MIDNIGHT

Oil Exploration Ltd.

ANNUAL INFORMATION FORM

For the period ended

December 31, 2007

March 18, 2008

TABLE OF CONTENTS

CERTAIN DEFINITIONS

Capitalized terms in this Annual Information Form have the meanings set forth below:

Entities

Board of Directors means the board of directors of Midnight.

Daylight means Daylight Energy Ltd.

Daylight Trust means Daylight Resources Trust and, where the context requires, includes its predecessor Daylight Energy Trust.

Midnight, **we**, **us, our** or the **Company** means Midnight Oil Exploration Ltd.

MOG means Midnight Oil & Gas Ltd.

Shareholders means holders of our Common Shares.

Vintage means Vintage Petroleum Canada Inc.

Independent Engineering

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

GLJ means GLJ Petroleum Consultants Ltd.

GLJ Report means the report of GLJ dated February 25, 2008 evaluating the crude oil, natural gas liquids and natural gas reserves of the Company as at December 31, 2007.

NI 51-101 means National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities.

Securities

Common Shares means our common shares, as presently constituted.

Warrants means our outstanding share purchase warrants to acquire Common Shares at an exercise price of $3.00 per warrant and expiring on November 29, 2008.

Other

Administration and Technical Service Agreement means the agreement effective November 29, 2004, as amended, pursuant to which certain administrative and technical services were provided by Daylight to Midnight until December 31, 2006.

ARTC means the Alberta Royalty Tax Credit.

Plan of Arrangement means the plan of arrangement pursuant to the *Business Corporations Act* (Alberta) involving, *inter alia*, Midnight, Daylight, Daylight Trust, Vintage and MOG completed on November 30, 2004;

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

ABBREVIATIONS

Oil and Natural Gas Liquids		Natural Gas	
bbl	barrel	bbls/d	barrels per day
bbls	barrels	Mcf	thousand cubic feet
Mbbls	thousand barrels	MMcf	million cubic feet
MMbbls	million barrels	Mcf/d	thousand cubic feet per day
NGLs	natural gas liquids	Mcfe	thousand cubic feet of gas equivalent
Mstb	thousand stock tank barrels of oil	MMcf/d	million cubic feet per day
Mboe	thousand barrels of oil equivalent	m^3	cubic metres
BOE or boe	barrels of oil equivalent	MMbtu	million British Thermal Units
boe/d	barrels of oil equivalent per day	GJ	Gigajoule

Other	
WTI	means West Texas Intermediate
°API	means the measure of the density or gravity of liquid petroleum products derived from a specific gravity
psi	means pounds per square inch
ARTC	Alberta Royalty Tax Credit

CONVERSION

The following table sets forth certain conversions between Standard Imperial Units and the International System of Units (or metric units).

To Convert From	To	Multiply By
Mcf	cubic metres	28.174
cubic metres	cubic feet	35.494
bbls	cubic metres	0.159
cubic metres	bbls	6.289
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.471
gigajoules	Mmbtu	0.950
MMbtu	gigajoules	1.0526

We have adopted the standard of 6 Mcf:1 bbl when converting natural gas to oil and 1 bbl: 6 Mcf when converting oil to natural gas. Boe's and Mcfe's may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf:1 bbl or an Mcfe conversion ratio of 1 bbl: 6 Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

CONVENTIONS

Certain terms used herein are defined in NI 51-101 and, unless the context otherwise requires, shall have the same meaning in this Annual Information Form as in NI 51-101. Unless otherwise indicated, references in this Annual Information Form to "$" or "dollars" are to Canadian dollars.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements contained in this Annual Information Form, and in certain documents incorporated by reference into this Annual Information Form, constitute forward-looking statements. These statements relate to future events or our future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek", "anticipate", "budget", "plan", "continue", "estimate", "expect", "forecast", "may", "will", "project", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe" and similar expressions. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. We believe the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in, or incorporated by reference into, this Annual Information Form should not be unduly relied upon. These statements speak only as of the date of this Annual Information Form or as of the date specified in the documents incorporated by reference into this Annual Information Form, as the case may be.

In particular, this Annual Information Form, and the documents incorporated by reference, contain forward-looking statements pertaining to the following:

- the performance characteristics of our oil and natural gas properties;
- oil and natural gas production levels;
- the size of the oil and natural gas reserves;
- projections of market prices and costs;
- supply and demand for oil and natural gas;
- expectations regarding the ability to raise capital and to continually add to reserves through acquisitions and development;
- treatment under governmental regulatory regimes and tax laws; and
- capital expenditures programs.

The actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this Annual Information Form:

- volatility in market prices for oil and natural gas;
- liabilities inherent in oil and natural gas operations;
- uncertainties associated with estimating oil and natural gas reserves;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- incorrect assessments of the value of acquisitions;
- geological, technical, drilling and processing problems;
- changes in income tax laws or changes in tax laws and incentive programs relating to the oil and gas industry and income trusts;
- failure to realize the anticipated benefits of acquisitions; and
- the other factors discussed under "*Risk Factors*".

Statements relating to "reserves" or "resources" are deemed to be forward looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the resources and reserves described can be profitably produced in the future. Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward looking statements contained in this Annual Information Form and the documents incorporated by reference herein are expressly qualified by this cautionary statement. We do not undertake any obligation to publicly update or revise any forward-looking statements except as required by securities law.

MIDNIGHT OIL EXPLORATION LTD.

General

We were incorporated on September 10, 2004 under the *Business Corporations Act* (Alberta). Our head office is located at Suite 2100, 144 – 4th Avenue S.W., Calgary, Alberta, T2P 3N4, and our registered office is located at Suite 1400, 350 - 7th Avenue S.W., Calgary, Alberta, T2P 3N9. We have one subsidiary Midnight Oil Resources Ltd., which, together with the Company, are the partners of Midnight Oil Exploration Partnership, a general partnership organized under the laws of the Province of Alberta.

GENERAL DEVELOPMENT OF THE BUSINESS

We are a natural gas and crude oil exploration, development and production company. Our primary activities are focused in three core areas: (i) the Peace River Arch, Alberta, (ii) Red Earth, Alberta; and (iii) West Central, Alberta. We pursue a risk-balanced portfolio of exploration and development targeting formations of the Cretaceous and Triassic periods. Selected acquisitions may be used to broaden our production base and to add to our inventory of opportunities.

History of Midnight

On November 29, 2004, we completed our initial capitalization through an initial private placement to our officers, directors and various service providers of 4,666,666 Common Shares for total proceeds of $7 million. Under a separate private placement, 2,333,333 Warrants were issued for total proceeds of $47,000. Each Warrant is exercisable into one Common Share at an exercise price of $3.00. The Warrants vest over three years provided that certain specific performance criteria are met and expire on November 29, 2008. For more information regarding the terms and conditions attached to the Warrants see "*Description of Capital Structure*".

We commenced operations on November 30, 2004, following the completion of the Plan of Arrangement, pursuant to which certain assets of MOG and Vintage were transferred to us and former holders of common shares of MOG and Series U subscription receipt holders of Daylight Trust received: (a) one trust unit of Daylight Trust and/or one exchangeable share of Daylight; and (b) 0.50 of a Common Share, for each common share of MOG or Series U subscription receipt of Daylight Trust held by such holders.

Pursuant to the Plan of Arrangement, we acquired petroleum and natural gas properties that produced approximately 700 boe/d at closing comprised of 15% of Vintage's interest in its properties in West Central Alberta and 142,000 acres of undeveloped land in the West Central Alberta, Foothills and Peace River Arch areas. In addition, we also acquired an option to farm-in on approximately 20,000 net acres of former Vintage undeveloped lands retained by Daylight Trust on standard industry terms, thereby providing us with an additional portfolio of opportunities.

In conjunction with the Plan of Arrangement, we entered into an Administrative and Technical Services Agreement with Daylight, which provided for the shared services required to manage our activities and govern the allocation of general and administrative expenses between Daylight and us. Under this agreement, Daylight received payment for certain technical and administrative services provided to us on a cost recovery basis. The Administrative and Technical Services Agreement was terminated effective December 31, 2006. Certain services between Daylight and Midnight that are administrative, provide reasonable economies of scale and do not involve competitive issues have continued through 2007 at an agreed upon monthly fee for service basis. Either party may cancel these services.

On November 29, 2005, we completed the acquisition of certain petroleum and natural gas assets located in the Red Earth area of Alberta, for a total acquisition cost, payable in cash, of $47.7 million. The assets acquired included 1.8 million boe of high quality, long life oil and natural gas reserves on a proved plus probable basis, 67,700 net acres of undeveloped land, 144 square kilometres of 3D seismic and production of approximately 850 boe/d before taking into consideration MRLs (Maximum Rate Limitations) which were temporarily lifted by the AEUB at the time we acquired the property. From October 1, 2005 (the effective date of the acquisition) to November 29, 2005 (the closing date), 4 gross (2.8 net) successful oil wells were drilled and production increased from 650 boe/d to approximately 850 boe/d.

The acquisition was funded by an issuance of 12,000,000 subscription receipts at a price of $4.00 per subscription receipt for gross proceeds of $48 million. Each subscription receipt was converted into one Common Share in accordance with its terms on November 30, 2005.

On May 17, 2006 we issued 4,000,000 "flow-through" Common Shares at a price of $5.10 per flow-through Common Share for gross proceeds of $20.4 million. The proceeds of the flow-through Common Share offering were used to fund our capital expenditure program. On November 7, 2006 we issued 5,500,000 million Common Shares at a price of $3.05 per Common Share for gross proceeds of approximately $16.8 million. Proceeds of the Common Share offering were used to pay down debt and fund our capital expenditure program.

On October 15, 2007, we filed a notice with the Toronto Stock Exchange ("**TSX**") to make a normal course issuer bid (the "**NCIB**") to purchase our outstanding Common Shares on the open market. Pursuant to the NCIB, we may purchase up to 4,320,826 Common Shares during the period from October 17, 2007 to October 16, 2008 or until such time that the NCIB is either completed or terminated at our option. Any Common Shares purchased under the NCIB bid will be purchased on the open market through the facilities of the TSX at the prevailing market price and cancelled. During the fourth quarter of 2007, we purchased and cancelled 232,700 Common Shares at an average market price of $1.13 per share reducing the total number of Common Shares outstanding at year-end to 47,595,129. In the first quarter of 2008, we purchased and cancelled an additional 172,500 Common Shares at an average market price of $1.10 per share, reducing the total number of Common Shares outstanding at March 18, 2008 to 47,422,629 Common Shares.

Since the start of our operations on November 30, 2004, we have drilled 101 gross (36.3 net) wells and have invested $120.6 million on our capital programs and $47.7 million on our Red Earth property acquisition.

Significant Acquisitions

We have not completed any significant acquisition during our most recently completed financial year for which disclosure is required under Part 8 of National Instrument 51-102.

Recent Developments

In early 2008, our Board of Directors approved a capital budget of $13.5 million for the first half of 2008. This will fund completion of the construction of our Red Earth water handling facility and will enable us to participate in the drilling of 10 gross (3 net) wells. The actual amount of capital expenditures for the year will be dependent on the success of our program and our ability to fund additional projects through our internally generated cash flow, credit facilities and may include issuing additional equity if available on favourable terms.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The statement of reserves data and other oil and gas information set forth below (the "**Statement**") is dated February 25, 2008 and prepared as of January 22, 2008. The effective date of the Statement is December 31, 2007.

