5.2 Mmcf/d of natural gas from the Inga area. The Corporation's 2007 Inga light oil and ngl production came mainly from two Charlie Lake sandstone oil pools. This oil is gathered into single well oil batteries and trucked to third party pipeline terminals for sale. Inga's natural gas is produced from several Triassic and Cretaceous, sandstone and carbonate natural gas pools spread throughout the area. The Company owns an interest in sixteen natural gas facilities in the Inga area which compress and dehydrate the natural gas production in preparation for delivery into the Fort Nelson gas processing facility. The Corporation drilled a total of 3 (2.1 net) wells in the Inga area in 2007 resulting in 1 (1.0 net) oil well and 2 (1.1 net) gas wells.

Crew's 2008 drilling plans for the Inga area includes drilling up to ten Triassic/Cretaceous conventional natural gas prospects. In addition, during 2007 and early 2008 Crew has successfully accumulated an interest in over 20 net sections of land prospective for Triassic, Montney natural gas. Recent advancements in drilling and completion techniques have proven successful in economically recovering portions of the substantial natural gas resource that exists in the Triassic Montney formation. Crew's plans for 2008 include the drilling of 10 wells into the Montney Formation and planning and designing a natural gas processing facility that will be built conditional on Montney drilling success in the area.

As at December 31, 2007 the GLJ Report showed Crew's greater Inga area to have total reserves of 1,224 Mbbl of oil and ngls along with 27,430 Mmcf of natural gas. At year end the Corporation owned 90,333 net acres of land with an average working interest of 49.1% in this area.

Sierra, British Columbia

The greater Sierra area includes Crew's operations in a 65 mile radius around Fort Nelson, British Columbia. The Company's operations in this area were acquired as part of Crew's acquisition of Enco (see "Significant Acquisitions" for details) in May 2007. At December 31, 2007 the Corporation had an interest in 12 (6.5 net) producing gas wells in this area. In 2007, Crew produced an average of 5.5 Mmcf/d of natural gas from the Sierra area. Natural gas production from this area comes predominantly from a Pine Point natural gas well that was producing approximately 7.5 Mmcf/d of sales gas at the end of 2007. 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 2007 has resulted in Crew generating net revenue from sulphur recovered in the latter half of the year. The Company did not drill any wells in this area in 2007. In 2008, Crew's plans for Sierra includes drilling of up to three conventional natural gas development wells in the area targeting Jean Marie, Mattson and Debolt formation natural gas.

Crew lands in the Sierra area include 15 net sections of land that have been identified as highly prospective for the Horn River Basin's Muskwa Shale natural gas resource play. The Muskwa Shale is approximately 500 feet thick and has gained a significant amount of attention since the February 2008 announcement by an industry participant of its successful drilling and testing of the Muskwa Shale in the Horn River Basin. The play is in its infancy but appears to be prospective over a large area in a relatively homogeneous geologic environment. Crew has currently not planned any drilling activity for the Muskwa Shales in 2008. The Company 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, 2007 the GLJ Report showed Sierra to have total reserves of 23,320 Mmcf of natural gas. At year end the Corporation owned 14,871 net acres of land with an average working interest of 47.5% in this area.

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, 2007 the Corporation had 39 (16.2 net) producing gas wells and 12 (7.9 net) producing oil wells in the area and in 2007 produced an average of 645 bbl/d of oil and ngls along with 10.4 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 4 (2.8 net) wells in the Ferrier area in 2007 resulting in 3 (1.8 net) cased gas wells and 1(1 net) dry and abandoned well. In addition, in the fourth quarter the Corporation (WI – 42.5%) successfully re-entered and completed a Nisku formation natural gas discovery. This well is a new pool wildcat discovery and represents the highest flow rate that Crew has tested since the Company's inception in 2003. The well had an absolute open flow rate of 56 Mmcf/d and is expected to commence production by the end of the first quarter of 2008 at 15 to 20 Mmcf/d. Crew now owns an interest in 18.25 sections of land on this play and is currently operating a second recompletion (WI - 41.5%) approximately two kilometers away from the discovery well. We now have three additional recompletion opportunities in the area with working interests ranging from 41.5% to 100%.

