



DIAZ RESOURCES LTD.

Annual Information Form

**Year Ended
December 31, 2008**

Report Date

April 1, 2009

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SCHEDULE "A", Form 51-101F3, Report of Management and Directors on Oil and Gas Disclosure

SCHEDULE "B", Form 51-101F2, Report on Reserves Data by Independent Qualified Reserves

Evaluator or Auditor

SCHEDULE "C", Audit Committee Mandate

ABBREVIATIONS

Oil and Natural Gas Liquids

Bbl	barrels
Bopd	barrels of oil per day
BOE	barrels of oil or natural gas and crude oil on the basis of 1 Bbl of crude oil for 6 Mcf of natural gas (and not based on energy content or current prices)
BOEd	BOE per day
MBbl	thousand barrels
Mstb	thousand stock tank barrels
Mstbe	thousand stock tank barrels equivalent
NGLs	Natural Gas Liquids

Natural Gas

McfGE	thousand cubic feet of gas equivalent (oil is equated to natural gas on the basis of 1 barrel = 6 Mcf)
Mcf	thousand cubic feet
MMbtu	million British thermal units
MMcf	million cubic feet
Bcf	billion cubic feet
GJd	gigajoule per day
Mcfd	thousand cubic feet per day
MMcfd	million cubic feet per day
psia	pounds per square inch absolute

Other

M\$	thousands of dollars
MM\$	millions of dollars
3D	three dimensional
AFE	authorization for expenditure
API	American Petroleum Institute
ARTC	Alberta Royalty Tax Credit
Cdn.	Canadian
NRI	net revenue interest
OPEC	Organization of the Petroleum Exporting Countries
W.I.	working interest

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

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.

FORWARD-LOOKING STATEMENTS

Certain of the statements contained herein including, without limitation, financial and business prospects and financial outlook, reserve and production estimates, drilling plans, activities to be undertaken in various areas, timing of drilling, recompletion and tie-in of wells, tax horizon, timing of development of undeveloped reserves, planned capital expenditures, the timing thereof and the method of funding may be forward looking statements which reflect management's expectations regarding future plans and intentions, growth, results of operations, performance and business prospects and opportunities. 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 Diaz's reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements. Readers are cautioned that the foregoing list of factors is not exhausted. Additional information on these and other factors that could effect Diaz'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) and at Diaz's website (www.diazresources.com). Although the forward-looking statements contained herein are based upon what management believes to be reasonable assumptions, management cannot assure that actual results will be consistent with these forward-looking statements. Investors should not place undue reliance on forward-looking statements. These forward-looking statements are made as of the date hereof and the Corporation assumes no obligation to update or review them to reflect new events or circumstances except as required by applicable securities laws.

Forward-looking statements and other information contained herein concerning the oil and gas industry and the Corporation's general expectations concerning this industry is based on estimates prepared by management using data from publicly available industry sources as well as from 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

The Corporation

Diaz Resources Ltd. ("Diaz") was incorporated under the laws of the Province of British Columbia on November 3, 1986, under the name "GMN The Gospel Music Network, Ltd." by registration of its Memorandum pursuant to the *Company Act* (British Columbia). Diaz changed its name on May 15, 1990, to "Your Host Foods Inc." and subsequently on June 1, 1994, changed its name to "Diaz Resources Ltd."

On April 14, 1998, Diaz was continued under the laws of the Province of Alberta and on May 6, 1998, the Articles of Diaz were amended to authorize an unlimited number of Class A Subordinate Voting Shares and authorize an unlimited number of Class B Multiple Voting Shares. Every four common shares then outstanding were changed to one Class A Subordinate Voting Share and one Class B Multiple Voting Share.

Pursuant to Articles of Amalgamation dated June 8, 1999, Brittany Energy Inc. ("Brittany"), Uniglobe Ventures Ltd. ("Uniglobe") and 825281 Alberta Ltd., a wholly owned subsidiary of Diaz, amalgamated and continued as one corporation, under the name "Diaz Energy Inc.", which continued to be a wholly-owned subsidiary of Diaz. Immediately thereafter, Diaz Energy Inc. was amalgamated with Diaz pursuant to Articles of Amalgamation dated June 8, 1999, and the amalgamated corporations continued under the name "Diaz Resources Ltd."

At its shareholders' meeting on June 9, 2005, the Corporation's shareholders approved an amendment to the Articles of the Corporation to change the outstanding Class A Subordinate Voting Shares and Class B Multiple Voting Shares into one class of common shares ("Common Shares"), on a one-for-one basis. As a result, the Corporation now has only one class of shares outstanding, being the Common Shares.

The head and principal office of Diaz is located at Suite 1800, 633 Sixth Avenue S.W., Calgary, Alberta, T2P 2Y5. The registered office of Diaz is Suite 1400, 350 Seventh Avenue S.W., Calgary, Alberta, T2P 3N9.

Subsidiaries

Diaz has two wholly owned subsidiaries, Diaz Resources, Inc. and Orbit Oil & Gas Inc., each incorporated pursuant to the laws of the State of Delaware. Both of these companies are involved in oil and gas exploration and production in the United States, and are registered in the state of Texas.

Reference to "Diaz" or the "Corporation" herein means Diaz Resources Ltd. together with its wholly-owned subsidiaries, Diaz Resources, Inc. and Orbit Oil & Gas Inc., unless the context otherwise requires.

GENERAL DEVELOPMENT OF THE BUSINESS

Diaz is engaged in the acquisition of, exploration for and development and production of, crude oil and natural gas in Western Canada and the United States.

Over the past three years Diaz has explored for natural gas in the United States through an informal joint venture agreement with Sharon Energy Ltd. The companies acquired land and seismic data

and jointly participated in drilling exploration wells in Texas. Sharon has also participated with Diaz in some of its Canadian exploration programs.

For the three year period ended December 31, 2008, Diaz raised a total of \$3.0 million by the issuance of Common Shares at an average price of \$0.56 per share, including \$1.0 million raised on December 19, 2007, on the issuance of 3,333,333 Common Shares at a price of \$0.30 per share. Diaz also raised an additional \$7.085 million on the issue of 8.75% convertible unsecured subordinated debentures ("Debentures") on March 26, 2007.

DESCRIPTION OF THE BUSINESS AND OPERATIONS

Diaz is engaged in the acquisition of, exploration for and development and production of, crude oil and natural gas in Western Canada and the United States. The primary focus of Diaz is exploring for natural gas in southern Alberta and in Texas and exploring for oil in Saskatchewan. The following is a description of the Corporation's assets.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The effective date of the statement of reserves data and other oil and gas information set forth below (the "Statement") is December 31, 2008 and the preparation date of the Statement is March 12, 2009.

Disclosure of Reserves Data

The reserves data set forth below (the "Reserves Data") is based upon an evaluation by AJM Petroleum Consultants ("AJM") with an effective date of December 31, 2008, contained in a report of AJM dated March 12, 2009 (the "AJM Report"). The Reserves Data summarizes the oil, 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 Reserves Data conforms to the requirements of National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities ("NI 51-101"). Additional information not required by NI 51-101 has been presented to provide continuity and information which we believe is important to the readers of this information. The Corporation engaged AJM to provide an evaluation of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

All of the Corporation's reserves are in Canada and the United States and, specifically, in the provinces of Alberta and Saskatchewan, in Canada, and in Texas in the United States.

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 reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. The actual reserves may be greater or less than the estimates provided herein.

The Report of Management and Directors on Oil and Gas Disclosure and the Report on Reserves Data by Independent Qualified Reserves Evaluator are attached as Schedule "A" and Schedule "B" hereto, respectively.

For the purpose of presentation in certain tables that follow, US dollar amounts in the AJM Report have been converted to Canadian dollars at an average rate of \$1.096 Canadian for each US dollar, unless otherwise stated.

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

<u>COMPANY TOTAL</u>	RESERVES								RESERVES	RESERVES
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS		NATURAL GAS LIQUIDS		TOTAL	TOTAL
	Gross (MBbl)	Net (MBbl)	Gross (MBbl)	Net (MBbl)	Gross (MMcf)	Net (MMcf)	Gross (MBbl)	Net (MBbl)	Gross (MBOE)	Net (MBOE)
RESERVES CATEGORY										
PROVED										
Developed Producing	109	88	-	-	5,144	4,047	25	15	992	778
Developed Non-producing	35	31	-	-	1,099	877	1	-	219	177
Undeveloped	2	1	-	-	-	3,307	29	18	686	570
TOTAL PROVED	146	120	-	-	10,172	8,231	55	33	1,897	1,525
PROBABLE	68	56	-	-	9,980	7,653	37	23	1,769	1,354
TOTAL PROVED PLUS										
PROBABLE	214	176	-	-	20,152	15,884	92	56	3,666	2,879

<u>COMPANY TOTAL</u>	NET PRESENT VALUES OF FUTURE NET REVENUE									
	BEFORE INCOME TAXES					AFTER INCOME TAXES				
	DISCOUNTED AT (% per year)									
RESERVES CATEGORY	0	5	10	15	20	0	5	10	15	20
	(MMS)	(MMS)	(MMS)	(MMS)	(MMS)	(MMS)	(MMS)	(MMS)	(MMS)	(MMS)
PROVED										
Developed Producing	27.0	22.9	19.9	17.7	16.0	26.0	21.9	19.1	16.9	15.3
Developed Non-producing	7.3	4.5	3.2	2.5	2.0	7.3	4.5	3.2	2.5	2.0
Undeveloped	18.6	11.6	7.8	-	3.8	14.0	9.0	6.1	4.2	3.1
TOTAL PROVED	52.9	39.0	30.9	25.6	21.8	47.3	35.4	28.4	23.6	20.4
PROBABLE	61.8	40.7	28.5	20.9	15.9	41.6	27.3	19.1	14.1	10.6
TOTAL PROVED PLUS										
PROBABLE	114.7	79.7	59.4	46.5	37.7	88.9	62.7	47.5	37.7	31.0

