



MIDNIGHT
Oil Exploration Ltd.

**REVISED
ANNUAL INFORMATION FORM**

**For the period ended
December 31, 2006**

March 21, 2007

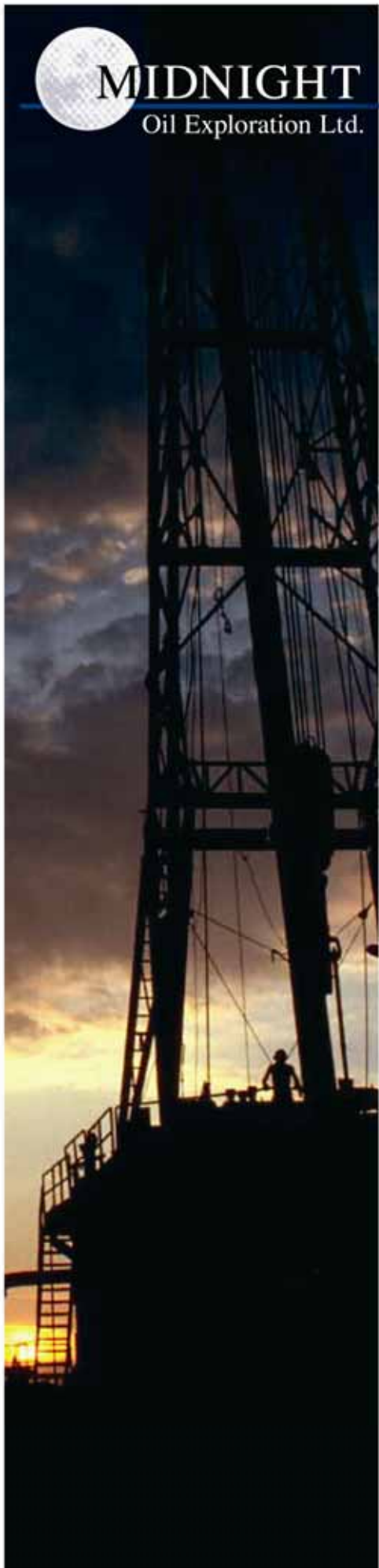


TABLE OF CONTENTS

CERTAIN DEFINITIONS	1
ABBREVIATIONS	2
CONVERSION	2
CONVENTIONS	2
SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS	3
MIDNIGHT OIL EXPLORATION LTD.....	4
General	4
GENERAL DEVELOPMENT OF THE BUSINESS	4
History of Midnight.....	4
Significant Acquisitions	4
Recent Developments.....	5
STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION.....	5
Reserves Data	5
Definitions and Other Notes to Reserves Data and Tables.....	8
Additional Information Relating to Reserves Data.....	16
Other Oil and Gas Information.....	18
DESCRIPTION OF CAPITAL STRUCTURE	23
Common Shares	23
Warrants	23
MARKET FOR SECURITIES	23
DIVIDEND POLICY	24
OFFICERS AND DIRECTORS.....	24
Corporate Cease Trade Orders or Bankruptcies	26
Penalties or Sanctions.....	26
Personal Bankruptcies	26
Conflicts	27
ESCROWED SECURITIES.....	27
AUDIT COMMITTEE INFORMATION	27
Audit Committee Charter	27
Composition of the Audit Committee.....	27
External Auditor Service Fees.....	28
LEGAL PROCEEDINGS	28
INTERESTS OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS	29
AUDITORS, TRANSFER AGENT AND REGISTRAR	29
MATERIAL CONTRACTS.....	29
INTERESTS OF EXPERTS.....	29
INDUSTRY CONDITIONS.....	29
RISK FACTORS	35
ADDITIONAL INFORMATION	42
SCHEDULE A Report of Management and Directors on Reserves Data and Other Information	
SCHEDULE B Report on Reserves Data	
SCHEDULE C Mandate and Terms of Reference of the Audit Committee	

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 24, 2006 evaluating the crude oil, natural gas liquids and natural gas reserves of the Company as at December 31, 2006.

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

bbl	barrel
bbls	barrels
Mbbls	thousand barrels
MMbbls	million barrels
NGLs	natural gas liquids
Mstb	thousand stock tank barrels of oil
Mboe	thousand barrels of oil equivalent
boe/d	barrels of oil equivalent per day

Natural Gas

bbls/d	barrels per day
Mcf	thousand cubic feet
MMcf	million cubic feet
Mcf/d	thousand cubic feet per day
MMcf/d	million cubic feet per day
m ³	cubic metres
MMbtu	million British Thermal Units
GJ	Gigajoule

Other

BOE or boe	means barrel of oil equivalent, using the conversion factor of 6 Mcf of natural gas being equivalent to one barrel of oil. Boes may be misleading, particularly if used in isolation. A boe conversion ratio of 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
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).

<u>To Convert From</u>	<u>To</u>	<u>Multiply By</u>
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

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. All financial information contained in this Annual Information Form has been presented in Canadian dollars in accordance with generally accepted accounting principals in Canada.

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; 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 the clastic 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 us and Daylight. 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. See "Recent Developments".

Significant Acquisitions

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 \$47.66 million. The assets acquired included 1.8 million boe of high quality, long life oil and natural gas reserves on a proven 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.

For further information, please refer to our business acquisition report dated February 10, 2006 with respect to this acquisition which has been filed on SEDAR at www.sedar.com. The assets acquired are reflected in this Annual Information Form in the "*Statement of Reserves Data and Other Oil and Gas Information*".

Recent Developments

On May 17, 2006 we issued 4.0 million "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 5.5 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.

Effective October 1, 2006 the Administrative and Technical Services Agreement with Daylight that had been in place was amended to only charge Midnight for the shared services that were being transitioned in the fourth quarter of 2006 including land administration, drilling and completion operations, marketing, certain accounting, and human resources and administration. Midnight incurred direct charges for technical personnel including: geologists, geophysicists, engineers, land negotiators, business development and land contracts that were functioning independently. Effective December 31, 2006 the Administrative and Technical Services Agreement was terminated. Certain services between Daylight and Midnight that are administrative, provide reasonable economy and do not involve competitive issues will continue beyond 2006 through an agreed upon monthly fee for service basis and these services may be cancelled by either party.

Since the start of our operations on November 30, 2004, we have drilled 80 gross (29.4 net) wells and have invested \$93.3 million on our capital programs and \$47.7 million on our Red Earth property acquisition.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The statement of reserves data and other oil and gas information set forth below (the "Statement") is dated March 19, 2007 and prepared as of February 28, 2007. The effective date of the Statement is December 31, 2006.

Reserves Data

The reserves data set forth below (the "Reserves Data") is based upon an evaluation by GLJ in the GLJ Report dated March 19, 2007 and effective December 31, 2006. The Reserves Data summarizes our oil, liquids and natural gas reserves and the net present values of future net revenue for these reserves using constant prices and costs and 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.

