



ANNUAL INFORMATION FORM

For the year ended

December 31, 2009

March 11, 2010

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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 26, 2010 evaluating our crude oil, natural gas liquids and natural gas reserves as at December 31, 2009.

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.

Trust Units means trust units of Daylight Trust.

Warrants means our share purchase warrants to acquire Common Shares at an exercise price of \$3.00 per warrant which expired 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 us until December 31, 2006.

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

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

ABBREVIATIONS

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

Other

WTI	means West Texas Intermediate
°API	means the measure of the density or gravity of liquid petroleum products derived from a specific gravity
psi	means pounds per square inch
M\$	means thousands of dollars

CONVERSION

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

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

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

CONVENTIONS

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

SPECIAL NOTE REGARDING FORWARD LOOKING STATEMENTS

Certain statements contained within 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.

In particular, this Annual Information Form contains the following forward-looking statements pertaining to, without limitation, the following: our capital expenditure and development program and the results therefrom; our production volumes and expectations regarding the timing of when additional production volumes will be brought on stream; our drilling plans and the results therefrom including expectations regarding well completions and the start up of new wells; future commodity prices; our future royalty rates and the realization of royalty incentives; the impact of the New Royalty Framework on our future royalties; future development and exploration activities and the timing thereof; future land expiries; our future tax liability; our estimated future contractual obligations and the amount expected to be incurred under our farm-in commitments; our future liquidity and financial capacity; and our ability to fund our working capital and forecasted capital expenditures. In addition, 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.

With respect to the forward-looking statements contained in this Annual Information Form, we have made assumptions regarding: future commodity prices; the impact of royalty regimes and certain royalty incentives, the timing and the amount of capital expenditures; production of new and existing wells and the timing of new wells coming on-stream; the performance characteristics of oil and natural gas properties; the size of oil and natural gas reserves; the ability to raise capital and to continually add to reserves through exploration and development; the continued availability of capital, undeveloped land and skilled personnel; the ability to obtain equipment in a timely manner to carry out exploration and development activities; the ability to obtain financing on acceptable terms; the ability to add production and reserves through exploration and development activities; and the continuation of the current tax and regulation.

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. The actual results could differ materially from those anticipated in these forward looking statements as a result of the risk factors including: volatility in market prices for oil and natural gas; counterparty credit risk; access to capital; changes or fluctuations in production levels; 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; stock market volatility and market valuation of our stock; geological, technical, drilling and processing problems; limitations on insurance; changes in environmental or legislation applicable to our operations, and our ability to comply with current and future environmental and other laws; changes in income tax laws or changes in tax laws and incentive programs relating to the oil and gas industry; and the other factors discussed under "*Risk Factors*" in this Annual Information Form. 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. The forward-looking statements contained in this document speak only as of the date of this document and we do not assume any

obligation to publicly update or revise them to reflect new events or circumstances, except as may be required pursuant to applicable securities laws.

MIDNIGHT OIL EXPLORATION LTD.

We were incorporated on September 10, 2004 under the *Business Corporations Act* (Alberta). Our head office is located at Suite 2500, 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 two core areas: the Peace River Arch and Red Earth, both located in Alberta. We pursue a risk-balanced portfolio of exploration and development targeting formations of the Cretaceous and Triassic periods. Selected acquisitions may be used to broaden our production base and to add to our inventory of opportunities.

History of Midnight

On November 29, 2004, we completed our initial capitalization through an initial private placement to our officers, directors and various service providers of 4,666,666 Common Shares for total proceeds of \$7 million. 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 conjunction with the Plan of Arrangement, we entered into the Administrative and Technical Services Agreement with Daylight, which provided for the shared services required to manage our activities and govern the allocation of general and administrative expenses between Daylight and us. The Administrative and Technical Services Agreement was terminated effective December 31, 2006.

On November 29, 2005, we completed the acquisition of certain petroleum and natural gas assets located in the Red Earth area of Alberta for a total acquisition cost, payable in cash, of \$47.7 million. The acquisition was funded by an issuance of 12.0 million subscription receipts at a price of \$4.00 per subscription receipt for gross proceeds of \$48 million. Each subscription receipt was converted into one Common Share in accordance with its terms on November 30, 2005.

On May 17, 2006, we issued 4.0 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 reduce long-term debt and fund our capital expenditure program.

On October 15, 2007, we filed a notice with the Toronto Stock Exchange (the "TSX") to make a normal course issuer bid to purchase our outstanding Common Shares on the open market. We were authorized to purchase up to 4,320,826 Common Shares during this bid, and we purchased and cancelled a total of 405,200 Common Shares at an average price of \$1.12 per Common Share.

On November 7, 2008, we filed a second notice with the TSX to make a normal course issuer bid. The TSX has authorized us to purchase up to 4,081,619 Common Shares during the period from November 12, 2008 to

November 11, 2009. We purchased and cancelled 1,247,500 Common Shares at an average price of \$0.80 per Common Share under this bid in 2008. The bid expired with no additional purchases made in 2009.

In October 2008 we sold our non-core assets in West Central Alberta to Daylight for 3.75 million Daylight Trust Units and \$1.9 million cash. The West Central lands were part of our original assets acquired pursuant to the Plan of Arrangement and were held jointly by us and Daylight (15% and 85% respectively). These assets accounted for approximately 550 boe/d of production and 2.1 million boe of our proved plus probable reserves at the time of sale. We sold the Trust Units in Q4 2008 and Q1 2009 for total proceeds of approximately \$29.6 million and used the proceeds to reduce debt and fund our capital program.

On April 9, 2009, we issued 8.0 million Common Shares at a price of \$0.77 per Common Share and 3.71 million flow-through Common Shares at a price of \$0.94 per flow-through Common Share for gross proceeds of \$9,647,400. The proceeds of the offering were used by the Corporation to temporarily reduce bank indebtedness, which was redrawn and applied to fund the Corporation's ongoing exploration and development activities and for general working capital purposes.

On September 30, 2009, we issued 10.6 million Common Shares at a price of \$0.95 per Common Share and 6.85 million flow-through Common Shares at a price of \$1.10 per flow-through Common Share for gross proceeds of \$17,605,000. The proceeds of the offering were used by the Corporation to reduce bank indebtedness, which was redrawn and applied as needed to fund the Corporation's ongoing exploration and development activities and for general working capital purposes.

Significant Acquisitions

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

Recent Developments

We have focused on applying new drilling and completion technologies in the Deep Basin of the Peace River Arch to improve the productive capability of tighter reservoirs which has established this area as the key to growing our production and reserves. We have tested the Cadomin and uphole zones, have developed the play concept and are now ready to move to the exploitation phase. We have also expanded our activities into the Nikanassin formation (which directly underlies the Cadomin formation) where we believe there exists additional resource potential. With our winter program substantially complete, we are forecasting the first quarter 2010 exit rate to be over 2,500 boe/d. We completed drilling 2 gross (0.8 net) Deep Basin wells which spud in December and we expect to have drilled an additional 3 gross (1.4 net) wells in the Deep Basin and one gross (1.0 net) well in Red Earth prior to break-up and to have completed and tied-in our 2009 drilling successes.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The statement of reserves data and other oil and gas information set forth below (the "**Statement**") is dated February 26, 2010 and prepared as of February 24, 2010. The effective date of the Statement is December 31, 2009.

Definitions and Other Notes to Reserves Data and Tables

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

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

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. "Exploratory 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 completing 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 is set forth below.

Reserve Categories

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

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

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

- (a) Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves; and
- (b) Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

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

Development and Production Status

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

- (a) Developed reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for

example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non producing:

- (i) Developed producing reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty; and
 - (ii) Developed non-producing reserves are those reserves that either have not been on production, or have previously been on production, but are shut in, and the date of resumption of production is unknown.
- (b) Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned.

In multi well pools it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

Levels of Certainty for Reported Reserves

The qualitative certainty levels referred to in the definitions above are applicable to individual reserve entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserves are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

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

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

10. Forecast prices and costs are future prices and costs that are:

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

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

11. 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.
12. Future net revenue is the estimated net amount to be received with respect to the development and production of reserves estimated using forecasted prices and costs. This net amount is computed by deducting from estimated future revenues: estimated amounts of future royalty obligations, costs related to the development and production of reserves, well abandonment costs and future income tax expenses.
13. 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.
14. The forecast price and cost and assumptions assume the continuance of current laws and regulations.
15. The extent and character of all factual data supplied to GLJ were accepted by GLJ as represented. No field inspection was conducted.
16. Columns may not add due to rounding.

