



ANNUAL INFORMATION FORM

FOR THE YEAR ENDED

DECEMBER 31, 2008

March 31, 2009

TABLE OF CONTENTS

	Page
ABBREVIATIONS	ii
CONVERSIONS	ii
CERTAIN DEFINITIONS	iii
FORWARD-LOOKING STATEMENTS	v
BACKGROUND	1
GENERAL DEVELOPMENT OF THE BUSINESS	1
DESCRIPTION OF THE BUSINESS AND OPERATIONS	3
STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION	5
DIVIDENDS	17
DESCRIPTION OF CAPITAL STRUCTURE	17
MARKET FOR SECURITIES	18
ESCROWED SECURITIES	18
DIRECTORS AND OFFICERS	18
AUDIT COMMITTEE INFORMATION	20
HUMAN RESOURCES	22
INDUSTRY CONDITIONS	22
RISK FACTORS	28
AUDITORS, TRANSFER AGENT AND REGISTRAR	36
LEGAL PROCEEDINGS AND REGULATORY ACTIONS	36
INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS	37
MATERIAL CONTRACTS	37
INTERESTS OF EXPERTS	37
ADDITIONAL INFORMATION	37
SCHEDULE "A" - REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE	
SCHEDULE "B" - REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATORS	
SCHEDULE "C" - AUDIT COMMITTEE MANDATES	

ABBREVIATIONS

Oil and Natural Gas Liquids

Bbl	barrel
Bbls	barrels
Mbbls	thousand barrels
MMbbls	million barrels
Mstb	1,000 stock tank barrels
Bbls/d	barrels per day
BOPD	barrels of oil per day
NGLs	natural gas liquids
STB	standard tank barrels

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
MM	Million

Other

AECO	A natural gas storage facility located at Suffield, Alberta.
API	American Petroleum Institute
°API	an indication of the specific gravity of crude oil measured on the API gravity scale.
ARTC	Alberta Royalty Tax Credit
BOE	barrel of oil equivalent of natural gas and crude oil on the basis of 1 BOE for 6 Mcf of natural gas (this conversion factor is an industry accepted norm and is not based on either energy content or current prices)
BOE/d	barrel of oil equivalent per day
m ³	cubic metres
MBOE	1,000 barrels of oil equivalent
\$000s	thousands of dollars
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

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.

CONVERSIONS

To Convert From	To	Multiply By
Mcf	Cubic metres	28.174
Cubic metres	Cubic feet	35.494
Bbls	Cubic metres	0.159
Cubic metres	Bbls 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

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;

"**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**" means:

- (a) in relation to the Corporation's interest in production and reserves, the Corporation's working interest (operating and non-operating) share after deduction of royalty obligations.
- (b) in relation to wells, the number of wells obtained by aggregating the Corporation's working interest in each of its gross wells; and
- (c) in relation to the Corporation's interest in a property, the total area in which the Corporation has an interest multiplied by the working interest owned by the Corporation.

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

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

"**Sproule**" means Sproule Associates Limited;

"**Sproule Report**" means the report of Sproule dated February 9, 2009, evaluating the crude oil, natural gas liquids and natural gas reserves of the Corporation as at December 31, 2008;

"**True Arrangement**" means the plan of arrangement made effective November 2, 2005 among, *inter alia*, True Energy Inc., True Energy Trust (formerly TKE Energy Trust) and Vero under the provisions of Section 193 of the ABCA;

"**TSX**" means the Toronto Stock Exchange; and

"**Vero**", the "**Company**" or the "**Corporation**" means Vero Energy Inc., a corporation amalgamated pursuant to the ABCA.

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

Unless otherwise specified, information in this Annual Information Form is as at the end of the Corporation's most recently completed financial year, being December 31, 2008.

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

FORWARD-LOOKING STATEMENTS

Certain of the statements contained herein including, without limitation, financial and business prospects and financial outlook, reserve 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, the effect of government announcements, proposals and legislation, plans regarding hedging, expected or anticipated production rates, timing of expected production increases, weighting of production between different commodities, expected commodity prices, exchange rates, production expenses, transportations costs and other costs and expenses, maintenance of productive capacity and capital expenditures and methods of financing thereof, may be forward-looking statements. Words such as "may", "will", "should", "could", "anticipate", "believe", "expect", "intend", "plan", "potential", "continue" and similar expressions may be used to identify these forward-looking statements. These statements reflect management's current beliefs and are based on information currently available to management. Forward-looking statements involve significant risk and uncertainties. A number of factors could cause actual results to differ materially from the results discussed in the forward-looking statements including, but not limited to, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers, inability to retain drilling rigs and other services, incorrect assessment of the value of acquisitions, failure to realize the anticipated benefits of acquisitions, 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 reserve estimates of Vero's reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements.

Forward-looking statements or information are based on a number of factors and assumptions which have been used to develop such statements and information but which may prove to be incorrect. Although Vero believes that the expectations reflected in such forward-looking statements or information are reasonable, undue reliance should not be placed on forward-looking statements because Vero can give no assurance that such expectations will prove to be correct. In addition to other factors and assumptions which may be identified in this document, assumptions have been made regarding, among other things: the impact of increasing competition; the general stability of the economic and political environment in which Vero operates; the timely receipt of any required regulatory approvals; the ability of Vero to obtain qualified staff, equipment and services in a timely and cost efficient manner; drilling results; the ability of the operator of the projects which Vero has an interest in to operate the field in a safe, efficient and effective manner; the ability of Vero to obtain financing on acceptable terms; field production rates and decline rates; the ability to replace and expand oil and natural gas reserves through acquisition, development of exploration; the timing and costs of pipeline, storage and facility construction and expansion and the ability of Vero to secure adequate product transportation; future oil and natural gas prices; currency, exchange and interest rates; the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which Vero operates; and the ability of Vero to successfully market its oil and natural gas products.

Readers are cautioned that the foregoing list of factors is not exhausted. Additional information on these and other factors that could effect Vero'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), at Vero's website (www.veroenergy.ca). 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 reserve 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.

BACKGROUND

Vero is a junior oil and natural gas company engaged in the exploration for, and the acquisition, development and production of oil and natural gas reserves primarily in western Canada.

Vero was initially formed on November 2, 2005 upon the amalgamation of Vero Energy Inc. and its then wholly-owned subsidiary, Vero Finance Corp, in connection with the True Arrangement. See "*General Development of the Business*".

Vero was amalgamated on June 1, 2008 under the ABCA with its wholly-owned subsidiary, Vero AcquisitionCo Ltd., which was incorporated under the ABCA.

Vero AcquisitionCo. Corp., a company created to acquire Revolve Energy Inc. was wound up on December 9, 2008 into Vero Energy Inc.

Vero currently has one wholly owned subsidiary, Vero Oil and Gas Ltd., a corporation amalgamated under the ABCA.

Vero's head office is located at 1400, 333 - 5th Avenue S.W., Calgary, Alberta T2P 3B6 and its registered office is located at 1400, 350 - 7th Avenue S.W., Calgary, Alberta, T2P 3N9.

The Common Shares of Vero trade on the TSX under the symbol "VRO".

GENERAL DEVELOPMENT OF THE BUSINESS

History of Vero

Pre-2008

Vero 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 commenced active operations in November 2005 following completion of the True Arrangement.

Pursuant to the True Arrangement, effective November 2, 2005 Vero acquired working interests in certain of True Energy Inc.'s producing assets and undeveloped lands primarily in the Whitecourt/Edson area of west central Alberta, in addition to other minor properties (the "**Vero Initial Properties**"). At the effective date of completion of the True Arrangement, the Vero Initial Properties were producing approximately 850 Boe/d, comprised of 3,774 MMcf/d of natural gas and 221 Bbls/d of light oil and natural gas liquids. In addition, the Vero Initial Properties included approximately 61,600 net acres of undeveloped lands. Vero's fourth quarter 2008 production averaged 7,076 Boe/d representing a 732% increase since Vero commenced operations.

Funding for Vero's growth has come from a combination of cash flow from ongoing operations, the Corporation's bank facility and equity financings undertaken from time to time as described herein.

Vero has completed several material acquisitions since its inception as described below.

On February 24, 2006 Vero completed the acquisition (the "**Ledge Acquisition**") of all of the outstanding shares of a private company, Ledge Resources Limited ("**Ledge**"), on the basis of \$1.90 in cash and 0.49473 of a Common Share of Vero for each share of Ledge. The previous shareholders of Ledge received a total of \$18.25 million in cash and approximately 4.75 million Common Shares of Vero in exchange for all of the outstanding shares of Ledge.

Ledge was a junior oil and natural gas company that held certain producing oil and natural gas assets located primarily in the Westeros and Wilson Creek areas of Alberta, which, upon closing of the Ledge Acquisition were producing approximately 850 BOE/d, comprised of approximately 55% natural gas and 45% liquids with the

liquids consisting mainly of light sweet oil. The area is characterized by year round access and the main property acquired was a light, sweet Belly River oil pool at Wilson Creek.