It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the constant prices and costs assumptions and forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserve estimates of crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquid reserves may be greater than or less than the estimates provided herein. 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 on Reserves Data by GLJ in Form 51-101F2 and the Report of Management and Directors on Oil and Natural Gas Disclosure in Form 51-101F3 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, 2006
CONSTANT PRICES AND COSTS**

<i>Reserves Category</i>	Light and Medium Oil		Natural Gas		Natural Gas Liquids		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
	<i>(Mbbbls)</i>	<i>(Mbbbls)</i>	<i>(MMcf)</i>	<i>(MMcf)</i>	<i>(Mbbbls)</i>	<i>(Mbbbls)</i>	<i>(Mboe)</i>	<i>(Mboe)</i>
Proved								
Developed Producing	1,217	1,087	11,786	9,239	276	182	3,457	2,809
Developed Non-Producing	13	12	2,178	1,661	44	29	420	318
Undeveloped	226	200	256	211	7	5	276	240
Total Proved	1,457	1,299	14,220	11,112	327	216	4,154	3,367
Probable	1,170	1,030	6,026	4,744	108	71	2,282	1,892
Total Proved Plus Probable	2,627	2,329	20,246	15,856	435	287	6,436	5,259

<i>(\$ thousands)</i>	Net Present Values of Future Net Revenue									
	Before Income Taxes Discounted at %/year					After Income Taxes Discounted at %/year				
	0%	5%	10%	15%	20%	0%	5%	10%	15%	20%
Proved										
Developed Producing	95,284	80,394	70,110	62,554	56,748	95,284	80,394	70,110	62,554	56,748
Developed Non-Producing	8,457	6,489	5,221	4,354	3,729	8,457	6,489	5,221	4,354	3,729
Undeveloped	6,711	4,682	3,333	2,386	1,693	6,711	4,682	3,333	2,386	1,693
Total Proved	110,452	91,564	78,664	69,294	62,169	110,452	91,564	78,664	69,294	62,169
Probable	60,330	37,014	25,259	18,294	13,744	51,643	31,636	21,636	15,718	11,840
Total Proved Plus Probable	170,782	128,578	103,923	87,587	75,912	162,094	123,200	100,300	85,012	74,009

**TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2006
CONSTANT 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
<i>(\$ thousands)</i>								
Proved Reserves	203,733	33,268	52,123	6,099	1,792	110,452	-	110,452
Proved Plus Probable Reserves	323,549	51,581	80,167	19,046	1,973	170,782	8,688	162,094

**FUTURE NET REVENUE
BY PRODUCTION GROUP
AS OF DECEMBER 31, 2006
CONSTANT PRICES AND COSTS**

Reserves Category	Production Group	Future Net Revenue Before Income Taxes (discounted at 10%/year)
<i>(\$ thousands)</i>		
Proved Reserves	Light and medium crude oil (including solution gas and other by-products)	39,106
	Natural gas (including by-products but excluding solution gas from oil wells)	39,559
	Other revenue and costs	-
	Total	<u>78,664</u>
Proved Plus Probable Reserves	Light and medium crude oil (including solution gas and other by-products)	55,014
	Natural gas (including by-products but excluding solution gas from oil wells)	48,909
	Other revenue and costs	-
	Total	<u>103,923</u>

**SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2006
FORECAST PRICES AND COSTS**

Reserves Category	Light and Medium Oil		Natural Gas		Natural Gas Liquids		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
	<i>(Mbbbls)</i>	<i>(Mbbbls)</i>	<i>(MMcf)</i>	<i>(MMcf)</i>	<i>(Mbbbls)</i>	<i>(Mbbbls)</i>	<i>(Mboe)</i>	<i>(Mboe)</i>
Proved								
Developed Producing	1,210	1,080	11,914	9,340	277	183	3,473	2,820
Developed Non-Producing	13	12	2,169	1,652	44	30	419	317
Undeveloped	219	192	256	211	7	5	269	233
Total Proved	<u>1,443</u>	<u>1,285</u>	<u>14,339</u>	<u>11,204</u>	<u>328</u>	<u>218</u>	<u>4,161</u>	<u>3,370</u>
Probable	1,183	1,044	6,066	4,774	108	71	2,303	1,911
Total Proved Plus Probable	<u>2,626</u>	<u>2,328</u>	<u>20,405</u>	<u>15,978</u>	<u>437</u>	<u>289</u>	<u>6,464</u>	<u>5,280</u>

(\$ thousands)	Net Present Values of Future Net Revenue									
	Before Income Taxes Discounted at %/year					After Income Taxes Discounted at %/year				
	0%	5%	10%	15%	20%	0%	5%	10%	15%	20%
Proved										
Developed Producing	109,484	91,298	79,125	70,348	63,684	109,484	91,298	79,125	70,348	63,684
Developed Non-Producing	11,698	8,787	6,962	5,740	4,879	11,698	8,787	6,962	5,740	4,879
Undeveloped	6,742	4,702	3,350	2,403	1,713	6,742	4,702	3,350	2,403	1,713
Total Proved	<u>127,925</u>	<u>104,788</u>	<u>89,437</u>	<u>78,491</u>	<u>70,275</u>	<u>127,925</u>	<u>104,788</u>	<u>89,437</u>	<u>78,491</u>	<u>70,275</u>
Probable	74,241	43,618	29,127	20,895	15,663	55,021	31,977	21,240	15,177	11,325
Total Proved Plus Probable	<u>202,166</u>	<u>148,406</u>	<u>118,564</u>	<u>99,386</u>	<u>85,938</u>	<u>182,946</u>	<u>136,765</u>	<u>110,676</u>	<u>93,668</u>	<u>81,600</u>

**TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2006
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
<i>(\$ thousands)</i>								
Proved Reserves	233,909	39,076	58,536	6,197	2,175	127,925	-	127,925
Proved Plus Probable Reserves	383,301	61,177	98,027	19,288	2,643	202,166	19,220	182,946

**FUTURE NET REVENUE
BY PRODUCTION GROUP
AS OF DECEMBER 31, 2006
FORECAST PRICES AND COSTS**

Reserves Category	Production Group	Future Net Revenue Before Income Taxes (discounted at 10%/year)
<i>(\$ thousands)</i>		
Proved Reserves	Light and medium crude oil (including solution gas and other by-products)	38,447
	Natural gas (including by-products but excluding solution gas from oil wells)	50,990
	Other revenue and costs	-
	Total	89,437
Proved Plus Probable Reserves	Light and medium crude oil (including solution gas and other by-products)	53,979
	Natural gas (including by-products but excluding solution gas from oil wells)	64,585
	Other revenue and costs	-
	Total	118,564

Definitions and Other Notes to Reserves Data and Tables

In the tables following in this section and elsewhere in this Annual Information Form the following definitions and other notes are applicable:

1. Columns may not add due to rounding.
2. "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.
3. "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.
4. "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.
5. "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.
6. "Exploration well" means a well that is not a development well, a service well or a stratigraphic test well.
7. "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 equipping exploratory wells; and
 - (e) costs of drilling exploratory type stratigraphic test wells.