Reserves Data

The reserves data set forth below (the "**Reserves Data**") is based upon an evaluation by GLJ in the GLJ Report dated February 26, 2010 and effective December 31, 2009. The Reserves Data summarizes our oil, liquids and natural gas reserves and the net present values of future net revenue for these reserves using forecast prices and costs. The Reserves Data conforms with the requirements of NI 51-101. We engaged GLJ to provide an evaluation of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

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

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

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

**SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2009
FORECAST PRICES AND COSTS**

Reserves Category	Light and Medium Oil		Natural Gas		Natural Gas Liquids		Total Oil Equivalent	
	Gross (Mbbbls)	Net (Mbbbls)	Gross (MMcfs)	Net (MMcfs)	Gross (Mbbbls)	Net (Mbbbls)	Gross (Mboe)	Net (Mboe)
Proved								
Developed Producing	567	455	10,336	9,262	246	191	2,535	2,190
Developed Non-Producing	120	78	3,115	2,657	47	38	686	559
Undeveloped	305	248	11,991	10,493	50	42	2,354	2,039
Total Proved	991	781	25,442	22,412	343	271	5,575	4,788
Probable	941	709	19,644	17,184	262	211	4,477	3,784
Total Proved Plus Probable	1,933	1,490	45,085	39,596	605	483	10,052	8,572

Reserves Category	Net Present Values of Future Net Revenue Before Income Taxes Discounted at (%/year)				
	0%	5%	10%	15%	20%
<i>(\$ thousands)</i>					
Proved					
Developed Producing		75,286	60,447	50,770	44,025
Developed Non-Producing		17,561	14,067	11,690	9,982
Undeveloped		55,320	36,316	24,999	17,787
Total Proved		148,167	110,831	87,458	71,794
Probable		127,510	68,321	40,737	25,948
Total Proved Plus Probable		275,678	179,152	128,196	97,743

Reserves Category	Net Present Values of Future Net Revenue After Income Taxes Discounted at (%/year)				
	0%	5%	10%	15%	20%
<i>(\$ thousands)</i>					
Proved					
Developed Producing		75,286	60,447	50,770	44,025
Developed Non-Producing		17,561	14,067	11,690	9,982
Undeveloped		53,324	35,428	24,585	17,586
Total Proved		146,171	109,942	87,044	71,593
Probable		96,204	52,081	31,468	20,283
Total Proved Plus Probable		242,375	162,023	118,512	91,876

**TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2009
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	298,189	41,085	76,455	30,195	2,286	148,167	1,997	146,171
Proved Plus Probable	585,972	85,540	156,411	65,075	3,268	275,678	33,303	242,375

**FUTURE NET REVENUE BY PRODUCTION GROUP
AS OF DECEMBER 31, 2009
FORECAST PRICES AND COSTS**

Reserves Category	Production Group	Future Net Revenue Before Income Taxes		
		(Discounted at 10%/year)	Unit Value Before Income Taxes (Discounted at 10%)⁽⁴⁾	
			(\$/boe)	(\$/Mcf)
Proved Producing	Light and Medium Crude Oil ⁽¹⁾⁽³⁾	19,628	41.73	6.95
	Natural Gas ⁽²⁾⁽³⁾	31,142	18.11	3.02
	Total	50,770	23.18	3.86
Proved Reserves	Light and Medium Crude Oil ⁽¹⁾⁽³⁾	30,661	38.28	6.38
	Natural Gas ⁽²⁾⁽³⁾	56,797	14.25	2.37
	Total	87,458	18.27	3.04
Proved Plus Probable	Light and Medium Crude Oil ⁽¹⁾⁽³⁾	48,254	31.74	5.29
	Natural Gas ⁽²⁾⁽³⁾	79,942	11.34	1.89
	Total	128,196	14.96	2.49

Notes:

- (1) Including solution gas and other by-products.
- (2) Including by-products, but excluding solution gas.
- (3) Other company revenue and costs not related to a specific production group have been allocated proportionately to production groups.
- (4) Unit values are based on net reserves and are product weighted averages on net reserve volumes using a volume conversion of 6 Mcf of natural gas to one barrel of oil equivalent.

Pricing Assumptions

The following sets for the benchmark reference prices, as at January 1, 2010, reflected in the Reserves Data. These price assumptions were provided by GLJ.

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS AS OF JANUARY 1, 2010 FORECAST PRICES AND COSTS

Year	OIL		NATURAL GAS		EDMONTON LIQUIDS PRICES				Exchange Rate (\$US/\$Cdn)
	WTI Cushing Oklahoma (\$US/bbl)	Edmonton Par Price 40° API (\$Cdn/bbl)	Cromer Medium 29.3° API (\$Cdn/bbl)	AECO/NIT Spot (\$Cdn/MMbtu)	Propane (\$Cdn/bbl)	Butane (\$Cdn/bbl)	Pentanes Plus (\$Cdn/bbl)	Ethane (\$Cdn/bbl)	
Forecast									
2010	80.00	83.26	76.60	5.96	52.46	64.11	84.93	20.02	0.950
2011	83.00	86.42	78.64	6.79	54.45	66.54	88.15	22.88	0.950
2012	86.00	89.58	80.62	6.89	56.43	68.98	91.37	23.24	0.950
2013	89.00	92.74	82.54	6.95	58.42	71.41	94.59	23.43	0.950
2014	92.00	95.90	85.35	7.05	60.42	73.84	97.82	23.79	0.950
2015	93.84	97.84	87.07	7.16	61.64	75.33	99.79	24.15	0.950
2016	95.72	99.81	88.83	7.42	62.88	76.85	101.81	25.06	0.950
2017	97.64	101.83	90.63	7.95	64.15	78.41	103.86	26.88	0.950
2018	99.59	103.88	92.46	8.52	65.45	79.99	105.96	28.84	0.950
2019	101.58	105.98	94.32	8.69	66.77	81.60	108.10	29.46	0.950
2020+	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	0.950

Our weighted average realized sales prices for the year ended December 31, 2009 were \$3.79/Mcf for natural gas, \$62.68/bbl for crude oil and \$28.06/bbl for natural gas liquids.

Reserve Reconciliations

In 2009 we focused our activities on our natural gas assets which are reflected in the current year reserve additions. We had significant reserve additions in the Peace River Arch area on our Elmworth, West Wapiti and Bilbo properties with minor additions at Caroline. These additions can be attributed to drilling activity as well as the addition of proved undeveloped and probable reserves for future locations. We had upward revisions on our proved reserves related primarily to better well performance and the conversion of wells previously booked in the probable category to the proven category as they are drilled. Only very minor overall downward technical revisions occurred in the proven plus probable category.

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

Reserve Category	Factors	Light & Medium Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	BOE (Mboe)
Proved	December 31, 2008	1,201	404	12,724	3,726
	Discoveries	-	-	-	-
	Extensions & improved recovery	-	89	11,437	1,995
	Technical revisions	(10)	(107)	3,826	520
	Production	(195)	(42)	(2,542)	(660)
	December 31, 2009	996	343	25,442	5,580
Probable	December 31, 2008	976	302	11,888	3,259
	Discoveries	-	-	-	-
	Extensions & improved recovery	-	68	10,084	1,748
	Technical revisions	(33)	(108)	(2,328)	(529)
	Production	-	-	-	-
	December 31, 2009	943	262	19,644	4,478
Proved Plus Probable	December 31, 2008	2,177	706	24,612	6,985
	Discoveries	-	-	-	-
	Extensions & improved recovery	-	156	21,521	3,743
	Technical revisions	(44)	(215)	1,497	(9)
	Production	(195)	(42)	(2,542)	(660)
	December 31, 2009	1,939	605	45,086	10,058

Notes:

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

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

Reserve Category	Factors	Light & Medium Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	BOE (Mboe)
Proved	December 31, 2008	1,201	404	12,723	3,725
	Discoveries	-	-	-	-
	Extensions & improved recovery	-	89	11,437	1,995
	Technical revisions	(15)	(107)	3,825	515
	Dispositions	-	-	-	-
	Production	(195)	(42)	(2,542)	(660)
	December 31, 2009	991	343	25,442	5,575
Probable	December 31, 2008	976	302	11,887	3,260
	Discoveries	-	-	-	-
	Extensions & improved recovery	-	68	10,084	1,742
	Technical revisions	(34)	(108)	(2,328)	(531)
	Dispositions	-	-	-	-
	Production	-	-	-	-
	December 31, 2009	941	262	19,644	4,477
Proved Plus Probable	December 31, 2008	2,177	706	24,610	6,985
	Discoveries	-	-	-	-
	Extensions & improved recovery	-	156	21,521	3,743
	Technical revisions	(49)	(215)	1,497	(16)
	Dispositions	-	-	-	-
	Production	(195)	(42)	(2,542)	(660)
	December 31, 2009	1,933	605	45,085	10,052

Notes:

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

Additional Information Relating to Reserves Data

Undeveloped Reserves

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

Proved Undeveloped Reserves

The majority of our proved undeveloped reserves relate to development drilling locations. All of these locations will be drilled into known horizons with offset production as infill or step out locations. The majority of these reserves are booked on our Elsworth, West Wapiti and Bilbo lands and our light oil property at Red Earth. We plan to drill all of the wells in the next two years.

The following table discloses, for each product type, the total volumes of gross proved undeveloped reserves at December 31, 2009 and the year in which they were first attributed.

	Light & Medium Oil (Mbbls)		Natural Gas (MMcf)		Natural Gas Liquids (Mbbls)		Oil Equivalent (Mboe)	
	First Attributed	Total at Year-end	First Attributed	Total at Year-end	First Attributed	Total at Year-end	First Attributed	Total at Year-end
Prior	286	411	2,281	2,306	12	17	679	812
2007	137	318	959	1,064	2	6	299	501
2008	2	319	1,379	2,055	18	19	250	680
2009	-	305	8,518	11,991	41	50	1,461	2,354

Note:

- (1) "First Attributed" refers to reserves first attributed at year-end of the corresponding fiscal year.