Definitions and Other Notes to Reserves Data and Tables

In the following tables included under "*Statement Of Reserves Data And Other Oil And Gas Information*" and elsewhere in this Annual Information Form, the following definitions and other notes are applicable:

1. Columns may not add due to rounding.

2. "Company interest" means in relation to our interest in production or reserves, our working interest (operating or non-operating) share before deduction of royalties and including our royalty interests.

3. "Gross" means:

   (a) in relation to our interest in production and reserves, our working interest (operating and non-operating) share before deduction of royalties and without including any royalty interest received by us;

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

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

4. "Net" means:

   (a) in relation to our interest in production and reserves, our working interest (operating and non-operating) after deduction of royalties obligations, plus our royalty interests in production or reserves;

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

   (c) in relation to our interest in a property, the total area in which we have an interest multiplied by the working interest owned by us.

5. "Development well" means a well drilled inside the established limits of an oil or gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.

6. "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, to the extent necessary in developing the reserves;

   (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.

7. "Exploratory well" means a well that is not a development well, a service well or a stratigraphic test well.

8. "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 (sometimes referred to in part as "prospecting costs") 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 (collectively sometimes referred to as "geological and geophysical costs");

(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 completing exploratory wells; and

(e) costs of drilling exploratory type stratigraphic test wells.

9. "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.

10. The crude oil, natural gas liquids and natural gas reserve estimates presented in the GLJ Report are based on the definitions and guidelines contained in the COGE Handbook. A summary of those definitions is set forth below.

Reserve Categories

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

(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.

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

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

"Economic Assumptions" are the forecast prices and costs used in the estimates.

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; and

(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% probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and

(b) at least a 50% 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.

11. Forecast prices and costs are 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 we are 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 us.

12. 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 (for example, Crown royalties) 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 Midnight's oil and gas activities the appropriate year-end statutory rates, taking into account future tax rates already legislated.

13. Future net revenue is the estimated net amount to be received with respect to the development and production of reserves estimated using forecasted prices and costs. This net amount is computed by deducting from estimated future revenues: estimated amounts of future royalty obligations, costs related to the development and production of reserves, well abandonment costs and future income tax expenses.

14. Estimated future abandonment and reclamation costs related to a property have been taken into account by GLJ in determining reserves that should be attributed to a property and in determining the aggregate future net revenue therefrom; the reasonable estimated future well abandonment costs were deducted. No allowance was made, however, for reclamation of well sites or the abandonment and reclamation of any facilities.

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

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

Reserves Data

The reserves data set forth below (the "**Reserves Data**") is based upon an evaluation by GLJ in the GLJ Report dated February 25, 2008 and effective December 31, 2007. The Reserves Data summarizes our oil, liquids and natural gas reserves and the net present values of future net revenue for these reserves using forecast prices and costs. The Reserves Data conforms with the requirements of NI 51-101. We engaged GLJ to provide an evaluation of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

All of our reserves are in Canada and, specifically, in the provinces of Alberta and British Columbia. We do not have any heavy oil reserves or any unconventional gas reserves.

Due to uncertainties and lack of sufficient details with which to determine royalties for some product types under the proposed Alberta new royalty framework (the "**NRF**"), the reserves data set forth below has been prepared using the existing royalties. See "*Industry Conditions – Provincial Royalties and Incentives – Alberta*" and "*Risk Factors – New Alberta Royalty Regime*". However, a high and low sensitivity calculation with respect to the potential impact of the NRF is provided in the notes to certain of the reserves data tables set forth below.

All evaluations of future net revenue are after the deduction of future income tax expenses (unless otherwise noted in the tables), royalties, development costs, production costs and well abandonment costs but before consideration of indirect costs such as administrative, overhead and other miscellaneous expenses. The estimated future net revenue contained in the following tables does not necessarily represent the fair market value of our reserves. There is no assurance that the forecast price and cost assumptions contained in the GLJ Report will be attained and variations could be material. Other assumptions and qualifications relating to costs and other matters are summarized in the notes to or following the tables below. The recovery and reserve estimates on our properties described herein are estimates only and there is no guarantee that the estimated reserves will be recovered. The actual reserves on our properties may be greater or less than those calculated. The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation. For more information as to the risks involved, see "*Risk Factors*".

The Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3 and the Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor in Form 51-101F2 are included in Schedules "A" and "B" to this Annual Information Form.

SUMMARY OF OIL AND GAS RESERVES AND NET PRESENT VALUES OF FUTURE NET REVENUE AS OF DECEMBER 31, 2007 FORECAST PRICES AND COSTS

	Light and Medium Oil		Natural Gas		Natural Gas Liquids		Total	
Reserves Category	**Gross (Mbbls)**	**Net (Mbbls)**	**Gross (MMcf)**	**Net (MMcf)**	**Gross (Mbbls)**	**Net (Mbbls)**	**Gross (Mboe)**	**Net (Mboe)**
Proved								
Developed Producing	1,034	909	11,215	8,860	263	173	3,167	2,559
Developed Non-Producing	145	126	2,260	1,542	19	13	541	396
Undeveloped	318	277	1,064	738	6	4	501	404
Total Proved	1,497	1,312	14,539	11,140	289	190	4,209	3,359
Probable	1,198	1,053	4,890	3,712	79	51	2,092	1,723
Total Proved Plus Probable	2,695	2,366	19,429	14,852	368	241	6,301	5,082

	Net Present Values of Future Net Revenue Before Income Taxes Discounted at (%/year) (1)(2)				
	0%	**5%**	**10%**	**15%**	**20%**
($ thousands)					
Proved					
Developed Producing	109,729	89,297	76,195	67,014	60,184
Developed Non-Producing	13,905	10,660	8,511	6,999	5,883
Undeveloped	13,132	9,123	6,482	4,646	3,318
Total Proved	136,767	109,080	91,188	78,660	69,385
Probable	75,869	44,041	29,511	21,369	16,231
Total Proved Plus Probable	212,636	153,121	120,698	100,029	85,615

Notes:

(1) Management has estimated that the impact of the NRF is to decrease the net present values of future net revenue (before income taxes) by approximately 10% to 13% using a 10% discount rate and using the GLJ forecast prices set forth in this Annual Information Form. See "*Industry Conditions – Provincial Royalties and Incentives – Alberta*" and "*Risk Factors – The New Alberta Royalty Regime*".

(2) The methodology used to calculate the new royalties for the net present value of future net revenue amounts set forth in Note (1) was based on the following criteria: (i) in the case of solution gas, the same rate and price basis as non-associated gas was used for the high case and in the low case royalty rates were determined in the same manner as the high case but were restricted to no less than the current royalty rate of 30% on solution gas; and (ii) in the case of deep gas, GLJ assumed that the deep gas royalty adjustment is applied to all existing and future wells in the high case and for the low case GLJ assumed that the deep gas royalty adjustment is applied only to wells drilled after 2008.

	Net Present Values of Future Net Revenue After Income Taxes Discounted at (%/year)				
	0%	5%	10%	15%	20%
($ thousands)					
Proved					
Developed Producing	109,729	89,297	76,195	67,014	60,184
Developed Non-Producing	13,905	10,660	8,511	6,999	5,883
Undeveloped	10,522	7,204	5,016	3,493	2,387
Total Proved	134,156	107,161	89,722	77,506	68,454
Probable	57,710	32,882	21,709	15,508	11,621
Total Proved Plus Probable	191,866	140,043	111,431	93,014	80,075

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2007
FORECAST PRICES AND COSTS

Reserves Category	Revenue	Royalties	Operating Costs	Development Costs	Well Abandonment Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
($ thousands)								
Proved	264,513	41,621	71,790	12,321	2,015	136,767	2,610	134,156
Proved Plus Probable	422,899	64,249	118,909	24,686	2,419	212,636	20,769	191,866

FUTURE NET REVENUE BY PRODUCTION GROUP
AS OF DECEMBER 31, 2007
FORECAST PRICES AND COSTS

Reserves Category	Production Group	Future Net Revenue Before Income Taxes (Discounted at 10%/year)(3)(5)(6)	Unit Value Before Income Taxes (Discounted at 10%)(4)	
			($/boe)	($/Mcfe)
($ thousands)				
Proved Reserves	Light and Medium Crude Oil (1) (3)	48,710	37.61	6.27
	Natural Gas (2) (3)	42,478	20.59	3.43
	Total	91,188	27.15	4.52
Proved Plus Probable	Light and Medium Crude Oil (1) (3)	70,758	30.21	5.03
	Natural Gas (2) (3)	49,940	18.23	3.04
	Total	120,698	23.75	3.96

Notes:
(1) Including solution gas and other by-products.
(2) Including by-products, but excluding solution gas.
(3) Other company revenue and costs not related to a specific production group have been allocated proportionately to production groups.
(4) Unit values are based on net reserves and are product weighted averages on net reserve volumes using a volume conversion of 6 Mcf of natural gas to one barrel of oil equivalent.
(5) Management has estimated that the impact of the NRF is to decrease the net present values of future net revenue (before income taxes) by approximately 10% to 13% using a 10% discount rate and using the GLJ forecast prices set forth in this Annual Information Form. See "*Industry Conditions – Provincial Royalties and Incentives – Alberta*" and "*Risk Factors – The New Alberta Royalty Regime*".

(6) The methodology used to calculate the new royalties for the net present value of future net revenue amounts set forth in Note (5) was based on the following criteria: (i) in the case of solution gas, the same rate and price basis as non-associated gas was used for the high case and in the low case royalty rates were determined in the same manner as the high case but were restricted to no less than the current royalty rate of 30% on solution gas; and (ii) in the case of deep gas, GLJ assumed that the deep gas royalty adjustment is applied to all existing and future wells in the high case and for the low case GLJ assumed that the deep gas royalty adjustment is applied only to wells drilled after 2008.

Pricing Assumptions

The following sets for the benchmark reference prices, as at January 1, 2008, reflected in the Reserves Data. These price assumptions were provided by GLJ.