Following the Ledge Acquisition, the name of Ledge Resources Limited was changed to Vero Resources Inc. and on January 1, 2007 Vero completed a short form amalgamation with Vero Resources Inc. and its wholly-owned subsidiary, 1144771 Alberta Ltd., to form "Vero Energy Inc."

On April 13, 2006 Vero completed a bought deal private placement of 2,131,150 Common Shares at a price of \$6.10 per share, for aggregate gross proceeds of \$13 million.

On April 5, 2007 Vero completed a bought deal private placement of 1,500,000 Common Shares at a price of \$5.55 per share and 1,500,000 Common Shares issued on a "flow-through" basis at a price of \$7.25 per share, for aggregate gross proceeds of \$19.2 million.

2008

On February 28, 2008 Vero completed a bought deal private placement of 1,940,000 Common Shares issued on a "flow-through" basis at a price of \$9.25 per share, for aggregate gross proceeds of \$17.9 million.

On April 15, 2008 Vero completed the acquisition (the "**Dorian Acquisition**") of all of the outstanding shares of a private company, Dorian Energy Inc. ("**Dorian**"), on the basis of 0.29366 of a Common Share of Vero for each share of Dorian. The previous shareholders of Dorian received an aggregate of approximately 1.8 million Common Shares of Vero in exchange for all of the outstanding shares of Dorian. Vero assumed approximately \$1.8 million of Dorian net debt in connection with the Dorian Acquisition. The Dorian Acquisition had many synergies for Vero including common working interests on over 50% of the purchased production and the addition of approximately 9,500 net acres of undeveloped land in Vero's core areas of Edson, Whitecourt and Ricinus.

On May 20, 2008 Vero completed the acquisition (the "**FX Acquisition**") of a private company, FX Energy Ltd. ("**FX**"), on the basis of \$0.25043 in cash for each share of FX. The previous shareholders of FX received a total of approximately \$2.4 million in exchange for all of the outstanding shares of FX. In addition Vero assumed approximately \$1.3 million of net debt as part of the consideration paid. Vero acquired approximately 11,400 net acres of undeveloped land and 355 thousand BOE of reserves as a result of the acquisition.

On November 10, 2008 Vero completed the acquisition (the "**Revolve Acquisition**") of all of the outstanding shares of a private company, Revolve Energy Inc. ("**Revolve**") pursuant to a plan of arrangement under the ABCA on the basis of 0.135 of a Common Share of Vero in exchange for each share of Revolve. The previous shareholders of Revolve received an aggregate of approximately 3.8 million Common Shares of Vero in exchange for all of the outstanding shares of Revolve. Vero assumed approximately \$4.3 million of Revolve net debt in connection with the Revolve Acquisition. Revolve was a junior oil and natural gas company that held certain producing oil and natural gas assets located primarily in the Edson area of Alberta which, upon closing of the Revolve Acquisition, were producing approximately 800 Boe/d. In addition, Vero acquired approximately 15,000 net undeveloped acres of high working interest land, 61 km (2) of proprietary 3D seismic data, 26 km (2) of trade 3D seismic data and 1,300 km of trade 2D seismic data pursuant to the Revolve Acquisition.

In connection with the Revolve Acquisition, Revolve was amalgamated with Vero's then wholly-owned subsidiary, 1405354 Alberta Ltd., to form Vero AcquisitionCo Corp., which was subsequently dissolved effective December 9, 2008.

Significant Acquisitions

There were no significant acquisitions completed by the Corporation during its most recently completed financial year for which disclosure is required under Part 8 of National Instrument 51-102.

Recent Developments

Effective March 25, 2009 Vero entered into an arrangement, with a new banking syndicate to provide a credit facility up to a maximum amount of \$115 million. The banking syndicate is made up of two Canadian financial institutions and the facility term will run until March 31, 2010 at which time the facility may be renewed by Vero at its option. The borrowing base will be subject to a semi-annual review in September, 2009.

DESCRIPTION OF THE BUSINESS AND OPERATIONS

Stated Business Objectives

The business plan of Vero is to generate profitable growth, measured by per share growth in production, proved reserves and cash flow from operations. To accomplish this, Vero will focus on the creation of value primarily through the generation and drilling of exploration and development prospects as well as through the exploitation and production of existing reserves. Vero targets areas and prospects that it believes could result in meaningful reserve and production additions.

Since commencing operations in November, 2005 Vero has concentrated on its core areas in Edson, Corbett and Whitecourt. These areas are characterized by multi-zone, liquids rich natural gas and light oil at medium depths. Vero also intends to pursue strategic acquisitions of oil and natural gas properties where it believes further exploration, exploitation and development opportunities exist. Vero's activities are currently directed predominantly towards natural gas and light oil prone prospects.

Vero will internally generate exploration and development opportunities possessing medium risk and multi-zone potential and will utilize a portfolio approach in developing these opportunities to achieve a balance of risk profiles and commodity exposures with a weighting predominantly towards natural gas. Vero will maintain a balance between exploration, development and exploitation drilling, combined with acquisition opportunities that meet its business parameters. To achieve sustainable and profitable growth, management of Vero believes in controlling the timing and costs of its projects wherever possible. Further, to minimize competition within its geographic areas of interest, Vero strives to maximize its working interest ownership in its properties where reasonably possible. While management believes that Vero has the skills and resources necessary to achieve its objectives, participation in exploration and development in the oil and natural gas industry has a number of inherent risks. See "*Risk Factors*".

In reviewing potential drilling or acquisition opportunities, Vero gives consideration to the following criteria:

- the capital required to secure or evaluate the investment opportunity;
- the potential return on the project, if successful;
- the likelihood of success; and
- the risked return versus cost of capital.

In general, Vero uses a portfolio approach in developing a large 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.

The board of directors of Vero may, in its discretion, but in discussion and agreement with the management of Vero, approve acquisitions that do not conform to these guidelines based upon its consideration of the qualitative aspects of the subject properties including risk profile, technical upside, reserve life and asset quality.

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

Competitive Conditions

Companies operating in the petroleum industry must manage risks, which are beyond the direct control of company personnel. Among these risks are those associated with exploration, environmental damage, commodity prices, foreign exchange rates and interest rates.

The oil and natural gas industry is intensely competitive and Vero will be required to compete with a substantial number of other corporations, which may have greater technical or financial resources. With the maturing nature of the Western Canadian Sedimentary Basin, the access to new prospects is becoming more and more competitive and complex. Management believes that Vero will be able to explore and develop new production and reserves with the objective of increasing its cash flow and reserve base.

Vero will attempt to enhance its competitive position by operating in areas where its technical personnel are able to reduce some of the risks associated with exploration, production and marketing because they are familiar with the areas of operation.

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 31, 2009. The effective date of the Statement is December 31, 2008 and the preparation date of the Statement is February 9, 2009.

Disclosure of Reserves Data

The reserves data set forth below (the "**Reserves Data**") is based upon evaluation by Sproule with an effective date of December 31, 2008 contained in the Sproule Report. The Reserves Data summarizes the crude oil, natural gas liquids and natural gas reserves of the Corporation and the net present values of future net revenue for these reserves using forecast prices and costs. The Sproule Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserve 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 Sproule to provide an evaluation of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

All of Vero's reserves are in Canada and, primarily, in the province of Alberta, with a minor amount attributed to Saskatchewan.

The Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3 and the Report on Reserves Data by Independent Qualified Reserves Evaluators in Form 51-101F2 are attached as Schedules "A" and "B" respectively, to this Annual Information Form.

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

Reserves Data (Forecast Prices and Costs)

SUMMARY OF OIL AND GAS RESERVES AND NET PRESENT VALUES OF FUTURE NET REVENUE AS OF DECEMBER 31, 2008 FORECAST PRICES AND COSTS

Reserves Category	Light and Medium Oil		Natural Gas		Natural Gas Liquids	
	Gross (Mbbls)	Net (Mbbls)	Gross (MMcf)	Net (MMcf)	Gross (Mbbls)	Net (Mbbls)
Proved Developed Producing	705.0	580.2	52,153	39,534	1,492.2	922.6
Proved Developed Non-Producing	-	-	2,965	2,299	87.1	54.6
Proved Undeveloped	91.2	76.0	31,374	23,548	926.4	600.0
Total Proved	796.2	656.2	86,492	65,381	2,505.7	1,577.2
Probable	380.6	288.4	37,640	27,731	1,072.1	680.7
Total Proved Plus Probable	1,176.8	944.6	124,132	93,112	3,577.8	2,257.9

NET PRESENT VALUES OF FUTURE NET REVENUE (\$000S)

Reserves Category	Before Income Taxes Discounted At (%/year)					After Income Taxes Discounted At (%/year)					Unit Value Before Income Tax Discounted at 10%/Year ⁽¹⁾
	0	5	10	15	20	0	5	10	15	20	(\$/Boe)
	Proved Developed Producing	345,619	273,918	229,289	198,827	176,646	308,018	245,590	206,568	179,812	160,248
Proved Developed Non-Producing	18,209	14,703	12,257	10,474	9,126	13,424	10,766	8,914	7,564	6,545	28.00
Proved Undeveloped	162,602	110,039	77,432	55,750	40,545	121,430	80,544	55,105	38,154	26,253	16.83
Total Proved	526,429	398,660	318,978	265,051	226,317	442,872	336,900	270,587	225,530	193,046	24.29
Probable	271,270	159,399	106,222	76,420	57,783	203,293	118,571	78,331	55,767	41,650	19.00
Total Proved Plus Probable	797,699	558,059	425,200	341,471	284,100	646,165	455,471	348,918	281,298	234,696	22.71