The Company's plans at Ferrier for 2008 also include drilling one (15% bpo, 46.5% apo), 3,700 meter Leduc natural gas prospect. The licensing of this well is awaiting surface access approvals and is expected to spud in the fourth quarter of 2008. Further exploration is planned at West Brazeau in the greater Ferrier area. Crew (WI - 37.5% to 100%) is targeting thrusted Belly River sandstone reservoirs on 30 sections of land the Company has accumulated in the area. The Company is currently drilling its first well on this prospect with analogous offsetting wells producing up to 5.5 Mmcf/d. Crew has identified up to 12 net drilling locations on this play.

As at December 31, 2007 the GLJ Report showed Ferrier to have total reserves of 1,723 Mbbl of light oil and ngls and 26,329 Mmcf of natural gas. At year-end, the Corporation owned 75,104 net acres of land with an average working interest of 66% 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, 2007 the Corporation had 80 (40.5 net) producing gas wells and 5 (4.3 net) producing oil wells in the area. Production averaged 441 bbl/d of oil and ngls along with 11.5 Mmcf/d of natural gas in 2007. The majority of the Corporation's 2007 natural gas production from this area was delivered through a gathering system to twin 810 bhp compressors owned by Crew (100%) and then into a 90 Mmcf/d sour gas processing facility in which Crew owns a 15% interest. In the fourth quarter of 2007, Crew constructed a 15 Mmcf/d gas processing and compression facility at Pine Creek in the northern part of the greater Edson Area. This facility was commissioned in early December to deliver gas from wells drilled in the Company's Pine Creek area to a third party gas processing facility in the region. In 2007, Crew drilled 17 (17.0 net) wells in this area resulting in 16 (16.0 net) gas wells and 1 (1.0 net) oil well.

Crew drilled the first two wells in the planned five well development drilling program in the Rock Creek Formation after receiving approval for four wells per section from the Energy Resources Conservation Board in the third quarter. Crew currently has a two to three year inventory of development drilling opportunities in its main Edson area with plans to drill approximately ten wells per year. The Company's 2006 investment in infrastructure has resulted in lower costs and quick tie-ins leading to attractive economic returns in this active area.

Pine Creek in the greater Edson area has been transformed into a core producing area from an exploration concept in less than one year. Crew now owns an interest in over 50 sections of land in the area. In the fourth quarter, the Company initiated production from its new gas facility and early in the first quarter of 2008 doubled the compression in order to process up to 15 Mmcf/d of raw gas. Natural gas production from this area is liquids rich yielding 45 to 50 bbls of natural gas liquids per one mmcf of natural gas produced. The area is characterized by drilling depths of 2,000 to 2,800 meters with multiple prospective horizons. The Company has been able to develop a significant land position in a short period of time which has resulted in a two to three year drilling inventory. Current plans for 2008 are to drill seven to ten wells in the Pine Creek area.

Carrot Creek, in the greater Edson area, is another full cycle exploration area the Company has taken from an exploration concept, to posting and purchasing Crown land, drilling three wells, purchasing a gas plant including associated infrastructure and production and increasing the controlled land position to 36 sections to create a new core area. Current production is estimated to be over 500 boe/d. Based on drilling success Crew has an inventory in excess of 21 drilling locations identified on this liquids rich natural gas play. In the first quarter of 2008, Crew purchased a 100% interest in a 5.5 Mmcf/d gas plant, associated pipeline infrastructure and approximately 500 mcf/d day of production. The acquisition of this facility is expected to reduce area operating costs from $1.00 per mcf to $0.23 per mcf. Targets for 2008 include filling the capacity of the gas plant and being in a position to expand the facility to 12 Mmcf/d.

As at December 31, 2007 the GLJ Report showed the greater Edson area to have reserves of 1,918 Mbbl of oil and ngls and 56,560 Mmcf of natural gas. At year end the Corporation owned 65,923 net acres of land with an average working interest of 71% in the area.