Probable Undeveloped Reserves

The majority of our probable undeveloped reserves relate to additional drilling locations that do not meet the criteria to be categorized as proved. The majority of our probable undeveloped locations are booked on our Peace River Arch assets in Elsworth, West Wapiti and Bilbo. We also have reserves booked at our light oil property in Red Earth for additional drilling locations. We plan on drilling a number of the Elsworth locations during 2010 with the remainder expected to be developed within the next two years.

The following table discloses, for each product type, the total volumes of gross probable undeveloped reserves at December 31, 2009 and the year in which they were first attributed.

	Light & Medium Oil (Mbbls)		Natural Gas (MMcf)		Natural Gas Liquids (Mbbls)		Oil Equivalent (Mboe)	
	First Attributed	Total at Year-end	First Attributed	Total at Year-end	First Attributed	Total at Year-end	First Attributed	Total at Year-end
Prior	627	735	2,039	2,305	16	23	983	1,142
2007	526	682	1,098	1,446	5	13	714	936
2008	(2)	649	7,586	7,857	188	188	1,451	2,147
2009	-	656	10,712	14,163	58	161	1,843	3,178

Note:

- (1) "First Attributed" refers to reserves first attributed at year-end of the corresponding fiscal year.

Significant Factors or Uncertainties

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

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

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

Future Development Costs

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

Year	Forecast Prices And Costs	
	Proved Reserves	Proved Plus Probable Reserves
<i>(\$ thousands)</i>		
2010	9,559	12,834
2011	13,048	33,745
2012	7,543	15,533
2013	0	2,918
Remaining	46	46
Total (Undiscounted)	30,195	65,075

In each year of our economic forecasts, our estimated future net revenues or operating income exceeds our estimated future development costs. Therefore, we should be able to fund our future development capital entirely out of our cash flow and no other sources of funding should be required. If additional funding were required, we typically 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. There can be no assurance that debt or equity financing, or cash generated by operations, as a result of uncertain levels of near term commodity prices, will be available or sufficient to meet these requirements or, if debt or equity financing is available, that it will be on terms acceptable to us. See "Risk Factors".

Other Oil and Gas Information

Oil and Gas Properties

All of our properties are located in the Peace River Arch and Red Earth areas of Alberta and British Columbia, with our exploration focus being in the Deep Basin of the Peace River Arch, where we hold the majority of our undeveloped lands. During 2009, our capital expenditures totalled approximately \$37.5 million with approximately 99% directed to the Peace River Arch.

The following is a description of our oil and natural gas properties.

Peace River Arch

Our management and technical staff have extensive experience in exploring for and developing the conventional sweet gas charged Upper Cretaceous aged reservoirs in this area as well as the Lower Cretaceous tight gas formations. Our primary areas of operation in the Peace River Arch area include: Elmworth, Chinook Ridge, Bilbo, Red Rock, and Wapiti, and also include Beaverlodge, Jackpine and Moberly. Our undeveloped land has multi-zone, sweet gas potential including, but not limited to the Dunvegan, Cadotte, Notikewan, Falher, Bluesky, Gething, Cadomin and Nikanassin reservoirs. Our reserves in this area account for approximately 80% of our total proved plus probable reserves.

Elmworth is a sweet gas producing property located in the Deep Basin approximately 60 km southwest of Grande Prairie, Alberta. We have developed the property and primarily drill Cadomin horizontal wells with Upper Cretaceous potential in the uphole. The assets include mostly operated properties with working interest ranging from 40% to 100%. Elmworth reserves account for 33% of our total proved and probable reserves. We drilled 1 gross (0.55 net) horizontal Cadomin well in the fourth quarter of 2009. This well was completed in Q1 2010 and was placed on production in early March 2010. There are six additional uphole zones to complete in the well which are scheduled for completion later in 2010. We have 3,700 net acres and downspacing has been approved for up to 4 wells per section on the majority of our lands. Elmworth continues to be an area of focus for us with a drilling inventory of 28 gross additional Cadomin wells on our operated lands.

Bilbo is a sweet gas producing property in the Deep Basin. We recently completed a large scale farm-in by drilling 7 gross wells at a 50% working interest to earn a 30% working interest in 42 sections of land with potential in the Paddy, Cadotte, Falhers, Gething, Cadomin and Nikanassin formations. These lands are 100% operated by Midnight and reserves in Bilbo account for 13% of our total proved plus probable reserves. We completed our last

earning well in Q1 2010 and continue to invest in infrastructure to place our wells on-stream. We are pleased with the results of our drilling program and we plan to conduct additional operations later in 2010 and 2011.

The Red Rock area is comprised of 19,100 net acres of prospective land (average 92% working interest) targeting the multi-zone potential of the conventional Cretaceous reservoirs and the tight gas of the Cadomin and the Nikanassin. We have identified a number of drilling and re-entry opportunities in this area which we intend to pursue in the future. As the Company is focusing on earning additional lands and maintaining expiring acreage in other areas, the Company does not have any development plans for this property in 2010 as there are no imminent expiry issues. The reserves in this area account for 12% of our total proved plus probable reserves.

Chinook Ridge is a sweet gas producing property approximately 25 km south of our Elsworth property in the Deep Basin. Midnight has pursued a number of farm-in opportunities and now has 14,000 net acres of undeveloped lands earned or to be earned and reserves in this area now account for 12% of our total proved plus probable reserves. The assets are 100% operated by us and we have varying working interests ranging from 25% to 100%. This resource property has both Nikanassin and Cadomin potential in the lower Cretaceous tight zones as well as the uphole conventional targets of the upper Cretaceous. Midnight has been very active on this property and will have drilled and/or deepened 4 gross (2.75 net) wells in this winter's program. Only one of these wells is anticipated to be on production before the end of Q1 2010 with additional completion and tie-in operations scheduled for Q3 and Q4 2010.

Our remaining Peace River Arch lands account for 9% of our total proved plus probable reserves and include approximately 40,000 net acres of undeveloped land. The majority of these lands are located in the Wapiti, Beaverlodge, Jackpine and Moberly areas. We do not have any development budgeted for these lands in 2010.

Red Earth

We acquired our Red Earth assets in November 2005. The main producing horizons in this area are the Granite Wash and Keg River formations. Both zones produce 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 20% of our total proved plus probable reserves. Along with the producing wells, we also have an interest in 36,400 net undeveloped acres that contain both exploratory and development potential. Uphole potential also exists in the Slave Point (light oil) and Bluesky (sweet gas) formations.

In Q1 2010, Midnight drilled and completed a Keg River oil well on 100% working interest lands. This location was chosen to test a structure defined on proprietary 3D seismic and came in according to prognosis. Tie-in operations are currently underway and it is anticipated that this well will be on stream before the end of Q1 2010.

Midnight initiated a waterflood in the Keg River B and N pools in 2008. The water handling and injection facilities that were installed continue to perform as designed. Besides providing increased ultimate oil recovery, water injection has stabilized and enhanced production from the pool, and contributed greatly to the reduction in our operating costs in this area. Midnight is currently evaluating the potential to expand the waterflood to other pools in this area as well as the potential to drill additional development wells in this area.

Minor

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

Exploration and Development Strategy

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 target land and drilling opportunities that have both

development and exploration drilling potential in areas in which we have expertise and that have multi-zone productive capability.

Oil and Gas Wells

The following table sets forth the number and status of wells in which we have a working interest as at December 31, 2009:

	Oil Wells				Natural Gas Wells			
	Producing		Non Producing		Producing		Non Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	37	16.34	19	12.38	42	21.20	35	22.07
British Columbia	-	-	-	-	1	0.19	1	1.00
Total	37	16.34	19	12.38	43	21.39	36	23.07

Properties with no Attributable Reserves

The following table sets out forth our undeveloped land holdings as at December 31, 2009:

	Undeveloped Acres	
	Gross	Net
Alberta	131,400	91,800
British Columbia	21,400	16,900
Total	152,800	108,700

Rights to explore, develop and exploit 44,000 net acres of our total net acres relate to title documents whose primary terms come to an end between January 1, 2010 and December 31, 2010. Of these, we estimate that over 28,000 net acres will be further continued through submission of continuation applications and additional drilling.

As of the date of this AIF, we did not have any material work commitments on our undeveloped properties.

Forward Contracts

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

Drilling Activity

The following table summarizes the gross and net exploration and development wells that we participated in during the year ended December 31, 2009:

	Exploratory		Development	
	Gross	Net	Gross	Net
Light and Medium Oil	-	-	-	-
Natural Gas	7	2.50	3	1.05
Dry	-	-	-	-
Total	7	2.50	3	1.05

For details of our current and likely exploration and development activities, see "Oil and Gas Properties" on pages 17 and 18 of this Annual Information Form.

Abandonment and Reclamation Costs

The following table discloses our abandonment and reclamation costs anticipated as at December 31, 2009, calculated both at an undiscounted and at a 10% discount rate with a portion thereof anticipated to be paid in each of the next three years:

Abandonment and reclamation costs	Undiscounted	Discounted at 10%
(\$ thousands)		
Total at December 31, 2009	4,509	1,267
Total expected to be incurred in the next three years	361	322

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

We currently estimate that the future environmental and reclamation obligations net of salvage value in respect of our assets will aggregate approximately \$4.5 million escalated at 2% per year. Of this amount, approximately \$2.3 million 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, 2009, we expected to incur reclamation and abandonment costs in respect of 73.2 net wells.