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
AS OF JANUARY 1, 2008
FORECAST PRICES AND COSTS

	OIL			**NATURAL GAS**	**EDMONTON LIQUIDS PRICES**				
Year	**WTI Cushing Oklahoma** ($US/bbl)	**Edmonton Par Price 40° API** ($Cdn/bbl)	**Cromer Medium 29.3° API ($Cdn/bbl)**	**AECO/NIT Spot ($Cdn/ MMbtu)**	**Propane** ($Cdn/bbl)	**Butane** ($Cdn/bbl)	**Pentanes Plus** ($Cdn/bbl)	**Inflation Rates(a)** %/Year	**Exchange Rate(b)** ($US/$Cdn)
Forecast									
2008	92.00	91.10	79.26	6.75	58.30	72.88	92.92	2.0	1.00
2009	88.00	87.10	75.78	7.55	55.74	69.68	88.84	2.0	1.00
2010	84.00	83.10	72.30	7.60	53.18	66.48	84.76	2.0	1.00
2011	82.00	81.10	70.56	7.60	51.90	64.88	82.72	2.0	1.00
2012	82.00	81.10	70.56	7.60	51.90	64.88	82.72	2.0	1.00
2013	82.00	81.10	70.56	7.60	51.90	64.88	82.72	2.0	1.00
2014	82.00	81.10	70.56	7.80	51.90	64.88	82.72	2.0	1.00
2015	82.00	81.10	70.56	7.97	51.90	64.88	82.72	2.0	1.00
2016	82.02	81.12	70.57	8.14	51.91	64.89	82.74	2.0	1.00
2017	83.66	82.76	72.00	8.31	52.97	66.21	84.42	2.0	1.00
2018	85.33	84.42	73.44	8.48	54.03	67.53	86.11	2.0	1.00
2019+	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	1.00

Our weighted average realized sales prices for the year ended December 31, 2007 were $6.68/Mcf for natural gas, $74.70/bbl for crude oil and $52.36/bbl for NGLs.

Reserve Reconciliations

RECONCILIATION OF COMPANY INTEREST RESERVES BY PRINCIPAL PRODUCT TYPE
FORECAST PRICES AND COSTS [(1)(2)(3)]

Reserve Category	**Factors**	**Light & Medium Oil (Mbbls)**	**Natural Gas Liquids (Mbbls)**	**Natural Gas (MMcf)**	**BOE (Mboe)**
Proved	December 31, 2006	1,443	330	14,438	4,180
	Discoveries	-	-	-	-
	Extensions & improved recovery	182	29	3,253	753
	Technical revisions	205	(3)	(848)	61
	Production	(333)	(65)	(2,208)	(766)
	December 31, 2007	1,497	291	14,635	4,227
Probable	December 31, 2006	1,184	109	6,084	2,306
	Discoveries	-	-	-	-
	Extensions & improved recovery	118	15	1,220	336
	Technical revisions	(104)	(44)	(2,392)	(547)
	Production	-	-	-	-
	December 31, 2007	1,198	80	4,912	2,096

Reserve Category	Factors	Light & Medium Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	BOE (Mboe)
Proved Plus Probable	December 31, 2006	2,627	439	20,522	6,486
	Discoveries	-	-	-	-
	Extensions & improved recovery	300	44	4,473	1,089
	Technical revisions	101	(47)	(3,240)	(486)
	Production	(333)	(65)	(2,208)	(766)
	December 31, 2007	2,695	371	19,547	6,323

Notes:
(1) All of our oil is light and medium crude and all of our natural gas is conventional natural gas.
(2) Closing balances are higher than reported gross reserves due to the inclusion of royalties receivable.
(3) We did not have any changes resulting from acquisitions, dispositions or economic factors.

RECONCILIATION OF GROSS (WORKING INTEREST) RESERVES BY PRINCIPAL PRODUCT TYPE FORECAST PRICES AND COSTS (1)(2)

Reserve Category	Factors	Light & Medium Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	BOE (Mboe)
Proved	December 31, 2006	1,443	328	14,339	4,161
	Discoveries	-	-	-	-
	Extensions & improved recovery	182	29	3,256	753
	Technical revisions	206	(3)	(848)	61
	Production	(333)	(65)	(2,208)	(766)
	December 31, 2007	1,497	289	14,539	4,209
Probable	December 31, 2006	1,183	108	6,067	2,303
	Discoveries	-	-	-	-
	Extensions & improved recovery	118	15	1,216	336
	Technical revisions	(104)	(44)	(2,392)	(547)
	Production	-	-	-	-
	December 31, 2007	1,198	79	4,890	2,092
Proved Plus Probable	December 31, 2006	2,626	437	20,406	6,464
	Discoveries	-	-	-	-
	Extensions & improved recovery	300	44	4,472	1,089
	Technical revisions	102	(48)	(3,240)	(486)
	Production	(333)	(65)	(2,208)	(766)
	December 31, 2007	2,695	368	19,429	6,301

Notes:
(1) All of our oil is light and medium crude and all of our natural gas is conventional natural gas.
(2) We did not have any changes resulting from acquisitions, dispositions or economic factors.

The majority of our natural gas reserves were added in Beaverlodge, Pine Creek, Oldman and Windfall as a result of drilling activity during the year. At Red Earth, oil reserves additions were realized as a result of drilling activity and the addition of proved undeveloped and probable undeveloped drilling locations. In the total proved category, negative technical revisions at Sheldon, Wapiti and Windfall were offset by positive revisions at Red Earth, Beaverlodge and Kaybob resulting in a small positive change for the year. The positive revisions noted resulted from stronger well performance and additional gas cap reserves at Beaverlodge while the negative revisions were due to poorer than expected well performance and early water encroachment. In the Proved plus Probable category, an overall negative revision occurred as a result of poorer than expected well performance and early water encroachment at Sheldon, Wapiti and Windfall.

Additional Information Relating to Reserves Data

Undeveloped Reserves

Undeveloped reserves are attributed by GLJ in accordance with standards and procedures contained in the COGE Handbook. Proved undeveloped reserves are those reserves that can be estimated with a high degree of certainty and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Probable undeveloped reserves are those reserves that are less certain to be recovered than proved reserves and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Historically we have not carried undeveloped reserves for long periods of time and generally the undeveloped reserves relate to projects that we plan to complete within two years.

Proved Undeveloped Reserves

The majority of our proved undeveloped reserves relate to development drilling locations. All of these locations will be drilled into known horizons with offset production as infill wells or step out locations. While the majority of these wells are oil wells at Red Earth, also included in this category is a horizontal Cadomin gas well at Elmworth and a lengthy gas well tie-in project in the Deep Basin. Both of these projects are budgeted to occur in the first quarter of 2008 and we anticipate developing the remaining proved undeveloped locations within the next two years.

The following table discloses, for each product type, the total volumes of gross proved undeveloped reserves at December 31, 2007 and the year in which they were first attributed.

Proved Undeveloped	**Total**	**2007**	**2006**	**2005**	**Prior**
Light and Medium Oil (Mbbls)	318	137	181	-	-
Natural Gas (MMcf)	1,064	959	104	-	-
Natural Gas Liquids (Mbbls)	6	2	4	-	-
Total (Mboe)	501	299	202	-	-

Probable Undeveloped Reserves

Our probable undeveloped reserves relate to more optimistic recoveries on wells categorized as proved and additional drilling locations that do not meet the criteria to be categorized as proved. More optimistic recoveries have been included for the proved undeveloped locations noted above including the horizontal Cadomin gas well and the tie-in project in the Deep Basin which will be completed in the first quarter of 2008. The additional probable undeveloped locations will be drilled into known horizons with offset production as infill wells or step out locations and are anticipated to be developed within the next two years.

The following table discloses, for each product type, the total volumes of gross probable undeveloped reserves at December 31, 2007 and the year in which they were first attributed.

Probable Undeveloped	**Total**	**2007**	**2006**	**2005**	**Prior**
Light and Medium Oil (Mbbls)	682	526	156	-	-
Natural Gas (MMcf)	1,446	1,098	348	-	-
Natural Gas Liquids (Mbbls)	13	5	8	-	-
Total (Mboe)	936	714	221	-	-

Significant Factors or Uncertainties

The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions. All of our reserves were evaluated by GLJ.

As circumstances change and additional data becomes available, reserve estimates also change. Estimates made are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and governmental restrictions

Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. As a result, subjective decisions, new geological or production information and a changing environment may impact these estimates. Revisions to reserve estimates can arise from changes in oil and gas prices and reservoir performance. Such revisions can either be positive or negative and could be material.

Future Development Costs

The following table sets forth development costs deducted in the estimation of our future net revenue attributable to the reserve categories noted below.

	Forecast Prices And Costs	
Year	**Proved Reserves**	**Proved Plus Probable Reserves**
($ thousands)		
2008	7,194	9,246
2009	3,559	11,933
2010	929	2,821
2011	234	242
2012	19	19
Remaining	386	425
Total (Undiscounted)	12,321	24,686

In each year of our economic forecasts, our estimated future net revenues or operating income exceeds our estimated future development costs. Therefore, we will be able to fund our future development capital entirely out of our cash flow and no other sources of funding should be required. If additional funding were required, we typically half three sources of funding to finance our capital expenditure programs: (i) internally generated cash flow; (ii) debt financing; and (iii) new equity issue, if available on favourable terms.

Other Oil and Gas Information

Oil and Gas Properties

Our production is located in West Central Alberta, the Peace River Arch and Red Earth, with our exploration focus being the Peace River Arch and Red Earth areas, where we hold the majority of our undeveloped lands. During 2007, we spent capital of approximately $27.3 million in our oil and gas properties in these areas. For the first half of 2008, our Board of Directors have approved a capital budget of $13.5 million. This will fund completion of the construction of our Red Earth water handling facility and will enable us to participate in the drilling of 10 gross (3 net) wells. The actual amount of capital expenditures for the year will be dependent on the success of our program and our ability to fund additional projects through our internally generated cash flow, credit facilities and may include issuing additional equity if available on favourable terms. The following is a description of these oil and natural gas properties.

West Central Alberta

Our primary producing properties in the West Central Area of Alberta are: Pine Creek, Kaybob, Fox Creek, Windfall, Fir, Bigstone, Oldman, Marlboro and Groat. We hold minor interests in numerous wells in these properties which account for approximately 32% of our proved plus probable reserves. These properties are within a 63 square township block between Edmonton and Grand Prairie, Alberta.

The West Central Area is characterized by multi-zoned gas and oil prospects from the shallower gas prone Belly River formation to the deeper but highly prospective Leduc and Wabamun gas horizons underlying the Pine Creek Gas Unit. We have access to or an ownership interest in a majority of the infrastructure that exists in this area.

In 2007, we participated in 12 (0.6 net) wells in this area. In the first half of 2008, we are participating in 6 (0.3 net) wells in this area with a combination of exploration and development drilling targeting many prospective horizons including, but not limited to: the Belly River, Cardium, Dunvegan, Viking, Notikewan, Bluesky, Gething, Cadomin, Jurassic Nordegg, Triassic, Montney, Wabamun and Leduc formations. Our technical teams have extensive experience in these types of reservoirs and will be employing the use of seismic and our extensive core and cutting database in addition to detailed log analysis and geological mapping to minimize the risk in order to maximize the potential return of each investment opportunity.

We also hold varying interests in exploratory lands within the highly prized Nisku oil fairway in Pembina which we intend to evaluate through a joint drilling program. Two 3D seismic programs have been shot over the undeveloped lands to assist in exploring for Nisku oil. We have working interests varying from 37.5% to 40% in 6 sections of land in this area and anticipate participating in one (0.4 net) well on the play in 2008.

Peace River Arch

Our management and technical staff have extensive experience in exploring for and developing the gas charged Cretaceous and Triassic aged reservoirs in this area. In 2007, we participated in 4 (2.2 net) wells in this area. Our undeveloped land base has multi-zone potential including, but not limited to, the Dunvegan, Cadotte, Notikewan, Falher, Gething, Cadomin, Halfway and Montney formations. Our reserves in this area account for approximately 24% of our total proved plus probable reserves. In the first half of 2008, we are participating in 3 (2.5 net) wells in this area. We will also continue to develop this opportunity rich land base through a combination of high working interest drilling and partial farm-outs to spread our risk exposure. To date, we have also entered into a number of farm-in agreements with third parties in the area.