Wimborne-Drumheller, Alberta

Wimborne-Drumheller is located in central Alberta approximately 150 kilometres northeast of Calgary. At December 31, 2007 Crew owned an interest in 63 (34.0 net) natural gas wells, 10 (2.9 net) producing oil wells and two natural gas processing facilities. Production from this area in 2007 averaged 2.7 Mmcf/d of natural gas and 42 bbl/d of oil and ngls. At Drumheller, the Corporation has a 42.3% working interest in a 7 Mmcf/d gas processing facility, and a 75.3% working interest in compression equipment at the same location. At Wimborne, the Corporation has a 83.5% working interest in a 7 Mmcf/d gas processing facility that is capable of accommodating low pressure coal bed methane production. During 2007, the Company drilled four (0.4 net) wells in the Wimborne area resulting in four (0.4 net) gas wells.

Crew's lands in the Wimborne area are surrounded by new natural gas developments targeting the Horseshoe Canyon coals. Typical Horseshoe Canyon natural gas developments incorporate the drilling of four to eight wells per section with production rates of 70-300 mcf/d per well. Crew has 42 net sections of Horseshoe Canyon coal rights in the Wimborne-Drumheller area.

As at December 31, 2007 the GLJ Report showed this area to have total reserves of 20,273 Mmcf of natural gas (including 15,969 Mmcf of coal bed methane) and 89 Mbbl of oil and ngls. At year end the Corporation owned 30,137 net acres of land with an average working interest of 51% 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, 2007.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	28	16.1	10	5.1	270	155.1	105	78.4
British Columbia	8	4.3	4	3.5	85	36.5	52	16.5
Total	36	20.4	14	8.6	355	191.6	157	94.9

Land Holdings Including Properties With No Attributable Reserves

The following table sets out the Corporation's developed and undeveloped land holdings as at December 31, 2007.

	Developed Acres		Undeveloped Acres	
	Gross	**Net**	**Gross**	**Net**
Alberta	211,257	111,002	207,623	167,939
British Columbia	96,801	37,618	118,344	67,585
Total	308,058	148,620	325,967	235,524

There are no material work commitments associated with the Corporation's undeveloped land holdings. Of the Corporation's undeveloped land, the rights to explore, develop and exploit 64,299 net acres may expire by December 31, 2008 if the Corporation takes no action to retain the land**.**

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	Price (Cdn $/gj)	Ceiling (Cdn $/gj)	Floor (Cdn $/gj)
AECO/Station 2 Differential Swap	10,000	Nov. 1, 2007-Oct. 31, 2008	AECO 5A less $0.16	-	-
AECO	10,000	Apr. 1, 2008-Oct. 31, 2008	AECO C Monthly Index	$8.00	$7.00
AECO	10,000	Apr. 1, 2008-Oct. 31, 2008	AECO Daily wkd	$8.30	$7.00
AECO	10,000	Apr. 1, 2008-Oct. 31, 2008	AECO C Monthly Index	$9.25	$7.50

A portion of the Corporation's natural gas reserves in central Alberta are committed to aggregator sales contracts. Previous owners of these properties executed these contracts. The sales contracts are dedicated to specific reserves and extend for the life of the reserves. In 2007, approximately 2.3 Mmcf/d of the Corporation's total natural gas sales were sold to aggregators. The Corporation does not currently intend to commit any additional sales volumes to aggregator contracts in the future.

Additional Information Concerning Abandonment and Reclamation Costs

The total net cost to abandon and reclaim Crew's assets was determined 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, 2007, management expected to incur abandonment and reclamation costs on 315.5 net wells. The total of such costs, net of estimated salvage value, was $13.9 million ($7.4 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 $20.3 million ($7.7 million discounted at 10%) and salvage values of $21.2 million ($4.8 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 $1.2 million ($1.1 million discounted at 10%).

Tax Horizon

The Corporation was not required to pay any cash income taxes for the period ended December 31, 2007. 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 2009 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, 2007:

	($ thousands)
Property acquisition costs	
Proved properties	(315)
Undeveloped properties	14,756
Exploration costs	27,901
Development costs	59,435
	101,777
Corporate acquisition - Enco	137,051
Total	238,828

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, 2007. This table does not include wells drilled in Enco prior to its acquisition on May 3, 2007:

	Gross			**Net**		
	Exploration	**Development**	**Total**	**Exploration**	**Development**	**Total**
Crude Oil	-	2	2	-	2.0	2.0
Natural Gas	13	15	28	11.6	10.7	22.3
Dry[(1)]	1	-	1	1.0	-	1.0
Service[(2)]	-	-	-	-	-	-
Total:	14	17	31	12.6	12.7	25.3

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 is 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. In addition, Crew plans to pursue several exploration opportunities on its large undeveloped land base in central and northwestern Alberta. The Corporation is currently budgeting for a $120 million exploration and development expenditure program in 2008, which will be financed through cash flow from operations and the Corporation's existing $180 million credit facility. 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 production for the year ended December 31, 2008 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*".