Note:

2. Unit value before income tax is calculated based on net reserve volumes.

**TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2008
FORECAST PRICES AND COSTS
(\$000S)**

Reserves Category	Revenue	Royalties	Operating Costs	Development Costs	Abandonment and Reclamation Costs	Future Net Revenue Before Income Taxes	Future Income Taxes	Future Net Revenue After Future Income Taxes
Proved	1,070,572	256,475	221,058	59,931	6,679	526,429	83,557	442,872
Proved Plus Probable	1,620,704	395,770	339,164	80,191	7,880	797,699	151,534	646,165

**FUTURE NET REVENUE
BY PRODUCTION GROUP
AS OF DECEMBER 31, 2008
FORECAST PRICES AND COSTS**

Reserves Category	Production Group	Future Net Revenue Before Income Taxes (discounted at 10%/year) (\$000s)	Unit Value (\$/Boe) of Net Reserves (Before Income Taxes and Discounted at 10%/year)
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	32,590	29.69
	Natural Gas (including by-products but excluding solution gas from oil wells)	286,388	23.80
Proved Plus Probable	Light and Medium Crude Oil (including solution gas and other by-products)	45,643	28.39
	Natural Gas (including by-products but excluding solution gas from oil wells)	379,557	22.18

Notes to Reserves Data Tables:

1. Columns may not add due to rounding.
2. The crude oil, natural gas liquids and natural gas reserve estimates presented in the Sproule Report are based on the definitions and guidelines contained in the COGE Handbook. A summary of those definitions are set forth below.

Reserve Categories

Reserves are estimated remaining quantities of oil and 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.

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

- (a) at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and
- (b) at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves.

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

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

3. Forecast Prices and Costs

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 Vero 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, inflation and exchange rates utilized by Sproule in the Sproule Report were the average forecast prices published by Sproule, GLJ Petroleum Consultants Ltd., McDaniel & Associates Consultants Ltd. and AJM Petroleum Consultants Ltd. as at December 31, 2008, which were as follows:

**SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
FORECAST PRICES AND COSTS**

Year	WTI Cushing Oklahoma (\$US/Bbl)	Light Sweet Crude Oil at Edmonton 40° API (\$Cdn/Bbl)	NATURAL GAS LIQUIDS Edmonton Butane (\$Cdn/Bbl)	NATURAL GAS LIQUIDS Edmonton Condensate (\$Cdn/Bbl)	NATURAL GAS NYMEX (\$US/ MMBtu)	NATURAL GAS AECO -C Spot (\$Cdn/ MMBtu)	INFLATION RATES ⁽¹⁾ %/Year	EXCHANGE RATE ⁽²⁾ (\$US/\$Cdn)
Forecast								
2009	56.56	67.24	51.65	69.29	6.76	7.20	2.0	0.82
2010	69.83	80.48	61.59	82.90	7.56	7.89	2.0	0.85
2011	78.80	87.85	67.24	90.49	8.12	8.21	2.0	0.88
2012	88.90	93.92	71.93	96.73	9.04	8.72	2.0	0.93
2013	97.42	99.81	76.44	102.81	9.84	9.24	2.0	0.96
2014	99.38	101.82	77.99	104.87	10.03	9.44	2.0	0.96
2015	101.36	103.88	79.57	107.00	10.23	9.64	2.0	0.96
2016	103.38	105.97	81.15	109.15	10.43	9.83	2.0	0.96
2017	105.43	108.06	82.75	111.28	10.64	10.04	2.0	0.96
2018	107.57	110.26	84.44	113.57	10.86	10.24	2.0	0.96
2019	109.71	112.46	86.13	115.82	11.07	10.45	2.0	0.96
Thereafter	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	2.0	0.96

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 Vero for the year ended December 31, 2008 were \$8.77/Mcf for natural gas, \$96.46/Bbl for light and medium gravity crude oil and \$81.80/Bbl for NGLs.
4. Estimated future abandonment costs related to a property have been taken into account by Sproule in determining reserves that should be attributed to a property and in determining the aggregate future net revenue therefrom, there was deducted the reasonable estimated future well abandonment costs. No allowance was made, however, for salvage values, reclamation of well sites or the abandonment and reclamation of any facilities.
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 Sproule was accepted by Sproule as represented. No field inspections were conducted.
7. The Alberta government has announced, but not yet enacted, provisions that allow for transitional royalties ("**Transitional Royalties**") to the NRF for certain elected wells. Reserves and net present values reflected in the above tables have been determined under the existing NRF and do not reflect Transitional Royalties that may be applicable on a well by well basis. No sensitivities were provided by Sproule as to the potential impact of Transitional Royalties.
8. On March 3, 2009 the Alberta government announced a three point incentive program to stimulate new and continued economic activity in Alberta which included a drilling royalty credit for new conventional oil and

natural gas wells and a new well royalty incentive program. Reserves and net present values represented in the above tables do not reflect the potential effect of this new program and no sensitivities were provided by Sproule as to the potential impact of same.

Reconciliation of Changes in Reserves

The following table sets out the reconciliation of Vero's gross reserves based on forecast prices and costs by principal product type:

FACTORS	LIGHT AND MEDIUM OIL			ASSOCIATED AND NON-ASSOCIATED GAS			NATURAL GAS LIQUIDS		
	Gross Proved (Mbbls)	Gross Probable (Mbbls)	Gross Proved Plus Probable (Mbbls)	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)	Gross Proved (Mbbls)	Gross Probable (Mbbls)	Gross Proved Plus Probable (Mbbls)
December 31, 2007	1,049	397	1,446	44,630	17,647	62,277	1,092	428	1,520
Extensions and Improved Recovery	83	(23)	60	27,343	13,317	40,660	775	376	1,151
Technical Revisions	(517)	(96)	(613)	(10,317)	(1,877)	(12,194)	(129)	(4)	(133)
Discoveries	35	17	52	20,383	4,960	25,343	641	155	796
Acquisitions	353	86	439	16,941	4,041	20,982	436	119	555
Dispositions	-	-	-	-	-	-	-	-	-
Economic Factors	7	0	7	(1,723)	(448)	(2,171)	(12)	(2)	(14)
Production	(214)	0	(214)	(10,765)	-	(10,765)	(297)	-	(297)
December 31, 2008	796	381	1,177	86,492	37,640	124,132	2,506	1,072	3,578

Notes:

- (1) The Corporation has no unconventional reserves (bitumen, synthetic crude oil, natural gas from coal, etc.).
- (2) There are no heavy oil reserves in 2008.

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 Vero's assets for the years ended December 31, 2008, 2007 and 2006 and, in the aggregate, before that time based on forecast prices and costs.

Proved Undeveloped Reserves

Year	Light and Medium Oil (Mtbl)		Natural Gas (MMcf)		NGLs (Mtbl)	
	First Attributed	Booked at Year End	First Attributed	Booked at Year End	First Attributed	Booked at Year End
Prior thereto	44	44	1,155	1,155	53	53
2006	0	0	1,486	2,641	28	81
2007	137	0	5,383	8,024	138	219
2008	91	91	25,191	31,373	708	926

Probable Undeveloped Reserves

Year	Light and Medium Oil (Mbbbl)		Natural Gas (MMcf)		NGLs (Mbbbl)	
	First Attributed	Booked at Year End	First Attributed	Booked at Year End	First Attributed	Booked at Year End
Prior thereto	69	69	3,947	3,947	177	177
2006	0	0	499	4,446	0	150
2007	80	0	3,278	7,894	52	202
2008	23	23	13,075	19,267	361	563

Proved and probable undeveloped reserves are attributed by Sproule in accordance with standards and procedures contained in the COGE Handbook. In general, once proved and/or probable undeveloped reserves are identified they are scheduled into Vero's development plans. Normally, the Corporation plans to develop its proved and probable undeveloped reserves within two years. However, if the economic climate is not conducive to developing these reserves within two years, Vero may, in its discretion, defer the development into the future. A number of factors that could result in delayed or cancelled development are as follows:

- changing economic conditions (due to commodity pricing, operating and capital expenditure fluctuations);
- changing technical conditions (production anomalies (such as water breakthrough, 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.

Recently in 2009 the industry has experienced significant reductions in natural gas prices which has created significant uncertainty regarding particular components of the reserves data. In addition, recent announcements from the Alberta Government providing royalty and drilling incentives to the industry are expected to impact Vero's reserve evaluations in a positive way. The reserves can be affected significantly by fluctuations in product pricing, capital expenditures, operating costs, royalty regimes and well performance that are all beyond our 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 reserve categories noted below (\$000s):

Year	Forecast Prices and Costs	
	Proved Reserves	Proved Plus Probable Reserves
2009	51,006.5	68,178.3
2010	8,924.5	12,012.5
2011	-	-
2012	-	-
2013	-	-
Thereafter	-	-
Total Undiscounted	59,931.0	80,190.7

We expect 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, we do not expect that the costs of funding will effect the disclosed reserves of future net revenue. However, the availability of internal cash flows is dictated in a significant way by commodity prices. If commodity prices decline, projects may be delayed as the funds available become restricted.