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

CANADIAN PROPERTIES	RESERVES								RESERVES	RESERVES
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS		NATURAL GAS LIQUIDS		TOTAL	TOTAL
	Gross (MBbl)	Net (MBbl)	Gross (MBbl)	Net (MBbl)	Gross (MMcf)	Net (MMcf)	Gross (MBbl)	Net (MBbl)	Gross (MBOE)	Net (MBOE)
RESERVES CATEGORY										
PROVED										
Developed Producing	99	81	-	-	4,187	3,328	25	15	822	651
Developed Non-producing	35	31	-	-	1,099	877	1	-	219	177
Undeveloped	-	-	-	-	3,773	3,187	29	18	658	549
TOTAL PROVED	134	112	-	-	9,059	7,392	55	33	1,699	1,377
PROBABLE	40	34	-	-	4,361	3,439	37	23	804	630
TOTAL PROVED PLUS PROBABLE	174	146	-	-	13,420	10,831	92	56	2,503	2,007

CANADIAN PROPERTIES	NET PRESENT VALUES OF FUTURE NET REVENUE									
	BEFORE INCOME TAXES					AFTER INCOME TAXES				
	DISCOUNTED AT (% per year)									
RESERVES CATEGORY	0 (MMS\$)	5 (MMS\$)	10 (MMS\$)	15 (MMS\$)	20 (MMS\$)	0 (MMS\$)	5 (MMS\$)	10 (MMS\$)	15 (MMS\$)	20 (MMS\$)
PROVED										
Developed Producing	22.0	18.4	15.9	14.0	12.6	22.0	18.4	15.9	14.0	12.6
Developed Non-producing	7.3	4.5	3.2	2.5	2.0	7.3	4.5	3.2	2.5	2.0
Undeveloped	17.7	11.0	7.3	5.1	3.6	13.5	8.7	5.9	4.1	3.0
TOTAL PROVED	47.0	33.9	26.4	21.6	18.2	42.8	31.6	25.0	20.6	17.6
PROBABLE	27.4	18.4	13.4	10.3	8.2	21.1	14.2	10.4	8.1	6.5
TOTAL PROVED PLUS PROBABLE	74.4	52.3	39.8	31.9	26.4	63.9	45.8	35.4	28.7	24.1

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

<u>U.S. PROPERTIES</u>	RESERVES								RESERVES	RESERVES
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS		NATURAL GAS LIQUIDS		TOTAL	TOTAL
	Gross (Mbbbl)	Net (Mbbbl)	Gross (Mbbbl)	Net (Mbbbl)	Gross (MMcf)	Net (MMcf)	Gross (Mbbbl)	Net (Mbbbl)	Gross (MBOE)	Net (MBOE)
RESERVES CATEGORY										
PROVED										
Developed Producing	10	7	-	-	957	719	-	-	170	127
Developed Non-producing	-	-	-	-	-	-	-	-	-	-
Undeveloped	2	1	-	-	156	120	-	-	28	21
TOTAL PROVED	12	8	-	-	1,113	839	-	-	198	148
PROBABLE	28	22	-	-	5,619	4,214	-	-	965	724
TOTAL PROVED PLUS PROBABLE	40	30	-	-	6,732	5,053	-	-	1,163	872

<u>U.S. PROPERTIES</u>	NET PRESENT VALUES OF FUTURE NET REVENUE									
	BEFORE INCOME TAXES					AFTER INCOME TAXES				
	DISCOUNTED AT (% per year)									
RESERVES CATEGORY	0 (MM\$)	5 (MM\$)	10 (MM\$)	15 (MM\$)	20 (MM\$)	0 (MM\$)	5 (MM\$)	10 (MM\$)	15 (MM\$)	20 (MM\$)
PROVED										
Developed Producing	5.0	4.5	4.0	3.7	3.4	4.0	3.5	3.2	2.9	2.7
Developed Non-producing	-	-	-	-	-	-	-	-	-	-
Undeveloped	0.9	0.6	0.5	0.3	0.2	0.5	0.3	0.2	0.1	0.1
TOTAL PROVED	5.9	5.1	4.5	4.0	3.6	4.5	3.8	3.4	3.0	2.8
PROBABLE	34.4	22.3	15.1	10.6	7.7	20.5	13.1	8.7	6.0	4.1
TOTAL PROVED PLUS PROBABLE	40.3	27.4	19.6	14.6	11.3	25.0	16.9	12.1	9.0	6.9

Additional Information Concerning Future Net Revenue (Future Prices and Costs)

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2008
FORECAST PRICES AND COSTS

<u>COMPANY TOTAL</u>	REVENUE (M\$)	ROYALTIES (M\$)	OPERATING COSTS (M\$)	DEVELOP- MENT COSTS (M\$)	WELL ABANDON- MENT COSTS (M\$)	FUTURE	FUTURE
						NET REVENUE BEFORE INCOME TAXES (M\$)	NET REVENUE AFTER INCOME TAXES (M\$)
RESERVES CATEGORY							
PROVED	116,830	22,207	32,188	6,566	2,994	52,876	47,342
PROVED PLUS PROBABLE	218,756	36,457	51,527	12,824	3,200	114,748	88,971

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

<u>COMPANY TOTAL</u>		FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10% per year)	UNIT VALUE at 10%/Year
RESERVES CATEGORY	PRODUCTION GROUP	(M\$)	
PROVED	Light and Medium Crude Oil (including solution gas and other by-products)	3,305	\$ 28.49 /Bbl
	Heavy Oil (including solution gas and other by-products)	755	\$ 24.67 /Bbl
	Natural Gas (including by-products but excluding solution gas from oil wells)	26,094	\$ 3.09 /Mcf
	Total	30,154	
PROVED PLUS PROBABLE	Light and Medium Crude Oil (including solution gas and other by-products)	5,122	\$ 34.12 /Bbl
	Heavy Oil (Including solution gas and other by-products)	971	\$ 31.73 /Bbl
	Natural Gas (including by-products but excluding solution gas from oil wells)	53,291	\$ 3.26 /Mcf
	Total	59,384	

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2008
FORECAST PRICES AND COSTS

CANADIAN PROPERTIES

RESERVES CATEGORY	REVENUE (M\$)	ROYALTIES (M\$)	OPERATING COSTS (M\$)	DEVELOP- MENT COSTS (M\$)	WELL ABANDON- MENT COSTS (M\$)	FUTURE NET REVENUE BEFORE INCOME TAXES (M\$)	FUTURE NET REVENUE AFTER INCOME TAXES (M\$)
						INCOME	INCOME
PROVED	108,517	21,660	30,645	6,428	2,832	46,952	42,846
PROVED PLUS PROBABLE	162,196	32,898	43,642	8,254	3,012	74,390	63,948

BY PRODUCTION GROUP
AS OF DECEMBER 31, 2008
FORECAST PRICES AND COSTS

CANADIAN PROPERTIES

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10% per year) (M\$)	UNIT VALUE at 10%/Year
PROVED	Light and Medium Crude Oil (including solution gas and other by-products)	3,305	\$ 28.49 /Bbl
	Heavy Oil (including solution gas and other by-products)	755	\$ 24.67 /Bbl
	Natural Gas (including by-products but excluding solution gas from oil wells)	21,596	\$ 2.86 /Mcf
Total		25,656	
PROVED PLUS PROBABLE	Light and Medium Crude Oil (including solution gas and other by-products)	5,122	\$ 34.12 /Bbl
	Heavy Oil (Including solution gas and other by-products)	971	\$ 31.73 /Bbl
	Natural Gas (including by-products but excluding solution gas from oil wells)	33,713	\$ 3.03 /Mcf
Total		39,806	

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2008
FORECAST PRICES AND COSTS

U.S. PROPERTIES

RESERVES CATEGORY	REVENUE (M\$)	ROYALTIES (M\$)	OPERATING COSTS (M\$)	DEVELOP- MENT COSTS (M\$)	WELL ABANDON- MENT COSTS (M\$)	FUTURE NET REVENUE BEFORE INCOME TAXES (M\$)	FUTURE NET REVENUE AFTER INCOME TAXES (M\$)
						INCOME	INCOME
PROVED	8,313	547	1,543	138	162	5,924	4,496
PROVED PLUS PROBABLE	56,560	3,559	7,885	4,570	188	40,358	25,023

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

U.S. PROPERTIES

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10% per year) (M\$)	UNIT VALUE at 10%/Year
PROVED	Light and Medium Crude Oil (including solution gas and other by-products)	-	\$ -
	Heavy Oil (including solution gas and other by-products)	-	\$ -
	Natural Gas (including by-products but excluding solution gas from oil wells)	4,498	\$ 5.05 /Mcf
Total		4,498	
PROVED PLUS PROBABLE	Light and Medium Crude Oil (including solution gas and other by-products)	-	\$ -
	Heavy Oil (Including solution gas and other by-products)	-	\$ -
	Natural Gas (including by-products but excluding solution gas from oil wells)	19,578	\$ 3.74 /Mcf
Total		19,578	

Definitions and Other Notes

In the tables set forth above in "Disclosure of Reserves Data" and elsewhere in this Annual Information Form the following definitions and other notes are applicable:

1. "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.

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

3. "Exploration well" means a well that is not a development well, a service well or a stratigraphic test well.

4. "Development costs" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:
 - (a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground draining, road building, and relocating public roads, gas lines and power lines, pumping equipment and wellhead assembly;
 - (b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and wellhead assembly;
 - (c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and

- (d) provide improved recovery systems.
5. "Development well" means a well drilled inside the established limits of an oil and gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.
6. "Exploration costs" means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:
- (a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies;
 - (b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence, and the maintenance of land and lease records;
 - (c) dry hole contributions and bottom hole contributions;
 - (d) costs of drilling and equipping exploratory wells; and
 - (e) costs of drilling exploratory type stratigraphic test wells.
7. "Service well" means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt water disposal, water supply for injection, observation or injection for combustion.
8. Definitions used for reserve categories are as follows:

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

- (a) analysis of drilling, geological, geophysical and engineering data;
- (b) the use of established technology; and
- (c) specified economic conditions (see the discussion of "Economic Assumptions" below).