Tax Horizon

Income taxes deducted in the calculations of future net revenues in the Reserves Data set forth in this Annual Information Form assumes that we produce out our existing reserves without reinvestment of cash flows and does not take into account general and administrative expenses or interest expenses. Under this scenario, using total proved reserves and forecast prices and costs, we would not be taxable in the next 10 years.

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 at least the next five years. This result is dependent upon commodity prices, capital spending and the success of our drilling program.

At December 31, 2009, we had approximately \$143 million in tax pools available to shelter taxable income in future years before deducting \$11 million of flow through share renunciations which will reduce tax pools in 2010.

Costs Incurred

The following table summarizes our capital expenditures for the year ended December 31, 2009:

Expenditures	2009
(\$ thousands)	
Property acquisition costs – Proved Properties	-
Property acquisition costs – Undeveloped Properties ⁽¹⁾	817
Exploration Costs ⁽²⁾	25,201
Development Costs ⁽³⁾	11,379
Non oil and gas assets	103
Total	37,500

Notes:

- (1) Cost of land acquired, lease rentals on unproved properties and net of dispositions and transfers.
- (2) Geological and geophysical costs, capitalized general and administration costs and drilling and completion costs for exploration wells.
- (3) Drilling and completion costs for development wells and equipping, tie in and facility costs for all wells.

Production Estimates

The following table sets out the 2009 Company Gross 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*":

	Light & Medium Oil	Natural Gas Liquids	Natural Gas	BOE
	(bbls/d)	(bbls/d)	(Mcf/d)	(boe/d)
Proved Producing				
Elmworth	-	5	1,983	336
Red Earth	375	-	162	402
Others	7	91	2,976	594
Total Proved Producing	382	96	5,120	1,332
Proved				
Elmworth	-	9	3,607	611
Red Earth	423	-	163	450
Others	7	110	4,685	898
Total Proved	430	119	8,456	1,959
Proved Plus Probable				
Elmworth	-	10	3,840	650
Red Earth	494	-	166	522
Others	7	112	4,933	941
Total Proved Plus Probable	502	122	8,939	2,114

Production History

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

	Quarters Ended 2009			
	Q1	Q2	Q3	Q4
Light and Medium Crude Oil (bbls/d)	584	560	537	457
Natural Gas Liquids (bbls/d)	124	128	98	108
Natural Gas (Mcf/d)	4,867	9,004	7,064	6,904
Combined (boe/d)	1,519	2,189	1,812	1,715

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 2009			
	Q1	Q2	Q3	Q4
Light and Medium Crude Oil (\$/bbls)				
Average Price Received	47.35	63.30	68.62	74.12
Royalties Paid	12.80	16.06	24.33	23.82
Operating Expenses	10.50	12.70	7.68	18.31
Transportation Expenses	0.98	1.04	0.89	0.74
Netback Received⁽¹⁾	23.07	33.50	35.72	31.25
Natural Gas Liquids (\$/bbls)				
Average Price Received	28.76	27.10	29.02	27.52
Royalties Paid	8.73	8.59	3.67	6.96
Operating Expenses	10.23	7.58	9.31	7.44
Transportation Expenses	-	-	-	-
Netback Received⁽¹⁾	9.80	10.93	16.04	13.12

	Quarters Ended 2009			
	Q1	Q2	Q3	Q4
Natural Gas (\$/Mcf)				
Average Price Received	5.26	3.45	2.85	4.20
Royalties Paid	1.26	0.46	0.16	0.10
Operating Expenses	1.70	1.26	1.55	1.24
Transportation Expenses	-	-	-	-
Netback Received ⁽¹⁾	2.30	1.73	1.14	2.86
Combined (\$/boe)				
Average Price Received	37.64	31.99	33.02	38.96
Royalties Paid	9.65	6.49	8.03	7.19
Operating Expenses	10.33	8.89	8.83	10.33
Transportation Expenses	0.37	0.27	0.26	0.20
Netback Received ⁽¹⁾	17.29	16.34	15.90	21.24

Note:

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

The following table indicates our average daily production from Elmworth, Red Earth and our other fields for the year ended December 31, 2009:

	Light & Medium Oil (bbls/d)	Natural Gas Liquids (bbls/d)	Natural Gas (Mcf/d)	BOE (boe/d)
Elmworth	-	1	3,073	513
Red Earth	525	-	153	551
Others	9	114	3,740	746
Total	534	115	6,966	1,810

DESCRIPTION OF CAPITAL STRUCTURE

Our authorized share capital consists of an unlimited number of Common Shares without nominal or par value. At March 11, 2010, we had outstanding, 75,335,129 Common Shares and 4,516,000 options, each of which are exercisable for one (1) Common Share at a weighted average exercise price of \$1.14 per share.

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 11, 2010, the number of options which may be issued under our stock option plan is currently limited to 7,533,512 options of which options to purchase 4,516,000 (6% of the outstanding Common Shares) are outstanding and 3,017,512 options are available for future grants (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 Board of Directors, non cumulative dividends at such rate and payable on such date as may be determined from time to time by our Board of Directors.

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

MARKET FOR SECURITIES

Our Common Shares are listed for trading on the TSX under the symbol "MOX". The following table sets out the price range for and trading volume of the Common Shares since January 1, 2009.

Period	High	Low	Volume (000s)
2009			
January	0.99	0.67	254
February	0.85	0.77	302
March	0.87	0.67	1,052
April	1.60	0.80	2,416
May	1.39	1.01	1,848
June	1.25	0.95	2,317
July	1.10	0.90	483
August	1.12	0.97	2,040
September	1.18	0.93	6,011
October	1.17	0.96	3,173
November	1.13	0.96	2,530
December	1.09	0.95	4,432
2010			
January	1.17	1.02	3,244
February	1.20	1.04	2,142
March 1 to March 10	1.15	1.06	256

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 our 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:

Name and Municipality of Residence	Position	Director Since	Principal Occupation and Positions for the Past Five Years
Fred Woods Calgary, Alberta	Chairman, President, Chief Executive Officer and Director	2004	Mr. Woods has been our Chairman since May 2007 and our President, Chief Executive Officer and a Director of our predecessor since May 2000. From March 1997 to May 2000, Mr. Woods was President and Chief Operating Officer of Ulster Petroleum Ltd. (an intermediate oil and gas company).
Anthony Lambert ⁽²⁾⁽³⁾⁽⁴⁾ Calgary, Alberta	Director	2004	Mr. Lambert has been President and Chief Executive Officer of Daylight Trust or its predecessor since November, 2004. On August 3, 2005 he resigned as our Vice President, Operations and Chief Operating Officer. Mr. Lambert has been a Director of us or our predecessor since July 2000. Prior thereto, Mr. Lambert was the Vice President, Operations of Ulster Petroleum Ltd.

Name and Municipality of Residence	Position	Director Since	Principal Occupation and Positions for the Past Five Years
Jay Squiers ⁽¹⁾⁽²⁾⁽³⁾⁽⁴⁾ Dallas, Texas	Director	2004	Mr. Squiers has been Executive Vice President of CSG Investments, an investment arm of Beal Financial Corporation since April 2009 and was Senior Vice President from January 2009 to April 2009. Prior thereto, Mr. Squiers was a Principal of American Capital in the Dallas based Energy Group starting in October 2007. Prior thereto Mr. Squiers was a Managing Director of Fortress Investment Group, LLC, an investment and asset management firm starting in August 2005. From August 2002 until July 2005, he was a Senior Vice-President of Prudential Capital Group, a private capital lender. Mr. Squiers began his career at Prudential Capital Group in 1991. Mr. Squiers holds a Bachelor of Economics from Princeton University and a law degree from the University of Texas, and he is also a Chartered Financial Analyst.
Peter Harrison ⁽¹⁾⁽²⁾⁽³⁾⁽⁴⁾ Brossard, Québec	Director	2007	Mr. Harrison is Manager, North American Equities for CN Investments since August 2009. Prior thereto, Mr. Harrison was Senior Vice President of Montrusco Bolton Investments Inc. (Montreal) since December 1997, where he managed that firm's Canadian Equity portfolios. Mr. Harrison has significant financial experience making investments which involve extensive analysis of financial statements. He holds a Bachelor of Commerce degree from McGill University, an MBA from the University of Western Ontario, and is a Chartered Financial Analyst. Mr. Harrison serves on the Board of Freehold Resources Ltd., administrator of Freehold Royalty Trust.
Robert Zakresky ⁽¹⁾⁽²⁾⁽³⁾⁽⁴⁾ Calgary, Alberta	Director	2009	Mr. Zakresky has held the position of President and Chief Executive Officer of Crocotta Energy Inc. since November 2006. From 1993 to October 2006, Mr. Zakresky has sequentially held the position of President, CEO and a director of Bellator Exploration Inc., Viracocha Energy Inc., Chamaelo Energy Inc. and Chamaelo Exploration Ltd. Mr. Zakresky holds a Bachelor of Commerce degree from the University of Saskatchewan and obtained his Chartered Accountant designation with Price Waterhouse.
Thomas Simons Calgary, Alberta	Director	2010	Mr. Simons has held the position of President and Chief Executive Officer of Canadian Energy Services & Technology Corp. or its predecessor since January 2006. Prior thereto, Mr. Simons was Vice-President and Principal of Impact Fluid Systems Inc. since 2001. Mr. Simons obtained a Business Administration Diploma from Medicine Hat College.
Judith Stripling Calgary, Alberta	Executive Vice President and Chief Financial Officer		Ms. Stripling is our Executive Vice President and Chief Financial Officer. Ms. Stripling was appointed our Executive Vice President in June 2006. Prior thereto, Ms. Stripling was Vice President, Finance and Chief Financial Officer of us or our predecessor since July 2000. Prior to July 2000, Ms. Stripling was Vice President, Finance and Chief Financial Officer of Ulster Petroleum Ltd.