8. "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.
9. 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 are set forth below.

Reserve Categories

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

- (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 prices and costs used in the estimate, namely:

- (a) constant prices and costs as at the last day of our financial year; and
- (b) forecast prices and costs.

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.

10. Forecast prices and costs

Future prices and costs that are:

- (a) generally acceptable as being a reasonable outlook of the future; and
- (b) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which 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.

11. Constant prices and costs

Prices and costs that are:

- (a) Our prices and costs as at the effective date of the estimation, held constant throughout the estimated lives of the properties to which the estimate applies; 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).

For the purposes of paragraph (a), Midnight's prices are the posted prices for oil and the spot price for gas, after historical adjustments for transportation, gravity and other factors.

12. Future income tax expenses

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

The estimated net amount to be received with respect to the development and production of reserves estimated using:

- (a) constant prices and costs; or
- (b) 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. Both the constant and 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.

Pricing Assumptions

The following sets for the benchmark reference prices, as at January 1, 2007, reflected in the Reserves Data. These price assumptions were provided by GLJ.

**SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
AS OF JANUARY 1, 2007
FORECAST PRICES AND COSTS**

Year	OIL			NATURAL GAS AECO Gas Price (\$Cdn/ MMbtu)	EDMONTON LIQUIDS PRICES			Inflation Rates ^(a) %/Year	Exchange Rate ^(b) (\$US/ \$Cdn)
	WTI Cushing Oklahoma (\$US/bbl)	Edmonton Par Price 40° API (\$Cdn/bbl)	Cromer Medium 29.3° API (\$Cdn/bbl)		Propane (\$Cdn/bbl)	Butane (\$Cdn/bbl)	Pentanes Plus (\$Cdn/bbl)		
<i>Forecast</i>									
2007	62.00	70.25	61.25	7.20	45.00	56.25	71.75	2.0	0.870
2008	60.00	68.00	59.25	7.45	43.50	50.25	69.25	2.0	0.870
2009	58.00	65.75	57.25	7.75	42.00	48.75	67.00	2.0	0.870
2010	57.00	64.50	56.00	7.80	41.25	47.75	65.75	2.0	0.870
2011	57.00	64.50	56.00	7.85	41.25	47.75	65.75	2.0	0.870
2012	57.50	65.00	56.50	8.15	41.50	48.00	66.25	2.0	0.870
2013	58.50	66.25	57.75	8.30	42.50	49.00	67.50	2.0	0.870
2014	59.75	67.75	59.00	8.50	43.25	50.25	69.00	2.0	0.870
2015	61.00	69.00	60.00	8.70	44.25	51.00	70.50	2.0	0.870
2016	62.25	70.50	61.25	8.90	45.00	52.25	72.00	2.0	0.870
2017	63.50	71.75	62.50	9.10	46.00	53.00	73.25	2.0	0.870
Thereafter	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	2.0	0.870

Notes:

- (1) Inflation rates for forecasting prices and costs.
- (2) Exchange rates used to generate the benchmark reference prices in this table.

The weighted average realized sales prices by us for the period ended December 31, 2006 were \$6.42/Mcf for natural gas, \$70.20/bbl for crude oil and \$56.92/bbl for NGLs.

The constant price assumptions assume the continuance of current laws, regulations and operating costs in effect on the date of the GLJ Report. Product prices were not escalated beyond December 31, 2006. In addition, operating and capital costs have not been increased on an inflationary basis. The prices used for the mix of crude oil gravities and various gas contracts were as follows (before adjustments for quality and transportation):

**SUMMARY OF PRICING ASSUMPTIONS
AS OF DECEMBER 31, 2006
CONSTANT PRICES AND COSTS**

Year	OIL			NATURAL GAS AECO Gas Price (\$Cdn/MMbtu)	EDMONTON LIQUID PRICES			EXCHANGE RATE (\$US/\$Cdn)
	WTI Cushing Oklahoma (\$US/bbl)	Edmonton Par Price 40° API (\$Cdn/bbl)	Cromer Medium 29.3° API (\$Cdn/bbl)		Propane (\$Cdn/bbl)	Butane (\$Cdn/bbl)	Pentanes Plus (\$Cdn/bbl)	
December 31, 2006	60.85	67.58	59.47	6.07	45.25	54.06	71.55	0.8581

*Reconciliations of Changes in Reserves and Future Net Revenue***RECONCILIATION OF COMPANY INTEREST RESERVES BY PRINCIPAL PRODUCT TYPE
FORECAST PRICES AND COSTS**

Reserve Category	Factors	Oil (Mbbls)	Natural gas liquids (Mbbl)	Natural Gas (MMcf)	BOE (Mboe)
Proved	At December 31, 2005	1,081.9	262.5	12,039.9	3,351.1
	Technical Revisions	47.0	(25.8)	(99.4)	4.6
	Discoveries	440.9	38.0	1,284.5	693.0
	Extensions	130.6	110.0	3,794.6	873.0
	Infill	-	3.7	97.8	20.0
	Improved Recovery	-	0.4	151.1	25.6
	Production	(257.5)	(58.4)	(2,831.0)	(787.7)
	December 31, 2006		<u>1,442.9</u>	<u>330.4</u>	<u>14,437.5</u>
Probable	At December 31, 2005	956.4	73.7	3,508.6	1,614.9
	Technical Revisions	(273.6)	(12.8)	351.4	(227.8)
	Discoveries	248.7	10.0	319.6	312.0
	Extensions	252.0	36.5	1,830.4	593.6
	Infill	-	1.3	35.1	7.2
	Improved Recovery	-	0.1	39.4	6.7
	Production	-	-	-	-
	December 31, 2006		<u>1,183.5</u>	<u>108.8</u>	<u>6,084.5</u>
Proved Plus Probable	At December 31, 2005	2,038.3	336.2	15,548.5	4,965.9
	Technical Revisions	(226.6)	(38.6)	252.0	(223.2)
	Discoveries	689.6	48.0	1,604.1	1,005.0
	Extensions	382.6	146.5	5,625.0	1,466.6
	Infill	-	5.0	132.9	27.2
	Improved Recovery	-	0.5	190.5	32.3
	Production	(257.5)	(58.4)	(2,831.0)	(787.7)
	December 31, 2006		<u>2,626.4</u>	<u>439.2</u>	<u>20,522.0</u>