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

- (d) 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.

- (e) 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 be met for the categorization of reserves are provided in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook").

- (f) "Economic Assumptions" will be the forecast prices and costs used in the estimate.

Development and Production Status

Each of the reserve categories (proved and probable) may be divided into developed and undeveloped categories:

- (a) 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.
- (b) 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 reserves are presented). 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.

9. Forecast prices and costs

Future prices and costs that are:

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

The forecast summary table under "Pricing Assumptions" identifies benchmark reference pricing that applies to the Corporation.

10. Future income tax expenses estimate (generally, year-by-year):

- (a) making appropriate allocations of estimated unclaimed costs and losses carried forward for tax purposes;
- (b) without deducting estimated future costs that are not deductible in computing taxable income;
- (c) taking into account estimated tax credits and allowances; and
- (d) applying to the future pre-tax net cash flows relating to the Corporation's oil and gas activities the appropriate year-end statutory rates, taking into account future tax rates already legislated.

11. Estimated future abandonment and reclamation costs related to a property have been taken into account by AJM in determining reserves that should be attributed to a property and in determining the aggregate future net revenue therefrom.

12. The forecast price and cost assumptions assumed the continuance of current laws and regulations.

13. The extended character of all factual data supplied to AJM was accepted by AJM as represented. No field inspection was conducted.

14. Numbers in tables may not add due to rounding.

15. Net present values reflected in the above tables have been determined under the New Royalty Framework (the "NRF") Alberta royalty regime announced by the Alberta government on October 25, 2007, and enacted on December 2, 2008.
16. The Alberta government has announced, but not yet enacted, provisions that allow for transitional royalties ("**Transitional Royalties**") to the NRF for certain elected wells. For the purposes of the AJM Report, Alberta Crown Royalties have been determined in accordance with the NRF. The impact of the optional Transitional Royalties was considered in our plans for future drilling in Alberta. Diaz was assumed to opt for Transitional Royalties where justified by a comparison of economics under Transitional Royalties and the NRF.
17. 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 reflected in the above tables do not reflect the potential effect of this new program and no sensitivities were provided by AJM as to the potential impact of same.

Pricing Assumptions

The following sets for the benchmark reference prices, as at December 31, 2008, reflected in the Reserves Data. These price assumptions were provided to the Corporation by AJM, the Corporation's independent qualified evaluator.

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
AS OF DECEMBER 31, 2008
FORECAST PRICES AND COSTS

YEAR	Inflation Rate	Exchange Rate	OIL		NATURAL GAS		NGLs		
			WTI	Edmonton	AECO	NYMEX	Edmonton Par Price		
			Cushing	Par Price	Gas Price	Gas Price	Propane	Butane	Condensate
			Oklahoma	40 ⁰ API	(\$Cdn/Mcf)	(\$US/Mcf)	(\$Cdn/bbl)	(\$Cdn/bbl)	(\$Cdn/bbl)
Historical									
2008	2.4%	0.951	99.58	102.85	8.22	8.83	56.99	82.72	109.23
Forecast									
2009	0.0%	0.820	55.00	65.40	7.00	6.50	42.50	52.30	68.65
2010	2.0%	0.860	75.00	85.50	7.90	7.50	56.70	69.75	91.55
2011	2.0%	0.900	85.00	92.75	7.90	8.00	62.75	77.20	101.35
2012	2.0%	0.950	95.00	98.30	8.50	9.00	67.80	83.45	109.50
2013	2.0%	0.950	100.00	103.50	9.00	9.50	72.85	89.65	117.65
2014	2.0%	0.950	100.00	103.50	9.00	9.50	74.25	91.40	119.95
2015	2.0%	0.950	100.00	103.50	9.00	9.50	75.75	93.25	122.35
2016	2.0%	0.950	100.00	103.50	9.00	9.50	77.30	95.10	124.85
2017	2.0%	0.950	100.00	103.50	9.00	9.50	78.80	97.00	127.30
2018	2.0%	0.950	100.00	103.50	9.00	9.50	80.40	98.95	129.90
2019	2.0%	0.950	100.00	103.50	9.00	9.50	82.00	100.90	132.45
2020	2.0%	0.950	100.00	103.50	9.00	9.50	83.65	102.95	135.15
2021	2.0%	0.950	100.00	103.50	9.00	9.50	85.30	105.00	137.80
2022	2.0%	0.950	100.00	103.50	9.00	9.50	87.05	107.10	140.60
2023	2.0%	0.950	100.00	103.50	9.00	9.50	88.75	109.25	143.40
2024	2.0%	0.950	100.00	103.50	9.00	9.50	90.55	111.45	146.25
2025	2.0%	0.950	100.00	103.50	9.00	9.50	92.35	113.70	149.20
2026+	2.0%	0.950	100.00	103.50	9.00	9.50	94.20	115.90	152.15

Weighted average prices (excluding fixed natural gas contracts) realized by the Corporation for the year ended December 31, 2008, in Canada, were \$7.53 Mcf for natural gas and \$84.12 Bbl for crude oil and natural gas liquids. In the United States, the weighted average prices were \$9.04 Mcf for natural gas and \$107.33 Bbl for oil.

Reconciliation of Changes in Gross Reserves

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

COMPANY TOTAL

FACTORS	LIGHT AND MEDIUM CRUDE OIL			HEAVY CRUDE OIL			NATURAL GAS LIQUIDS			ASSOCIATED AND NON-ASSOCIATED GAS			EQUIVALENT BOEs (MBOEs)		
	Proved (MBbl)	Probable (MBbl)	Proved Plus	Proved (MBbl)	Probable (MBbl)	Proved Plus	Proved (MBbl)	Probable (MBbl)	Proved Plus	Proved (MMcf)	Probable (MMcf)	Proved Plus	Proved (MBOE)	Probable (MBOE)	Proved Plus
			Probable (MBbl)			Probable (MBbl)			Probable (MMcf)			Probable (MBOE)			
December 31, 2007	182.5	75.9	258.4	-	-	-	84.0	31.2	115.2	12,922.8	13,742.1	26,664.9	2,420.3	2,397.5	4,817.7
Technical revisions	4.9	(11.0)	(6.1)	-	-	-	(36.8)	19.5	(17.3)	(1,951.0)	(5,109.6)	(7,060.6)	(357.0)	(843.2)	(1,200.2)
Extensions and improved recovery	(11.5)	8.3	-	12.5	2.5	-	14.5	(14.1)	-	628.2	460.7	1,088.9	120.2	73.5	181.5
Discoveries	3.0	11.7	14.7	-	-	-	-	-	-	263.4	875.2	1,138.6	46.9	157.6	204.5
Acquisitions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Economic factors	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Production	(33.9)	-	(33.9)	(1.1)	-	(1.1)	(7.3)	-	(7.3)	(1,709.4)	-	(1,709.4)	(327.2)	-	(327.2)
December 31, 2008	145.0	84.9	233.1	11.4	2.5	(1.1)	54.4	36.6	90.6	10,154.0	9,968.4	20,122.4	1,903.2	1,785.4	3,676.3

Reconciliation of Changes in Gross Reserves

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

CANADIAN PROPERTIES

FACTORS	LIGHT AND MEDIUM CRUDE OIL			HEAVY CRUDE OIL			NATURAL GAS LIQUIDS			ASSOCIATED AND NON-ASSOCIATED GAS			EQUIVALENT BOEs (MBOEs)		
	Proved (MBbl)	Probable (MBbl)	Proved Plus	Proved (MBbl)	Probable (MBbl)	Proved Plus	Proved (MBbl)	Probable (MBbl)	Proved Plus	Proved (MMcf)	Probable (MMcf)	Proved Plus	Proved (MBOE)	Probable (MBOE)	Proved Plus
			Probable (MBbl)			Probable (MBbl)			Probable (MMcf)			Probable (MBOE)			
December 31, 2007	182.5	75.9	258.4	-	-	-	55.0	20.8	75.8	10,123.4	4,964.4	15,087.8	1,924.7	924.1	2,848.8
Technical revisions	(6.8)	(27.3)	(34.1)	-	-	-	(7.8)	29.9	22.1	(515.0)	(585.9)	(1,100.9)	(100.4)	(95.1)	(195.5)
Extensions and improved recovery	(11.5)	8.3	-	12.5	2.5	-	14.5	(14.1)	-	628.2	(29.0)	599.2	120.2	(8.1)	99.9
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Economic factors	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Production	(30.8)	-	(30.8)	(1.1)	-	(1.1)	(7.3)	-	(7.3)	(1,195.8)	-	(1,195.8)	(238.5)	-	(238.5)
December 31, 2008	133.4	56.9	193.5	11.4	2.5	(1.1)	54.4	36.6	90.6	9,040.8	4,349.5	13,390.3	1,706.0	820.9	2,514.7

U.S. PROPERTIES

FACTORS	LIGHT AND MEDIUM CRUDE OIL			HEAVY CRUDE OIL			NATURAL GAS LIQUIDS			ASSOCIATED AND NON-ASSOCIATED GAS			EQUIVALENT BOEs (MBOEs)		
	Proved (MBbl)	Probable (MBbl)	Proved Plus	Proved (MBbl)	Probable (MBbl)	Proved Plus	Proved (MBbl)	Probable (MBbl)	Proved Plus	Proved (MMcf)	Probable (MMcf)	Proved Plus	Proved (MBOE)	Probable (MBOE)	Proved Plus
			Probable (MBbl)			Probable (MBbl)			Probable (MMcf)			Probable (MBOE)			
December 31, 2007	-	-	-	-	-	-	29.0	10.4	39.4	2,799.4	8,777.7	11,577.1	495.6	1,473.4	1,968.9
Technical revisions	11.7	16.3	28.0	-	-	-	(29.0)	(10.4)	(39.4)	(1,436.0)	(4,523.7)	(5,959.7)	(256.6)	(748.1)	(1,004.7)
Extensions and improved recovery	-	-	-	-	-	-	-	-	-	-	489.7	489.7	-	81.6	81.6
Discoveries	3.0	11.7	14.7	-	-	-	-	-	-	263.4	875.2	1,138.6	46.9	157.6	204.5
Acquisitions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Economic factors	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Production	(3.1)	-	(3.1)	-	-	-	-	-	-	(513.6)	-	(513.6)	(88.7)	-	(88.7)
December 31, 2008	11.6	28.0	39.6	-	-	-	-	-	-	1,113.2	5,618.9	6,732.1	197.2	964.5	1,161.6

Additional Information Relating to Reserves Data***Undeveloped Reserves****Proved Undeveloped Reserves*

Proved undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Diaz's proved undeveloped reserves include wells drilled which have not been tied-in at the effective date of the reserve report and infill drilling locations. Approximately 60% of the proved undeveloped gas reserves at December 31, 2008, were assigned to drilled wells waiting to be tied-in, which are scheduled to be connected within the next three years.