	2008 AVERAGE DAILY PRODUCTION (1)							
	LIGHT AND MEDIUM OIL		**NATURAL GAS LIQUIDS**		**NATURAL GAS(2)**		**TOTAL OIL EQUIVALENT**	
RESERVES CATEGORY	**Gross (bbl/d)**	**Net (bbl/d)**	**Gross (bbl/d)**	**Net (bbl/d)**	**Gross (Mcf/d)**	**Net (Mcf/d)**	**Gross (Boe/d)**	**Net (Boe/d)**
Proved Producing								
Edson	67	53	594	385	15,889	11,122	3,309	2,292
Ferrier	106	83	380	266	6,532	4,719	1,575	1,136
Other Properties	250	211	537	391	24,709	19,346	4,905	3,826
	423	348	1,511	1,042	47,130	35,187	9,789	7,254
Total Proved								
Edson	67	53	644	419	17,935	12,578	3,700	2,569
Ferrier	106	83	431	301	9,580	6,871	2,134	1,530
Other Properties	255	216	608	447	28,056	21,854	5,539	4,305
	428	352	1,684	1,167	55,572	41,303	11,373	8,403
Total Proved plus probable								
Edson	72	57	697	453	19,164	13,408	3,963	2,745
Ferrier	107	84	461	321	11,163	7,983	2,429	1,736
Other Properties	285	240	685	513	30,178	23,539	6,000	4,676
	465	381	1,843	1,288	60,505	44,930	12,392	9,158

Notes:

(1) The Corporation's Edson and Ferrier fields are the only fields which have greater than 20% or more of the Corporation's estimated 2008 production in the December 31, 2007 GLJ Report.

(2) Estimated 2008 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			
	2007			
	Dec. 31	**Sept. 30**	**June 30**	**Mar. 31**
Average Daily Production[(1)]				
Light and Medium Crude Oil (bbl/d)	445	890	468	374
Natural Gas (Mcf/d)[(3)]	47,204	47,820	45,128	32,407
NGLs (bbl/d)	1,329	408	978	1,094
Combined (BOE/d)	9,641	9,268	8,967	6,869
Average Price Received				
Light and Medium Crude Oil ($/bbl)	83.10	73.20	66.16	62.40
Natural Gas ($/Mcf)[(3) (4)]	6.40	5.72	7.50	7.74
NGLs ($/bbl)	63.29	63.10	55.52	48.24
Combined ($/BOE) [(4)]	43.90	39.32	47.27	47.61
Transportation Expenses				
Light and Medium Crude Oil ($/bbl)	1.61	2.15	1.62	3.77
Natural Gas ($/Mcf)[(3)]	0.39	0.51	0.43	0.13
NGLs ($/bbl)	0.04	0.37	0.48	0.27
Combined ($/BOE)	2.01	2.83	2.30	0.86
Royalties Paid				
Light and Medium Crude Oil ($/bbl)	7.12	10.92	5.76	4.63
Natural Gas ($/Mcf)[(3)]	0.93	0.13	1.57	1.76
NGLs ($/bbl)	21.19	13.60	15.33	14.95
Combined ($/BOE)	7.81	2.36	9.85	10.95
Operating Expenses				
Light and Medium Crude Oil ($/bbl)	8.55	4.03	7.07	6.71
Natural Gas ($/Mcf)[(3)]	1.06	1.04	1.02	1.03
NGLs ($/bbl)	5.74	12.62	5.92	5.19
Combined ($/BOE)	6.35	6.29	6.16	6.06
Netback Received [(2)]				
Light and Medium Crude Oil ($/bbl)	65.82	56.10	51.71	47.29
Natural Gas ($/Mcf)[(3)]	4.02	4.04	4.48	4.82
NGLs ($/bbl)	36.32	36.51	33.79	27.84
Combined ($/BOE)	27.73	27.84	28.96	29.74

Notes:

(1) Before deduction of royalties and including royalty interests.