Red Earth

We acquired our Red Earth assets effective November 29, 2005. The main producing horizons in this area are the Granite Wash and Keg River formations. Both zones contain sweet, light (40° API) oil. The assets include a mix of operated and non-operated wells ranging in interests from 25% to 100%. Our reserves in Red Earth account for approximately 43% of our total proved plus probable reserves. Along with the producing wells, we also have an interest in 60,000 net undeveloped acres that contain both exploratory and development oil potential. Uphole potential also exists in the Slave Point (oil) and Bluesky (gas). In 2007, we participated in 5 (4.0 net) wells in this area.

For the first half of 2008, we will participate in 1 (0.25 net) oil wells. The existing Keg River pools in this area are being actively water flooded. During the first quarter of 2008, we completed the installation of water injection facilities in our operated Red Earth area and water injection has commenced. Besides providing increased oil recovery, water injection should act to stabilize and enhance production from the pool and reduce corporate operating costs. In addition, we can now economically expand the water flood into other pools in the area.

Minor

We also hold varying interests in other minor properties throughout Alberta. These reserves account for only 1% of our total proved plus probable reserves and we have no exploration or development plans for these properties.

Exploration and Development Strategy of Midnight

Our exploration and development strategy involves the expansion of our asset base in Western Canada through: (i) drilling on our existing properties; (ii) adding lands and opportunities through acquisitions at Crown sales; (iii) farm-ins involving the drilling of wells to earn a negotiated working interest on the third parties' properties; and (iv) the acquisition of new properties from third parties. We intend to acquire additional land and drilling opportunities that have both development and exploration drilling potential in areas in which we have expertise and that have multi-zone productive capability.

Oil and Gas Wells

The following table sets forth the number and status of wells in which we have a working interest as at December 31, 2007:

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	49	19.2	28	12.7	177	23.3	89	15.5
British Columbia	-	-	-	-	1	0.2	1	0.5
Total	49	19.2	28	12.7	178	23.5	90	16.0

Properties with no Attributable Reserves

The following table sets out the Company's undeveloped land holdings as at December 31, 2007:

	Undeveloped Acres	
	Gross	Net
Alberta	260,000	125,000
British Columbia	33,000	23,000
Total	293,000	148,000

Rights to explore, develop and exploit 40,000 net acres of our total net acres relate to title documents whose primary terms come to an end between January 1, 2008 and December 31, 2008. Of these, we estimate that over 18,000 net acres will be further continued through submission of continuation applications and additional drilling.

At December 31, 2007, we did not have any material work commitments on our undeveloped properties.

Forward Contracts

We are not bound by any agreement (including a transportation agreement), directly or through an aggregator, under which we may be precluded from fully realizing, or may be protected from the full effect of, future market prices for oil or gas.

Drilling Activity

The following table summarizes the gross and net exploration and development wells that we participated in during the year ended December 31, 2007:

	Exploratory		Development	
	Gross	Net	Gross	Net
Light and Medium Oil	2	1.5	1	1.0
Natural Gas	6	2.4	11	1.5
Dry	1	0.5	-	-
Total	9	4.4	12	2.5

For details of our current and likely exploration and development activities, see "*Oil and Gas Properties*" on pages 15 to 17.

Abandonment and Reclamation Costs

The following table discloses our abandonment and reclamation costs anticipated as at December 31, 2007, calculated both at an undiscounted and at a 10% discount rate with a portion thereof anticipated to be paid in each of the next three years:

Abandonment and reclamation costs	**Undiscounted**	**Discounted at 10%**
($ thousands)		
Total at December 31, 2007	4,389	1,639
Total expected to be incurred in the next three years	464	413

We are liable for our share of ongoing environmental obligations and for the ultimate reclamation of the properties held by us upon abandonment. Ongoing environmental obligations are expected to be funded out of cash flow.

We currently estimate that the future environmental and reclamation obligations net of salvage value in respect of our assets will aggregate approximately $4,389,000 escalated at 2% per year. Of this amount, $2,015,000 has been reflected in the disclosed Reserves Data for total proved reserves.

We estimate the costs to abandon and reclaim all shut-in and producing wells, facilities, gas plants, pipelines, batteries and satellites. Our model for estimating the amount and timing of future abandonment and reclamation expenditures is done on an operating area level. Estimated expenditures for each operating area are based on management's prior experience in the areas. Abandonment and reclamation costs have been estimated over an approximate 40-year period with the majority of the costs estimated to be incurred in the next 20 years. Facility reclamation costs are scheduled to be incurred in the year following the end of the reserve life of our associated reserves. We estimate that future salvage recovery on facilities is expected to exceed future abandonment costs on those facilities. As at December 31, 2007, we expected to incur reclamation and abandonment costs in respect of 71.4 net wells.

Tax Horizon

We forecast our tax horizon assuming a continuing business model whereby we re-invest cash flow at historic capital efficiencies and incur general and administrative costs and interest on our bank debt. Under this scenario, we do not forecast being in a taxable position for the next five years. This result is dependent upon commodity prices, capital spending and the success of our drilling program.

Income taxes deducted in the calculations of future net revenues in the reserves tables in this Annual Information Form assumes the Company produces out its existing reserves without reinvestment of cash flows and does not take into account general and administrative expenses or interest expenses. Under this scenario, using total proved reserves and forecast prices and costs, we would be taxable in 2010.

At December 31, 2007 we had approximately $131 million in tax pools available to shelter taxable income in future years.

Costs Incurred

The following table summarizes capital expenditures for the year ended December 31, 2007:

Expenditures	**2007**
($ thousands)	
Property acquisition costs – Proved Properties	-
Property acquisition costs – Undeveloped Properties [(1)]	(1,371)
Exploration Costs [(2)]	12,812
Development Costs [(3)]	15,842
Non-oil and gas assets	47
Total	27,330

Notes:

(1) Cost of land acquired, lease rentals on unproved properties and net of dispositions and transfers.

(2) Geological and geophysical costs, capitalized general and administration costs and drilling and completion costs for exploration wells.

(3) Drilling and completion costs for development wells and equipping, tie-in and facility costs for all wells.

Production Estimates

The following table sets out the 2008 working interest yearly average rates for our production as estimated by GLJ which is reflected in the estimate of future net revenue disclosed in the tables contained under "*Statement of Reserves Data and Other Oil and Gas Information – Reserves Data*". Red Earth is our only property that accounts for greater than 20% of our forecast production in 2008:

	Light & Medium Oil	**Natural Gas Liquids**	**Natural Gas**	**BOE**
	(bbls/d)	**(bbls/d)**	**(Mcf/d)**	**(boe/d)**
Proved Producing				
Red Earth	644	-	249	686
Others	33	109	5,098	992
Total Proved Producing	677	109	5,347	1,678
Proved				
Red Earth	685	-	566	779
Others	35	114	5,728	1,103
Total Proved	719	114	6,294	1,882
Proved Plus Probable				
Red Earth	748	-	578	844
Others	36	115	5,932	1,140
Total Proved Plus Probable	784	115	6,510	1,984

Production History

The following table summarizes our net daily production, before royalties, for the periods indicated:

	Quarters Ended 2007			
	Q1	**Q2**	**Q3**	**Q4**
Light and Medium Crude Oil (bbls/d)	920	1,008	898	820
NGLs (bbls/d)	170	177	152	216
Natural Gas (Mcf/d)	6,891	5,769	5,981	5,573
Combined (boe/d)	2,239	2,146	2,047	1,965

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

	Quarters Ended 2007			
	Q1	**Q2**	**Q3**	**Q4**
Light and Medium Crude Oil ($/bbls)				
Average Price Received	64.04	69.80	81.23	85.23
Royalties Paid	10.21	14.80	17.04	17.89
Transportation Expenses	2.21	3.37	3.01	2.63
Operating Expenses	10.80	8.61	13.19	18.06
Netback Received (1)	40.82	43.02	47.99	46.65
NGLs ($/bbls)				
Average Price Received	47.07	49.43	53.13	58.26
Royalties Paid	14.03	11.80	15.46	17.61
Transportation Expenses	-	-	-	-
Operating Expenses	10.80	9.57	10.77	13.13
Netback Received (1)	22.24	28.06	26.90	27.52

	Quarters Ended 2007			
	Q1	Q2	Q3	Q4
Natural Gas ($/Mcf)				
Average Price Received	7.82	7.22	5.33	6.17
Royalties Paid	1.50	0.14	(0.05)	(0.10)
Transportation Expenses	0.01	0.01	0.01	0.01
Operating Expenses	1.80	1.60	1.80	2.19
Netback Received (1)	4.51	5.47	3.57	4.07
Combined ($/boe)				
Average Price Received	54.06	56.37	55.43	59.81
Royalties Paid	9.88	8.29	8.48	9.12
Transportation Expenses	0.93	1.59	1.36	1.11
Operating Expenses	10.80	9.12	11.82	15.19
Netback Received (1)	32.45	37.37	33.77	34.39

Note:
(1) Netbacks are calculated by subtracting royalties, operating expenses and transportation expenses from average prices received on a per unit basis.

The following table indicates our average daily production from Red Earth and our other fields for the year ended December 31, 2007:

	Light & Medium Oil	Natural Gas Liquids	Natural Gas	BOE
	(bbls/d)	(bbls/d)	(Mcf/d)	(boe/d)
Red Earth	857	-	260	900
Others	54	179	5,790	1,198
Total	911	179	6,050	2,098

DESCRIPTION OF CAPITAL STRUCTURE

Our authorized share capital consists of an unlimited number of Common Shares without nominal or par value. At March 18, 2008, we had outstanding, 47,422,629 Common Shares, 2,994,500 options, each of which is exercisable for one (1) Common Share at a weighted average exercise price of $2.55 per share and 2,013,333 Warrants.

Our shareholders have authorized the number of Common Shares that may be subject to options granted under our stock option plan at any time to 10% of the number of outstanding Common Shares from time to time. Based on the issued and outstanding Common Shares as at March 18, 2008, the number of options which may be issued under our stock option plan is currently limited to 4,742,262 options of which options to purchase 2,994,500 (6.3% of the outstanding Common Shares) are outstanding and 1,747,762 options are available for future grants (3.7% of the outstanding Common Shares).

The following is a description of the rights, privileges, restrictions and conditions attaching to our authorized and outstanding share capital. Our share provisions have been filed on SEDAR at www.sedar.com.

Common Shares

Subject to the provisions of the *Business Corporations Act* (Alberta), holders of Common Shares are entitled to receive notice of, to attend and vote at all meetings of our shareholders and are entitled to one vote, in person or by proxy, for each Common Share held.

Holders of Common Shares are entitled to receive, if, as and when declared by our directors, non-cumulative dividends at such rate and payable on such date as may be determined from time to time by our directors.