The remaining 40% of the proved undeveloped reserves are associated with planned infill drilling programs primarily in the Enchant and Retlaw areas in Canada. Reserves have been assigned based on geological mapping, pressure declines and production declines. To the extent that reserves are not expected to be economically drained through existing production wells and infill drilling is economically feasible, proved reserves have been assigned to the undrilled spacing units.

Diaz plans to drill up to 33 (13.7 net) wells in the two Canadian areas over the next three years. This program will require capital expenditures of approximately \$220,000 in 2009 and \$4.3 million in 2010 to develop the proved reserves and a further \$606,000 to develop the probable undeveloped reserves. The timing of the program is also dependent upon working interest partners in the area, who may or may not agree with the plans of Diaz.

PROVED UNDEVELOPED RESERVES
AS OF DECEMBER 31, 2008

<u>COMPANY TOTAL</u>	PROVED UNDEVELOPED RESERVES					
	LIGHT AND MEDIUM OIL (MBbl)		NATURAL GAS (MMcf)		NGL's (MBbl)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
Prior thereto	-	63	1,154	7,129	-	14
2006	-	-	1,115	5,918	-	13
2007	-	-	139	5,105	9	22
2008	2	2	199	3,929	-	29

<u>CANADA</u>	PROVED UNDEVELOPED RESERVES					
	LIGHT AND MEDIUM OIL (MBbl)		NATURAL GAS (MMcf)		NGL's (MBbl)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
Prior thereto	-	63	897	6,547	-	14
2006	-	-	198	5,185	-	13
2007	-	-	139	5,105	9	22
2008	-	-	42	3,773	-	29

<u>UNITED STATES</u>	PROVED UNDEVELOPED RESERVES					
	LIGHT AND MEDIUM OIL (MBbl)		NATURAL GAS (MMcf)		NGL's (MBbl)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
Prior thereto	-	-	257	582	-	-
2006	-	-	917	733	-	-
2007	-	-	-	-	-	-
2008	2	2	157	156	-	-

Probable Undeveloped Reserves

Probable undeveloped reserves are those reserves which are to be recovered from known accumulations where a significant expenditure is required to render them capable of production; however, these reserves are less certain to be recovered. Reserves have been assigned based on geological mapping, pressure declines and production declines. To the extent that reserves are not expected to be economically drained through existing production wells and infill drilling is economically feasible and that the certainties of recovering additional reserves does not meet the proved threshold, probable undeveloped reserves have been assigned.

Diaz's probable undeveloped reserves include wells drilled which have not been tied-in at the effective date of the AJM Report and for infill drilling locations. Approximately 66% of the probable undeveloped gas reserves are in the U.S. and are associated with behind pipe zones at Allen Ranch, Hound Dog, N.W. Speaks and Provident City. These reserves are either waiting for operations to commence or will be tied-in when production from existing gas zones reach their economic limit and as such may not be developed for lengthy periods of time.

PROBABLE UNDEVELOPED OIL AND GAS RESERVES
AS OF DECEMBER 31, 2008

<u>COMPANY TOTAL</u>	PROBABLE UNDEVELOPED RESERVES					
	LIGHT AND MEDIUM OIL (MBbl)		NATURAL GAS (MMcf)		NGL's (MBbl)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
Prior thereto	43	101	4,078	14,955	-	17
2006	74	148	3,765	14,243	5	19
2007	19	76	1,538	13,742	11	32
2008	16	68	964	9,980	-	37

<u>CANADA</u>	PROBABLE UNDEVELOPED RESERVES					
	LIGHT AND MEDIUM OIL (MBbl)		NATURAL GAS (MMcf)		NGL's (MBbl)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
Prior thereto	43	101	350	6,348	-	16
2006	74	148	15	4,916	-	12
2007	19	76	214	4,964	7	22
2008	5	40	89	4,361	-	37

<u>UNITED STATES</u>	PROBABLE UNDEVELOPED RESERVES					
	LIGHT AND MEDIUM OIL (MBbl)		NATURAL GAS (MMcf)		NGL's (MBbl)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
Prior thereto	-	-	3,728	8,607	-	1
2006	-	-	3,750	9,327	5	7
2007	-	-	1,324	8,778	4	10
2008	11	28	875	5,619	-	-

Significant Factors or Uncertainties

Proved and probable undeveloped reserves require significant expenditures of capital to render them capable of production. The corporation may not have access to such capital. See “Risk Factors – Availability under Credit Facility” There is also significant risk that service or equipment may not be available at the time required and this may change the forecast of production.

The estimate of the net present value of future net revenue attributable to the Corporation's reserves, as set forth in the AJM Report and summarized herein, is based on AJM's forecast of prices and costs as at December 31, 2008, and was therefore determined at a point in time and will not necessarily represent prices and costs or estimates of future prices and costs as at other points in time. The net present value of future net revenue does not represent fair market value. See “Risk Factors – Reserve Estimates”

As set forth under "Reconciliation of Changes in Gross Reserves", the AJM Report provides that the Corporation's proved plus probable reserves at December 31, 2008 decreased from that at December 31, 2007 as a result of, among other things, the fact that technical revisions and production during the year exceeded reserve additions. The reduction in reserves could have a negative impact on the Corporation, including the Corporation's borrowing base and amounts available under its credit facility. See “Risk Factors – Availability Under Credit Facility”

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.

<u>CANADA</u>	FORECAST PRICES & COSTS	
	Proved Reserves	Proved Plus Probable Reserves
Year	(MM\$)	(MM\$)
2009	\$ 0.60	\$ 0.90
2010	\$ 4.90	\$ 5.70
2011	\$ 0.60	\$ 1.30
2012	-	-
2013	-	-
Thereafter	\$ 0.40	\$ 0.40
TOTAL	\$ 6.50	\$ 8.30
Discounted at 10%	\$ 5.30	\$ 6.80

<u>UNITED STATES (\$CDN)</u>	FORECAST PRICES & COSTS	
	Proved Reserves	Proved Plus Probable Reserves
Year	(MM\$)	(MM\$)
2009	-	-
2010	\$ 0.01	\$ 3.51
2011	-	-
2012	-	\$ 0.03
2013	\$ 0.12	\$ 0.37
Thereafter	-	\$ 0.66
TOTAL	\$ 0.13	\$ 4.57
Discounted at 10%	\$ 0.10	\$ 3.60

Diaz plans to finance the above capital expenditures using internally generated cash flow and equity or debt financing as required and if available on acceptable terms. The current plan, which is incorporated into the reserves analysis, is to delay significant capital spending until 2010. Certain capital expenditures may be delayed from time to time as the Corporation's capital requirements are prioritized in an effort to maximize future cash flow and return on investment.

Other Oil and Gas Information

Principal Properties

The following is a description of Diaz's principal oil and natural gas properties as at December 31, 2008 (unless otherwise indicated). Production stated is average working interest for the periods indicated unless otherwise stated. Gross and net acres and well information is as at December 31, 2008, unless otherwise specified. Reserve information is as evaluated by AJM in the AJM Report. The estimates of reserves and future net revenue for individual properties may not reflect the same competence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

United States Drilling Program

Diaz's United States drilling program has been in the Wilcox deep gas trend concentrated in an area 100 miles South West of Houston, Texas. During the year ended December 31, 2008, 5 wells were drilled (net 0.8) resulting in 3 gas wells (0.4) and 2 dry and abandoned wells (net 0.3).

Provident City, Lavaca County, Texas – Working Interest 13%

The Company owns a 13% working interest in two natural gas wells producing from zones in the Wilcox formation in the Provident City field, Lavaca County.

The Provident City #1 well was producing at an average rate of approximately 2.4 MMcfd (312 Mcfd net to Diaz) during the month of December 2008. Also, during the month of December, the Provident City #2 well averaged a production rate of 595 Mcfd (77 Mcfd net to Diaz); however, subsequent to December a workover was completed which resulted in the production rate increasing to over 1 MMcfd (net 130 Mcfd).

Provident City	Oil and NGLs	Natural Gas
Reserves		
Proved developed producing	4 MBbl	415 MMcf
Probable	13 MBbl	1,246 MMcf
Total proved plus probable	17 MBbl	1,661 MMcf
Q4 2008 average production	4 Bopd	369 Mcfd

Black Owl, Wharton County, Texas – Working Interest 24.4%

The Black Owl #1 well, Wharton County, Texas, came on stream November 6, 2007. The well encountered 14 feet of pay in the Yegua zone and has been producing an average of 1.4 MMcfd (net 340 Mcfd) with 23 barrels (net 5.6 barrels) of condensate per day since early November 2007 until mid February 2009. From mid February until mid March the average rate declined to 416 Mcfd (net 102 Mcfd) with no residual condensate. It appears the production rate is stabilizing at approximately 200 Mcfd (net 49 Mcfd).

Black Owl	Natural Gas
Reserves	
Proved developed producing	238 MMcf
Probable	75 MMcf
Total proved plus probable	313 MMcf
Q4 2008 average production	347 Mcfd

Hound Dog, Lavaca County, Texas – Working Interest 28.1% and 25.3%

Diaz has a 28.1% working interest in the R. Dickson #1 well, a 25.3% working interest in the R. Dickson #2 well and a 25.3% working interest in the balance of the 1,635 acres of land.