Other Oil and Gas Information

Principal Properties

The following is a description of Vero's principal oil and natural gas properties as at December 31, 2008. Unless otherwise indicated, production stated is the average production for the year ended December 31, 2008 received by us in respect of our working interest share before deduction of royalties. Unless otherwise specified, gross and net acres and well count information is as at December 31, 2008.

Vero's core area of operations is centered on an area approximately 150 kilometers west of the city of Edmonton and is situated between the towns of Whitecourt to the north and Rocky Mountain House to the south. The Company's properties are characterized by multi-zoned liquids rich natural gas and sweet light oil targets with depth ranges from 400 to 2,500 meters. Production for the year averaged 6,295 BOE/d (78% natural gas) with a year end exit rate of approximately 8,000 BOE/d (81% natural gas). At December 31, 2008 Vero's properties were comprised of 221 (123.2 net) producing natural gas wells and 50 (25.8 net) producing oil wells in the aggregate

In 2008, Vero drilled 34 (26.7 net) wells, resulting in 32 (25.2 net) gas wells, 1 (1.0 net) oil wells and 1 (0.5 net) dry wells. Of the successful wells, 23 (17.4 net) are tied-in and producing and 10 (8.8 net) are completed and awaiting tie-in.

During the year the total land holdings were positively influenced by purchases at Alberta Crown land-sales as well as strategic acquisitions primarily within our Whitecourt and Edson core areas. A total of four acquisitions were made, three corporate and one comprising producing properties and undeveloped lands. At the end of 2008 Vero's land holdings were 178,882 gross (90,701 net) developed acres and 232,363 (171,183 net) undeveloped acres. Undeveloped land increased by 77,827 net acres in 2008.

Edson is the Company's largest and most active drilling and production area where a total of 25 gross (18.7 net) wells were drilled in 2008. Production for Edson averaged 4,038 BOE/d (80% natural gas) for the year. At the Company's inception just over three years ago the drilling program consisted primarily of vertical wells along with a small percentage of horizontal drills. Due to the continued success, the horizontal drilling portion of our program has steadily increased so that at year end a total of 22 gross (18.5 net) horizontal wells had been drilled. In 2008 alone, a total of 14 gross (12.2 net) horizontal wells were drilled equating to 56% of our Edson wells. Going forward, Vero's 2009 drilling plans for the Edson area include drilling up to 13 gross (12.3 net) wells including up to 11 gross (10.3 net) horizontal wells. The Company initially targeted the Rock Creek sands at a depth of about 2,400m with horizontal wells. At year end there were 15 producing Rock Creek horizontal wells with one additional well being completed and tied-in for production. The Edson area is characterized by multi-zone prospectivity, with the Company producing from a total of eight (8) different zones. Such prospectivity holds the potential for further horizontal drilling over a number of targets beyond just the Rock Creek. As such, during 2008 the Company made a commitment, by drilling, to evaluate the productive potential of some of these other zones. Subsequent horizontal drilling activity in these other tight gas sands resulted in six (6) producing horizontal wells at year end. Extension into additional gas charged zones has substantially increased Vero's visible project inventory. At year end Vero's acreage in the Edson area consisted of 68,640 gross (37,528 net) developed acres and 66,240 gross (50,349 net) undeveloped acres. It is expected that in due course, a majority of this acreage will have a minimum of two wells per section in order to drain the gas reserves which have been identified.

The Whitecourt area is located approximately 150 kilometers northwest of Edmonton and Vero's interest in the area currently consists of 34 (18.7 net) producing natural gas wells. Whitecourt production averaged 847 BOE/d for the year ended December 31, 2008, weighted 86% to natural gas. The Whitecourt area had limited drilling activity during the year with 1 (1.0 net) well drilled during the year. A number of drilling opportunities have been identified within the Whitecourt core area. Resembling Edson, the Whitecourt area has a number of tight Mannville gas charged sands that require a reduced drilling spacing to a density of more than one well per section in order to efficiently drain the gas. Reduced spacing applications have been made and approved on a number of these opportunities, so that, once commodity prices improve; we have the flexibility to execute on them. Due to the success that we have had with our horizontal drilling in the Edson core, we plan to transfer this technology and expertise to this area. At year end Vero's acreage in the area consisted of 42,556 gross (22,612 net) developed acres and 66,400 gross (52,261 net) undeveloped acres.

The Corbett area is located approximately 50 kilometers northwest of Edmonton and consists of 11 (7.4 net) producing natural gas wells and 5 (5.0 net) oil wells. Corbett production averaged 842 BOE/d for the year ended December 31, 2008, weighted 68% to natural gas and 32% to oil and natural gas liquids.

The Wilson Creek area is located approximately 100 kilometers southwest of Edmonton and consists of 12 (7.4 net) producing natural gas wells and 22 (9.2 net) producing oil wells. Wilson Creek production averaged 304 BOE/d for the year ended December 31, 2008, weighted 62% to natural gas and 38% to oil and natural gas liquids.

Oil And Gas Wells

The following table sets forth the number and status of wells in which the Corporation had a working interest as at December 31, 2008.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	45	24.3	4	3.1	221	123.2	183	94.1
Saskatchewan	5	1.5	2	0.6	-	-	4	4.0
Total	50	25.8	6	3.7	221	123.2	187	98.1

Land Holdings Including Properties with no Attributed Reserves

The following table sets out the Corporation's developed and undeveloped land holdings as at December 31, 2008.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Alberta	173,660	89,869	220,777	160,119	394,437	249,988
Saskatchewan	324	97	10,926	10,869	11,250	10,966
British Columbia	4,898	735	660	195	5,558	930
Total	178,882	90,701	232,363	171,183	411,245	261,884

There are no material work commitments associated with the Corporation's undeveloped land holdings as of the date of this AIF. The Corporation's rights to explore, develop and/or exploit 39,935 net acres of its undeveloped land holdings may expire by December 31, 2009. We plan to drill or submit applications to continue selected portions of the above acreage.

Forward Contracts and Marketing

Vero's crude oil, natural gas and natural gas liquid production is sold directly to credit-worthy counterparties, with the exception of small quantities of non-operated properties, which are marketed by the operator.

The board of directors of Vero has authorized management to hedge up to 50% of its total production from time to time to provide downside commodity price protection through the use of financial derivative structures and short-term physical contracts. As at December 31, 2008 there were no hedges outstanding.

Additional Information Concerning Abandonment and Reclamation Costs

The Corporation uses its internal historical costs to estimate its abandonment and reclamation costs when available. The costs are estimated on an area by area basis. The industry's historical costs are used when available. If representative comparisons are not readily available, an estimate is prepared based on the various regulatory abandonment requirements. As at December 31, 2008 the Corporation has 250.9 net wells for which it expects to incur abandonment and reclamation costs.

The total of such costs, net of estimated salvage value, was \$7,880 thousand (undiscounted) and \$2,185 thousand (discounted at 10%). One hundred percent of such amounts were deducted as abandonment and reclamation costs in estimating future net revenue of the Corporation in respect of proved reserves as disclosed above. The following table sets forth abandonment costs deducted in the estimation of the Corporation's future net revenue:

Forecast Prices and Costs (Total Proved) (\$000s)

Year	Abandonment Costs (Undiscounted)
2009	214
2010	88
2011	275
2012	266
2013	455
Thereafter	5,381
Total Undiscounted	6,679
Total Discounted @ 10%	2,522

Tax Horizon

The income tax deducted in the calculation of future net revenue above assumes a blow-down scenario whereby Vero produces out its existing reserves and does not reinvest any capital. Under this scenario, and given Vero's existing tax pools at December 31, 2008, it is currently anticipated that Vero would not be taxable in 2009 or 2010.

Capital Expenditures

The following table summarizes capital expenditures (including capitalized and general administrative expenses) related to the Corporation's activities for the year ended December 31, 2008:

	000's
Property acquisition costs	
Proved properties	19,537
Undeveloped properties ⁽¹⁾	5,228
Exploration costs	7,206
Development costs	93,874
Administrative	39
Dispositions	(15)
Corporate Acquisitions	2,816
Total	<u>128,685</u>

Notes:

- (1) Cost of land acquired and non-producing lease rentals on those lands.

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells in which Vero participated in the year ended December 31, 2008. This table does not include wells drilled in any of Dorian, FX or Revolve prior to their respective acquisition by Vero in 2008.

	Exploratory Wells		Development Wells	
	Gross	Net	Gross	Net
Natural Gas	6	5.2	26	20.1
Light and Medium Oil	-	-	1	1.0
Service	-	-	6	4.8
Dry	-	-	1	0.5
Total	<u>6</u>	<u>5.2</u>	<u>34</u>	<u>26.4</u>

See "*Principal Properties*" for a description of the Corporation's most important current and likely exploration and development plans during 2009.