(2) Netbacks are calculated by subtracting, transportation, royalties and operating costs from revenues and including ARTC.

(3) Average daily coal bed methane production in 2007 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 Company's realized gains and losses on financial instruments.

The following table indicates the Corporation's average daily production, before deduction of royalties and including royalty interests, from its important fields for the year ended December 31, 2007:

	Light and Medium Crude Oil (bbl/d)	Natural Gas[(1)] (Mcf/d)	NGLS (bbl/d)	BOE (BOE/d)
Edson	118	11,548	323	2,366
Ferrier	234	10,352	437	2,396
Wimborne-Drumheller	14	2,656	28	485
Other	3	7,785	25	1,326
Total Alberta	369	32,341	813	6,573
Inga	176	5,288	139	1,196
Greater Sierra	-	5,564	-	927
Total British Columbia	176	10,852	139	2,123
Total	545	43,193	952	8,696

Notes:
(1) Average daily coal bed methane production in 2007 was less than 1% of the total natural gas production and therefore was not considered material.

For the year ended December 31, 2007, approximately 23% of Crew's gross revenue was derived from crude oil and natural gas liquids production and 77% was derived from natural gas production.

DIVIDEND POLICY

Crew has not paid any dividends on the outstanding Common Shares. The Board of Directors of Crew will determine the actual timing, payment and amount of dividends, if any, that may be paid by Crew from time to time based upon, among other things, the cash flow, results of operations and financial 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. Each Performance Share was convertible into a percentage of a Common Share equal to the closing trading price of the Common Shares on the TSX on the trading day prior to such conversion (the "**Current Market Price**") less $1.65, if positive, divided by the Current Market Price.

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**
2007			
January	12.30	10.30	5,843,424
February	12.40	10.53	4,718,850
March	10.75	7.79	11,264,237
April	11.19	10.10	6,705,415
May	12.00	10.37	6,475,813
June	12.30	10.03	5,486,643
July	10.55	8.15	2,157,112
August	8.35	7.00	8,144,713
September	9.06	7.12	7,148,011
October	9.09	8.02	8,482,784
November	9.01	7.50	4,546,242
December	8.25	6.50	3,371,658
2008			
January	9.38	6.76	7,838,884
February	12.59	8.75	9,938,779
March (1-20)	12.84	11.18	5,529,284

ESCROWED SECURITIES

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

DIRECTORS AND OFFICERS

The names, municipalities 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 and Municipality of Residence	Office Held	Principal Occupation	Director Since
Dale O. Shwed(6) Calgary, Alberta	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. Brussa(2)(3)(4)(8) Calgary, Alberta	Chairman	Partner, Burnet, Duckworth & Palmer LLP (a law firm).	September, 2003

Name and Municipality of Residence	Office Held	Principal Occupation	Director Since
Fred C. Coles(1)(2)(4) Calgary, Alberta	Director	Independent businessman since April 1, 2002; prior thereto, Executive Chairman of Applied Terravision Systems Ltd.	September, 2003
Gary J. Drummond(9) Nassau, Bahamas	Director	Independent businessman since January 1, 2003; prior thereto, President of Direct Energy Marketing, a subsidiary of Centrica PLC.	September, 2003
Dennis L. Nerland(1)(3)(4)(7) Calgary, Alberta	Director	Partner, Shea Nerland Calnan (a law firm).	September, 2003
John A. Thomson, CA(1)(2)(3) Calgary, Alberta	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
Ryan K. Chong Calgary, Alberta	Vice-President, Engineering	Vice-President, Production of the Corporation since September, 2003; prior thereto, Manager, Acquisitions and Corporate Development of Baytex.	N/A
John G. Leach, CA Calgary, Alberta	Vice-President, Finance and Chief Financial Officer	Vice-President and Chief Financial Officer of the Corporation since September, 2003; prior thereto, Vice President, Finance and Administration of Baytex.	N/A
Ken Truscott Calgary, Alberta	Vice-President, Land	Vice-President, Land since September, 2007; prior thereto, Independent businessman since May, 2006; prior thereto President and Chief Executive Officer of Morpheus Energy Corporation.	N/A
Michael D. Sandrelli Calgary, Alberta	Corporate Secretary	Partner, Burnet, Duckworth & Palmer LLP since January, 2004; prior thereto, Associate, Burnet, Duckworth & Palmer LLP.	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. Drummond is a trustee of Heating Oil Partners Income Fund a Canadian income fund that distributes heating oil in the United States of America. On September 26, 2005, the Fund's operating subsidiary Heating Oil Partners, L.P. filed a voluntary petition for reorganization under Chapter 11 of the United States Bankruptcy Code and filed for recognition of the Chapter 11 proceedings under the Companies' Creditors Arrangement Act (Canada). As a consequence of these filings, the Fund's trust units were suspended from listing on the TSX effective at the close of business on October 6, 2005 and were subsequently delisted on November 7, 2005.