The R. Dickson #1 well was producing 250 Mcfd (net 70 Mcfd) at the end of December 2008. The R. Dickson #2 well was producing 460 MMcfd (net 116 Mcfd) at year end.

During the fourth quarter of 2008, Diaz drilled the Dow #1 well on the northern flank of the Hound Dog field. The primary deep target zone was not present; however, there are two upper Wilcox sands that appear to be productive as part of a high side closure or on the flank of the Provident City Upper Wilcox field. The operator has declined to complete the upper sands and has relinquished its working interest. Diaz is waiting for a new operator to be selected from the remaining partners so that completion operations can begin sometime in the second quarter of 2009. No reserves have been attributed to the Dow#1 well in the year end reserves report.

Hound Dog	Natural Gas
Reserves	
Proved developed producing	159 MMcf
Probable	2,313 MMcf
Total proved plus probable	2,472 MMcf
Q4 2008 average production	177 Mcfd

N.W. Speaks Robertson #1 Well, Lavaca County, Texas – Working Interest 21.6 %

The N.W. Speaks Robertson #1 well was fracture stimulated and brought on stream in early May 2008 at a rate of 2.45 MMcfd. At the end of June production tubing was run and the well brought back on production in early July 2008. On December 31, 2008, the well was producing at 392 Mcfd (net 85 Mcfd).

The Company has identified three more development locations which could be drilled on this structure.

NW Speaks	Natural Gas
Reserves	
Proved developed producing	64 MMcf
Proved undeveloped	157 MMcf
Probable	875 MMcf
Total proved plus probable	1,096 MMcf
Q4 2008 average production	113 Mcfd

Allen Ranch, Colorado County, Texas – Working Interest 20%

Diaz has a 20% working interest in two successful wells that have been drilled on the property.

The Hancock #1 well has been completed and fracture stimulated in four Wilcox sands which are producing. The Hancock #2 well was cased in February 2006. In Q1 2007, during completion operations a hole in the production tubing was discovered at 9,500 feet. Diaz continues to wait for the operator to conduct operations to restore production from the Hancock #2 well pending the results of litigation against the pipe manufacturer.

Allen Ranch	Natural Gas
Reserves	
Proved developed producing	44 MMcf
Probable	1,020 MMcf
Total proved plus probable	1,064 MMcf
Q4 2008 average production	66 Mcfd

Canadian Drilling Program

In Canada, during the year ended December 31, 2008, 3 wells were drilled (net 0.9) resulting in 1 gas well (net 0.2) and 2 oil wells (net 0.7).

Retlaw, Alberta

Diaz has interests in 41 producing gas wells (15.2 net wells), 1 shut-in gas well (0.5 net wells) and 1 oil well (0.5 net) in the Retlaw area located 90 miles southeast of Calgary, Alberta.

Diaz had planned to drill three wells in the fall of 2008 as part of an infill program on the property but has deferred this drilling until natural gas prices recover to acceptable levels. A new well was added during the year (0.2 net) which combined with workover operations in other wells has significantly improved field results in the area.

The Company's production at Retlaw, throughout 2008, averaged 1,021 Mcfd compared with 733 Mcfd for 2007. Q4 2008 production increased to 1,424 Mcfd compared with 839 Mcfd in Q4 2007.

Retlaw	Natural Gas
Reserves	
Proved developed producing	1,559 MMcf
Proved undeveloped	1,409 MMcf
Probable	846 MMcf
Total proved plus probable	3,814 MMcf
Q4 2008 average production	1,424 Mcfd

Enchant South – Hays, Alberta

In the Enchant South – Hays area, located 110 miles southeast of Calgary, Diaz has an interest in 39 producing gas wells (22.5 net wells) and 3 producing oil wells (2.1 net wells).

Enchant	Natural Gas
Reserves	
Proved developed producing	608 MMcf
Proved developed non-producing	178 MMcf
Proved undeveloped	573 MMcf
Probable	1,296 MMcf
Total proved plus probable	2,655 MMcf
Q4 2008 average production	444 Mcfd

Provost, including Leahurst – Alberta

Diaz holds an 80% working interest in the Leahurst field located in the Provost area. The well was drilled during October 2007 and began first production during June 2008 at over 600 Mcfd (net 480 Mcfd). The well has produced continuously since then with a natural gas production rate for the well on December 31, 2008, of 523 Mcfd (net 418 Mcfd).

Provost, including Leahurst	Natural Gas
Reserves	
Proved developed producing	768 MMcf
Proved developed non-producing	555 MMcf
Proved undeveloped	88 MMcf
Probable	225 MMcf
Total proved plus probable	1,636 MMcf
Q4 2008 average production	432 Mcfd

Big Bend – North-central Alberta

Diaz has an 80% working interest in the Big Bend field, located in north-central Alberta. This area is winter access only. The initial well drilled in December 2007 had a flow rate of approximately 500 Mcfd (net 400 Mcfd) with average production of 141 Mcfd (net 113 Mcfd) during Q4 2008. During January 2009, Diaz conducted workover operations to complete two new zones in the well resulting in an increase in production to rates in excess of 900 Mcfd with the stabilized flow rate expected to be approximately 500 Mcfd. During Q4 2008 and Q1 2009, Diaz acquired additional lands and seismic around the discovery area with three new additional prospects identified.

Big Bend	Natural Gas
Reserves	
Proved developed producing	121 MMcf
Proved developed non-producing	50 MMcf
Proved undeveloped	268 MMcf
Probable	487 MMcf
Total proved plus probable	926 MMcf
Q4 2008 average production	113 Mcfd

Southeast Saskatchewan

Parkman Area

Diaz presently holds an interest in 7 oil wells (4.62 net) in the Parkman area, producing from the Tilston carbonates of Mississippian age. Diaz drilled a horizontal oil well (0.5 net) during the third quarter of 2007 which is currently producing at a steady rate of approximately 53 Bopd (27 Bopd net).

Parkman	Oil and NGLs
Reserves	
Proved developed producing	37 MBbl
Proved developed non-producing	35 MBbl
Probable	19 MBbl
Total proved plus probable	91 MBbl
Q4 2008 average production	27 Bopd

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.

LOCATION	OIL WELLS				NATURAL GAS WELLS			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	23	4.81	9	1.94	174	77.80	63	28.53
Saskatchewan	7	6.30	-	-	-	-	-	-
Texas	-	-	-	-	9	1.62	1	0.20
Total	30	11.11	9	1.94	183	79.42	64	28.73

Properties with no Attributable Reserves

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

LOCATION	UNDEVELOPED ACRES	
	Gross	Net
Alberta	108,372	44,611
Saskatchewan	7,838	5,497
Texas	12,130	4,042
Other U.S. Properties	2,221	279
Total	130,561	54,429

The Corporation expects that rights to explore, develop and exploit approximately 8,000 net acres of its undeveloped land holdings in Canada will expire by December 31, 2009, unless drilling activity is conducted on the lands or applications for extension are accepted by the government or lessors before their expiry. Approximately 400 net acres of land holdings in the United States are expected to expire during 2009.

Marketing and Forward Contracts

Diaz's net share of oil and gas production is sold to marketing companies and other third party purchasers at the oil terminal or sales gas pipeline, with the exception of small amounts of product which are marketed by the well operators.

Where appropriate, in the opinion of management, the Corporation will sell products forward or use other derivative transactions to fix the price of its product or the exchange rate. During the year ended December 31, 2008, natural gas forward sales agreements decreased the revenue Diaz would have otherwise received for its natural gas production by \$12,000 or (\$0.01) per Mcf.

The following fixed price contracts, in place at the date hereof, obligate the Corporation to deliver natural gas at the prices indicated for the contract periods.

Fixed Price Volume	Fixed Price (\$/Mcf)	Time Period for Contract
948 Mcfd	\$ 8.65	Jan 1, 2009 - Mar 31, 2009
474 Mcfd	8.94	Jan 1, 2009 - Mar 31, 2009
475 Mcfd	5.06	Apr 1, 2009 - Oct 31, 2009
475 Mcfd	4.85	Apr 1, 2009 - Dec 31, 2009
950 Mcfd	6.36	Nov 1, 2009 - Mar 31, 2010

Additional Information Concerning Abandonment and Reclamation Costs

The Corporation estimates the cost to abandon wells and the cost to reclaim the leases and facility sites based on costs incurred in the areas for similar wells. Salvage costs of equipment which will be removed from the site are also based on estimates currently available for such equipment. Such costs are escalated to the expected date of abandonment at an inflation rate estimate of 2%.

At December 31, 2008, Diaz had an interest in 286 wells (121 net wells) which it would be responsible for the costs to abandon in the future. The Corporation's share of the estimated abandonment cost is \$5.0 million and the present value of this amount, discounted at 10%, is \$3.3 million. In addition, the Corporation estimated it would receive \$1.5 million in total salvage revenues for these properties. Diaz estimates that \$1.1 million of abandonment costs will be incurred over the next three years, having a present value of \$875,000 at a 10% discounted rate.

The AJM Report considers only the cost of abandoning wells with respect to the future net reserves estimated. The abandonment costs were estimated to be \$2.9 million in total or a present value of \$1.5 million at a 10% discount rate.

Tax Horizon

Based on the forecasted production, revenue and capital expenditures used in the AJM Report for total proved reserves, Diaz will commence paying tax on its Canadian income in 2018. Diaz will continue to be taxable on its U.S. income in 2009 based on the proved reserves estimate of cash flow and capital expenditures.