Production Estimates

The following table sets out the volume of the Corporation's production estimated for the year ended December 31, 2009 as evaluated by Sproule, which is reflected in the estimate of gross proved reserves and gross probable reserves disclosed in the tables contained under "*Disclosure of Reserves Data*".

Reserves Category	Light and Medium Oil	Natural Gas	Natural Gas Liquids	Total
	Gross (Bbls/d)	Gross (Mcf/d)	Gross (Bbls/d)	Gross (BOE/d)
PROVED				
Edson	58	24,729	773	4,952
Other Properties	397	14,681	348	3,185
Total Proved	455	39,371	1,121	8,138
PROVED PLUS PROBABLE				
Edson	64	26,795	837	5,367
Other Properties	421	15,622	365	3,383
TOTAL PROVED PLUS PROBABLE	485	42,377	1,202	8,750

The Corporation's Edson field is the only field which accounts for 20% or more of the Corporation's estimated 2009 production in the Sproule Report.

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:

	2008			
	Quarter Ended			
	Dec. 31	Sept. 30	June 30	Mar. 31
Average Daily Production ⁽¹⁾				
Light and Medium Crude Oil (Bbls/d)	486	515	666	567
Natural Gas (Mcf/d)	33,428	30,059	27,705	26,730
NGLs (Bbls/d)	1,018	711	804	749
Combined (BOE/d)	7,076	6,236	6,087	5,771
Average Price Received				
Light and Medium Crude Oil (\$/Bbl)	56.20	112.72	120.61	88.07
Natural Gas (\$/Mcf)	8.43	7.27	10.64	8.51
NGLs (\$/Bbls)	42.34	100.07	111.23	86.89
Combined (\$/BOE)	49.80	55.78	76.30	59.35
Royalties Paid				
Light and Medium Crude Oil (\$/Bbls)	5.31	20.86	14.65	11.85
Natural Gas (\$/Mcf)	2.24	2.08	2.36	2.38
NGLs (\$/Bbls)	14.37	32.54	40.13	30.82
Combined (\$/BOE)	13.03	15.44	17.65	16.17
Operating & Transportation Expenses (\$/BOE)				
Light and Medium Crude Oil (\$/Bbls)	10.95	11.71	11.98	10.56
Natural Gas (\$/Mcf)	1.94	1.16	0.97	0.94
NGLs (\$/Bbls)	12.14	14.21	12.05	7.66
Combined (\$/BOE)	11.63	8.17	7.34	6.32

Netback Received (\$/BOE) ⁽²⁾				
Light and Medium Crude Oil (\$/Bbls)	39.94	80.15	93.98	65.66
Natural Gas (\$/Mcf)	4.25	4.03	7.31	5.19
NGLs (\$/Bbls)	15.83	53.32	59.05	48.41
Combined (\$/BOE)	25.14	32.17	51.31	36.86

Notes:

- (1) Before deduction of royalties.
(2) Netbacks are calculated by subtracting royalties and operating costs from revenues.

The following table indicates the Corporation's average daily production from its important fields for the year ended December 31, 2008:

	Light and Medium Crude Oil (Bbls/d)	Natural Gas (Mcf/d)	NGLS (Bbls/d)	BOE (BOE/d)
Edson	157	19,354	655	4,037
Corbett	238	3,446	29	841
Whitecourt	64	4,357	56	846
Wilson Creek	66	1,138	48	304
Other Alberta	31	1,199	33	265
Total Alberta	556	29,494	821	6,293
Saskatchewan	2	-	-	2
Total Company	558	29,494	821	6,295

Vero's crude oil production for the year ended December 31, 2008 was 100% light and medium quality crude oil (25° API or greater).

For the year ended December 31, 2008, approximately 69% of Vero's gross revenue was derived from natural gas production; 14% was derived from crude oil production; 18% was derived from natural gas liquids and the remainder of (1)% was derived from hedging gains.

DIVIDENDS

Vero has not paid any dividends on the outstanding Common Shares. The board of directors of Vero will determine the actual timing, payment and amount of dividends, if any, that may be paid by Vero from time to time based upon, among other things, the cash flow, results of operations and financial conditions of Vero, the needs for funds to finance ongoing operations and other business considerations as the board of directors of Vero considers relevant. Payment of dividends is subject to the consent of Vero's lenders.

DESCRIPTION OF CAPITAL STRUCTURE

The authorized capital of Vero consists of an unlimited number of Common Shares and an unlimited number of first preferred shares issuable in series. The following is a summary of the rights, privileges, restrictions and conditions attaching to the securities of Vero.

Common Shares

Holders of Common Shares are entitled to one vote per share at meetings of shareholders of Vero, to receive dividends if, as and when declared by the board of directors of Vero and to receive pro rata the remaining property and assets of Vero upon its dissolution, liquidation or winding-up, subject to the rights of shares having priority over the Common Shares. As at December 31, 2008 there were 36,969,162 Common Shares outstanding.

First Preferred Shares

Each series of first preferred shares shall consist of such number of shares and having such rights, privileges, restrictions and conditions as may be determined by the board of directors of Vero prior to the issuance thereof. With respect to the payment of dividends and distribution of assets in the event of liquidation, dissolution or winding-up of Vero, whether voluntary or involuntary, the first preferred shares are entitled to preference over the Common Shares and any other shares ranking junior to the preferred shares from time to time and may also be given such other preferences over the Common Shares and any other shares ranking junior to the first preferred shares as may be determined at the time of creation of such series. As at December 31, 2008, no series of preferred shares has been created.

MARKET FOR SECURITIES

The Common Shares are listed and posted for trading on the TSX and trade under the symbol "VRO". 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		Volume (000s)
	High (\$/share)	Low (\$/share)	
2008			
January	7.10	5.61	4,625
February	7.98	6.75	4,438
March	8.25	6.50	1,560
April	9.00	7.50	5,102
May	9.95	8.70	4,760
June	11.34	9.11	5,162
July	10.90	8.12	2,899
August	9.95	8.18	1,536
September	9.15	6.55	2,612
October	7.84	5.00	4,072
November	7.20	5.51	2,092
December	6.07	4.48	2,149
2009			
January	5.94	3.97	3,561
February	4.10	2.86	5,416
March (1-30)	3.81	2.70	3,273

ESCROWED SECURITIES

There are currently no securities of Vero held in escrow.

DIRECTORS AND OFFICERS

The names, province and country of residence, office held with the Corporation and principal occupation of the directors and officers of the Corporation are set out below:

<u>Name, Province and Country of Residence</u>	<u>Office Held</u>	<u>Principal Occupation Held During Last Five Years</u>
Paul R. Baay ⁽²⁾⁽³⁾ Alberta, Canada	Chairman of the Board and a Director	Managing Director of Abacus Energy and Chairman of Veraz Petroleum Ltd.; prior thereto, President and Chief Executive Officer of True Energy Inc. since its formation on August 31, 2000 until May 14, 2007.

Name, Province and Country of Residence	Office Held	Principal Occupation Held During Last Five Years
Douglas J. Bartole Alberta, Canada	President, Chief Executive Officer and a Director	President and Chief Executive Officer of Vero since November, 2005; prior thereto, Vice-President, Operations of True Energy Inc. since April 2005; prior thereto held various positions with True Energy Inc. since May 2001; prior thereto, from 1997-2000 held various positions with Renaissance Energy Ltd.
Gerald N. Gilewicz Alberta, Canada	Vice-President, Finance and Chief Financial Officer	Vice-President of Finance and Chief Financial Officer of Vero since November, 2005; prior thereto, Vice President of Finance and Chief Financial Officer of Dual/Devlan Exploration Inc. from 1999 to November 2005; prior thereto, Senior Manager with Deloitte & Touche LLP.
Kevin W. Yakiwchuk Alberta, Canada	Vice-President, Exploration	Vice-President, Exploration of Vero since November, 2005; prior thereto, Vice-President, Exploration of True Energy Inc. since January 2005; prior thereto held various positions with True Energy Inc. since May 2001; prior thereto, geologist with Crestar Energy Inc. from April 2000-May 2001
Robert Bachynski Alberta, Canada	Vice President, Land	Vice President, Land of Vero since November 2005; prior thereto, Manager of Land at Apache Canada Ltd. since January 2001; prior thereto Manager Land at Canadian Forest Oil Ltd.; prior thereto has held management positions for various oil and gas exploration companies in Western Canada.
Shane Manchester Alberta, Canada	Vice-President, Operations	Vice President of Operations of Vero since April of 2006; prior thereto, Production and Engineering Manager with True Energy Inc.; prior thereto held various positions with Renaissance Energy Ltd., Husky Energy Ltd. and National Fuel Exploration Corporation.
Leslie Kende Alberta, Canada	Vice-President, Engineering	Vice President of Engineering of Vero since July 2008; prior thereto, Vice President New Ventures with Pengrowth Management Limited from November 2007; prior thereto Vice President and Director of Tristone Capital Inc. from April 2003; prior thereto held a various positions for a number of oil and gas exploration companies in Western Canada.
W.C. (Mickey) Dunn ⁽²⁾⁽³⁾⁽⁴⁾ Alberta, Canada	Director	Independent businessman; Director of Vero Energy Inc.; Chairman of True Energy Trust; Director of Cash Store Financial Inc.; prior thereto President and Chief Executive Officer of Cardium Service and Supply Ltd., Cardium Tool Services Inc. and Colorado Silica Sand Inc.
Robert G. Rowley ⁽¹⁾⁽³⁾ Alberta, Canada	Director	Independent Businessman; Director and Officer of various private oil and gas companies; former Director of True Energy Inc.; former partner with Macleod Dixon LLP (Barristers and Solicitors).