Upon our liquidation, dissolution or winding-up, or any other distribution of our assets among our shareholders for the purpose of winding-up our affairs, holders of the Common Shares shall be entitled to receive our remaining property and assets.

Warrants

The Warrants were issued under and pursuant to a private placement on November 29, 2004. Each Warrant is exercisable for one (1) Common Share at a price of $3.00 per share provided that certain specific performance criteria are met. All of the performance requirements were met in December 2005 and all of the Warrants have vested and are exercisable. The Warrants expire on November 29, 2008.

MARKET FOR SECURITIES

Our Common Shares are listed for trading on the TSX under the symbol "MOX". The following table sets out the price range for and trading volume of the Common Shares since January 1, 2007.

Period	High	Low	Volume (000s)
2007			
January	2.39	1.76	1,884
February	2.18	1.68	961
March	1.80	1.35	1,854
April	1.95	1.72	973
May	1.92	1.61	3,667
June	2.10	1.71	2,394
July	1.89	1.72	288
August	1.81	1.31	180
September	1.60	1.41	146
October	1.45	1.17	3,581
November	1.34	0.93	1,521
December	1.18	0.92	4,886
2008			
January	1.25	0.99	614
February	1.54	0.93	1,488
March 1 to March 18	1.52	1.30	673

DIVIDEND POLICY

We have not paid or declared any dividends on our outstanding Common Shares and have no intention of paying dividends in the foreseeable future. The payment of dividends depends upon our requirements to fund future growth, our financial condition and other factors that the board of directors may consider appropriate in the circumstances.

OFFICERS AND DIRECTORS

Officers and Directors

The names, municipalities of residence of our directors and officers, their positions and offices currently held with us, the date they became a director and their principal occupations during the past five years are as follows:

Name and Municipality of Residence	Position	Director Since	Principal Occupation and Positions for the Past Five Years
Fred Woods Calgary, Alberta	Chairman, President, Chief Executive Officer and Director	2004	Mr. Woods has been Chairman since May 2007 and President, Chief Executive Officer and a Director of Midnight or its predecessor since May 2000. From March 1997 to May 2000, Mr. Woods was President and Chief Operating Officer of Ulster Petroleums Ltd. (an intermediate oil and gas company).

Name and Municipality of Residence	Position	Director Since	Principal Occupation and Positions for the Past Five Years
Anthony Lambert(2)(3)(4) Calgary, Alberta	Director	2004	Mr. Lambert has been President and Chief Executive Officer of Daylight Resources Trust or its predecessor since November, 2004. On August 3, 2005 he resigned as Vice-President, Operations and Chief Operating Officer of Midnight. Mr. Lambert has been a Director of Midnight or its predecessor since July 2000. Prior thereto, Mr. Lambert was the Vice-President, Operations of Ulster Petroleums Ltd.
Jay Squiers(1)(2)(3)(4) Dallas, Texas	Director	2004	Mr. Squiers has been a Principal of American Capital in the Dallas based Energy Group since October 2007. Prior thereto Mr. Squiers was a Managing Director of Fortress Investment Group, LLC, an investment and asset management firm starting in August 2005. From August 2002 until July 2005, he was a Senior Vice-President of Prudential Capital Group, a private capital lender. Mr. Squiers began his career at Prudential Capital Group in 1991. Mr. Squiers earned a JD with Honours from the University of Texas School of Law at Austin and a Bachelor of Economics, magna cum laude, from Princeton University and he is also a Chartered Financial Analyst.
Tom Medvedic(1)(2)(3)(4) Calgary, Alberta	Director	2004	Mr. Medvedic is Senior Vice-President, Finance and Chief Financial Officer of Calfrac Well Services Ltd. Mr. Medvedic was appointed Chief Financial Officer of Calfrac Well Services Ltd. in December 2004. Prior to July 2004, Mr. Medvedic was Treasurer of Ensign Resource Service Group Inc. Mr. Medvedic is a Chartered Accountant with a specialization in tax.
Peter Harrison(1)(2)(3)(4) Brossard, Québec	Director	2007	Mr. Harrison is a Senior Vice-President of Montrusco Bolton Investments Inc. (Montreal) since December 1997 and previously managed Canadian Equities for the CN Investment Division based in Montreal, Québec. Mr. Harrison has significant financial experience making investments which involve extensive analysis of financial statements. He holds a Bachelor of Commerce degree from McGill University, and an MBA from the University of Western Ontario, and is a Chartered Financial Analyst. Mr. Harrison also sits on the board of Montrusco Bolton Investments Inc. and Freehold Royalty Trust.
Judith Stripling Calgary, Alberta	Executive Vice President and Chief Financial Officer		Ms. Stripling is Executive Vice-President and Chief Financial Officer of Midnight. Ms. Stripling was appointed Executive Vice-President of Midnight in June 2006. Prior thereto, Ms. Stripling was Vice-President, Finance and Chief Financial Officer of Midnight or its predecessor since July 2000. Prior to July 2000, Ms. Stripling was Vice-President, Finance and Chief Financial Officer of Ulster Petroleums Ltd.
Thomas Moslow Calgary, Alberta	Senior Vice President, Exploration		Dr. Moslow is Senior Vice-President, Exploration of Midnight and was appointed to this office in June 2006. Prior thereto, Dr. Moslow was Vice-President, Exploration of Midnight or its predecessor since July 2000. Prior to July 2000, Dr. Moslow was Vice-President of New Ventures and Technology at Ulster Petroleums Ltd.

Name and Municipality of Residence	Position	Director Since	Principal Occupation and Positions for the Past Five Years
Andrew Weldon Calgary, Alberta	Vice President, Business Development		Mr. Weldon is Vice-President, Business Development of Midnight and was appointed to this office in June 2006. Prior thereto, Mr. Weldon was Vice-President, Land of Midnight since February 2002. From March 1998 to January 2001, Mr. Weldon was Vice-President, Land at Startech Energy Inc. (an intermediate publicly traded oil and gas company).
Chad Kalmakoff Calgary, Alberta	Vice-President, Finance		Mr. Kalmakoff is Vice-President, Finance of Midnight and was appointed to this office in June 2006. Prior thereto, Mr. Kalmakoff was Financial Controller of Daylight Energy Trust or its predecessor since June 2003. Prior thereto, Mr. Kalmakoff held various positions with KPMG LLP.
C. Donald Leitch Calgary, Alberta	Vice-President, Operations		Mr. Leitch has been Vice-President, Operations of Midnight since June 2006. Prior thereto, Mr. Leitch was Vice-President, Operations of Caribou Resources Corp. since December 2004. Prior thereto, Mr. Leitch was Operations Manager at Paramount Resources Ltd. since November 2002. Prior thereto, Mr. Leitch was Consulting Project Engineer at Calpine Canada Resources Ltd.
Peter O'Leary Calgary, Alberta	Vice-President, Geology		Mr. O'Leary is Vice-President, Geology of Midnight and was appointed to this office in June 2006. Prior thereto, Mr. O'Leary was Exploration Manager, PRA/Deep Basin of Daylight Energy Trust or its predecessor since February 2003. Prior thereto, Mr. O'Leary was Exploration Manager of the Peace River Arch District at Devon Canada Corporation.
E. Martin Saizew Calgary, Alberta	Vice-President, Engineering		Mr. Saizew is Vice-President, Engineering of Midnight and was appointed to this office in June 2006. Prior thereto, Mr. Saizew was Exploitation Manager, PRA & Foothills of Daylight Energy Trust or its predecessor since May 2003. Prior thereto, Mr. Saizew was Senior Exploitation Engineer at Pengrowth Energy Trust.
Chris von Vegesack Calgary, Alberta	Corporate Secretary		Mr. Vegesack has been a partner at Burnet, Duckworth & Palmer LLP, a Calgary based law firm, since 1986. Mr. Vegesack specializes in corporate finance and mergers and acquisitions. Mr. Vegesack has been the Corporate Secretary of Midnight or its predecessor since July 2000.

Notes:

(1) Member of the Audit Committee, Tom Medvedic is the Chairman of this committee.

(2) Member of the Reserves Committee, Anthony Lambert is the Chairman of this committee.

(3) Member of the Compensation Committee, Jay Squiers is the Chairman of this committee.

(4) Member of the Corporate Governance Committee, Peter Harrison is the Chairman of this committee. Midnight does not have an executive committee.

(5) The terms of office of all directors of Midnight will expire on the date of the next annual meeting of shareholders of Midnight.

As at the date hereof, our directors and officers and their associates and affiliates, as a group, beneficially own, control or direct, directly or indirectly, approximately 4.7 million Common Shares representing 10% of our outstanding Common Shares. The directors and officers also hold 2,013,333 Warrants and 2,350,000 options which would increase their beneficial ownership to 17% of the outstanding Common Shares on a fully diluted basis. The information as to the number of Common Shares beneficially owned, controlled or directed, directly or indirectly, or over which control or direction is exercised, is based upon information received from such directors and officers.

Corporate Cease Trade Orders, Bankruptcies or Penalties or Sanctions

None of our directors or executive officers (nor any personal holding company of any of such persons) is, as of the date of this Annual Information Form, or was within ten years before the date of this Annual Information Form, a director, chief executive officer or chief financial officer of any company (including us), that was subject to a cease trade order (including a management cease trade order), an order similar to a cease trade order or an order that denied the relevant company access to any exemption under securities legislation, in each case that was in effect for a period of more than 30 consecutive days (collectively, an "**Order**") that was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer or was subject to an Order that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer.

None of our directors or executive officers (nor any personal holding company of any of such persons), or shareholder holding a sufficient number of our securities to affect materially the control of us is, as of the date of this Annual Information Form, or has been within the ten years before the date of this Annual Information Form, a director or executive officer of any company (including us) that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets or has, within the ten years before the date of this Annual Information Form, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, executive officer or shareholder.

None of our directors or executive officers (nor any personal holding company of any of such persons), or shareholder holding a sufficient number of our securities to affect materially the control of us, has been subject to any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority or any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

Conflicts

Certain of our directors and officers may have interests in other oil and gas companies and oil and gas properties which may from time to time conflict with our interests. Any such conflicts will be resolved in accordance with the requirements of the *Business Corporations Act* (Alberta). Mr. von Vegesack, our Corporate Secretary, is a partner in a law firm which provides services to us. We periodically utilize the oilfield services of Calfrac Well Services Ltd. in its operations, of which Mr. Medvedic, one of our directors, is the Senior Vice-President, Finance and Chief Financial Officer. Our board of directors does not believe that any activities undertaken by Mr. von Vegesack or Mr. Medvedic interfere, or could be perceived to interfere, in any material way with their ability to act with a view to our best interests.

ESCROWED SECURITIES

To the knowledge of Midnight, none of our securities are held in escrow.

AUDIT COMMITTEE INFORMATION

Audit Committee Charter

We have established an audit committee to assist our Board of Directors in carrying out its oversight responsibilities with respect to financial reporting, internal controls and our external audit process. The Mandate and Terms of Reference of the Audit Committee is attached as Schedule "C".