Capital Expenditures

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

(\$000)	Canada	U.S.	Total
Property Acquisition Costs			
Proved properties	\$ -	\$ -	\$ -
Undeveloped properties	584	755	1,339
Exploration Costs	937	1,738	2,675
Development Costs	2,712	182	2,894
Equipment and Other Assets	572	402	974
TOTAL	\$ 4,805	\$ 3,077	\$ 7,882

Exploration and Development Activities

During 2008, Diaz participated in drilling or re-entering 8 wells (1.5 net) resulting in 4 gas wells (0.6 net), 2 oil wells (0.7 net) and 2 dry and abandoned wells (0.3 net). The following table sets forth the number of wells drilled or re-entered during the year ended December 31, 2008.

Exploration Wells	CANADA		U.S.	
	Gross	Net	Gross	Net
Light and Medium Oil	-	-	-	-
Natural Gas	-	-	3	0.39
Dry	-	-	1	0.25
TOTAL - Exploration	-	-	4	0.64
Development Wells				
Light and Medium Oil	2	0.70	-	-
Natural Gas	1	0.17	-	-
Dry	-	-	1	0.01
TOTAL - Development	3	0.87	1	0.01
TOTAL WELLS	3	0.87	5	0.65

Wells classified as gas wells or oil wells are wells that Diaz believes are capable of production in economic quantities. See "Principal Properties" for a description of the Corporation's exploration and development plans.

Production Estimates

The following table sets out the volume of the Corporation's production, before royalties, estimated for the year ended December 31, 2009 which is reflected in the estimate of future net revenue disclosed in the tables contained under "Disclosure of Reserves Data".

	Light and Medium Oil (Bopd)	Heavy Oil (Bopd)	Natural Gas (Mcf)	Natural Gas Liquids (Bopd)	BOE (BOEd)
Total Company					
Proved developed producing	89	-	3,722	24	733
Proved developed non-producing	-	-	-	-	-
Proved undeveloped	5	-	224	-	43
Total Proved	85	-	3,946	24	776
Probable	3	-	573	7	105
Proved plus probable	97	-	4,519	31	881
Canada					
Proved developed producing	80	-	2,816	24	573
Proved developed non-producing	-	-	-	-	-
Proved undeveloped	5	-	224	-	43
Total Proved	85	-	3,040	24	616
Probable	2	-	446	7	83
Proved plus probable	87	-	3,486	31	699
U.S.					
Proved producing	9	-	906	-	160
Proved developed non-producing	-	-	-	-	-
Proved undeveloped	-	-	-	-	-
Total Proved	-	-	906	-	160
Probable	1	-	127	-	22
Proved plus probable	10	-	1,033	-	182

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:

	CANADA				U.S. (US\$)			
	QUARTER ENDED				QUARTER ENDED			
	2008				2008			
	Dec. 31	Sept. 30	June 30	Mar. 31	Dec. 31	Sept. 30	June 30	Mar. 31
Average Daily Production ⁽¹⁾								
Oil & NGLs (Bopd)	120.5	109.7	138.6	142.7	9.8	11.0	14.2	12.3
Gas (Mcf)	3,298.3	3,488.1	3,055.4	2,311.5	1,143.6	1,174.5	1,760.5	1,657.1
Combined (BOEd)	670.2	691.0	647.9	527.9	200.4	206.8	307.6	288.5
Average Price Received								
Oil & NGLs (\$/Bbl)	69.64	114.29	115.02	72.69	97.78	135.11	118.24	89.45
Gas (\$/Mcf)	7.67	7.70	8.51	8.20	7.39	10.23	10.95	7.30
Combined (\$/BOE)	50.24	56.99	64.74	55.55	46.97	65.29	68.12	45.75
Royalties Paid								
Oil & NGLs (\$/Bbl)	24.63	11.37	8.78	11.57	-	-	-	-
Gas (\$/Mcf)	0.49	0.90	1.03	0.76	0.61	0.67	1.09	0.83
Combined (\$/BOE)	6.83	6.34	6.73	6.46	3.50	3.83	6.22	4.78
Operating Expenses								
Oil & NGLs (\$/Bbl)	17.75	16.85	17.86	21.18	-	-	-	-
Gas (\$/Mcf)	2.39	2.55	2.31	2.35	0.47	0.16	0.14	0.19
Combined (\$/BOE)	14.94	15.57	14.72	16.01	2.71	0.94	0.77	1.07
Netback Received ⁽²⁾								
Oil & NGLs (\$/Bbl)	27.26	86.07	88.38	39.94	97.78	135.11	118.24	89.45
Gas (\$/Mcf)	4.79	4.25	5.17	5.09	6.31	9.40	9.72	6.28
Combined (\$/BOE)	28.47	35.08	43.29	33.08	40.76	60.52	61.13	39.90

Notes:

(1) Before deduction of royalties.

(2) Netbacks are calculated by subtracting royalties and operating costs from revenues.

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.

Availability under Credit Facility

The Corporation's borrowing base and availability under its credit facility is subject to review in April or May 2009. The level of the borrowing base will be determined by the Corporation's lender and will be based upon the Corporation's latest Canadian reserve information, the lender's internal commodity price deck and other factors. If the borrowing base is reduced, it may reduce the financial flexibility of the Corporation and, if lowered below the amount drawn under the credit facility at that time, the shortfall would be required to be paid pursuant to the terms of the credit facility or as otherwise agreed to by the lender. Funding for this amount would be required to come from alternate sources of debt, equity financing, cash flow from operations or proceeds from asset dispositions, which may or may not be available in sufficient amounts or on acceptable terms. Any reduction in the Corporation's borrowing base could adversely affect the Corporation's financial condition, results of operations and prospects. While management expects to be able to renew the Corporation's credit facility, no assurance can be given that it will be able to do so, or be able to do so on acceptable terms. As a result of the uncertainty of the Corporation's borrowing base and the reduction in the Corporation's cash flow due to lower commodity prices, the financial statements include a going concern note. For further details in respect of the going concern, see Note (1) to the Corporation's comparative consolidated financial statements for the year ended December 31, 2008, which is hereby incorporated by reference herein and can be found on SEDAR at www.sedar.com.

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 to meet the limits required by the Kyoto Protocol or as otherwise determined, could have a material impact on the nature of oil and natural gas operations, including those of the Corporation. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact on the Corporation and its operations and financial condition. See "Industry Conditions – Environmental Regulation".

Variations in Foreign Exchange Rates and Interest Rates

World oil and gas prices are quoted in United States dollars and the price received by Canadian producers is therefore effected by the Canadian/U.S. dollar exchange rate, which will fluctuate over time. In recent years, the Canadian dollar has increased materially in value against the United States dollar although the Canadian dollar has recently decreased from such levels. Material increases in the value of

the Canadian dollar negatively impact the Corporation's production revenues. Future Canadian/United States exchange rates could accordingly impact the future value of the Corporation's reserves as determined by independent evaluators.

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

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

Substantial Capital Requirements

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

Additional Funding Requirements

The Corporation's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times. From time to time, the Corporation may require additional financing in order to carry out its oil and gas acquisition, exploration and development activities. Failure to obtain such financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Corporation's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect the Corporation's ability to expend the necessary capital to replace its reserves or to maintain its production. If the Corporation's cash flow from operations is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or, if available, on terms acceptable to the Corporation. 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. The Corporation is not aware that any claims have been made in respect of its properties and assets; however, if a claim arose and was successful such claim may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Seasonality

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

Third Party Credit Risk

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

may impact a joint venture partner's willingness to participate in the Corporation's ongoing capital program, potentially delaying the program and the results of such program until the Corporation finds a suitable alternative partner.

Conflicts of Interest

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

Reliance on Key Personnel

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

INDUSTRY CONDITIONS

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

Pricing and Marketing - Oil and Natural Gas

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

The price of natural gas is determined by negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 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 governments of Alberta, British Columbia, and Saskatchewan also regulate the volume of natural gas that may be removed from those provinces for consumption elsewhere based on such factors as reserve availability, transportation arrangements, and market considerations.

Pipeline Capacity

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

The North American Free Trade Agreement

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

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

Provincial Royalties and Incentives

General

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

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

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

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.

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

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

British Columbia

Producers of oil and natural gas in British Columbia are required to pay annual rental payments with respect to the Crown leases and royalties and freehold production taxes in respect of oil and gas produced from Crown and freehold lands. The amount payable as a royalty in respect of oil depends on the type of oil, the value of the oil, the quantity of oil produced in a month, and the vintage of the oil. Generally, the vintage of oil is based on the determination of whether the oil is produced from a pool discovered before October 31, 1975 (old oil), between October 31, 1975, and June 1, 1998 (new oil), or after June 1, 1998 (third-tier oil). The royalty rates are calculated in three stages, which take into account the vintage of the oil, if the oil produced has already been sold and any royalty exempt value applicable (exempt wells). Oil produced from newly discovered pools may be exempt from the payment of a royalty for the first 36 months of production or 11,450m³ produced, whichever comes first; and the royalties for third-tier oil are the lowest reflecting the higher costs of exploration and extraction that the producers would incur. The royalty payable on natural gas is determined by a sliding scale based on a reference price, which is the greater of the price obtained by the producer, and a prescribed minimum price. However, when the reference price is below the select price (a parameter used in the royalty rate formula), the royalty rate is fixed. As an incentive for the production and marketing of natural gas, which may have been flared, natural gas produced in association with oil has a lower royalty than the royalty payable on non-conservation gas.

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

Some of the financial incentives in the Strategy include:

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

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

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

Saskatchewan

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

The amount payable as a royalty in respect of natural gas is determined by a sliding scale based on a reference price (which is the greater of the amount obtained by the producer and a prescribed minimum price), the quantity produced in a given month, the type of natural gas, and the vintage of the natural gas. As an incentive for the production and marketing of natural gas which may have been flared, the royalty rate on natural gas produced in association with oil is less than on non-associated natural gas.

The royalty and production tax classifications of gas production are "fourth tier gas" introduced October 1, 2002, "third tier gas", "new gas", and "old gas". The Crown royalty and freehold production tax for gas is price sensitive and varies between the base royalty rate of 5% for "fourth tier gas" and 20% for "old gas". The marginal royalty rates are between 30% for "fourth tier gas" and 45% for "old gas".