Name and Municipality of Residence	Position	Director Since	Principal Occupation and Positions for the Past Five Years
Dale A. Miller Balzac, Alberta	Vice President and Chief Operating Officer		Mr. Miller is our Vice President and Chief Operating Officer of Midnight and was appointed to this office in November 2009. Prior thereto, Mr. Miller was Vice President, Operations and Engineering with Gibraltar Exploration Ltd., a private exploration and production oil and gas company, since 2003. Prior thereto, Mr. Miller was the Vice President, Operations and Engineering at Penn West Petroleum Ltd.
Thomas Moslow Calgary, Alberta	Senior Vice President, Exploration		Dr. Moslow is our Senior Vice President, Exploration and was appointed to this office in June 2006. Prior thereto, Dr. Moslow was Vice President, Exploration of us or our predecessor since July 2000. Prior to July 2000, Dr. Moslow was Vice President of New Ventures and Technology at Ulster Petroleums Ltd.
Andrew Weldon Calgary, Alberta	Vice President, Business Development		Mr. Weldon is our Vice President, Business Development and was appointed to this office in June 2006. Prior thereto, Mr. Weldon was Vice President, Land of us or our predecessor since February 2002. From March 1998 to January 2001, Mr. Weldon was Vice President, Land at Startech Energy Inc. (an intermediate publicly traded oil and gas company).
Chad Kalmakoff Calgary, Alberta	Vice President, Finance		Mr. Kalmakoff is our Vice President, Finance and was appointed to this office in June 2006. Prior thereto, Mr. Kalmakoff was Financial Controller of Daylight Trust or its predecessor since June 2003. Prior thereto, Mr. Kalmakoff held various positions with KPMG LLP.
Peter O'Leary Calgary, Alberta	Vice President, Geology		Mr. O'Leary is our Vice President, Geology and was appointed to this office in June 2006. Prior thereto, Mr. O'Leary was Exploration Manager, PRA/Deep Basin of Daylight Trust or its predecessor since February 2003. Prior thereto, Mr. O'Leary was Exploration Manager of the Peace River Arch District at Devon Canada Corporation.
E. Martin Saizew Calgary, Alberta	Vice President, Engineering		Mr. Saizew is our Vice President, Engineering and was appointed to this office in June 2006. Prior thereto, Mr. Saizew was Exploitation Manager, PRA & Foothills of Daylight 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. von Vegesack has been a partner at Burnet, Duckworth & Palmer LLP, a Calgary based law firm, since 1986. Mr. von Vegesack specializes in corporate finance and mergers and acquisitions. Mr. von Vegesack has been our Corporate Secretary or our predecessor since July 2000.

Notes:

- (1) Member of the Audit Committee, Peter Harrison is the Chairman of this committee.
- (2) Member of the Reserves Committee, Anthony Lambert is the Chairman of this committee.
- (3) Member of the Compensation Committee, Jay Squiers is the Chairman of this committee.
- (4) Member of the Corporate Governance Committee, Robert Zakresky is the Chairman of this committee. We do not have an executive committee.
- (5) The terms of office of all of our directors will expire on the date of the next annual meeting of our shareholders.

As at the date hereof, our directors and officers and their associates and affiliates, as a group, beneficially own, control or direct, directly or indirectly, approximately 7.3 million Common Shares representing approximately 9.7% of our outstanding Common Shares. The directors and officers also hold 3.3 million options which would increase their beneficial ownership to approximately 13.2% of the outstanding Common Shares on a fully diluted basis. The information as to the number of Common Shares beneficially owned, controlled or directed, directly or indirectly, or over which control or direction is exercised, is based upon information received from such directors and officers.

Corporate Cease Trade Orders, Bankruptcies or Penalties or Sanctions

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

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

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

Conflicts of Interest

Certain of our directors and officers may have interests in other oil and gas companies and oil and gas properties which may from time to time conflict with our interests. Any such conflicts will be resolved in accordance with the requirements of the *Business Corporations Act* (Alberta). Mr. von Vegesack, our Corporate Secretary, is a partner in a law firm which provides services to us. We periodically utilize the oilfield services of Canadian Energy Services & Technology Corp. in our operations, of which Mr. Simons, one of our directors, is a Director and Chief Executive Officer. Our Board of Directors does not believe that any activities undertaken by Mr. von Vegesack or Mr. Simons interfere, or could be perceived to interfere, in any material way with their ability to act with a view to our best interests.

AUDIT COMMITTEE INFORMATION

Audit Committee Charter

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

Composition of the Audit Committee

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

Name	Independent	Financially Literate	Relevant Education and Experience
Peter Harrison (Chairman)	Yes	Yes	Mr. Harrison holds a Bachelor of Commerce Degree from McGill University, a Master of Business Administration from the Ivey School of Business, at the University of Western Ontario, and is a Chartered Financial Analyst. Mr. Harrison has worked in the investment industry in excess of 29 years. As Manager, North American Equities for CN Investments and as previous Senior Vice President of Montrusco Bolton Investments Inc. (Montreal), Mr. Harrison has significant financial experience making investments which involve extensive analysis of financial statements. Additionally Mr. Harrison is a director and member of an audit committee of a publicly traded oil and gas royalty trust.
Jay Squiers	Yes	Yes	Mr. Squiers holds a law degree (Honours) from University of Texas, a Bachelor of Economics (magna cum laude) from Princeton and earned the Chartered Financial Analyst designation in 1997. Mr. Squiers is currently Executive Vice President of CSG Investments, an investment arm of Beal Financial Corporation. Mr. Squiers has obtained significant financial experience and exposure to accounting and financial issues in his career at Prudential Capital Group. As a Senior Vice-President, he was actively involved in originating, underwriting and managing a portfolio of private placement investments for a division of Prudential Financial, Inc. As a Managing Director of Fortress Investment Group, LLC., he was responsible for identifying, underwriting and executing debt acquisition and originating opportunities in the energy and general corporate sectors. As a Principal of American Capital in the Dallas-based Energy Group, Mr. Squiers focuses on debt and minority equity financings in support of private equity sponsors, acquisitions, as well as direct financings for companies across the energy sector.
Robert Zakresky	Yes	Yes	Mr. Zakresky holds a Bachelor of Commerce degree from the University of Saskatchewan and obtained his Chartered Accountant designation with Price Waterhouse in 1990. As President and CEO of Crocotta Energy Inc., and as previous President, CEO, and Director of Bellator Exploration Inc., Viracocha Energy Inc., Chamaelo Energy Inc. and Chamaelo Exploration Ltd., Mr. Zakresky has significant industry and financial experience with lead exposure to business financial issues and decisions.

External Auditor Service Fees

Audit Fees

The 2009 audit fees of \$77,500 were paid or payable to KPMG LLP for professional services rendered for the audit of our consolidated financial statements for the period ended December 31, 2009 and for services provided in connection with statutory and regulatory filings. In addition, professional services for quarterly reviews for 2009 of \$41,500 were paid to KPMG LLP. In 2009 other audit services of \$63,000 were paid to KPMG LLP for professional services rendered in filing our two prospectuses. In 2008, audit fees of \$81,500 were paid to KPMG LLP for professional services rendered for the audit of our consolidated financial statements for the period ended December 31, 2008 and for services provided in connection with statutory and regulatory filings. In addition, professional services for quarterly reviews for 2008 of \$46,000 were paid to KPMG LLP.

Tax, Audit and Related Fees

For the year ended December 31, 2009, we paid KPMG LLP \$5,500 for tax services and did not pay any additional fees for professional services other than disclosed above in "*Audit Fees*". For the year ended December 31, 2008, we paid KPMG LLP \$8,100 for tax services and did not pay any additional fees for professional services other than disclosed above in "*Audit Fees*".

Pre-approval of Policies and Procedures

We have adopted 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 13 of the Audit Committee Mandate and Terms of Reference as laid out in Schedule C. The Audit Committee has approved the provision of a specified list of audit and permitted non-audit services that the Audit Committee believes to be typical, recurring or otherwise likely to be provided by KPMG LLP during the current fiscal year. The list of services is sufficiently detailed as to the particular services to be provided to ensure that the Audit Committee knows precisely what services it is being asked to pre-approve and it is not necessary for any member of management to make a judgment as to whether a proposed service fits within pre-approved services. Any service that is not on the list of services requires Audit Committee approval and any service greater than \$25,000 but less than \$50,000 requires approval of the Audit Committee chair while any service greater than \$50,000 requires approval of the Audit Committee.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

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

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

INTERESTS OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

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

AUDITORS, TRANSFER AGENT AND REGISTRAR

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

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

MATERIAL CONTRACTS

The only material contracts entered into by us within the last year, which are currently material and other than in the ordinary course of business, is the credit agreement in respect of our \$35.0 million credit facility with a Canadian chartered bank. Our credit facility is described in Note 5 to our consolidated financial statements for the year ended December 31, 2009 which is incorporated by reference herein. Copies of the agreement are available on SEDAR at www.sedar.com.