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

Reserve Category	Factors	Oil (Mbbbls)	Natural gas liquids (Mbbbl)	Natural Gas (MMcf)	BOE (Mboe)
Proved	At December 31, 2005	940.7	173.9	9,239.3	2,654.5
	Technical Revisions	54.8	(16.2)	99.6	55.2
	Discoveries	390.2	25.5	908.5	567.1
	Extensions	115.4	73.7	3,028.3	693.8
	Infill	-	2.3	70.8	14.1
	Improved Recovery	-	0.3	110.0	18.6
	Production	(216.3)	(41.8)	(2,253.0)	(633.6)
	December 31, 2006	<u>1,284.8</u>	<u>217.7</u>	<u>11,203.5</u>	<u>3,369.8</u>
Probable	At December 31, 2005	866.8	49.0	2,741.4	1,372.7
	Technical Revisions	(246.1)	(9.3)	297.6	(205.8)
	Discoveries	203.1	6.7	229.0	248.0
	Extensions	219.8	24.2	1,453.3	486.2
	Infill	-	0.8	24.5	4.9
	Improved Recovery	-	-	28.6	4.8
	Production	-	-	-	-
	December 31, 2006	<u>1,043.6</u>	<u>71.4</u>	<u>4,774.4</u>	<u>1,910.7</u>
Proved Plus Probable	At December 31, 2005	1,807.5	222.9	11,980.7	4,027.2
	Technical Revisions	(191.3)	(25.5)	397.2	(150.6)
	Discoveries	593.3	32.2	1,137.5	815.1
	Extensions	335.2	97.9	4,481.6	1,180.0
	Infill	-	3.1	95.3	19.0
	Improved Recovery	-	0.3	138.6	23.4
	Production	(216.3)	(41.8)	(2,253.0)	(633.6)
	December 31, 2006	<u>2,328.4</u>	<u>289.1</u>	<u>15,977.9</u>	<u>5,280.5</u>

**RECONCILIATION OF CHANGES IN NET PRESENT VALUES OF FUTURE NET REVENUE
DISCOUNTED AT 10% PER YEAR PROVED RESERVES
CONSTANT PRICES AND COSTS**

Period and Factor	2006 After Tax	2006 Before Tax
<i>(\$ thousands)</i>		
Estimated Future Net Revenue at December 31, 2005	75,138	82,584
Oil and Gas Sales During the Period, Net of Production Costs, Royalties and Transportation Expenses ⁽¹⁾	(25,050)	(25,050)
Net Change in Prices, Production Costs and Royalties Related to Future Production ⁽²⁾	(24,296)	(24,296)
Development Costs Incurred During the Period ⁽³⁾	50,658	50,658
Changes in Estimated Future Development Costs ⁽⁴⁾	(46,992)	(46,992)
Extensions and Improved Recovery ⁽⁵⁾	16,971	16,971
Discoveries ⁽⁵⁾	13,247	13,247
Acquisitions of Reserves ⁽⁵⁾	-	-
Dispositions of Reserves ⁽⁵⁾	-	-
Net Change Resulting from Revisions in Quantity Estimates	-	-
Accretion of Discount ⁽⁶⁾	8,258	8,258
Net Change in Income Taxes ⁽⁷⁾	7,446	-
Changes Resulting from Technical Reserves Revisions	1,289	1,289
All Other Changes ⁽⁸⁾	1,995	1,995
Estimated Future Net Revenue at December 31, 2006	<u>78,664</u>	<u>78,664</u>

Notes:

- (1) Our actual before income taxes, excluding general and administrative expenses and interest charges.
- (2) The impact of the changes in prices and other economic factors on future net revenue.
- (3) Actual capital expenditures relating to the exploration, development and production of oil and gas reserves.
- (4) The change in forecast development costs.
- (5) End of period net present value of the related reserves.
- (6) Estimated at 10% of the beginning of the period net present value.
- (7) The difference between forecast income taxes at beginning of period and the actual taxes for the period plus forecast income taxes at the end of the period.
- (8) Includes changes due to revised production profiles, development timing, operating costs, royalty rates, actual price received in 2006 versus forecast, etc.

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

The following discussion generally describes the basis on which we attribute our proved and probable undeveloped reserves and our plans for developing those undeveloped reserves.

Proved Undeveloped Reserves

Proved undeveloped reserves are generally those reserves related to infill drilling locations yet to be drilled, wells that have been tested and not yet tied-in, wells drilled near the end of the fiscal year or secondary zones in wells that will be brought on production once the primary zone has been depleted. We do not carry proved undeveloped reserves for long periods of time and plan to have the majority of these reserves on stream within a two-year time frame.

As of December 31, 2006 the total estimated development capital associated with proven reserves is \$6.1 million (undiscounted). Of this, 92% of the capital is forecast to be spent within the next two years to develop these reserves.

Probable Undeveloped Reserves

Probable undeveloped reserves are generally those reserves tested or indicated by analogy to be productive infill drilling locations, and land contiguous to production. The majority of these reserves are planned to be on stream within a two-year time frame.

As of December 31, 2006 the total estimated development capital associated with probable reserves is \$19.3 million (undiscounted). Of this, 97% of the capital is forecast to be spent within the next two years to develop these reserves.

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.

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:

Year <i>(\$ thousands)</i>	Forecast Prices and Costs		Constant Prices and Costs	
	Proved Reserves	Proved Plus Probable Reserves	Proved Reserves	Proved Plus Probable Reserves
2007	4,617	10,698	4,617	10,698
2008	969	7,930	950	7,774
2009	53	56	51	54
2010	102	108	96	102
2011	19	19	18	18
Thereafter	437	477	367	307
Total Undiscounted	6,197	19,288	6,099	18,953
Total Discounted at 10%	5,550	17,404	5,499	17,231

We estimate that our internally generated cash flow will be sufficient to fund our future development costs. We typically have 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 in Red Earth, with our exploration focus in the Peace River Arch and Red Earth areas, where we hold the majority of our undeveloped lands. 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: Fox Creek, Windfall, Kaybob, Fir, Bigstone, Oldman, Marlboro, Pine Creek, Groat and McLeod. We hold minor interests in numerous wells in these properties which account for approximately 33% 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 2006, we participated in 9 (0.8 net) wells in this area. In 2007, we anticipate participating in 18 (1.1 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 management has 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 recently 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 are committed to participate in one (0.4 net) well on the play in 2007.

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 2006, we participated in 12 (8.4 net) wells in this area. Our undeveloped land base has multi-zoned 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 26% of our total proved plus probable reserves. In 2007, we anticipate participating in 8 (3.7 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, 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 40% of our total proved plus probably reserves. Along with the producing wells, we also have an interest in 67,000 net undeveloped acres that contain both exploratory and development oil potential. Uphole potential also exists in the Slave Point (oil) and Bluesky (gas). In 2006, we participated in 12 (8.0 net) oil wells in this area.