Name, Province and Country of Residence	Office Held	Principal Occupation Held During Last Five Years
Kenneth P. Acheson ⁽¹⁾⁽⁴⁾ Alberta, Canada	Director	President, Kennington Properties Ltd. (commercial real estate company)
Clinton T. Broughton ⁽¹⁾⁽²⁾⁽⁴⁾ Alberta, Canada	Director	Independent businessman; previously Chief Operating Officer then Executive Vice-President of True Energy Inc. from April 25, 2005 to November 30, 2006; prior thereto Vice President of True Energy Inc. since its formation on August 31, 2000
Michael D. Sandrelli Alberta, Canada	Corporate Secretary	Partner with Burnet, Duckworth & Palmer LLP (Barristers and Solicitors).

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) Vero does not have an executive committee of its board of directors.

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

All of the directors of Vero were appointed in September 2005. The term of office of each director expires at the next annual meeting of shareholders of the Corporation.

As at December 31, 2008, the directors and officers of Vero, as a group, beneficially owned, or controlled or directed, directly or indirectly, an aggregate of 3,599,118 Common Shares or approximately 10% of the issued and outstanding Common Shares.

Conflicts of Interest

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

AUDIT COMMITTEE INFORMATION

Audit Committee Mandate and Terms of References

The Mandate and Terms of Reference of the Audit Committee of the board of directors is attached hereto as Schedule "C".

Composition of the Audit Committee

The following table sets forth the names of each current member of the Audit Committee, whether such member is independent (in accordance with National Instrument 52-110), whether such member is financially literate and the relevant education and experience of such member:

<u>Name</u>	<u>Independent</u>	<u>Financially Literate</u>	<u>Relevant Education and Experience</u>
Kenneth P. Acheson	Yes	Yes	Mr. Acheson graduated from University of Manitoba with a Bachelor of Science and subsequently received his Chartered Accountant designation in 1982. Mr. Acheson chairs the audit committee of Vero Energy and is a member of the board of directors. Mr. Acheson served as chairman of the audit committee and on the board of directors of True Energy during 2005. Mr. Acheson is the president of a private real estate company.
Robert G. Rowley	Yes	Yes	Mr. Rowley graduated from the University of Calgary in 1964 with a BSc. Degree and from the University of Alberta with an LLB degree in 1967. Mr. Rowley practiced commercial law in Calgary with the firm of Macleod Dixon until his retirement as an equity partner in 1996 and thereafter continued in practice with that firm as a non-equity partner until 2002. Mr. Rowley continues as a member of the Alberta Law Society as Counsel to Clanrob Resources Inc. In 1989 Mr. Rowley was appointed Queen's Counsel. Mr. Rowley is a director or officer of various private oil and gas companies and is a former director and audit committee member of True Energy Inc.
Clinton T. Broughton	Yes	Yes	Mr. Broughton is a professional engineer who has been active in the oil and gas industry for over 40 years including 22 in senior corporate management roles for both large and mid-sized companies. He retired as Executive Vice President and member of the Disclosures Committee of True Energy Trust on November 30, 2006.

Pre-Approval of Policies and Procedures

As of the date hereof the Audit Committee has not adopted specific policies or procedures in respect of the provision of non-audit services to the Corporation.

Vero has adopted the following policies and procedures with respect to the pre-approval of audit and permitted non-audit services to be provided by its auditors: 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 its auditors. 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 judgment as to whether a proposed service fits within the preapproved 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.

Vero 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.

External Auditor Service Fees

Audit Fees

The aggregate fees billed by our external auditor in each of the last two fiscal years for audit services were \$57,900 in respect of the 2007 audit and \$78,000 in respect of the 2008 audit. 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

The aggregate fees billed in each of the last two fiscal years for assurance and related services by the Corporation's external auditor that are reasonably related to the performance of the audit or review of the Corporation's financial statements that are not reported under "Audit Fees" above were \$36,000 in respect of 2007 and \$37,500 in respect of 2008. These fees were for the review of the quarterly financial statements and MD&A of Vero.

Tax Fees

The aggregate fees billed in each of the last two fiscal years for professional services rendered by the Corporation's external auditor for tax compliance, tax advice, tax subscriptions and tax planning were \$700 in 2007 and \$700 in 2008. The fees noted were paid solely in relation to a tax subscription service.

All Other Fees

The aggregate fees billed in each of the last two fiscal years for products and services provided by the Corporation's auditors other than services reported above were \$39,400 in 2007 and \$13,300 in 2008. The fees in 2007 were for a review of Vero's internal controls and work performed related to the Company's private placement. In 2008 the fees were paid in respect of a private placement and the review of the Information Circular related to Vero's acquisition of a private company in November.

HUMAN RESOURCES

Vero currently employs 32 full-time employees, 3 part-time employees and 4 consultants all of which are located in the head office.

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 and Alberta, all of which should be carefully considered by investors in the oil and gas industry. It is not expected that any of these controls or regulations will affect the Corporation's operations in a manner materially different than they would affect other oil and gas companies of similar size. All current legislation is a matter of public record and the Corporation is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry.

Pricing and Marketing - Oil and Natural Gas

The producers of oil are entitled to negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Oil prices are primarily based on worldwide supply and demand. The specific price depends in part on oil quality, prices of competing fuels, distance to the markets, the value of refined products, the supply/demand balance, and other contractual terms. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude

oil, provided that an order approving such export has been obtained from the National Energy Board of Canada (the "NEB"). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB and the issuance of such licence requires a public hearing and the approval of the Governor in Council.

The price of natural gas is determined by negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 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 a public hearing and the approval of the Governor in Council.

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

Pipeline Capacity

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

The North American Free Trade Agreement

The North American Free Trade Agreement ("NAFTA") among the governments of Canada, United States of America, and Mexico became effective on January 1, 1994. NAFTA carries forward most of the material energy terms that are contained in the Canada United States Free Trade Agreement. In the context of energy resources, Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to domestic use (based upon the proportion prevailing in the most recent 36 month period); (ii) impose an export price higher than the domestic price subject to an exception with respect to certain voluntary measures which only restrict the volume of exports; and (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum or maximum export or import price requirements, provided, in the case of export price requirements, any prohibition in any circumstances in which any other form of quantitative restriction is prohibited, and in the case of import-price requirements, such requirements do not apply with respect to enforcement of countervailing and anti-dumping orders and undertakings.

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

Provincial Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations which govern land tenure, royalties, production rates, environmental protection, and other matters. The royalty regime is a significant factor in the profitability of crude oil, natural gas liquids, sulphur, and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiation between the mineral freehold owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Crown

royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery, and the type or quality of the petroleum product produced. Other royalties and royalty-like interests are, from time to time, carved out of the working interest owner's interest through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests, or net carried interests.

Occasionally the governments of the western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays, and tax credits, and are generally introduced when commodity prices are low. The programs are designed to encourage exploration and development activity by improving earnings and cash flow within the industry. Royalty holidays and reductions would reduce the amount of Crown royalties paid by oil and gas producers to the provincial governments and would increase the net income and funds from operations of such producers. However, the trend in recent years has been for provincial governments to eliminate, amend or allow such incentive programs to expire without renewal, and consequently few such incentive programs are currently operative.

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

Alberta

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

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

Oil sands projects are now subject to the NRF, and regulated, among others, by the Oil Sands Royalty Regulation, 2009 Oil Sands Allowed Costs (Ministerial) Regulation and the Bitumen Valuation Methodology (Ministerial) Regulation, 2009, all approved by the Government of Alberta on December 10, 2008. The rates applicable to oil sands are between 1% and 9% and are calculated depending on the price of oil. The royalty payable is 1% when oil is priced below or at \$55 per barrel and it increases for every dollar over and above that price, to a maximum of 9% when oil is priced at \$120 or higher. The after payout net royalty starts at 25% and increases for every dollar when oil is priced above \$55 up to 40% when oil is priced at \$120 or higher.

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

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

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

In response to a significant reduction in oil and gas activity toward the latter part of 2008, on November 19, 2008 the Alberta Government announced that for wells that commenced drilling after this date companies can elect, on a well by well basis to either have the NRF apply to the production from that well or have the old, transitional rates apply for new wells between 1,000 and 3,500 metres in depth. Transitional royalties provide for favourable adjustments to royalty rates at moderate to high prices, and capping the quantity component at a lower rate than the

NRF. In addition, the transitional program removes the depth factor adjustment that currently exists in the NRF. This five-year transitional royalty system is designed to help stimulate drilling in Alberta. Vero will make a determination on each well to see which method is most advantageous.