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

- A new Crown royalty and freehold production tax regime applicable to associated natural gas (gas produced from oil wells) that is gathered for use or sale and is produced from: (a) oil wells with a finished drilling date on or after October 1, 2002, and (b) oil wells with a finished drilling date prior to October 1, 2002, where the individual oil well has a gas-oil production ratio in any month of more than 3,500 cubic metres of gas for every cubic metre of oil. The royalty/tax will be payable on associated natural gas produced from an oil well that exceeds approximately 65,000 cubic metres in a month. The associated natural gas royalty/tax regime will apply to gas produced from oil wells affected by concurrent production approvals after October 1, 2002 if the oil wells meet (a) or (b) above.
- A modified system of incentive volumes and maximum royalty/tax rates applicable to the initial production from oil wells and gas wells with a finished drilling date on or after October 1, 2002, was introduced. The incentive volumes are applicable to various well types and are subject to a maximum royalty rate of 2.5% and a freehold production tax rate of zero per cent.
- The elimination of the re-entry and short section horizontal oil well royalty/tax categories. All horizontal oil wells with a finished drilling date on or after October 1, 2002, will receive the "fourth tier" royalty/ tax rates and new incentive volumes.
- A horizontal oil well, with a finished drilling date on or after October 1, 2002, that is a non-deep oil well qualifies for a 6,000 cubic metre incentive volume.
- A horizontal oil well, with a finished drilling date on or after October 1, 2002, that is a deep oil well qualifies for a 16,000 cubic metre incentive volume.

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

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

Land Tenure

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

Environmental Regulation

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

Environmental legislation in Alberta has been consolidated into the *Environmental Protection and Enhancement Act* (Alberta) (the "**EPEA**"), which came into force on September 1, 1993, and the *Oil and Gas Conservation Act* (Alberta) (the "**OGCA**"). The EPEA and OGCA impose stricter environmental standards, require more stringent compliance, reporting and monitoring obligations, and significantly increased penalties. In 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.

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

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

The Government of Canada and the Province of Alberta released on January 31, 2008 the final report of the Canada-Alberta ecoENERGY Carbon Capture and Storage Task Force, which recommends among others: (i) incorporating carbon capture and storage into Canada's clean air regulations; (ii)

allocating new funding into projects through competitive process; and (iii) targeting research to lower the cost of technology.

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

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

CONFLICTS OF INTEREST

Certain directors and officers of the Corporation may have interests in other oil and gas companies and oil and gas properties which may from time to time conflict with the interests of the Corporation. Any such conflicts will be resolved in accordance with the requirements of the *Business Corporations Act* (Alberta).

HUMAN RESOURCES

At December 31, 2008, Diaz employed 14 staff, all of which were based at its office in Calgary.

DIVIDEND POLICY

The Corporation has not paid any dividends on its outstanding shares. The future payment of dividends will be dependent upon the financial requirements of the Corporation to fund future growth, the financial condition of the Corporation and other factors the board of directors of the Corporation may consider appropriate in the circumstances. Pursuant to Diaz's current credit facility it is restricted from paying dividends or redeeming or repurchasing any of its outstanding shares without the written consent of its lender.

DESCRIPTION OF CAPITAL STRUCTURE

Authorized Share Capital

Diaz is authorized to issue an unlimited number of Common Shares. The holders of Common Shares are entitled to receive notice of, to attend and to vote at any meeting of shareholders of the Corporation (other than meetings of a class or series of shares of the Corporation other than the Common Shares as such) and to one vote per share on a ballot. The holders of Common Shares are also entitled to receive dividends as and when declared by the Board of Directors of the Corporation on the Common Shares as a class, subject to prior satisfaction of all preferential rights to dividends attached to all shares of other classes of shares of the Corporation ranking in priority to the Common Shares in respect of dividends.

The holders of Common Shares shall be entitled in the event of liquidation, dissolution or winding-up of the Corporation, whether voluntary or involuntary, or any other distribution of the assets of the Corporation among its shareholders for the purpose of winding-up its affairs, and subject to prior satisfaction of all preferential rights to return of capital on dissolution attached to all shares of other classes of shares of the Corporation ranking in priority to the Common Shares in respect of return of capital on dissolution, to share rateably, together with the holders of shares of any class of shares of the Corporation ranking equally with the Common Shares in respect of return of capital, in such assets of the Corporation as are available for distribution.

MARKET FOR SECURITIES

The Common Shares of the Corporation are listed for trading on the Toronto Stock Exchange (the "TSX") under the symbol "DZR". The following table sets forth the price range and trading volume of such shares on the TSX (as reported by the TSX) for the periods indicated.

SHARE TRADING - 2008

Month	Common Shares		
	High	Low	Volume
January	0.28	0.18	1,322,400
February	0.33	0.20	400,800
March	0.35	0.27	469,400
April	0.28	0.22	601,400
May	0.26	0.22	2,514,300
June	0.33	0.23	4,322,400
July	0.36	0.23	1,388,200
August	0.24	0.20	936,100
September	0.20	0.14	677,300
October	0.15	0.09	1,121,700
November	0.12	0.09	1,016,200
December	0.09	0.06	1,088,700

DIRECTORS AND OFFICERS

Directors

The names, municipalities of residence, positions with Diaz, principal occupations and the period served as a director, of the directors of Diaz are set out below.

Name and Municipality	Number of Common Shares Beneficially Owned, or Controlled or Directed, Directly or Indirectly	Offices Held and Time as Director	Principal Occupation
Robert W. Lamond Calgary, Alberta Canada	22,901,967 ⁽⁴⁾	Chairman of the Board, President and Chief Executive Officer; director since March 11, 1994	Chairman of the Board and President of the Corporation and of Humboldt Capital Corporation ("Humboldt")
Raj K. Agrawal ⁽¹⁾⁽⁶⁾ Calgary, Alberta Canada	766,875 ⁽⁵⁾	Director since June 1, 1999	President, NRG Engineering Ltd. (petroleum engineering consulting company)
Donald K. Clark Calgary, Alberta Canada	695,061	Vice-President, Operations and Chief Operating Officer; director since January 28, 1998	Vice-President, Operations and Chief Operating Officer of the Corporation and Vice President, Operations of Humboldt
John G.F. McLeod ⁽²⁾ Calgary, Alberta Canada	35,000	Director since June 9, 2005	President of California Oil & Gas Corp. also President and Chief Executive Officer of Paris Energy Inc. and Tuscany Energy Ltd. (all public oil and gas companies)
Robert L. McPherson ⁽¹⁾⁽³⁾ Calgary, Alberta Canada	38,750	Director since June 9, 2005	Independent Businessman
Clive M. Stockdale ⁽¹⁾⁽²⁾ Vancouver, B.C. Canada	469,400	Director since April 11, 1996	Vice-President, Canaccord Capital Corporation (investment dealer)
Charles A. Teare Calgary, Alberta Canada	1,180,217	Executive Vice-President; director since March 11, 1994	Executive Vice-President of the Corporation and of Humboldt
Allan R. Twa ⁽²⁾⁽³⁾⁽⁸⁾ Calgary, Alberta Canada	162,000	Director since January 28, 1998	Partner, Burnet, Duckworth & Palmer LLP (barristers and solicitors)
	26,249,270		

Notes:

- (1) Member of Audit Committee. Additional information with respect to the Audit Committee, including its composition, a copy of its mandate and information with respect to fees paid to the Corporation's auditors is provided under the heading "Audit Committee Information".
- (2) Member of the Compensation Committee.
- (3) Member of the Corporate Governance Committee.

- (4) Includes 18,597,293 Common Shares held by Humboldt and 176,250 Common Shares held by Mr. Lamond's spouse.
- (5) Includes 168,750 Common Shares held by Mr. Agrawal's spouse.
- (6) Raj K. Agrawal entered into a settlement agreement with the Alberta Securities Commission (the "ASC") on July 18, 2003 (approved by the ASC on August 13, 2003) in connection with an insider trading matter pursuant to which Mr. Agrawal was cease traded in securities of issuers for which he is engaged to provide professional advice or services for a period of two years from the date of the settlement agreement, paid an administrative penalty in the amount of \$30,000 and paid a portion of the costs of the investigation
- (7) Clive M. Stockdale was a director of Enterprise Development Corporation, which was subject to a cease trade order for several months in 1998 due to certain officers of the company breaching the policy of the stock exchange on transferring options. Two officers of the company, other than Mr. Stockdale, were disciplined in the matter.
- (8) Allan R. Twa was a director of Gauntlet Energy Corporation, which secured creditor protection pursuant to the *Companies' Creditors Arrangement Act* on June 17, 2003 and was subsequently acquired by Ketch Resources Ltd. in December 2003.

The information as to shares beneficially owned or controlled or directed, directly or indirectly, is based upon information furnished to the Corporation by the respective nominees.

All of the directors have been engaged for more than five years in their present principal occupations or executive positions with the same or associated companies, with the exception of Mr. McPherson, who recently retired; and Mr. McLeod, who was President of Onco Petroleum Inc., a private oil and gas company from 2005 to March 2006 and Rally Energy Corporation, an oil and gas exploration and development company from 2001 to 2005. Mr. McLeod also joined Paris Energy Inc. and Tuscany Energy Ltd. in 2008, as President and Chief Executive Officer for both companies.

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

Officers

The names, municipalities of residence, positions with Diaz and the principal occupations of the senior officers of Diaz are set out below.

Name and Municipality of Residence	Office Held	Principal Occupation
Robert W. Lamond Calgary, Alberta	President, Chief Executive Officer and Chairman of the Board	Chairman of the Board and President of the Corporation and of Humboldt Capital Corporation ("Humboldt")
Brad R. Perry Calgary, Alberta	Chief Financial Officer	Chief Financial Officer of Diaz
Charles A. Teare Calgary, Alberta	Executive Vice-President and a Director	Executive Vice-President of the Corporation and of Humboldt
Donald K. Clark Calgary, Alberta	Vice-President, Operations, Chief Operating Officer and a Director	Vice-President, Operations and Chief Operating Officer of the Corporation and Vice President, Operations of Humboldt
C. Steven Cohen Calgary, Alberta	Corporate Secretary	Partner with Burnet, Duckworth & Palmer LLP (barristers & solicitors)
Ray D. Arsenault Calgary, Alberta	Controller	Controller of Diaz

As at December 31, 2008, the directors and senior officers of the Corporation as a group beneficially owned, or controlled or directed, directly or indirectly, over 26,326,270 Common Shares, representing approximately 39% of the outstanding Common Shares of the Corporation.