We anticipate participating in 12 (6.3 net) oil wells for an average working interest of 53% in this area in 2007. The existing Keg River pools in this area are being actively water flooded. Our operated lands are in various stages of development and are being considered for water flooding in the future.

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 which are within an area with existing production facilities accessible to or owned by us.

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, 2006:

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	64	20.4	30	7.4	179	22.9	53	10.5
British Columbia	-	-	-	-	1	0.2	1	0.5
Total	64	20.4	30	7.4	180	23.1	54	11.0

Properties with no Attributable Reserves

The following table sets out the Company's undeveloped land holdings as at December 31, 2006:

	Undeveloped Acres	
	Gross	Net
Alberta	300,000	148,000
British Columbia	34,000	25,000
Total	334,000	173,000

Rights to explore, develop and exploit 65,000 net acres of our total net acres relate to title documents whose primary terms come to an end between January 1, 2007 and December 31, 2007. Of these, we estimate that over 35,000 net acres will be further continued through submission of continuation applications and additional drilling.

We have committed to drill two farm-in wells which will be drilled in the first quarter of 2007. Our committed expenditures for these two wells are \$2.6 million.

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, 2006:

	Exploratory		Development	
	Gross	Net	Gross	Net
Light and Medium Oil	6	5.0	6	3.0
Natural Gas	4	3.3	14	3.8
Dry	3	2.1	-	-
Total	13	10.4	20	6.8

For details of our current and likely exploration and development activities, see “*Oil and Gas Properties*” on pages 18 to 19.

Abandonment and Reclamation Costs

The following table discloses our abandonment and reclamation costs anticipated as at December 31, 2006, 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 Undiscounted (\$000)	Abandonment and Reclamation Discounted at 10% (\$000)
Total as at December 31, 2006	3,847	1,349
Total anticipated to be paid in next three years	656	569

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 \$3,847,000 escalated at 2% per year. Of this amount, \$2,175,000 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, 2006, we expected to incur reclamation and abandonment costs in respect of 61.9 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 four to 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 above tables 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.

At December 31, 2006 we had approximately \$145 million in tax pools available to shelter taxable income in future years before the renunciation of \$20.4 million in flow-through expenditures.

Costs Incurred

The following table summarizes capital expenditures for the year ended December 31, 2006:

Expenditures	2006
<i>(\$ thousands)</i>	
Property acquisition costs – Proved Properties	4,997
Property acquisition costs – Undeveloped Properties ⁽¹⁾	-
Exploration Costs ⁽²⁾	22,894
Development Costs ⁽³⁾	33,842
Non-oil and gas assets	19
Total	61,752

Notes:

- (1) Cost of land acquired, and lease rentals on unproved properties.
- (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 2007 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*". The production estimates in the reserve forecast are the same for both constant price and costs and forecast price and costs. Red Earth is our only property that accounts for greater than 20% of our forecast production in 2007:

	Light and Medium Oil	Natural Gas	Natural Gas Liquids	boe
	<i>(bbls/d)</i>	<i>(Mcf/d)</i>	<i>(bbls/d)</i>	<i>(boe/d)</i>
Proved Producing				
Red Earth	724	358	-	784
Others	83	7,075	155	1,417
Total Proved Producing	807	7,433	155	2,201
Total Proved				
Red Earth	772	734	-	895
Others	85	7,500	168	1,502
Total Proved	857	8,234	168	2,397
Proved Plus Probable				
Red Earth	905	753	-	1,030
Others	91	7,790	174	1,564
Total Proved Plus Probable	996	8,543	174	2,594

Production History

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

	Quarters Ended 2006			
	Q1	Q2	Q3	Q4
Light and Medium Crude Oil (<i>bbls/d</i>)	765	660	704	694
NGLs (<i>bbls/d</i>)	136	170	137	196
Natural Gas (<i>mcf/d</i>)	5,926	10,091	7,637	7,352
Combined (<i>boe/d</i>)	1,889	2,512	2,114	2,115

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 2006			
	Q1	Q2	Q3	Q4
Light and Medium Crude Oil (\$/bbls)				
Average Price Received	64.91	75.06	79.17	62.23
Royalties Paid	(4.98)	(14.46)	(16.18)	(9.82)
Transportation Expenses	(2.77)	(0.23)	(0.44)	(0.77)
Operating Expenses	(8.75)	(9.19)	(8.85)	(9.45)
Netback Received ⁽¹⁾	48.41	51.18	53.70	42.19
NGLs (\$/bbls)				
Average Price Received	60.01	61.99	65.94	44.14
Royalties Paid	(17.02)	(17.27)	(16.47)	(14.71)
Transportation Expenses	-	-	-	-
Operating Expenses	(10.21)	(7.26)	(8.37)	(12.44)
Netback Received ⁽¹⁾	32.78	37.46	41.10	16.99
Natural Gas (\$/mcf)				
Average Price Received	7.39	5.98	5.85	6.84
Royalties Paid	(2.27)	(1.06)	(1.19)	(1.03)
Transportation Expenses	-	-	-	-
Operating Expenses	(1.71)	(1.20)	(1.39)	(2.08)
Netback Received ⁽¹⁾	3.41	3.72	3.27	3.73
Combined (\$/boe)				
Average Price Received	54.07	48.07	51.92	48.35
Royalties Paid	(9.73)	(8.61)	(10.11)	(7.51)
Transportation Expenses	(1.12)	(0.06)	(0.14)	(0.25)
Operating Expenses	(9.68)	(7.72)	(8.52)	(11.51)
Netback Received ⁽¹⁾	33.54	31.68	33.15	29.08

Notes:

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

The following table indicates our average daily production from Red Earth and our other fields for the year ended December 31, 2006:

	Light and Medium Crude Oil	NGLs	Gas	boe
	(<i>bbls/d</i>)	(<i>bbls/d</i>)	(<i>Mcf/d</i>)	(<i>boe/d</i>)
Red Earth	599	-	261	643
Other Fields	107	160	7,494	1,516
Total	706	160	7,755	2,158

DESCRIPTION OF CAPITAL STRUCTURE

Our authorized share capital consists of an unlimited number of Common Shares without nominal or par value. At March 21, 2007, we had outstanding, 47,827,829 Common Shares, 3,691,800 options, each of which is exercisable for one (1) Common Share at a weighted average exercise price of \$2.82 per share and 2,083,333 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 21, 2007, the number of options which may be issued under our stock option plan is currently limited to 4,782,783 options of which options to purchase 3,636,800 (7.6% of the outstanding Common Shares) are outstanding and 1,145,983 options are available for future grants (2.4% 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.