Composition of the Audit Committee

The following table sets forth the name of each current member of the Audit Committee, whether such member is independent, financially literate and the relevant education and experience of such member:

Name	Independent	Financially Literate	Relevant Education and Experience
Tom Medvedic (Chairman)	Yes	Yes	Mr. Medvedic is Senior Vice-President, Finance and Chief Financial Officer of Calfrac Well Services Ltd. As a Chartered Accountant, Mr. Medvedic has attained experience in preparing, analyzing and evaluating financial statements. Mr. Medvedic has an understanding of the accounting principles used by Midnight as well as the implications of those accounting principles on Midnight's financial results. As a Chief Financial Officer of a public company, Mr. Medvedic is well informed of new accounting pronouncements and of best practises.
Peter Harrison	Yes	Yes	Mr. Harrison holds a Bachelor of Commerce Degree from McGill University, a Master of Business Administration from the Ivey School of Business, at the University of Western Ontario, and is a Chartered Financial Analyst. Mr. Harrison has worked in the investment industry in excess of 27 years. As Senior Vice-president of Montrusco Bolton Investments Inc. (Montreal) and as previously managing Canadian equities for the CN Investment Division, Mr. Harrison has significant financial experience making investments which involve extensive analysis of financial statements. Additionally Mr. Harrison is a member of the Board of Directors of Montrusco Bolton Investments Inc. and a director and member of an audit committee of a publicly traded oil and gas royalty trust.
Jay Squiers	Yes	Yes	Mr. Squiers holds a law degree (Honours) from University of Texas, a Bachelor of Economics (magna cum laude) from Princeton and earned the Chartered Financial Analyst designation in 1997. Mr. Squiers has obtained significant financial experience and exposure to accounting and financial issues in his career at Prudential Capital Group. As a Senior Vice-President, he was actively involved in originating, underwriting and managing a portfolio of private placement investments for a division of Prudential Financial, Inc. As a Managing Director of Fortress Investment Group, LLC., he was responsible for identifying, underwriting and executing debt acquisition and originating opportunities in the energy and general corporate sectors. As a Principal of American Capital in the Dallas-based Energy Group, Mr. Squiers focuses on debt and minority equity financings in support of private equity sponsors, acquisitions, as well as direct financings for companies across the energy sector.

External Auditor Service Fees

Audit Fees

The audit fees consist of a budget for 2007 of $81,500 payable to KPMG LLP for professional services rendered for the audit of our consolidated financial statements for the period ended December 31, 2007 and for services provided in connection with statutory and regulatory filings. In addition, professional services for quarterly reviews for 2007 of $43,000 were paid to KPMG LLP.

Tax, Audit and Related Fees

For the year ended December 31, 2007, we paid KPMG LLP $8,500 for tax services and did not pay any additional fees for professional services other than disclosed above in "Audit Fees".

Pre-Approval of Policies and Procedures

We have adopted polices and procedures with respect to the pre-approval of audit and permitted non-audit services to be provided by KPMG LLP as set forth in item 13 of the Audit Committee Mandate and Terms of Reference as laid out in Schedule "C". The Audit Committee has approved the provision of a specified list of audit and permitted non-audit services that the audit committee believes to be typical, recurring or otherwise likely to be provided by KPMG LLP during the current fiscal year. The list of services is sufficiently detailed as to the particular services to be provided to ensure that the audit committee knows precisely what services it is being asked to pre-approve and it is not necessary for any member of management to make a judgment as to whether a proposed service fits within pre-approved services.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

There are no legal proceedings that we are or was a party to, or that any of our property is or was the subject of, during the most recently completed financial year, that were or are material to us, and there are no such material legal proceedings that we are currently aware of that are contemplated.

There were no: (i) penalties or sanctions imposed against us by a court relating to securities legislation or by a security regulatory authority during the most recently completed financial year; (ii) other penalties or sanctions imposed by a court or regulatory body against us that would likely be considered important to a reasonable investor in making an investment decision; or (iii) settlement agreements we entered into before a court relating to securities legislation or with a securities regulatory authority during our most recently completed financial year.

INTERESTS OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There are no material interests, direct or indirect, of our directors and senior officers, or any holder of our Common Shares who beneficially owns, or controls or directs, directly or indirectly, more than 10% of our outstanding Common Shares, or any known associate or affiliate of such persons, in any transaction within the last fiscal year and in any proposed transaction which has materially affected or is reasonably expected to materially affect us, other than as disclosed herein.

AUDITORS, TRANSFER AGENT AND REGISTRAR

Our auditors are KPMG LLP chartered accountants, Suite 2700, 205 – 5th Avenue S.W., Calgary, Alberta, T2P 4B9.

Valiant Trust Company at its principal office in Calgary, Alberta and through its co-agent, BNY Trust Company of Canada at its principal office in Toronto, Ontario, is transfer agent and registrar of our Common Shares.

MATERIAL CONTRACTS

The only material contract entered into by us within the most recently completed financial year and which are presently material other than in the ordinary course of business, is the credit agreement in respect of our $37.5 million credit facility with a Canadian chartered bank, which agreement is described in Note 4 to our consolidated financial statements for the year ended December 31, 2007, which note is incorporated by reference herein. A copy of this agreement is available on SEDAR at www.sedar.com.

INTERESTS OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a report, valuation, statement or opinion described or included in a filing, or referred to in a filing, made under National Instrument 51-102 by us during, or related to, our most recently completed financial year other than GLJ, our independent engineering evaluator and KPMG LLP, our auditors. None of the designated experts of GLJ had any registered or beneficial interests, direct or indirect, in any securities or other property of Midnight.

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 us or of any associate or affiliate of us except for Chris von Vegesack, our Corporate Secretary, who is a partner at Burnet, Duckworth & Palmer LLP, which law firm renders legal services to us.

INDUSTRY CONDITIONS

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

Pricing and Marketing - Oil and Natural Gas

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

The price of natural gas is determined by negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m3/day), must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or a larger quantity requires an exporter to obtain an export licence from the NEB and the issuance of such licence requires the approval of the Governor in Council.

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

Pipeline Capacity

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

The North American Free Trade Agreement

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

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

Provincial Royalties and Incentives

General

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

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

The Canadian federal corporate income tax rate levied on taxable income is 22.1% effective January 1, 2007 for active business income including resource income. With the elimination of the corporate surtax effective January 1, 2008 and other rate reductions introduced in the October 2007 Economic Statement and Notice of Ways and Means Motion, 2006 Federal Budget, the federal corporate income tax rate will decrease to 15% in five steps: 19.5% on January 1, 2008, 19% on January 1, 2009; 18% on January 1, 2010, 16.5% on January 1, 2011 and 15% on January 2012.

Alberta

In Alberta, companies are granted the right to explore, produce and develop petroleum and natural gas resources in exchange for royalties, bonus bid payments and rents. Currently, the amount of royalties that are payable is influenced by the oil production, density of the oil, and the vintage of the oil. Originally, the vintage classified oil as "new oil" and "old oil" depending on when the oil pools were discovered. If the pool was discovered prior to March 31, 1974 it is considered "old oil", if it was discovered after March 31, 1974 and before September 1, 1992, it is considered "new oil". The Alberta government introduced in 1992 a Third Tier Royalty with a base rate of 10% and a rate cap of 25% for oil pools discovered after September 1, 1992. The new oil royalty reserved to the Crown has a base rate of 10% and a rate cap of 30%. The old oil royalty reserved to the Crown has a base rate of 10% and a rate cap of 35%.

The royalty reserved to the Crown in respect of natural gas production, subject to various incentives, is between 15% and 30%, in the case of new natural gas, and between 15% and 35%, in the case of old natural gas, depending upon a prescribed or corporate average reference price. Natural gas produced from qualifying intervals in eligible gas wells spudded or deepened to a depth below 2,500 metres is also subject to a royalty exemption, the amount of which depends on the depth of the well.

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

Regulations made pursuant to the *Mines and Minerals Act* (Alberta) provided various incentives for exploring and developing oil reserves in Alberta. However, the Alberta Government announced in August of 2006 that four royalty programs were to be amended, a new program was to be introduced and the Alberta Royalty Tax Credit Program ("**ARTC**") was to be eliminated, effective January 1, 2007. The programs affected by this announcement are: (i) Deep Gas Royalty Holiday; (ii) Low Productivity Well Royalty Reduction; (iii) Reactivated Well Royalty Exemption; and (iv) Horizontal Re Entry Royalty Reduction. The program being introduced is the Innovative Energy Technologies Program (the "**IETP**") which is intended to promote the producers' investment in research, technology and innovation for the purposes of improving environmental performance while creating commercial value. The IETP provides royalty reductions which are presumed to reduce financial risk. Alberta Energy will be the one to decide which projects qualify and the level of support that will be provided. The deadline for the IETP's third round of applications was May 31, 2007. The successful applicants have not yet been announced and it appears, based on the previous two rounds, that the selection process can take at least 8 months. The technical information gathered from this program is to be made public once a two-year confidentiality period expires.

On October 25, 2007, the Alberta government released a report entitled "The New Royalty Framework" (the "NRF") containing the government's proposals for Alberta's new royalty regime that is scheduled to be effective on January 1, 2009. The proposed NRF includes new royalty formulas for conventional oil and natural gas that will operate on sliding scales that are determined by commodity prices and well productivity; in addition to the policy of "shallow rights reversion". The Alberta government is intending to implement this policy in order to maximize the development of currently undeveloped resources which is consistent with the government's objective of maximizing recovery of known gas resources, while increasing royalty revenues. The policy's 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. It appears that leaseholders will get a grace period before the shallower zones are reverted to the Crown, which is still to be determined. Substantial legislative, regulatory and systems updates will be introduced before changes become fully effective in January 2009. See "Risk Factors – New Alberta Royalty Regime".

British Columbia

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

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

Some of the financial incentives in the Strategy include:

- Royalty credits of up to $30 million annually towards the construction, upgrading, and maintenance of road infrastructure in support of resource exploration and development. Funding will be contingent upon an equal contribution from industry.

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

Land Tenure

Crude oil and natural gas located in the western provinces is owned predominantly by the respective provincial governments. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences, and permits for varying terms, 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 the Province of Alberta has been consolidated into the *Environmental Protection and Enhancement Act* (Alberta) (the "**EPEA**"), which came into force on September 1, 1993, and the *Oil and Gas Conservation Act* (Alberta) (the "**OGCA**"). The EPEA and OGCA impose stricter environmental standards, require more stringent compliance, reporting and monitoring obligations, and significantly increased penalties. In 2006, the Alberta Government enacted regulations pursuant to the EPEA to specifically target sulphur oxide and nitrous oxide emissions from industrial operations including the oil and gas industry. In addition, the reduction emission guidelines outlined in the *Climate Change and Emissions Management Amendment Act* came into effect on July 1, 2007. Under this legislation, Alberta facilities emitting more than 100,000 tonnes of greenhouse gases a year must reduce their emissions intensity by 12%. Industries have three options to choose from in order to meet the reduction requirements outlined in this legislation, and these are: (i) by making improvement to operations that result in reductions; (ii) by purchasing emission credits from other sectors or facilities that have emissions below the 100,000 tonne threshold and are voluntarily reducing their emission; or (iii) by contributing to the Climate Change and Emissions Management Fund. Industries can either choose one of these options or a combination thereof. We are committed to meeting our responsibilities to protect the environment wherever we operate and anticipate making increased expenditures of both a capital and an expense nature as a result of the increasingly stringent laws relating to the protection of the environment, and will be taking such steps as required to ensure compliance with the EPEA and similar legislation in other jurisdictions in which we operate. We believe that we are in material compliance with applicable environmental laws and regulations. We also believe that it is reasonably likely that the trend towards stricter standards in environmental legislation and regulation will continue.