INTERESTS OF EXPERTS

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

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

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

Pricing and Marketing

Oil

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 contractual terms of sale. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National Energy Board of Canada (the "NEB"). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB and the issuance of such a licence requires a public hearing and the approval of the Governor in Council.

Natural Gas

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

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

Pipeline Capacity

Although pipeline expansions are ongoing, the lack of firm pipeline capacity continues to affect the oil and natural gas industry and limits the ability to produce and to market oil and natural gas production. In addition, the 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, the United States and Mexico became effective on January 1, 1994. NAFTA carries forward most of the material energy terms that are contained in the Canada United States Free Trade Agreement. In the context of energy resources, Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to domestic use (based upon the proportion prevailing in the most recent 36 month period); (ii) impose an export price higher than the domestic price (subject to an exception with respect to certain voluntary measures which only restrict the volume of exports); and (iii) disrupt normal channels of supply. All three signatory countries are prohibited from imposing minimum or maximum export or import price requirements, provided, in the case of export price requirements, that any prohibition in any circumstances in which any other form of quantitative restriction is applied is prohibited, and in the case of import-price requirements, that 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, minimize disruption of contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, all of which are important for Canadian oil and natural gas exports.

Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations which govern royalties, production rates and other matters. The royalty regime in a given province is a significant factor in the profitability of crude oil, natural gas liquids, sulphur and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiation between the mineral freehold owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Royalties from production on Crown lands are determined by governmental regulation and are generally calculated as a percentage of the value of 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 or royalty tax credits and are generally introduced when commodity prices are low to encourage exploration and development activity by improving earnings and cash flow within the industry.

Alberta

Producers of oil and natural gas from Crown lands in Alberta are required to pay annual rental payments, currently at a rate of \$3.50 per hectare, and make monthly royalty payments in respect of oil and natural gas produced. On October 25, 2007, the Government of Alberta released a report entitled "The New Royalty Framework" ("**NRF**") containing the Government's proposals for Alberta's new royalty regime which were subsequently implemented by the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*. The NRF took effect on January 1, 2009.

With respect to conventional oil, the NRF eliminated the classification system used by the previous royalty structure which classified oil based on the date of discovery of the pool. Under the NRF, royalty rates for conventional oil are set by a single sliding rate formula which is applied monthly and incorporates separate variables to account for production rates and market prices. Royalty rates for conventional oil under the NRF range from 0-50%, an increase from the previous maximums of 30-35% depending on the vintage of the oil, and rate caps are set at \$120 per barrel.

Royalty rates for natural gas under the NRF are similarly determined using a single sliding rate formula incorporating separate variables to account for production rates and market prices. Royalty rates for natural gas under the NRF range from 5-50%, an increase from the previous maximums of 5-35%, and rate caps are set at \$17.75/GJ.

Oil sands projects are also subject to the NRF. Prior to payout, the royalty is payable on gross revenues of an oil sands project. Gross revenue royalty rates range between 1-9% depending on the market price of oil: rates are 1% when the market price of oil is less than or equal to \$55 per barrel and increase for every dollar of market price of oil increase to a maximum of 9% when oil is priced at \$120 or higher. After payout, the royalty payable is the greater of the gross revenue royalty based on the gross revenue royalty rate of 1-9% and the net revenue royalty based on the net revenue royalty rate. Net Revenue royalty rates start at 25% and increase for every dollar of market price of oil increase above \$55 up to 40% when oil is priced at \$120 or higher. An oil sands project reaches payout when its cumulative revenue exceeds its cumulative costs. Costs include specified allowed capital and operating costs related to the project plus a specified return allowance. As part of the implementation of the NRF, the Government of Alberta renegotiated existing contracts with certain oil sands producers that were not compatible with the NRF.

In August 2006, the Government of Alberta introduced the Innovative Energy Technologies Program (the "**IETP**"), which has a stated objective of promoting producers' investment in research, technology and innovation for the purposes of improving environmental performance while creating commercial value. The IETP is backed by a \$200 million funding commitment over a five-year period beginning April 1, 2005 and provides royalty adjustments to specific pilot and demonstration projects that utilize innovative technologies to increase recovery from existing reserves.

On April 10, 2008, the Government of Alberta introduced two new royalty programs to be implemented along with the NRF and intended to encourage the development of deeper, higher cost oil and gas reserves. A five-year program for conventional oil exploration wells over 2,000 metres provides qualifying wells with up to a \$1 million or 12 months of royalty relief, whichever comes first, and a five-year program for natural gas wells deeper than 2,500 metres provides a sliding scale royalty credit based on depth of up to \$3,750 per metre.

On November 19, 2008, in response to the drop in commodity prices experienced during the second half of 2008, the Government of Alberta announced the introduction of a five-year program of transitional royalty rates with the intent of promoting new drilling. The 5-year transition option is designed to provide lower royalties at certain price

levels in the initial years of a well's life when production rates are expected to be the highest. Under this new program companies drilling new natural gas or conventional oil deep wells (between 1,000 and 3,500 m) are given a one-time option, on a well-by-well basis, to adopt either the new transitional royalty rates or those outlined in the NRF. In order to qualify for this program wells must be drilled during the period starting on November 19, 2008 and ending on December 31, 2013. Following this period all new wells drilled will automatically be subject to the NRF and wells that operated under the transitional royalty rates will revert to royalty rates determined by the NRF.

On March 3, 2009, the Government of Alberta announced a three-point incentive program in order to stimulate new and continued economic activity in Alberta. The program introduced a drilling royalty credit for new conventional oil and natural gas wells and a new well royalty incentive program, both applying to conventional oil or natural gas wells drilled between April 1, 2009 and March 31, 2010. The drilling royalty credit provides up to a \$200 per metre royalty credit for new wells and is primarily expected to benefit smaller producers since the maximum credit available will be determined using the company's production level in 2008 and its drilling activity between April 1, 2009 and March 31, 2010, favouring smaller producers with lower activity levels. The new well incentive program will apply to wells that begin producing conventional oil or natural gas between April 1, 2009 and March 31, 2010 and provides for a maximum 5% royalty rate for the first 12 months of production, up to a maximum of 50,000 barrels of oil or 500 MMcf of natural gas. In June, 2009, the Government of Alberta announced the extension of these two incentive programs for one year to March 31, 2011.

In addition to the foregoing, Alberta currently maintains a royalty reduction program for low productivity oil and oil sands wells, a royalty adjustment program for deep marginal gas wells and a royalty exemption for re-entry wells, among others.

British Columbia

Producers of oil and natural gas from Crown lands in British Columbia are required to pay annual rental payments, currently at a rate of \$3.50 per hectare, and make monthly royalty payments in respect of oil and natural gas produced. The amount payable as a royalty in respect of oil depends on the type and vintage of the oil, the quantity of oil produced in a month and the value of that oil. Generally, oil is classified as either light or heavy and 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 calculation takes into account the production of oil on a well-by-well basis, the specified royalty rate for a given vintage of oil, the average unit selling price of the oil and any applicable royalty exemptions. Royalty rates are reduced on low productivity wells, reflecting the higher unit costs of extraction, and are the lowest for third-tier oil, reflecting the higher unit costs of both exploration and extraction.

The royalty payable in respect of natural gas produced on Crown lands is determined by a sliding scale formula based on a reference price, which is the greater of the average net price obtained by the producer and a prescribed minimum price. For non-conservation gas (not produced in association with oil), the royalty rate depends on the date of acquisition of the oil and natural gas tenure rights and the spud date of the well and may also be impacted by the select price, a parameter used in the royalty rate formula to account for inflation. Royalty rates are fixed for certain classes of non-conservation gas when the reference price is below the select price. Conservation gas is subject to a lower royalty rate than non-conservation gas as an incentive for the production and marketing of natural gas which might otherwise have been flared.

Producers of oil and natural gas from freehold lands in British Columbia are required to pay monthly freehold production taxes. For oil, the level of the freehold production tax is based on the volume of monthly production. For natural gas, the freehold production tax is determined using a sliding scale formula based on the reference price similar to that applied to natural gas production on Crown land, and depends on whether the natural gas is conservation gas or non-conservation gas.