On 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. One-third of the Warrants vested on November 29, 2005 and were exercisable if the ten day weighted average trading price of the Common Shares is equal to or greater than \$3.00 per share. An additional one-third of the Warrants vested on November 29, 2006 and were exercisable if the ten day weighted average trading price of the Common Shares is equal to or greater than \$3.75 per share. The balance of the Warrants will vest on November 29, 2007 and will be exercisable if the ten day weighted average trading price of the Common Shares is equal to or greater than \$4.50 per share. All of these performance requirements were met in December 2005 and two-thirds 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 Toronto Stock Exchange under the symbol "MOX". The following table sets out the price range for and trading volume of the Common Shares since commencement of trading on December 2, 2004.

	<u>High</u>	<u>Low</u>	<u>Volume (000s)</u>
2004			
December	\$4.20	\$3.20	6,559
2005			
First quarter	\$4.98	\$3.06	7,363
Second quarter	\$4.05	\$3.10	7,468
Third quarter	\$4.59	\$3.20	6,871
Fourth quarter	\$4.85	\$3.80	3,725
2006			
First quarter	\$4.70	\$3.70	4,973
Second quarter	\$4.25	\$3.30	2,328
Third quarter	\$4.00	\$3.00	1,623
Fourth quarter	\$3.38	\$2.26	4,505
2007			
January	\$2.39	\$1.76	1,844
February	\$2.18	\$1.68	961
March 1 - 21	\$1.70	\$1.35	1,038

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

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:

<u>Name and Municipality of Residence</u>	<u>Position</u>	<u>Director Since</u>	<u>Principal Occupation and Positions for the Past Five Years</u>
Paul E. Moynihan ⁽¹⁾⁽²⁾⁽³⁾⁽⁴⁾ Calgary, Alberta	Chairman and Director	2004	Mr. Moynihan has been a Managing Director & Partner of Mustang Capital Partners Inc., a Calgary based investment banking and funds management firm, since December 2002. Prior thereto, Mr. Moynihan was a Managing Director in the Investment Banking division of TD Securities Inc.
Fred Woods Calgary, Alberta	President, Chief Executive Officer and Director	2004	Mr. Woods has been President, Chief Executive Officer and a Director of Midnight or its predecessor since July 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). Prior thereto, Mr. Woods was Executive Vice-President of Ulster Petroleums Ltd.
Anthony M. Lambert Calgary, Alberta	Director	2004	Mr. Lambert has been President and Chief Executive Officer of Daylight Resources Trust or its predecessor since December, 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.

Name and Municipality of Residence	Position	Director Since	Principal Occupation and Positions for the Past Five Years
Jay D. Squiers ⁽¹⁾⁽²⁾⁽³⁾⁽⁴⁾ Dallas, Texas	Director	2004	Mr. Squiers has been a Managing Director of Fortress Investment Group, LLC. an investment and asset management firm based in Dallas, Texas, since August 2005. Prior thereto, Mr. Squiers was a Senior Vice-President of Prudential Capital Group, a private capital lender since 2002. Mr. Squiers began his career at Prudential Capital Group in 1991.
Tom J. Medvedic ⁽¹⁾⁽²⁾⁽³⁾⁽⁴⁾ Calgary, Alberta	Director	2004	Mr. Medvedic is 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.
Judith A. 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 Petroleum Ltd.
Thomas F. 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 Petroleum Ltd.
Andrew D. 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 L. Kalmakoff	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	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 R. O'Leary	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.

Name and Municipality of Residence	Position	Director Since	Principal Occupation and Positions for the Past Five Years
E. Martin Saizew	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, Paul Moynihan 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, Tom Medvedic is the Chairman of this committee. The Corporate Governance committee also reviews the technical services matters.
- (5) Midnight does not have an executive committee.
- (6) The terms of office of all directors of Midnight will expire on the date of the next annual meeting of shareholders of Midnight. Paul Moynihan will not be standing for re-election at the next annual meeting.

As at the date hereof, our directors and officers and their associates and affiliates, as a group, beneficially own, directly or indirectly, or exercise control or direction over, approximately 4.77 million Common Shares representing 10% of our outstanding Common Shares. The directors and officers also hold 2,083,333 Warrants and 2,300,000 options which would increase their beneficial ownership to 17.1% of the outstanding Common Shares on a fully diluted basis. The information as to Common Shares beneficially owned, 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 or Bankruptcies

No director, officer or promoter of Midnight has, within the last 10 years, been a director, officer or promoter of any reporting issuer that, while such person was acting in that capacity, was the subject of a cease trade or similar order or an order that denied the company access to any statutory exemption for a period of more than 30 consecutive days or was declared a bankrupt or made a voluntary assignment in bankruptcy, made a proposal under any legislation relating to bankruptcy or been 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 that person.

Penalties or Sanctions

No director, officer or promoter of Midnight, within the last 10 years, has been subject to any penalties or sanctions imposed by a court or securities regulatory authority relating to trading in securities, promotion or management of a publicly traded issuer or theft or fraud.

Personal Bankruptcies

No director, officer or promoter of Midnight, or, to our knowledge, a shareholder holding sufficient securities of Midnight to affect materially the control of Midnight, or a personal holding company of any such persons, has, within the last 10 years, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or been 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 individual.

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. Moynihan, one of our directors, is a partner in an investment banking firm which provides services to us. 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 Vice-President, Finance and Chief Financial Officer. Our board of directors does not believe that any activities undertaken by Mr. Moynihan, 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.

The Common Shares subscribed for in our initial private placement on November 29, 2004 were subject to a contractual hold period whereby 25% of the shares were released from such hold period on March 29, 2005 and the remaining 75% balance of the shares were released from such hold period on November 29, 2005.

In addition, in connection with the above referenced initial private placement, a contractual hold period was imposed on the former senior executives of MOG to hold any Common Shares subject to the following terms: 25% of the shares were released from the contractual hold period on March 31, 2005, an additional 37.5% were released on March 31, 2006 and the balance of the shares are eligible for release on March 31, 2007. These securities may be released from this contractual hold period earlier in certain circumstances with the consent of MOG's former financial advisor.

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:

<u>Name</u>	<u>Independent</u>	<u>Financially Literate</u>	<u>Relevant Education and Experience</u>
Tom J. Medvedic (Chairman)	Yes	Yes	Mr. Medvedic is 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.

<u>Name</u>	<u>Independent</u>	<u>Financially Literate</u>	<u>Relevant Education and Experience</u>
Paul E. Moynihan	Yes	Yes	Mr. Moynihan holds a Bachelor of Applied Science in Chemical Engineering from the University of Waterloo and a Master of Business Administration degree from the University of Western Ontario (Ivey). During his fifteen year career as an investment banker, Mr. Moynihan has obtained significant financial experience and exposure to mergers and acquisitions, capital markets, accounting and financial issues along with securities and other industry matters.
Jay D. Squiers	Yes	Yes	Mr. Squiers holds a law degree (Honors) 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 is responsible for identifying, underwriting and executing debt acquisition and originating opportunities in the energy and general corporate sectors.