AUDIT COMMITTEE INFORMATION

Audit Committee Mandate and Terms of Reference

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

Composition of the Audit Committee

As of the date herof, the members of the Audit Committee are Messrs Agrawal, McPherson and Stockdale. Other than McPherson, all of the members of the Audit Committee are independent (in accordance with National Instrument 52-110 "NI 52-110") and all three are financially literate.

Mr. McPherson is not independent for the purposes of NI 52-110 as Mr. Lamond, the President, Chief Executive Officer and Chairman of the Corporation was on the compensation committee of the board of directors of Paris Energy Inc. ("**Paris**") while Mr. McPherson acted as its Chief Executive Officer. Mr. McPherson resigned as Chief Executive Officer of Paris in 2008.

In appointing Mr. McPherson to the audit committee, the Corporation has relied upon the exemption to the requirement that each member of the audit committee be independent provided in section 3.6 of NI 52-110. The board of directors of the Corporation has determined that Mr. McPherson is able to exercise the impartial judgement necessary for him to fulfil his responsibilities as an audit committee member and that his appointment is required by the best interests of the Corporation and its shareholders.

The following is a description of the education and experience of each member of the Audit Committee.

– Raj Agrawal received a B.Sc. (Honors) in Petroleum Engineering from the Indian School of Mines in 1964 and a M.Sc. in Petroleum Engineering from the University of Alberta in 1968. Mr. Agrawal is President of NRG Engineering Ltd, which specializes in evaluation of reserves and value for oil and gas properties and companies. Mr. Agrawal co-founded NRG in 1978. Since then, he has served and continues to serve on the Board of Directors of several oil and gas companies, both public and private. Prior to NRG, Mr. Agrawal was Manager of Engineering for Inercomp Resources Development & Engineering where he worked from 1970. Prior to Inercomp, Mr. Agrawal was an Exploitation Engineer and Reservoir Engineer for Shell Canada. Mr. Agrawal is a member of a number of professional associations, including the Society of Petroleum Evaluation Engineers, the Petroleum Society of CIM, AIME (Society of Petroleum Engineers) and the Association of Professional Engineers, Geologists and Geophysicists of Alberta.

– Robert McPherson received a B.Comm. (with distinction) with a focus in finance, from the University of Calgary in 1974. Mr. McPherson was previously the Chief Executive Office of Paris Energy Inc., a TSX-V listed oil and gas company, and was previously President and CEO of KVR Resources, a private oil and gas company, from January 2004 until its sale in February 2006 and President and CEO of Nycan Energy Corp, a TSX listed company from April 1994 until its sale in April 2003.

- Clive Stockdale is a graduate from the London School of Economics, with a joint honours degree in Philosophy and Economics. Mr Stockdale has over 36 years experience evaluating oil securities both as an analyst and as a financier.

Pre-Approval of Policies and Procedures

The Audit Committee has pre-approved non-audit services for due diligence, U.S. tax compliance, Canadian tax compliance and tax planning of up to \$40,000 per service.

External Auditor Services Fees

Audit Fees

The aggregate fees billed by the Corporation's external auditor in each of the last two fiscal years for audit services were \$108,538 in 2008 and \$182,375 in 2007.

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 included in "Audit Fees" above were \$77,300 in 2008 and \$103,200 in 2007. These fees related to the review of the Corporation's quarterly and year end financial statements.

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 and tax planning were \$31,238 in 2008 and \$79,175 in 2007. These fees related to the preparation of the Corporation's tax returns and tax compliance.

All Other Fees

There were no other 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.

LEGAL PROCEEDINGS

To the knowledge of the Corporation, there are no legal proceedings material to the Corporation to which the Corporation or its subsidiaries is a party or of which any of their respective properties is the subject matter nor are there any such proceedings known to the Corporation to be contemplated.

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 of the Corporation or any other Informed Person (as defined in National Instrument 51-102) or any known associate or affiliate of such persons in any transactions within the three most recently completed financial years of the Corporation or during the current financial year which has materially affected, or would reasonably be expected to materially affect, the Corporation or its subsidiary other than the following.

1. Humboldt owned 34% of the outstanding shares of Diaz at December 31, 2008.
2. From January 2005 to October 2006, Humboldt paid Diaz \$10,000 per month as its share of certain common overhead costs. The rate was increased to \$24,000 per month in November 2006 and is reviewed annually.
3. On December 19, 2007, Humboldt subscribed for the purchase of 233,167 Common Shares of Diaz at a price of \$0.30 per share on a flow-through share basis. The transaction represented 7% of a Diaz offering of 3.3 million shares.

TRANSFER AGENT AND REGISTRAR

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

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, the Corporation has not entered into any material contracts within the most recently completed financial year, or before the most recently completed financial year that were still in effect other than: (a) the indenture dated March 26, 2007, between Diaz Resources Ltd. and Computershare Trust Company of Canada providing for the issue of Diaz's 8.75% convertible unsecured subordinated debentures; and (b) the Company has a \$9.0 million secured revolving production loan with a Canadian financial institution. The facility carries an interest rate of Prime plus 0.75%, resulting in an effective rate of 5.50% at December 31, 2008. The loan is payable on demand and is subject to an annual review in April 2009.

INTERESTS OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a statement, report or

valuation described or included in a filing, or referred to in a filing, made under National Instrument 51-102 by the Corporation during, or related to, the Corporation's most recently completed financial year other than AJM, the Corporation's independent engineering evaluator and PricewaterhouseCoopers LLP, the Corporation's auditors. None of the principals of AJM had any registered or beneficial interests, direct or indirect, in any securities or other property of the Corporation or of the Corporation'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 has prepared the auditor's report on the consolidated financial statements of the Corporation for the year ended December 31, 2008. PricewaterhouseCoopers LLP has advised that they are independent with respect to the Corporation within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

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

ADDITIONAL INFORMATION

Additional information relating to the Corporation may 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 is contained in the Corporation's Information Circular for its most recent annual meeting of shareholders. Additional financial information is contained in the Corporation's consolidated financial statements for the year ended December 31, 2008 and the related management's discussion and analysis for its most recently completed financial year.

Additional copies of this Annual Information Form, and any financial statements which have been issued by the Corporation, are available upon request by contacting the Corporation at its offices at 1800, 633 - 6th Avenue S.W., Calgary, Alberta, T2P 2Y5, or by phone at (403) 269-9889, or fax at (403) 269-9890.

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

Management of Diaz Resources Ltd. (the "Corporation") is responsible for the preparation and disclosure of information with respect to the Corporation's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data which are estimates of proved and probable oil and gas 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 Corporation's reserves data. The report of the independent qualified reserves evaluator will be filed with securities and regulatory authorities concurrently with this report.

The board of directors of the Corporation has:

- (a) reviewed the Corporation's procedures for providing information to the independent qualified reserves evaluator;
- (b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and
- (c) reviewed the reserves data with management and the independent qualified reserves evaluator.

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

- (d) the content and filing with securities regulatory authorities of the reserves data and other oil and gas information;
- (e) the filing of the report of the independent qualified reserves evaluator on the reserves data; and
- (f) 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: March 30, 2009

(Signed) "R.W. Lamond"
President and Chief Executive Officer

(Signed) "B.R. Perry"
Chief Financial Officer

(Signed) "D.K. Clark"
Director

(Signed) "C. A. Teare"
Director

Schedule "B"

FORM 51-101 F2
 REPORT ON RESERVES DATA
 BY
 INDEPENDENT QUALIFIED RESERVES
 EVALUATOR OR AUDITOR

To the Board of Directors of Diaz Resources Ltd. (the "Company"):

1. We have evaluated 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 (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year end December 31, 2008 and identifies the respective portions thereof that we have evaluated and reported on to the Company's management/Board of Directors:

Independent Qualified Reserves Evaluator or Auditor	Diaz Resources Ltd. Reserve Estimation and Economic Evaluation	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (\$M, before income taxes, 10% discount rate)			
			Audited	Evaluated	Reviewed	Total
AJM Petroleum Consultants	March 12, 2009	Canada	-	\$39,806.8	-	\$39,806.8
AJM Petroleum Consultants	March 12, 2009	United States	-	\$19,578.1	-	\$19,578.1

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. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.
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 judgments regarding future events, actual events will vary and the variations may be material. However, any variation 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:

AJM Petroleum Consultants
 Fifth Avenue Place, East Tower
 6th Floor, 425 – 1st Street S.W.
 Calgary, Alberta
 T2P 3P8

Original signed by: "Robin G. Bertram"
 Robin G. Bertram, P. Eng.
 Vice President Engineering

Execution date: March 12, 2009



SCHEDULE "C"
AUDIT COMMITTEE MANDATE

MANDATE

Role and Objective

The Audit Committee (the "Committee") is a committee of the board of directors (the "Board") of Diaz Resources Ltd. ("Diaz" 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 Diaz 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 Diaz 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 Diaz'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 Diaz 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 Diaz's disclosure of all other financial information and will periodically access 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 Diaz 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 Diaz) their assessment of the internal controls of Diaz, 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 Diaz and its subsidiaries.
 7. Review risk management policies and procedures of Diaz (i.e. hedging, litigation and insurance).
 8. Establish a procedure for:
 - the receipt, retention and treatment of complaints received by Diaz regarding accounting, internal accounting controls or auditing matters; and
 - the confidential, anonymous submission by employees of Diaz of concerns regarding questionable accounting or auditing matters.
 9. Review and approve Diaz's hiring policies regarding partners and employees and former partners and employees of the present and former external auditors of Diaz.

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

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