As at the beginning of 2009, British Columbia maintained a number of targeted royalty programs for key resource areas intended to increase the competitiveness of British Columbia's low productivity wells. These include both royalty credit and royalty reduction programs, including the following:

- *Summer Royalty Credit Program* providing a royalty credit of 10% of drilling and completion costs up to \$100,000 for wells drilled between April 1 and November 30 of each year, intended to increase summer drilling activity, employment and business opportunities in northeastern British Columbia;
- *Deep Royalty Credit Program* providing a royalty credit equal to approximately 23% of drilling and completion costs for vertical wells with a true vertical depth greater than 2,500 metres and horizontal wells with a true vertical depth greater than 2,300 metres spud between December 1, 2003 and September 1, 2009;
- *Deep Re-Entry Royalty Credit Program* providing royalty credits for deep re-entry wells with a true vertical depth greater than 2,300 metres and a re-entry date subsequent to December 1, 2003;
- *Deep Discovery Royalty Credit Program* providing the lesser of a 3-year royalty holiday or 283,000,000 m³ of royalty free gas for deep discovery wells with a true vertical depth greater than 4,000 metres whose surface locations are at least 20 km away from the surface location of any well drilled into a recognized pool within the same formation;
- *Coalbed Gas Royalty Reduction and Credit Program* providing a royalty reduction for coalbed gas wells with average daily production less than 17,000 m³ as well as a royalty credit for coalbed gas wells equal to \$50,000 for wells drilled on Crown land and a tax credit equal to \$30,000 for wells drilled on freehold land;
- *Marginal Royalty Reduction Program* providing royalty breaks for low productivity natural gas wells with average monthly production under 25,000 m³ during the first 12 production months and average daily production less than 23 m³ for every metre of marginal well depth;
- *Ultra-Marginal Royalty Reduction Program* providing additional royalty breaks for low productivity shallow natural gas wells with a true vertical depth of less than 2,300 m, average monthly production under 60,000 m³ during the first 12 production months and average daily production less than 11.5 m³ (development wells) or 17 m³ (exploratory wildcat wells) for every 100 metres of marginal well depth;
- *Net Profit Royalty Reduction Program* providing reduced initial royalty rates to facilitate the development and commercialization of technically complex resources such as coalbed gas, tight gas, shale gas and enhanced-recovery projects, with higher royalty rates applied once capital costs have been recovered.

Oil produced from an oil well event on either Crown or freehold land and completed in a new pool discovery subsequent to June 30, 1974 may also be exempt from the payment of a royalty for the first 36 months of production or 11,450 m³ of production, whichever comes first.

On March 2, 2009, the Government of British Columbia announced the 2009 Infrastructure Royalty Credit Program (the "**Infrastructure Royalty Credit Program**") which allocates \$120 million in royalty credits for oil and gas companies. The Infrastructure Royalty Credit Program provides royalty credits for up to 50% of the cost of certain approved road construction or pipeline infrastructure projects intended to improve, or make possible, the access to new and underdeveloped oil and gas areas.

On August 6, 2009, the Government of British Columbia announced an oil and gas stimulus package designed to attract investment in and create economic benefits for British Columbia. The stimulus package includes four royalty initiatives related primarily to natural gas drilling and infrastructure development. Natural gas wells spudded within the 10-month period from September 1, 2009 to June 30, 2010 and brought on production by December 31, 2010 qualify for a 2% royalty rate for the first 12 months of production, beginning from the first month of production for the well (the "**Royalty Relief Program**"). British Columbia's existing Deep Royalty Credit Program was permanently amended for wells spudded after August 31, 2009 by increasing the royalty deduction on deep drilling for natural gas by 15% and extending the program to include horizontal wells drilled to depths of between 1,900 and 2,300 m. Wells spud between September 1, 2009 and June 30, 2010 may qualify for both the Royalty Relief

Program and the Deep Royalty Credit Program but will only receive the benefits of one program at a time. An additional \$50 million was also allocated to be distributed through the Infrastructure Royalty Credit Program to stimulate investment in oilfield-related road and pipeline construction.

Environmental Regulation

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

In December, 2008, the Government of Alberta released a new land use policy for surface land in Alberta, the Alberta Land Use Framework (the "**ALUF**"). The ALUF sets out an approach to manage public and private land use and natural resource development in a manner that is consistent with the long-term economic, environmental and social goals of the province. It calls for the development of region-specific land use plans in order to manage the combined impacts of existing and future land use within a specific region and the incorporation of a cumulative effects management approach into such plans. The *Alberta Land Stewardship Act* (the "**ALSA**") was proclaimed in force in Alberta on October 1, 2009, providing the legislative authority for the Government of Alberta to implement the policies contained in the ALUF. Regional plans established pursuant to the ALSA are deemed to be legislative instruments equivalent to regulations and are binding on the Government of Alberta and provincial regulators, including those governing the oil and gas industry. In the event of a conflict or inconsistency between a regional plan and another regulation, regulatory instrument or statutory consent, the regional plan will prevail. Further, the ALSA requires local governments, provincial departments, agencies and administrative bodies or tribunals to review their regulatory instruments and make any appropriate changes to ensure that they comply with an adopted regional plan. The ALSA also contemplates the amendment or extinguishment of previously issued statutory consents such as regulatory permits, licenses, approvals and authorizations in order for the purpose of achieving or maintaining an objective or policy resulting from the implementation of a regional plan. Among the measures to support the goals of the regional plans contained in the ALSA are conservation easements, which can be granted for the protection, conservation and enhancement of land; and conservation directives, which are explicit declarations contained in a regional plan to set aside specified lands in order to protect, conserve, manage and enhance the environment. Although no regional plans have been established under the ALSA, the planning process is underway for the Lower Athabasca Region (which contains the majority of oil sands development) and the South Saskatchewan Region. While the potential impact of the regional plans established under the ALSA cannot yet be determined, it is clear that such regional plans may have a significant impact on land use in Alberta and may affect the oil and gas industry.

Climate Change Regulation

Federal

In December 2002, the Government of Canada ratified the Kyoto Protocol ("**Kyoto Protocol**"), which requires a reduction in greenhouse gas emissions by signatory countries between 2008 and 2012. The Kyoto Protocol officially came into force on February 16, 2005 and commits Canada to reduce its greenhouse gas emissions levels to 6% below 1990 "business-as-usual" levels by 2012.

In anticipation of the expiry of the Kyoto Protocol in 2012, government leaders and representatives from approximately 170 countries met in Copenhagen, Denmark from December 6 to 18, 2009 (the "**Copenhagen Conference**") to attempt to negotiate a successor to the Kyoto Protocol. The primary result of the Copenhagen Conference was the Copenhagen Accord, which represents a broad political consensus rather than a binding international treaty like the Kyoto Protocol and has not been endorsed by all participating countries. The Copenhagen Accord reinforces the commitment to reducing GHG emissions contained in the Kyoto Protocol and promises funding to help developing countries mitigate and adapt to climate change. Although certain countries, including Canada, have committed to reducing their emissions individually or jointly by at least 80% by 2050, the

Copenhagen Accord does not establish binding GHG emissions reduction targets. The Copenhagen Accord calls for a review and implementation of its stated goals by 2016.

In response to the Copenhagen Accord, the Government of Canada has recently indicated that it will seek to achieve a 17% reduction in greenhouse gas emissions from 2005 levels by 2020. This goal is similar to the goal expressed in previous policy documents which are discussed below.

On February 14, 2007, the House of Commons passed Bill C-288, *An Act to ensure Canada meets its global climate change obligations under the Kyoto Protocol*. The resulting *Kyoto Protocol Implementation Act* came into force on June 22, 2007. Its stated purpose is to "ensure that Canada takes effective and timely action to meet its obligations under the Kyoto Protocol and help address the problem of global climate change." It requires the federal Minister of the Environment to, among other things, produce an annual climate change plan detailing the measures to be taken to ensure Canada meets its obligations under the Kyoto Protocol. It also authorizes the establishment of regulations respecting matters such as emissions limits, monitoring, trading and enforcement.

On April 26, 2007, the Government of Canada released "Turning the Corner: An Action Plan to Reduce Greenhouse Gases and Air Pollution" (the "**Action Plan**") which set forth a plan for regulations to address both greenhouse gases and air pollution. An update to the Action Plan, "Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions" was released on March 10, 2008 (the "**Updated Action Plan**"). Although draft regulations for the implementation of the Updated Action Plan were intended to be published in the fall of 2008 and become binding on January 1, 2010, no such regulations have been proposed to date. Further, representatives the Government of Canada have recently indicated that the proposals contained in the Updated Action Plan will be modified to ensure consistency with the direction ultimately taken by the United States with respect to greenhouse gas emissions regulation. The approach of the United States is expected to include an absolute cap on emissions combined with allowances to be used for compliance that may be partially auctioned off to regulated entities. It is also unclear whether the approach adopted by the United States will provide for the payment into a technology fund as a compliance mechanism, as is currently permitted in Alberta and by the Updated Action Plan. As a result, many provisions of the Updated Action Plan, described below, are expected to be significantly modified.

The stated goal of the Updated Action Plan, as currently drafted, is to reduce greenhouse gas emissions to 20% below 2006 levels by 2020 and 60-70% by 2050. As noted above, the goal has now been modified by the Government of Canada. The Updated Action Plan outlines emissions intensity-based targets which will be applied to regulated sectors on either a facility-specific, sector-wide or company-by-company basis. Facility-specific targets applied to the upstream oil and gas, oil sands, petroleum refining and natural gas pipelines sectors. Unless a minimum regulatory threshold applies, all facilities within a regulated sector will be subject to the emissions intensity targets.