External Auditor Service Fees

Audit Fees

The audit fees consist of a budget for 2006 of \$80,000 payable to KPMG LLP for professional services rendered for the audit of our financial statements for the period ended December 31, 2006 and for services provided in connection with statutory and regulatory filings. In addition, professional services for quarterly reviews for 2006 of \$37,000 were paid to KPMG LLP.

Tax, Audit and Related Fees

We have paid \$62,500 to KPMG LLP for professional services and related fees and \$2,500 for tax fees for the period ended December 31, 2006.

Pre-Approval of Policies and Procedures

We have adopted policies 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 5 of the Audit Committee charter, under the heading "*Audit Committee Charter – Responsibilities and Duties*". 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, re-occurring 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

There are no legal proceedings material to us and we are not aware of any material proceedings that are contemplated or pending.

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 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 would 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

Except for contracts entered into in the ordinary course of business, we have not entered into any material contracts within the most recently completed financial year, or before the most recently completed financial year but still in effect, other than the Administrative and Technical Services Agreement with Daylight dated November 29, 2004, as amended, which agreement was terminated effective December 31, 2006. See “General Developments of the Business – Recent Developments”. A copy of this agreement has been filed 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 statement, report or valuation 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 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 our 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 market, 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 oil other than heavy crude, and not exceeding two years in the case of

heavy crude, provided that an order approving any such export has been obtained from the National Energy Board of Canada ("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 a 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 criteria prescribed by the NEB and the Government of Canada. Natural gas 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/d) 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 license 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 limits 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 are justified under certain provisions of the General Agreement on Tariffs and Trade, and further provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to domestic use (based upon the proportion prevailing in the most recent 36 month period); (ii) impose an export price higher than the domestic price subject to an exception with respect to certain voluntary measures which only restrict the volume of exports; and (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum or maximum export or import price requirements, provided, in the case of export-price requirements, prohibition in any circumstances in which any other form of quantitative restriction is prohibited, and in the case of import-price requirements, such requirements do not apply with respect to enforcement of countervailing and anti-dumping orders and undertakings.

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

Provincial Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations which govern land tenure, royalties, production rates, environmental protection and other matters. The royalty regime is a significant factor in the profitability of crude oil, natural gas liquids, sulphur and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the mineral owner and the lessee, although production from such lands is also 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 2006 Federal Budget, the federal corporate income tax rate will decrease to 19% in three steps: 20.5% on January 1, 2008, 20% on January 1, 2009 and 19% on January 1, 2010.

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, viscosity of the oil and the vintage of the oil. Originally, the vintage classified oil in "new oil" and "old oil" depending on when the oil pools were discovered. If prior to March 31, 1974 is considered "old oil", if after March 31, 1974 and before September 1, 1992, is considered "new oil". The Alberta government also 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 natural 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, 2007, 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 is May 31, 2007.

On February 16, 2007, the Alberta Government announced that a review of the province's royalty and tax regime (including income tax and freehold mineral rights tax) pertaining to oil, gas and oil sands will be conducted by a panel of experts, with the assistance of individual Albertans and key stakeholders. The purpose of this process is to

ensure that Albertans are receiving a fair share from energy development through royalties, taxes and fees. The issues to be reviewed during this examination process are: (i) undertaking a comparison of Alberta's royalty system to other oil and gas producing jurisdictions, taking into account investment economics and industry returns and risks in Alberta; (ii) whether Alberta's royalty system is sufficiently sensitive to market conditions; (iii) whether the current revenue minus cost system for oil sands royalties is optimal; (iv) which programs built into the existing royalty system should be retained or strengthened, and which should be adapted or eliminated; (v) how the tax treatment of the oil and gas sector compares to other sectors and jurisdictions; (vi) the economic and fiscal impacts of any possible changes to the royalty and corporate tax structures; and (vii) how existing resource development should be treated if changes are to be made to the fiscal regime. The review panel is to provide a final report that will be presented to the Minister of Finance by August 31, 2007.

British Columbia

Producers of oil and natural gas in the Province of British Columbia are required to pay annual rental payments in 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 takes 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 resource 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.

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. 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 establishing of an infrastructure royalty program (combining roads and pipelines); (iv) the elimination of routine flaring at producing wells; (v) the creation of policies and measures for the reduction of emissions; (vi) the development of unconventional resources such as tight gas and coalbed gas; and (vii) new 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

Environmental Regulation

The oil and natural gas industry is subject to environmental regulation 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 facilities 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, 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. No additional expenses are foreseen that are associated with complying with the new regulations. 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.

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 and review process.

In December, 2002, the Government of Canada ratified the Kyoto Protocol ("Protocol"). The Protocol calls for Canada to reduce its greenhouse gas emissions to 6% below 1990 "business-as-usual" levels between 2008 and 2012. Given revised estimates of Canada's normal emissions levels, this target translates into an approximately 40% gross reduction in Canada's current emissions. It remains uncertain whether the Kyoto target of 6% below 1990 emission levels will be enforced in Canada. The Federal Government has introduced legislation aimed at reducing greenhouse gas emissions using an "intensity based" approach, the specifics of which have yet to be determined. Bill C288, 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.

Land Tenure

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

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. The continued 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. Changes to any of these or other factors create price volatility.

Crude oil is influenced by the world economy Organization of the Petroleum Exporting Country's ability to adjust supply to world demand. 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 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.

A second trend within the Canadian oil and gas industry is the fairly consistent "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. 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 "October 31, 2006 Proposals") relating to income trusts and other "specified investment flow-through" entities ("SIFTs"). Pursuant to the existing provisions of the *Income Tax Act* (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 October 31, 2006 Proposals, 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. Although the October 31, 2006 Proposals will not affect the method in which we will be taxed, they may have an impact on the ability of a SIFT to purchase producing assets from junior oil and gas 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 small to mid-sized oil and gas companies. This may be a benefit for us as we will 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.

Generally during the past year, the economic recovery combined with increased commodity prices has caused an increase in new equity financings in the oil and gas industry, although the level of same was negatively impacted by the October 31, 2006 Proposals. We will compete with the numerous new companies and their new management teams and development plans in our access to capital. The competitive nature of the oil and gas industry will cause opportunities for equity financings to be selective. Some companies will have to rely on internally generated funds to conduct their exploration and developmental programs.

RISK FACTORS

An investment in the Corporation should be considered highly speculative due to the nature of the Corporation's activities and the present stage of its development. Investors should carefully consider the risk factors set out below and consider all other information contained herein and in the Corporation's other public filings before making an investment decision.

Exploration, Development and Production Risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. 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, 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 we will discover or acquire further commercial quantities of oil and natural gas.