As a result of the current global financial crisis and its resulting impact on the economy of Alberta, Premier Ed Stelmach stated on February 5th, 2009, that the Government of Alberta was going to provide incentives to junior and mid-size companies with the objective of easing access to capital for such companies and promoting investment. On March 3, 2009 The Alberta Government released a three-point incentive program aimed at stimulating new and continued economic activity for conventional producers. A summary of the plan is as follows:

The highlights of the province's three-point plan include the following.

- A drilling royalty credit for new, conventional, oil and natural gas wells drilled between April 1, 2009 and March 31, 2010. This one-year program will provide a \$200-per-metre-drilled royalty credit to companies on a sliding scale based on their production levels from the prior year. Based on last years production, Vero will qualify for the maximum credit under this plan.
- A new well incentive program, which offers a maximum five-per-cent royalty rate for the earlier of 500 mmcf for a gas well or 50,000 bbl for an oil well, with respect to the first year of production commencing after April 1, 2009.
- To encourage the clean-up of inactive oil and gas wells, the province will invest \$30 million in a fund committed to abandoning and reclaiming old well sites.

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 will be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage, and the imposition of material fines and penalties.

Environmental legislation in Alberta has been consolidated into the *Environmental Protection and Enhancement Act* (Alberta) (the "**EPEA**"), which came into force on September 1, 1993, and the *Oil and Gas Conservation Act* (Alberta) (the "**OGCA**"). The EPEA and OGCA impose stricter environmental standards, require more stringent compliance, reporting and monitoring obligations, and significantly increased penalties. In 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 ("**CCEMAA**"). Under this legislation, Alberta facilities emitting more than 100,000 tonnes of greenhouse gases a year must reduce their emissions intensity by 12%. Industries have three options to choose from in order to meet the reduction requirements outlined in this legislation, and these are: (i) by making improvement to operations that result in reductions; (ii) by purchasing emission credits from other sectors or facilities that have emissions below the 100,000 tonne threshold and are voluntarily reducing their emission; or (iii) by contributing to the Climate Change and Emissions Management Fund (the "**Fund**"). Industries can either choose one of these options or a

combination thereof. Pursuant to CCEMAA and the *Specified Gas Emitters Regulation*, companies were obliged to reduce their emission intensity by 12% by March 31, 2008. Alberta industries have achieved 2.6 million tonnes of actual reduction, due to changes in operations and investing on verified offset projects. In addition, certain companies contributed \$40 million to the Fund. It is reasonably likely that the trend towards stricter standards in environmental legislation and regulation will continue.

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

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

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

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

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

2012 and later, those which use heavier hydrocarbons, up-graders and *in-situ* production will have mandatory standards in 2018 that will be based on carbon capture and storage.

In the following regulated sectors, the Updated Action Plan will apply only to facilities exceeding a minimum annual emissions threshold: (i) 50,000 tonnes of CO₂ equivalent per year for natural gas pipelines; (ii) 3,000 tonnes of CO₂ equivalent per upstream oil and gas facility; and (iii) 10,000 boe/d/company. These proposed thresholds are significantly stricter than the current Alberta regulatory threshold of 100,000 tonnes of CO₂ equivalent per year per facility.

Four separate compliance mechanisms are provided in respect of the above targets: Technology Fund contributions, offset credits, clean development credits and credits for early action. The most significant of these compliance mechanisms, at least initially, will be the Technology Fund and for which regulated entities will be able to contribute in order to comply with emissions intensity reductions. The contribution rate will increase over time, beginning at \$15 per tonne for the 2010-12 period, rising to \$20 per tonne in 2013, and thereafter increasing at the nominal rate of GDP growth. Contribution limits will correspondingly decline from 70% in 2010 to 0% in 2018. Monies raised through contributions to the Technology Fund will be used to invest in technology to reduce greenhouse gas emissions. Alternatively, regulated entities may be able to receive credits for investing in large-scale and transformative projects at the same contribution rate and under similar requirements as mentioned above.

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

Under the Updated Action Plan, regulated entities will also be able to purchase credits created through the Clean Development Mechanism of the Kyoto Protocol. The purchase of such Emissions Reduction Credits will be restricted to 10% of each firm's regulatory obligation, with the added restriction that credits generated through forest sink projects will not be available for use in complying with the Canadian regulations.

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

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

RISK FACTORS

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

Exploration, Development and Production Risks

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

markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by the Corporation.

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

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

Global Financial Crisis

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions, have caused significant volatility to commodity prices. These conditions worsened in 2008 and are continuing in 2009, causing a loss of confidence in the broader U.S. and global credit and financial markets and resulting in the collapse of, and government intervention in, major banks, financial institutions and insurers and creating a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. These factors have negatively impacted company valuations and will impact the performance of the global economy going forward.

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

Prices, Markets and Marketing

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

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

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

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

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The Corporation makes acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner as well as the Corporation's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Corporation. The integration of acquired 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 has limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect the Corporation's financial performance. The Corporation's return on assets operated by others therefore depends upon a number of factors that may be outside of the Corporation's control, including the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

Project Risks

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

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of storage capacity;
- the supply of and demand for oil and natural gas;
- the availability of alternative fuel sources;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- changes in regulations;
- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

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

Competition

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

Regulatory

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

Kyoto Protocol

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

Environmental

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Corporation to incur costs to remedy such discharge. Although the Corporation believes that it will be in material compliance with current applicable environmental regulations no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. There has been much public debate with respect to Canada's ability to meet these targets and the Government's strategy or alternative strategies with respect to climate change and the control of greenhouse gases. Implementation of strategies for reducing greenhouse gases whether the limits required by the Kyoto Protocol or as otherwise determined, could have a material impact on the nature of oil and natural gas operations, including those of the Corporation. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact on the Corporation and its operations and financial condition. See "Industry Conditions – Environmental Regulation".

Variations in Foreign Exchange Rates and Interest Rates

Vero is also exposed to fluctuations in the exchange rate between the Canadian and US dollar. Most commodity prices are based on U.S. dollar benchmarks, which result in our realized prices being influenced by the Canadian/U.S. currency exchange rates. In recent years, the Canadian dollar has both increased materially in value against the United States dollar and then in more recent times decreased from such levels. Because the Canadian economy is heavily weighted to resources, there is a strong correlation between the movement of world oil and gas prices and foreign exchange rates. Therefore, while commodity prices may increase materially, the effect is somewhat muted by the corresponding increase in the value of the Canadian dollar. Nevertheless, the correlation is not perfect and an increase in the value of the Canadian dollar has the potential to negatively impact the Corporation's production revenues. Future Canadian/United States exchange rates could accordingly impact the future value of the Corporation's reserves as determined by independent evaluators.

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

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

Substantial Capital Requirements

The Corporation anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. If the Corporation's revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future drilling programs. In addition, uncertain levels of near term industry activity coupled with the present global credit crisis exposes the Corporation to additional access to capital risk. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Corporation. The inability of the Corporation to access sufficient capital for its operations could have a material adverse effect on the Corporation's business financial condition, results of operations and prospects.

Additional Funding Requirements

The Corporation's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times. From time to time, the Corporation may require additional financing in order to carry out its oil and gas acquisition, exploration and development activities. Failure to obtain such financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Corporation's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect the Corporation's ability to expend the necessary capital to replace its reserves or to maintain its production. If the Corporation's cash flow from operations is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or, if available, on terms acceptable to the Corporation. Continued uncertainty in domestic and international credit markets could materially affect the Corporation's ability to access sufficient capital for its capital expenditures and acquisitions, and as a result, may have a material adverse effect on the Corporation's ability to execute its business strategy and on its business, financial condition, results of operations and prospects.

Issuance of Debt

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

Hedging

From time to time the Corporation may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline; however, if commodity prices increase beyond the levels set in such agreements, the Corporation will not benefit from such increases and the Corporation may nevertheless be obligated to pay royalties on such higher prices, even though not received by it, after giving effect to such agreements. Similarly, from time to time the Corporation may enter into agreements to fix the exchange rate of Canadian to United States dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar; however, if the Canadian dollar declines in value compared to the United States dollar, the Corporation will not benefit from the fluctuating exchange rate.

Availability of Drilling Equipment and Access

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

Title to Assets

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat the Corporation's claim which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set

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

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

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

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

Insurance

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

Geo-Political Risks

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

In addition, the Corporation's oil and natural gas properties, wells and facilities could be subject to a terrorist attack. If any of the Corporation's properties, wells or facilities are the subject of terrorist attack it may

have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The Corporation will not have insurance to protect against the risk from terrorism.

Dilution

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

Management of Growth

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

Expiration of Licences and Leases

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

Dividends

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

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights to portions of western Canada and have also made claims that certain developments, including oil and gas exploration development, may have been proceeding without the Crown carrying out appropriate consultations in the course of allowing such developments to proceed. An action has been commenced on behalf of the Sunchild First Nation ("Sunchild") against the Provincial Crown, various provincial ministries, the Energy Resources Conservation Board (the "ERCB") and numerous respondent oil and gas companies, including the Corporation, that appear to have interests in the area in question. Sunchild seeks judicial review of various Crown and ERCB decisions issued since June 30, 2008 in relation to what is claimed to be their traditional land, and which appears to include a significant portion of the foothills area of Alberta, on the basis that the Crown failed to properly consult and accommodate Sunchild, in the context of issuing licences to the oil and gas companies, forestry and coal companies within Sunchild's reserve and claimed foothills traditional lands area since the end of June, 2008. While the proceedings could result in a change in the consultative and decision-making processes with respect to the granting of Crown rights and other licences in respect of the area or some portion of it, it is too early to assess the likelihood of such a possibility or its impact on the Corporation's future operations in this area.