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, 2007, the directors and officers of Crew, as a group, beneficially owned, directly or indirectly, 5,335,410 Common Shares or approximately 10% of the issued and outstanding Common Shares.

Conflicts of Interest

Directors and officers of the Corporation may, from time to time, be involved with the business and operations of other oil and gas issuers, in which case a conflict may arise. Such conflicts must be disclosed in accordance with, and are subject to such other procedures and remedies as applicable under the ABCA.

AUDIT COMMITTEE INFORMATION

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

Name	Independent	Financially Literate	Relevant Education and Experience
John A. Thomson, CA	Yes	Yes	Mr. Thomson is a Chartered Accountant; was Senior Vice President and Chief Financial Officer of Renaissance Energy Ltd., a major Canadian oil and gas Company for 16 years and has been a board member and Officer for other public reporting oil and natural gas companies.
Fred C. Coles	Yes	Yes	Mr. Coles is a Professional Engineer with over 40 years of experience in the Oil and Gas Industry. He is the President of Menehune Resources Ltd., a private oil and gas company. Prior thereto, Mr. Coles was the Executive Chairman of Applied Terravision Systems Inc., a computer software development company, from 1994 to March 2002. Prior to 1994, Mr. Coles provided independent petroleum consulting to domestic and international clients for 21 years during his employment at Coles Gilbert Associates Ltd. (now GLJ) as Chairman and President. Mr. Coles is also a director of a number of private and public oil and gas companies.

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, the American Bar Association and the International Bar Association. Mr. Nerland is also a director of a number of public and private 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 2007 and 2006:

	Aggregate fees billed	
	2007	2006
Audit fees	130,000	70,000
Audit-related fees	92,000	67,000
Tax fees	66,205	1,029
All other fees	-	-
	288,205	138,029

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 Committees' Mandate and Terms of Reference is attached as Appendix C.

HUMAN RESOURCES

Crew currently employs 45 full-time employees, of which 41 are located in the head office and 4 are field employees, and 3 part-time consultants. Crew intends to add additional professional and administrative staff as the need arises.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

To the knowledge of the Corporation, there are no legal proceedings material to the Corporation to which the Corporation is or was a party to or of which any of its properties is or was the subject of, during the financial year ended December 31, 2007 nor are there any such proceedings known to the Corporation to be contemplated.

During the year ended December 31, 2007, 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

None of the directors or executive officers of Crew, and no person or company who owns, directly or indirectly, more than 10% of the common shares of Crew, nor any associate or affiliate of such persons, has or has had, at any time, any material interest in any transaction or proposed transaction that has materially affected or would materially affect Crew.

TRANSFER AGENT AND REGISTRAR

Valiant Trust Company, at its principal offices in Calgary, Alberta and through its agent BNY Trust Company of Canada in 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 Enco 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 rule 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.

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 and British Columbia, 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 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 m3/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 the approval of the Governor in Council.