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

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, cratering, sour gas releases and spills, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or personal injury. In particular, 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 non-core assets of ours, if disposed of, could be expected to realize less than their carrying value on the 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 will manage a variety of small and large projects in conducting 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;
- changes in regulations;
- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, 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 will compete with numerous other organizations in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. Our competitors will include oil and natural gas companies that have substantially greater financial resources, staff and facilities than us. 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. At this time the Alberta Government is in the process of examining the royalty and tax regime applicable to oil, gas and oil sands – see "Industry Conditions – Provincial Royalties and Incentives". 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.

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 which will likely subject us to possible future legislation regulating emissions of greenhouse gases. The Government of Canada has proposed a Bill, which suggests further legislation will set greenhouse gases emission reduction requirements for various industrial activities, including oil and gas exploration and production. Future federal legislation, together with provincial emission reduction requirements, such as those included in Alberta's Climate Change and Emissions Management Act (partially in force), may require the reduction of emissions (or emissions intensity) produced by our expected operations and facilities. 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 the us to incur costs to remedy such discharge. Although we believe that it will be in material compliance with current applicable environmental regulations no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise adversely affect 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 either the nature of those requirements or the impact on us and our operations and financial condition. See "Industry Conditions – Environmental Regulation".

Prices, Markets and Marketing of Crude Oil and Natural Gas

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.

Our revenues, profitability and future growth and the carrying value of our oil and gas properties are substantially dependent on prevailing prices of oil and gas. Our ability to borrow and to obtain additional capital on attractive terms is also substantially dependent upon oil and gas prices. 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, political stability in the Middle East and elsewhere, the foreign supply of oil and gas, the price of foreign imports and the availability of alternative fuel sources. Any substantial and extended decline in the price of oil and gas would have an adverse effect on the carrying value of our proved reserves, borrowing capacity, revenues, profitability and cash flows from operations.

The exchange rate between the Canadian and U.S. dollar also affects our profitability and the Canadian dollar has strengthened recently against the U.S. dollar.

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.

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 favourable 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 our 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 both constant and forecast prices and costs in estimating the reserves and future net cash flows as summarized herein. Actual future net cash flows will be affected by other factors, such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

Actual production and cash flows derived from 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, blowouts, 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 are the subject of terrorist attack it could have a material adverse effect on us. We will 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 operations and our financial condition, the need for funds to finance ongoing operations and other business considerations as the 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 our 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 the immediate and near term operations of ours 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 the 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, is contained in our Information Circular - Proxy Statement dated March 27, 2007 and will be contained in our Information Circular - Proxy Statement for our Annual and Special Meeting of Shareholders to be held on May 11, 2007 and further information in respect of financial matters is provided in our financial statements for the years ended December 31, 2006 and 2005.

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

Midnight Oil Exploration Ltd.
Suite 2100, 144 – 4th Avenue S.W.
Calgary, Alberta
T2P 3N4

Tel: (403) 303-8500
Fax: (403) 264-0085
Email: info@midnightoil.ca
Website: www.midnightoil.ca

SCHEDULE A

REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION (FORM 51-101 F3)

Management of Midnight Oil Exploration Ltd. (the "Company") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which consist of the following:

- (a) (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2006 using forecast prices and costs; and
- (a) (ii) the related estimated future net revenue; and
- (b) (i) proved oil and gas reserves estimated as at December 31, 2006 using constant prices and costs; and
- (b) (ii) the related estimated future net revenue.

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

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

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

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

- (a) the content and filing with securities regulatory authorities of the reserves data and other oil and gas information;
- (b) the filing of the report of the independent qualified reserves evaluator on the reserves data; and
- (c) the content and filing of this report.

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

Signed "Fred Woods"

Fred Woods, President and Chief Executive Officer

Signed "Judy Stripling"

Judy Stripling, Executive Vice President and Chief Financial Officer

Signed "Paul Moynihan"

Paul Moynihan, Director and Chairman of the Reserves Committee

Signed "Jay Squiers"

Jay Squiers, Director and Member of the Reserves Committee

March 21, 2007

SCHEDULE B

REPORT ON RESERVES DATA (FORM 51-101 F2)

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, 2006. The reserves data consist of the following:
 - (a)
 - (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2006 using forecast prices and costs; and
 - (ii) the related estimated future net revenue; and
 - (b)
 - (i) proved oil and gas reserves estimated as at December 31, 2006 using constant prices and costs; and
 - (ii) the related estimated future net revenue.
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 total proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10%, included in the reserves data of the Company evaluated by us for the period ended December 31, 2006, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator or Auditor	Preparation Date of Evaluation Report	Location of Reserves	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate)			
			Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants Ltd.	February 28, 2007	Canada	\$nil	\$118,564	\$nil	\$118,564

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 this evaluation for events and circumstances occurring after the preparation dates.
7. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

GLJ Petroleum Consultants Ltd

Signed "Doug Sutton"
Doug R. Sutton, P. Eng
Vice President
March 19, 2007

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 among directors on the Committee, management and external auditors.

Membership of Committee

1. 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 "unrelated directors" (as such term is used in the Report of the Toronto Stock Exchange on Corporate Governance in Canada) and "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;
2. The Board shall appoint the Committee Chair, who shall be an independent director; and
3. 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

1. 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;
2. 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.

3. 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
 - obtain explanations of significant variances with comparative reporting periods.
4. The Committee is to review the financial statements, prospectuses, MD&A, annual information forms ("AIF") and all public disclosure containing audited or unaudited financial information (including, without limitation, annual and interim press releases and any other press releases disclosing earnings or financial results) before release and prior to Board approval. The Committee must be satisfied that adequate procedures are in place for the review of Midnight's disclosure of all other financial information.
5. 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(s) report to the Committee at the next scheduled meeting such pre-approval and the member(s) comply with such other procedures as may be established by the Committee from time to time.
6. Review with the external auditors (and the 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.

7. The Committee shall review risk management policies and procedures of Midnight (eg. hedging, litigation and insurance).
8. 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;
9. 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;
10. 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; and
11. The Committee may retain persons having special expertise and/or obtain independent professional advise to assist in filling their responsibilities at the expense of Midnight without any further approval of the Board.

Meetings and Administrative Matters

1. 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;
2. 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;
3. 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;
4. 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;
5. 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;
6. Agendas, approved by the Chair, shall be circulated to Committee members along with background information on a timely basis prior to the Committee meetings;
7. The Committee may invite such officers, directors and employees of 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;
8. Minutes of the Committee will be recorded and maintained and circulated to directors who are not members of the Committee or otherwise made available at a subsequent meeting of the Board;

9. The Committee may retain persons having special expertise and/or obtain independent professional advice to assist in fulfilling its responsibilities at the expense of Midnight;
10. 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; and
11. Any issues arising from the Audit Committee 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.