In January 24, 2008, the Alberta Government announced a new climate change action plan that will cut Alberta's projected 400 million tonnes of emissions in half by 2050. This plan is based on three areas: (i) carbon capture and storage, which will be mandatory for *in situ* oil sand facilities that use heavy fuels for steam generation; (ii) energy conservation and efficiency; and (iii) greening production through increased investment in clean energy technology, including supporting research on new oil sands extraction processes, as well as the funding of projects that reduce the cost of separating CO2 from other emissions supporting carbon capture and storage.

British Columbia's *Environmental Assessment Act* became effective June 30, 1995. This legislation rolls the previous processes for the review of major energy projects into a single environmental assessment process with public participation in the environmental review process. On February 27, 2007 the Government of British Columbia unveiled the Energy Plan outlining the Province's strategy towards the environment and which includes targeting for zero net greenhouse gas emissions, promoting new investments in innovation, and becoming the world's leader in sustainable environmental management. For this purpose, on December 18, 2007 proposals were sought for applications to the Innovative Clean Energy Fund, in order to attract new technologies that will help solve energy and environmental issues. With regards to the oil and gas industry the objective is to achieve clean energy through conservation and energy efficient practices, whilst competitiveness is advocated in order to attract investment for the development of the oil and gas sector. Among the changes to be implemented are: (i) a new Net Profit Royalty Program; (ii) the creation of a Petroleum Registry; (iii) the establishment of an infrastructure royalty program (combining roads and pipelines); (iv) the elimination of routine flaring at producing wells; (v) the creation of policies and measures for the reduction of emissions; (vi) the development of unconventional resources such as tight gas and coalbed gas; and (vii) a new Oil and Gas Technology Transfer Incentive Program that encourages the research, development and use of innovative technologies to increase recoveries from existing reserves and promotes responsible development of new oil and gas reserves. Furthering these initiatives, on February 19, 2008 the provincial Government announced that starting on July 1, 2008, provided the legislation is approved; a revenue-neutral carbon tax will be applied to all fossil fuels used in the Province. The tax would be phased in, and the initial rate would be based on CO_2e of $10 per tonne for the first six months of 2009 and $15 per tonne for the last six months of 2009, following $5 per tonne increases on July of every year until 2012. Tax credits and reductions will be used in order to offset the tax revenues that the Government would receive otherwise.

In December, 2002, the Government of Canada ratified the Kyoto Protocol ("**Protocol**"). The Protocol calls for Canada to reduce its greenhouse gas emissions to 6% below 1990 "business as usual" levels between 2008 and 2012. Given revised estimates of Canada's normal emissions levels, this target translates into an approximately 40% gross reduction in Canada's current emissions. It is questionable, based on the Updated Action Plan announced by the federal government (see below), that the Kyoto 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 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 oils 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 CO_2 equivalent per year for natural gas pipelines; (ii) 3,000 tonnes of CO_2 equivalent per upstream oil and gas facilities; and (iii) 10,000 boe/d/company. These proposed thresholds are significantly stricter than the current Alberta regulatory threshold of 100,000 tonnes of CO_2 equivalent per year per facility.

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

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

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

Finally, a one-time credit of up to 15 million metric 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 us and our operations and financial condition at this time.

Trends

There are a number of trends that have been developing in the oil and gas industry during the past several years that appear to be shaping the near future of the business.

The first trend is the volatility of commodity prices. Natural gas is a commodity influenced by factors within North America. A tight supply-demand balance for natural gas causes significant elasticity in pricing, whereas higher than average storage levels tend to depress natural gas pricing. Drilling activity, weather, fuel switching and demand for electrical generation are all factors that affect the supply-demand balance. Recently, liquefied natural gas shipments to North America have also resulted in natural gas supply and natural gas pricing being based more on factors other than supply and demand in North America. Changes to any of these or other factors create price volatility.

Crude oil is influenced by the world economy, Organization of the Petroleum Exporting Countries' ability to adjust supply to world demand and weather. Crude oil prices have been kept high by political events causing disruptions in the supply of oil and concern over potential supply disruptions triggered by unrest in the Middle East and more recently have been impacted by weather and increased storage levels. Political events trigger large fluctuations in price levels.

The impact on the oil and gas industry from commodity price volatility is significant. During periods of high prices, producers generate sufficient cash flows to conduct active exploration programs without external capital. Increased commodity prices frequently translate into very busy periods for service suppliers triggering premium costs for their services. Purchasing land and properties similarly increase in price during these periods. During low commodity price periods, acquisition costs drop, as do internally generated funds to spend on exploration and development activities. With decreased demand, the prices charged by the various service suppliers also decline.

World oil and gas prices are quoted in United States dollars and the price received by Canadian producers is therefore affected by the Canadian/U.S. dollar exchange rate, which will fluctuate over time. In recent times, the Canadian dollar has increased materially in value against the United States dollar. Such material increases in the value of the Canadian dollar may negatively impact production revenues from Canadian producers and further increases in the value of the Canadian dollar would exacerbate this negative impact. Such increases may also negatively impact the future value of such entities' reserves as determined by independent evaluators.

A second trend within the Canadian oil and gas industry is the "renewal" of private and small junior oil and gas companies starting up business. These companies often have experienced management teams from previous industry organizations that have disappeared as a part of the ongoing industry consolidation. Many are able to raise capital and recruit well qualified personnel. To the extent that this trend continues, we will have to compete with these companies and others to attract qualified personnel.

A third trend currently affecting the oil and gas industry is the impact on capital markets caused by investor uncertainty in the North American economy. The capital market volatility in Canada has also been affected by uncertainties surrounding the economic impact that the Protocol, and other environmental initiatives, will have on the sector and, in more recent times, by the October 31, 2006 proposals of the Federal government of Canada (the

"**Trust Proposal**") relating to income trusts and other "specified investment flow-through" entities ("**SIFTs**") and by the October 25, 2007 proposal of the Alberta government relating to the NRF. The impact of the NRF is still being determined and will vary company to company based on the percentage of production in Alberta, their commodity mix and depths of production, among other things. The announcement by the Alberta government may also impact upon investor sentiment to invest in the province of Alberta. The amount and degree of these impacts have yet to be determined.

Pursuant to the existing provisions of the *Income Tax Ac*t (Canada), to the extent that a SIFT has any income for a taxation year after certain inclusions and deductions, the SIFT will be permitted to deduct all amounts of income which are paid or become payable by it to unitholders in the year. Under the Trust Proposal, SIFTs will be liable for tax at a rate consistent with the taxes currently imposed on corporations commencing in January 2011, provided that the SIFT experiences only "normal growth" and no "undue expansion" before then, in which case the tax could be imposed prior to the January 2011 deadline. Bill C-52, which received Royal Assent on June 22, 2007, contained legislation implementing the Trust Proposal. Although the Trust Proposal will not affect the method in which we will be taxed, it may have an impact on the ability of a SIFT to purchase producing assets from oil and gas exploration and production companies (as well as the price that a SIFT is willing to pay for such an acquisition) thereby affecting exploration and production companies' ability to be sold to a SIFT which has been a key "exit strategy" in recent years for oil and gas companies. This may be a benefit for us as we compete with SIFTs for the acquisition of oil and gas properties from junior producers. However, it may also limit our ability to sell producing properties or pursue an exit strategy.

RISK FACTORS

Investors should carefully consider the risk factors set out below and consider all other information contained herein and in our 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. Our long-term commercial success depends on our ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, any existing reserves we may have at any particular time, and the production therefrom will decline over time as such existing reserves are exploited. A future increase in our reserves will depend not only on our ability to explore and develop any properties we may have from time to time, but also on our ability to select and acquire suitable producing properties or prospects. No assurance can be given that we will be able to continue to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, our management 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 us.

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 ensure 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, we 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 us. In accordance with industry practice, we are not fully insured against all of these risks, nor are all such risks insurable. Although we maintain liability insurance in an amount that we consider consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits, in which event we could incur significant costs that could have a material adverse effect upon our financial condition. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks could have a material adverse effect on us.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

We make 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 our ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with ours. 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 may be periodically disposed of, so that we can focus our efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain of our non-core assets, if disposed of, could be expected to realize less than their carrying value on our financial statements.

Operational Dependence

Other companies operate some of the assets in which we have an interest. As a result, we will have limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect our financial performance. Our return on assets operated by others will therefore depend upon a number of factors that may be outside of our 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

We manage a variety of small and large projects in the conduct of our business. Project delays may delay expected revenues from operations. Significant project cost over runs could make a project uneconomic. Our ability to execute projects and market oil and natural gas will depend upon numerous factors beyond our 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;
- 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, we 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. We compete with numerous other organizations in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. Our competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than ours. Our ability to increase our reserves in the future will depend not only on our ability to explore and develop our present properties, but also on our 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 our costs, any of which may have a material adverse effect on our intended business, financial condition and results of operations. In order to conduct oil and gas operations, we will require licenses from various governmental authorities. There can be no assurance that we will be able to obtain all of the licenses and permits that may be required to conduct operations that we may wish to undertake.

New Alberta Royalty Regime

On October 25, 2007, the Alberta government released a report entitled "The New Royalty Framework" containing the government's proposals for Alberta's new royalty regime which is scheduled to be effective on January 1, 2009. Given that the NRF has only recently been announced, it is not possible at this time to determine the full impact of the NRF on our financial condition and operations.

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

Kyoto Protocol

Canada is a signatory to the United Nations Framework Convention on Climate Change and has ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nationwide emissions of carbon dioxide, methane, nitrous oxide and other so called "greenhouse gases". Our exploration and production facilities and other operations and activities emit greenhouse gases and will subject us 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 government of Canada's proposed *Clean Air Act of 2006* and Alberta's recently enacted *Climate Change and Emissions Management Act.* The direct or indirect costs of these regulations may adversely affect our business. 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 us to incur costs to remedy such discharge. Although we believe that we are in material compliance with current applicable environmental regulations no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise adversely affect our financial condition, results of operations or 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 ours. 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 us and our operations and financial condition. See "*Industry Conditions – Environmental Regulation*".

Prices, Markets and Marketing

The marketability and price of oil and natural gas that may be acquired or discovered by us is and will continue to be affected by numerous factors beyond our control. Our ability to market our oil and natural gas may depend upon our ability to acquire space on pipelines that deliver natural gas to commercial markets. We may also be affected by deliverability uncertainties related to the proximity of our 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 are subject to fluctuation. Any material decline in prices could result in a reduction of our 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 our reserves. We might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in our expected net production revenue and a reduction in 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 our control. These factors include economic conditions in the United States and Canada, the actions of the Organization of Petroleum Exporting Countries, governmental regulation, the 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 our carrying value of the proved reserves, borrowing capacity, revenues, profitability and cash flows from operations.