The governments of Alberta and British Columbia 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, 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 negotiations between the mineral 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 22.1% effective January 1, 2007 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, the federal corporate income tax rate will decrease to 15% in five steps: 19.5% on January 1, 2008, 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. Currently, the amount of royalties that are payable is influenced by the oil production, density of the oil, and the vintage of the oil. Originally, the vintage classified oil as "new oil" and "old oil" depending on when the oil pools were discovered. If the pool was discovered prior to March 31, 1974 it is considered "old oil", if it was discovered after March 31, 1974 and before September 1, 1992, it is 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 has a base rate of 10% and a rate cap of 30%. The old oil royalty reserved to the Crown has a base rate of 10% and a rate cap of 35%.

The royalty reserved to the Crown in respect of natural gas production, subject to various incentives, is 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. Natural gas produced from qualifying intervals in eligible gas wells spudded or deepened to a depth below 2,500 metres is also subject to a royalty exemption, the amount of which depends on the depth of the well.

Oil sands projects are subject to a specific regulation made effective July 1, 1997, and expiring June 30, 2009 which, among other things, determines the Crown's share of crude and processed oil sands products.

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 ("**ARTC**") was to be eliminated, effective January 1, 2007. The programs affected by this announcement are: (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 being introduced is the Innovative Energy Technologies Program (the "**IETP**") which is intended to promote 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 will be the one to decide which projects qualify and the level of support that will be provided. The deadline for the IETP's third round of applications was May 31, 2007. The successful applicants have not yet been announced and it appears, based on the previous two rounds, that the selection process can take at least 8 months. The technical information gathered from this program is to be made public once a two year confidentiality period expires.

On October 25, 2007, the Alberta government released a report entitled "The New Royalty Framework" containing the government's proposals for Alberta's new royalty regime which is scheduled to be effective on January 1, 2009. The proposed NRF includes new royalty formulas for conventional oil and natural gas that will operate on sliding scales that are determined by commodity prices and well productivity. Substantial legislative, regulatory and systems updates will be introduced before changes become fully effective in January 2009. See "*General Development of the Business – Recent Developments*" and "*Risk Factors – New Alberta Royalty Regime*".

British Columbia

Producers of oil and natural gas in the Province of 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 11,450m3 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 the Province of 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 of up to $30 million annually 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.

- 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.

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.

In December, 2002, the Government of Canada ratified the Kyoto Protocol ("**Protocol**"). The 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 remains uncertain whether the Kyoto target of 6% below 1990 emission levels will be enforced in Canada. The Federal Government has introduced legislation aimed at reducing greenhouse gas emissions using a "intensity based" approach, the specifics of which have yet to be determined. 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 targeting research to lower the cost of technology.

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 of Canada'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 industries. The Updated Action Plan is intended to force industry to reduce greenhouse gas emissions and 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. The Updated Action Plan provides for: (i) mandatory reductions of 18% from the 2006 baseline starting in 2010 and by an additional 2% in subsequent years for existing facilities; (ii) new facilities built between 2004 and 2011 will have mandatory emissions standards based upon clean fuel standards (natural gas) with a 2% reduction below the third years intensity levels; and (iii) oil sands plants built in 2012 and later which use heavier hydrocarbons and upgraders and in situ production will have mandatory standards in 2018 based carbon capture and storage or other green technologies intensity. For the upstream oil and gas industry the Updated Action Plan also provides for a company threshold of 10,000 boe/day and facility threshold of 3,000 tonnes of C02.

Environmental legislation in the Province of 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 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 reduction emission guidelines outlined in the Climate Change and Emissions Management Amendment Act came into effect on July 1, 2007. 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. Industries can either choose one of these options or a combination thereof. The Corporation will be committed to meeting its responsibilities to protect the environment wherever it operates and anticipates making increased expenditures of both a capital and an expense nature as a result of the increasingly stringent laws relating to the protection of the environment, and will be taking such steps as required to ensure compliance with the EPEA and similar legislation in other jurisdictions in which it operates. The Corporation believes that it is in material compliance with applicable environmental laws and regulations. The Corporation also believes that 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 CO2 from other emissions supporting carbon capture and storage.

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 the Province's 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 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 gas sector. Among the changes to be implemented are: (i) a new 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 coal bed gas; and (vii) the new 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, on February 19, 2008 the provincial Government announced that starting on July 1, 2008, provided the legislation is approved, a revenue-neutral carbon tax will be applied to all fossil fuels used in the Province. 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 would receive otherwise.