Seasonality

The level of activity in the Canadian oil and gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Also, certain oil and gas producing areas are located in areas that are inaccessible other than during

the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding declines in the demand for the goods and services of the Corporation.

Third Party Credit Risk

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

Conflicts of Interest

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

Reliance on Key Personnel

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

AUDITORS, TRANSFER AGENT AND REGISTRAR

The auditors of the Corporation are PricewaterhouseCoopers LLP, Chartered Accountants, Petro-Canada Centre, Suite 3100, 111 5th Avenue SW, Calgary, Alberta T2P 5L3.

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

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

Vero is not a party to any legal proceeding nor was it a party to, nor is or was any of its property the subject of any legal proceeding, during the financial year ended December 31, 2008, nor is Vero aware of any such contemplated legal proceedings, which involve a claim for damages, exclusive of interest and costs, that may exceed 10% of the current assets of Vero. See "Risk Factors – Aboriginal Claims".

During the year ended December 31, 2008, there were no (i) penalties or sanctions imposed against the Corporation by a court relating to securities legislation or by a securities regulatory authority; (ii) penalties or sanctions imposed by a court or regulatory body against the Corporation that would likely be considered important to a reasonable investor in making an investment decision, or (iii) settlement agreements the Corporation entered into before a court relating to securities legislation or with a securities regulatory authority.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

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

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, there have been no material contracts entered into by the Corporation within the most recently completed financial year, or before the most recently completed financial year that are still in effect.

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 NI 51-102 by Vero during, or related to, the year ended December 31, 2008 other than Sproule, Vero's independent engineering evaluators, and PricewaterhouseCoopers LLP, Vero's auditors. None of the principals of Sproule had any registered or beneficial interests, direct or indirect, in any securities or other property of Vero or of Vero's associates or affiliates either at the time they prepared the statement, report or valuation prepared by it, at any time thereafter or to be received by them. PricewaterhouseCoopers LLP, Vero's auditor's, are independent in accordance with the auditor's rules of professional conduct in Canada.

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 Vero or any associate or affiliate of Vero.

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 and proxy statement for the Corporation's annual meeting of shareholders to be held on May 14th, 2009. Additional financial information is contained in the Corporation's consolidated financial statements and the related management's discussion and analysis for the year ended December 31, 2008.

Additional copies of this Annual Information Form and the materials listed in the preceding paragraph are available on the foregoing basis and upon request by contacting the Corporation at its offices at 1400, 333 - 5th Avenue S.W., Calgary, Alberta T2P 3B6, by phone at (403) 403 218-2063, fax at (403) 218-2064 or email at general.info@veroenergy.ca

SCHEDULE "A"
FORM 51-101F3
REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

Management of Vero Energy Inc. (the "Company") are responsible for the preparation and disclosure of information with respect to Vero's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2008 estimated using forecast prices and costs:

An independent qualified reserves evaluator has evaluated the reserves data. The report of the independent qualified reserves evaluator is presented below.

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

- (a) reviewed the procedures of the Company 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 of the Company has reviewed the 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 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 45-101F1 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.

DATED as of this 31st day of March, 2009.

(signed) "*Douglas J. Bartole*"
Douglas J. Bartole
President and Chief Executive Officer

(signed) "*Gerald Gilewicz*"
Gerald Gilewicz
Vice-President, Finance and Chief Financial Officer

(signed) "*Clinton T. Broughton*"
Clinton T. Broughton
Director and Chairman of the Reserves Committee

(signed) "*W.C. (Mickey) Dunn*"
W.C. (Mickey) Dunn
Director and member of the Reserves Committee

SCHEDULE "B"
FORM 51-101F2
REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATORS

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

1. We have prepared and evaluation of the Company's reserves data as at December 31, 2008. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2008 estimated using forecast prices and costs.
2. The Reserves Data are the responsibility of the Company'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 attributed to proved plus probable reserves, estimated using forecast prices and costs on a before tax basis and calculated using a discount rate of 10%, included in the reserves data of the Company evaluated by us as of December 31, 2008, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's Management and Board of Directors:

Independent Qualified Reserves Evaluator	Description and Preparation Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate – M\$)			
			Audited	Evaluated	Reviewed	Total
Sproule Associates Limited	Evaluation of the PN&G Reserves of Vero Energy Inc. as of December 31, 2008, prepared between October 2008 and February 2009	Canada	Nil	425,200	Nil	425,200

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 their respective 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.

Executed as to our report referred to above:

Sproule Associates Limited, Calgary, Alberta, Canada, February 9, 2009

Per: "Signed"
Hans J. Firla
Associate

Per: "Signed"
Micheal W. Maughan
Vice-President, Geoscience

Per: "Signed"
Robert J. Johnson
Vice-President, Engineering

SCHEDULE "C"

VERO 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 Vero Energy Inc. ("Vero" 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 Vero and related matters;
2. To provide better communication between directors and external auditors;
3. To enhance the external auditor's independence;
4. To increase the credibility and objectivity of financial reports; and
5. To strengthen the role of the outside directors by facilitating in depth discussions between directors on the Committee, management and external auditors.

Membership of Committee

1. The Committee will be comprised of at least three (3) directors of Vero or such greater number as the Board may determine from time to time and all members of the Committee shall be "independent" (as such term is used in Multilateral Instrument 52-110 — Audit Committees ("MI 52-110")) unless the Board determines that the exemption contained in MI 52-110 is available and determines to rely thereon.
2. The Board of Directors may from time to time designate one of the members of the Committee to be the Chair of the Committee.
3. All of the members of the Committee must be "financially literate" (as defined in MI 52-110) unless the Board determines that an exemption under MI 52-110 from such requirement in respect of any particular member is available and determines to rely thereon in accordance with the provisions of MI 52-110.

Mandate and Responsibilities of Committee

It is the responsibility of the Committee to:

1. Oversee the work of the external auditors, including the resolution of any disagreements between management and the external auditors regarding financial reporting.
2. Satisfy itself on behalf of the Board with respect to Vero's internal control systems:
 - identifying, monitoring and mitigating business risks; and

- ensuring compliance with legal, ethical and regulatory requirements.
3. Review the annual and interim financial statements of Vero and related management's discussion and analysis ("MD&A") prior to their submission to the Board for approval. The process should include but not be limited to:
- reviewing changes in accounting principles and policies, or in their application, which may have a material impact on the current or future years' financial statements;
 - reviewing significant accruals, reserves or other estimates such as the ceiling test calculation;
 - reviewing accounting treatment of unusual or non-recurring transactions;
 - ascertaining compliance with covenants under loan agreements;
 - reviewing disclosure requirements for commitments and contingencies;
 - reviewing adjustments raised by the external auditors, whether or not included in the financial statements;
 - reviewing unresolved differences between management and the external auditors; and
 - obtain explanations of significant variances with comparative reporting periods.
4. Review the financial statements, prospectuses, MD&A, annual information forms ("AIF") and all public disclosure containing audited or unaudited financial information (including, without limitation, annual and interim press releases and any other press releases disclosing earnings or financial results) before release and prior to Board approval. The Committee must be satisfied that adequate procedures are in place for the review of Vero's disclosure of all other financial information and will periodically assess the accuracy of those procedures.
5. With respect to the appointment of external auditors by the Board:
- recommend to the Board the external auditors to be nominated;
 - recommend to the Board the terms of engagement of the external auditor, including the compensation of the auditors and a confirmation that the external auditors will report directly to the Committee;
 - on an annual basis, review and discuss with the external auditors all significant relationships such auditors have with the Corporation to determine the auditors' independence;
 - when there is to be a change in auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change; and
 - review and pre-approve any non-audit services to be provided to Vero or its subsidiaries by the external auditors and consider the impact on the independence of such auditors. The Committee may delegate to one or more independent members the authority to pre-approve non-audit services, provided that the member(s) report to the Committee at the next scheduled meeting such pre-approval and the member(s) comply with such other procedures as may be established by the Committee from time to time.
6. Review with external auditors (and internal auditor if one is appointed by Vero) their assessment of the internal controls of Vero, 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 Vero and its subsidiaries.

7. Review risk management policies and procedures of Vero (i.e. hedging, litigation and insurance).
8. Maintain and administer the Corporation's "whistleblower" policy.
9. Review and approve Vero's hiring policies regarding partners and employees and former partners and employees of the present and former external auditors of Vero.

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 Vero. All employees of Vero are to cooperate as requested by the Committee.

The Committee may also retain persons having special expertise and/or obtain independent professional advice to assist in filling their responsibilities at such compensation as established by the Committee and at the expense of Vero 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.