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

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 affected by the Canadian/U.S. dollar exchange rate, which will fluctuate over time. In recent years, the Canadian dollar has increased materially in value against the United States dollar. Such material increases in the value of the Canadian dollar have negatively impacted our operating entities' production revenues. Further material increases in the value of the Canadian dollar would exacerbate this negative impact. This increase in the exchange rate for the Canadian dollar and future Canadian/United States exchange rates could accordingly impact the future value of our reserves as determined by independent evaluators.

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

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

Substantial Capital Requirements

We anticipate making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. If our revenues or reserves decline, we may not have access to the capital necessary to undertake or complete future drilling programs. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to us. Our inability to access sufficient capital for our operations could have a material adverse effect on our financial condition, results of operations and prospects.

Additional Funding Requirements

Our cash flow from our reserves may not be sufficient to fund our ongoing activities at all times. From time to time, we may require additional financing in order to carry out our oil and gas acquisition, exploration and development activities. Failure to obtain such financing on a timely basis could cause us to forfeit our interest in certain properties, miss certain acquisition opportunities and reduce or terminate our operations. If our revenues from our reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect our ability to expend the necessary capital to replace our reserves or to maintain our production. If our cash flow from operations is not sufficient to satisfy our 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 us.

Issuance of Debt

From time to time we 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 our debt levels above industry standards for oil and natural gas companies of similar size. Depending on future exploration and development plans, we may require additional equity and/or debt financing that may not be available or, if available, may not be available on favourable terms. Neither our articles nor our by laws limit the amount of indebtedness that we may incur. The level of our indebtedness from time to time, could impair our ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

Hedging

From time to time we 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, we will not benefit from such increases and we may nevertheless be obligated to pay royalties on such higher prices, even though not received by us, after giving effect to such agreements. Similarly, from time to time we 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, we 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 us and may delay exploration and development activities. To the extent we are not the operator of our oil and gas properties, we will be dependent on such operators for the timing of activities related to such properties and will be largely unable to direct or control the activities of the operators.

Title to Assets

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat our claim which could result in a reduction of the revenue received by us.

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. All such estimates are to some degree speculative, and classifications of reserves are only attempts to define the degree of speculation involved. For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times, may vary. Our actual production, revenues, taxes and development and operating expenditures with respect to our 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, our 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 our 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 we intend 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 our reserves since that date.

Insurance

Our involvement in the exploration for and development of oil and natural gas properties may result in us becoming subject to liability for pollution, blow outs, property damage, personal injury or other hazards. Although we maintain 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, we 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 us. The occurrence of a significant event that we are not fully insured against, or the insolvency of the insurer of such event, could have a material adverse effect on us.

Geo Political Risks

The marketability and price of oil and natural gas that may be acquired or discovered by us 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 our net production revenue.

In addition, our oil and natural gas properties, wells and facilities could be subject to a terrorist attack. If any of our properties, wells or facilities is the subject of terrorist attack it could have a material adverse effect on us. We do not have insurance to protect against the risk from terrorism.

Dilution

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

Management of Growth

We may be subject to growth related risks including capacity constraints and pressure on our internal systems and controls. Our ability to manage growth effectively will require us to continue to implement and improve our operational and financial systems and to expand, train and manage our employee base. Our inability to deal with this growth could have a material adverse impact on our business, operations and prospects.

Expiration of Licences and Leases

Our properties are held in the form of licences and leases and working interests in licences and leases. If we 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 our licences or leases or the working interests relating to a licence or lease may have a material adverse effect on our results of operations and business.

Dividends

We have not paid any dividends on our outstanding shares. Payment of dividends in the future will be dependent on, among other things, the cash flow, results of our operations and financial condition, the need for funds to finance ongoing operations and other business considerations as our Board of Directors considers relevant.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights to portions of western Canada. We are not aware that any claims have been made in respect of our properties and assets; however, if a claim arose and was successful this could have an adverse effect on us and our operations.

Seasonality

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

Third Party Credit Risk

We may be exposed to third party credit risk through our contractual arrangements with current or future joint venture partners, marketers of our petroleum and natural gas production and other parties. In the event such entities fail to meet their contractual obligations to us, such failures could have a material adverse effect on us and our cash flow from operations. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in our ongoing capital program, potentially delaying the program and the results of such program until we find a suitable alternative partner.

Conflicts of Interest

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

Reliance on Key Personnel

Our success depends in large measure on certain key personnel. The loss of the services of such key personnel could have a material adverse affect on us. The contributions of the existing management team to our immediate and near term operations 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 we will be able to continue to attract and retain all personnel necessary for the development and operation of our business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of our management.

ADDITIONAL INFORMATION

Additional information relating to us may be found on SEDAR at www.sedar.com. Additional information including remuneration of our directors and officers, principal holders of Common Shares and options to acquire Common Shares, will be contained in our Information Circular - Proxy Statement for our Annual Meeting of Shareholders to be held on May 14, 2008 and further information in respect of financial matters is provided in our consolidated financial statements for the years ended December 31, 2007 and 2006.

For additional copies of the Annual Information Form and the materials listed in the preceding paragraphs please contact:

Midnight Oil Exploration Ltd.	Tel:(403) 303-8500
Suite 2100, 144 – 4th Avenue S.W.	Fax: (403) 264-0085
Calgary, Alberta	Email: info@midnightoil.ca
T2P 3N4	Website: www.midnightoil.ca

SCHEDULE A

REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

(FORM 51-101 F3)

Management of Midnight Oil Exploration Ltd. ("**Midnight**") is responsible for the preparation and disclosure of information with respect to Midnight's oil and natural gas activities in accordance with securities regulatory requirements. This information includes reserves data which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2007, estimated using forecast prices and costs.

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

The Reserves Committee of the Board of Directors of Midnight has:

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

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

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

The Reserves Committee of the Board of Directors has reviewed Midnight's procedures for assembling and reporting other information associated with oil and natural gas activities and has reviewed that information with management. The Board of Directors has, on the recommendation of the Reserves Committee, approved:

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

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

(c) the content and filing of this report.

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material. However, any variation should be consistent with the fact that reserves are categorized according to the probability of their recovery.

(signed) "*Fred Woods*"

Fred Woods
President and Chief Executive Officer

(signed) "*Martin Saizew*"

Martin Saizew
Vice President, Engineering

(signed) "*Anthony Lambert*"
Anthony Lambert
Director and Chairman of the Reserves Committee

(signed) "*Peter Harrison*"
Peter Harrison
Director and Member of the Reserves Committee

March 18, 2008

SCHEDULE B

REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

(FORM 51-101F2)

To the board of directors of Midnight Oil Exploration Ltd. (the "Company"):

1. We have prepared an evaluation of the Company's reserves data as at December 31, 2007. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2007, estimated using forecast prices and costs.

2. The reserves data are the responsibility of the 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 ended December 31, 2007, and identifies the respective portions thereof that we have evaluated and reported on to the Company's board of directors:

			Net Present Value of Future Net Revenue (before income taxes, 10% discount rate – $000)			
Independent Qualified Reserves Evaluator or Auditor	Preparation Date of Evaluation Report	Location of Reserves	Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants	January 22, 2008	Canada	$nil	$120,698	$nil	$120,698

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

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

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

GLJ Petroleum Consultants Ltd.
(signed) "Doug Sutton"
Doug R. Sutton, P.Eng
Vice President
February 25, 2008

SCHEDULE C

MIDNIGHT OIL EXPLORATION LTD.

MANDATE AND TERMS OF REFERENCE OF THE AUDIT COMMITTEE

Role and Objective

The Audit Committee (the "Committee") is a committee of the board of directors (the "Board") of Midnight Oil Exploration Ltd. ("Midnight") to which the Board has delegated its responsibility for oversight of the nature and scope of the annual audit, management's reporting on internal accounting standards and practices, financial information and accounting systems and procedures, financial reporting and statements and 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 on meeting their responsibilities in respect of the review and approval of the financial statements of Midnight and related documentation;

2. To provide a communication link between independent directors and external auditors;

3. To enhance the external auditor's independence;

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

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

Membership of Committee

6. The Committee shall be comprised of at least three (3) directors of Midnight, none of whom are members of management of Midnight and all of whom are independent (as such term is used in Multilateral Instrument 52-110 — Audit Committees ("MI 52-110") unless the Board shall have determined that the exemption contained in Section 3.6 of MI 52-110 is available and has determined to rely thereon.

7. The Board shall appoint the Committee Chair, who shall be an independent director.

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

Mandate and Responsibilities of Committee

9. The Committee shall provide oversight on the work of the external auditors, including resolution of disagreements between management and the external auditors regarding financial reporting.

10. The Committee shall satisfy itself on behalf of the Board with respect to Midnight's Internal Control Systems and its ability to:

    - identify, monitor and mitigate business risks; and

    - ensure compliance with legal, ethical and regulatory requirements.

11. The primary responsibility of the Committee is to review the annual and interim financial statements of Midnight 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;
- 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
- obtaining explanations of significant variances with comparative reporting periods.

12. The Committee is to review the financial statements, prospectuses, MD&A, annual information form ("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 Midnight's disclosure of all other financial information.

13. With respect to the appointment of external auditors by the Board, the Committee shall:

- 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 shall 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 Midnight 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 report to the Committee at the next scheduled meeting such pre–approval and the member comply with such other procedures as may be established by the Committee from time to time.

14. Review with external auditors (and internal auditor if one is appointed by Midnight) their assessment of the internal controls of Midnight, their written reports containing recommendations for improvement, and management's response and follow-up to any identified weaknesses. The Committee shall 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 Midnight and its subsidiaries.

15. The Committee shall review risk management policies and procedures of Midnight (eg. hedging, litigation and insurance).

16. The Committee shall establish a procedure for:

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

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

17. The Committee shall review and be apprised of any intent of Midnight regarding the hiring of partners and employees who work on Midnight's account and former partners and employees of the present and former external auditors of Midnight.

18. The Committee shall have the authority to investigate any financial activity of Midnight. All employees of Midnight are to cooperate as requested by the Committee.

19. The Committee may retain persons having special expertise and/or obtain independent professional advice to assist in fulfilling their responsibilities at the expense of Midnight without any further approval of the Board.

Meetings and Administrative Matters

20. At all meetings of the Committee every motion shall be decided by a majority of the votes cast. In case of an equality of votes, the Chair of the meeting shall not be entitled to a second or casting vote.

21. The Chair shall preside at all meetings of the Committee, unless the Chair is not present, in which case the members of the Committee present shall designate from among the members present the Chair for purposes of the meeting.

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

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

24. The Committee shall 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. At each of these meetings, the Committee will have an "in-camera" session with the external auditors.

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

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

27. 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.

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

29. Any members of the Committee may be removed or replaced at any time by the Board and shall 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 shall exist on the Committee, the remaining members may exercise all its powers so long as a quorum remains. Subject to the foregoing, each member of the Committee shall hold such office until the close of the next annual meeting of shareholders following appointment as a member of the Committee.

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

Definitions – In this Charter:

"**financially literate**" means the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of the issues that can reasonably be expected to be raised by Midnight's financial statements.