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

An investment in the Corporation should be considered highly speculative due to the nature of the Corporation's activities and the present stage of its development. 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 that could have a material adverse effect upon its financial condition. 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 could have a material adverse effect on the Corporation.

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 business 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 will have 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 will therefore depend 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 will manage 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 will depend 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 will compete 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 will 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 intended business, financial condition and results of operations. 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.

New Alberta Royalty Regime

On October 25, 2007, the Alberta government released a report entitled "The New Royalty Framework" (the "**NRF**") containing the government's proposals for Alberta's new royalty regime which is scheduled to be effective on January 1, 2009. See "*General Development of our Business – Recent Developments*".

The Corporation cannot provide any assurance that the NRF will be implemented in the form proposed. If changes are made to the NRF before it is implemented by the Alberta government, such changes could result in the implementation of a new royalty regime that impacts the Corporation in a materially different manner, and that is more adverse to the Corporation, than the NRF as currently proposed.

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". Crew's exploration and production facilities and other operations and activities emit greenhouse gases which will likely subject Crew to possible future legislation regulating emissions of greenhouse gases, such as the government of Canada's proposed Clean Air Act of 2006 and Alberta's recently enacted Climate Change and Emissions Management Act. The direct or indirect costs of these regulations may adversely affect the expected business of Crew. 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 adversely affect the Corporation's financial condition, results of operations or prospects. See "*Industry Conditions – Environmental Regulation*".

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.

Both oil and natural gas prices are unstable and are 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. In addition, bank borrowings available to The Corporation will be in part determined by The Corporation's borrowing base. A sustained material decline in prices from historical average prices could reduce The Corporation's expected borrowing base, therefore reducing the bank credit available to The Corporation which could require that a portion, or all, of The Corporation's expected bank debt be repaid and a liquidation of assets.

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. 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 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 favourable terms acceptable to the Corporation.

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.

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. To the extent the Corporation is not the operator of its oil and gas properties, the Corporation will be dependent on such operators for the timing of activities related to such properties and will be largely unable to direct or control the activities of the operators.

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 could result in a reduction of the revenue received by the Corporation.

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

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

In accordance with applicable securities laws, the Corporation's independent reserves evaluator has used both constant and 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 reserves evaluation, and such variations could be material. The reserves 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 reserves evaluation will be reduced to the extent that such activities do not achieve the level of success assumed in the reserves evaluation. The reserves evaluation is effective as of a specific effective date and has not been updated and thus does not reflect changes in the Corporation's reserves since that date.

Insurance

The Corporation's involvement in the exploration for and development of oil and natural gas properties may result in the Corporation becoming subject to liability for pollution, blow outs, 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, could have a material adverse effect on the Corporation.

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 could have a material adverse effect on the Corporation. 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 could have a material adverse impact on its business, 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 results of operations and business.

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 business 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 this could have an adverse effect on the Corporation and its operations.

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 could have a material adverse effect on the Corporation and its cash flow from operations. 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

The directors or officers of the Corporation may also be directors or officers of other oil and gas companies or otherwise involved in natural resource exploration and development and situations may arise where they are in a conflict of interest with the Corporation. Conflicts of interest, if any, which arise will be subject to and governed by procedures prescribed by the Business Corporations Act (Alberta) (the "**ABCA**") which require a director or officer of a corporation who is a party to, or is a director or an officer of, or has a material interest in any person who is a party to, a material contract or proposed material contract with the Corporation disclose his or her interest and, in the case of directors, to refrain from voting on any matter in respect of such contract unless otherwise permitted under the ABCA.

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 could have a material adverse affect on 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.

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 22, 2008. 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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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, 2007 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
Vice-President, Finance and Chief Financial Officer

(signed) "Fred C. Coles"
Fred C. Coles
Director and Chairman of the Reserves Committee

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

March 25, 2008

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, 2007. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2007 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.

   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).

3. 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.

4. 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, 2007, 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 21, 2008	Canada	$-	$577,247	$-	$577,247

5. 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.

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

7. 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
March 3, 2008

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

6. 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.

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

8. 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:

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

10. 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.

11. 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.

12. 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.

13. 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.

14. 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.

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

16. 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.

17. 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.