The Updated Action Plan makes a distinction between "Existing Facilities" and "New Facilities". For Existing Facilities, the Updated Action Plan requires an emissions intensity reduction of 18% below 2006 levels by 2010 followed by a continuous annual emissions intensity improvement of 2%. "New Facilities" are defined as facilities beginning operations in 2004 and include both greenfield facilities and major facility expansions that (i) result in a 25% or greater increase in a facility's physical capacity, or (ii) involve significant changes to the processes of the facility. New Facilities will be given a 3-year grace period during which no emissions intensity reductions will be required. Targets requiring an annual 2% emissions intensity reduction will begin to apply in the fourth year of commercial operation of a New Facility. Further, emissions intensity targets for New Facilities will be based on a cleaner fuel standard to encourage continuous emissions intensity reductions over time. The method of applying this cleaner fuel standard has not yet been determined. In addition, the Updated Action Plan indicates that targets for the adoption of carbon capture and storage ("CCS") technologies will be developed for oil sands in-situ facilities, upgraders and coal-fired power generators that begin operations in 2012 or later. These targets will become operational in 2018, although the exact nature of the targets has not yet been determined.

Given the large number of small facilities within the upstream oil and gas and natural gas pipeline sectors, facilities within these sectors will only be subject to emissions intensity targets if they meet certain minimum emissions thresholds. That threshold will be (i) 50,000 tonnes of CO₂ equivalents per facility per year for natural gas pipelines; (ii) 3,000 tonnes of CO₂ equivalents per facility per year for the upstream oil and gas facility; and (iii) 10,000 boe/d/company. These regulatory thresholds are significantly lower than the regulatory threshold in force in

Alberta, discussed below. In all other sectors govern by the Updated Action Plan, all facilities will be subject to regulation.

Four separate compliance mechanisms are provided for in the Updated Action Plan in respect of the above targets: Technology Fund contributions, offset credits, clean development credits and credits for early action. Regulated entities will be able to use Technology Fund contributions to meet their emissions intensity targets. The contribution rate for Technology Fund contributions will increase over time, beginning at \$15 tonnes per CO₂ equivalent for the 2010-12 period, rising to \$20 in 2013, and thereafter increasing at the nominal rate of GDP growth. Maximum contribution limits will also decline from 70% in 2010 to 0% in 2018. Monies raised through contributions to the Technology Fund will be used to invest in technology to reduce greenhouse gas emissions. Alternatively, regulated entities may be able to receive credits for investing in large-scale and transformative projects at the same contribution rate and under similar requirements as described above.

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

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

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

Alberta

Alberta enacted the *Climate Change and Emissions Management Act* (the "**CCEMA**") on July 1, 2007, amending it through the *Climate Change and Emissions Management Amendment Act* which received royal assent on November 4, 2008. The CCEMA is based on an emissions intensity approach similar to the Updated Action Plan and aims for a 50% reduction from 1990 emissions relative to GDP by 2020.

Alberta facilities emitting more than 100,000 tonnes of greenhouse gases a year are subject to comply with the CCEMA. Similarly to the Updated Action Plan, the CCEMA and the associated *Specified Gas Emitters Regulation* make a distinction between "Existing Facilities" and "New Facilities". Existing Facilities are defined as facilities that completed their first year of commercial operation prior to January 1, 2008 or that have completed 8 or more years of commercial operation. Existing Facilities were required to reduce their emissions intensity by March 31, 2008 by 12% from a baseline established by their average emissions intensity between 2003 and 2005. New Facilities are defined as facilities that completed their first year of commercial operation subsequent to December 31, 2008, have completed less than 8 years of commercial operation, or are designated as New Facilities in accordance with the *Specified Gas Emitters Regulation*. New Facilities are also required to reduce their emissions intensity by 12% but this target is based on the emissions intensity of the facility in its third year of commercial operation and does not apply during the first 3 years of operation of the New Facility. Unlike the Updated Action Plan, the CCEMA does not contain any provision for continuous annual improvements beyond the 12% emissions intensity required.

The CCEMA contains similar compliance mechanisms as the Updated Action Plan. Regulated emitters can meet their emissions intensity targets by contributing to the Climate Change and Emissions Management Fund (the "**Fund**") at a rate of \$15 per tonne of CO₂ equivalent. Unlike the Updated Action Plan, CCEMA contains no provisions for an increase to this contribution rate. Emissions credits can be purchased from regulated emitters that have reduced their emissions below the 100,000 tonne threshold or non-regulated emitters that have generated

emissions offsets through activities that result in emissions reductions in accordance with established protocols published by the Government of Alberta. Unlike the Updated Action Plan, the CCEMA does not contemplate a linkage to external compliance mechanisms such as the Kyoto Protocol's Clean Development Mechanism.

British Columbia

In February, 2008, British Columbia announced a revenue-neutral carbon tax that took effect July 1, 2008. The tax is consumption-based and applied at the time of retail sale or consumption of virtually all fossil fuels purchased or used in British Columbia. The initial level of the tax was set at \$10 per tonne of CO₂ equivalent and rose to \$15 per tonne of CO₂ equivalent on July 1, 2009. It is scheduled to further increase at a rate of \$5 per tonne of CO₂ equivalent on July 1 of every year until it reaches \$30 per tonne of CO₂ equivalent on July 31, 2012. In order to make the tax revenue-neutral, British Columbia has implemented tax credits and reductions in order to offset the tax revenues that the Government of British Columbia would otherwise receive from the tax.

On April 3, 2008, British Columbia introduced the *Greenhouse Gas Reduction (Cap and Trade) Act* (the "**Cap and Trade Act**") which received royal assent on May 29, 2008 and will come into force by regulation of the Lieutenant Governor in Council. Unlike the emissions intensity approach taken by the federal government and the Government of Alberta, the Cap and Trade Act establishes an absolute cap on greenhouse gas emissions. It is expected that greenhouse gas emissions restrictions will be applied to facilities emitting more than 25,000 tonnes of CO₂ equivalents per year, which will be required to meet established targets through a combination of emissions allowances issued by the Government of British Columbia and the purchase of emissions offsets generated through activities that result in a reduction in greenhouse gas emissions. Although more specific details of British Columbia's cap and trade plan have not yet been finalized, on January 1, 2010, new reporting regulations will come into force requiring all British Columbia facilities emitting over 10,000 tonnes of CO₂ equivalents per year to begin reporting their emissions. Facilities reporting more than 25,000 tonnes of CO₂ equivalents per year are required to have their emissions reports verified by a third party.

RISK FACTORS

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

Exploration, Development and Production Risks

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

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

over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

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

Global Financial Crisis

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

Prices, Markets and Marketing

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

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

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

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

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The Corporation makes acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner as well as the Corporation's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Corporation. The integration of acquired business may require substantial management effort, time and resources and may divert management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of services provided and assets required to provide such services. In this regard, non-core assets are periodically disposed of, so that the Corporation can focus its efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain non-core assets of the Corporation, if disposed of, could be expected to realize less than their carrying value on the financial statements of the Corporation.

Operational Dependence

Other companies operate some of the assets in which the Corporation has an interest. As a result, the Corporation has limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect the Corporation's financial performance. The Corporation's return on assets operated by others therefore depends upon a number of factors that may be outside of the Corporation's control, including the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

Project Risks

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

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

- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

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

Competition

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

Regulatory

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

Environmental

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Corporation to incur costs to remedy such discharge. Although the Corporation believes that it will be in material compliance with current applicable environmental regulations, no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Climate Change

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". 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. Recently, representatives from approximately 170 countries met in Copenhagen, Denmark to attempt to negotiate a successor to the Kyoto Protocol. The result of such meeting was the

Copenhagen Accord, a non-binding political consensus rather than a binding international treaty such as the Kyoto Protocol. The Corporation's exploration and production facilities and other operations and activities emit greenhouse gases and require the Corporation to comply with Alberta's greenhouse gas emissions legislation contained in the *Climate Change and Emissions Management Act* and the *Specified Gas Emitters Regulation*. The Corporation will also be required to comply with the regulatory scheme for greenhouse gas emissions ultimately adopted by the federal government, which are now expected to be consistent with the regulatory scheme for greenhouse gas emissions adopted by the United States. The direct or indirect costs of these regulations may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The future implementation or modification of greenhouse gas regulations, whether to meet the limits required by the Kyoto Protocol, the Copenhagen Accord or as otherwise determined, could have a material impact on the nature of oil and natural gas operations, including those of the Corporation. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact on the Corporation and its operations and financial condition. See "Industry Conditions – Climate Change Regulation".

Variations in Foreign Exchange Rates and Interest Rates

World oil and gas prices are quoted in United States dollars and the price received by Canadian producers is therefore affected by the Canadian/U.S. dollar exchange rate, which will fluctuate over time. In recent years, the Canadian dollar has increased materially in value against the United States dollar. Material increases in the value of the Canadian dollar negatively impact the Corporation's production revenues. Future Canadian/United States exchange rates could accordingly impact the future value of the Corporation's reserves as determined by independent evaluators.

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

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

Substantial Capital Requirements

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

Additional Funding Requirements

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

Issuance of Debt

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

Hedging

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

Availability of Drilling Equipment and Access

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

Title to Assets

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

Reserve Estimates

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

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

same reserves based upon production history and production practices will result in variations in the estimated reserves and such variations could be material.

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

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

Insurance

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

Geo-Political Risks

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

In addition, the Corporation's oil and natural gas properties, wells and facilities could be subject to a terrorist attack. If any of the Corporation's properties, wells or facilities are the subject of terrorist attack it may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The Corporation will not have insurance to protect against the risk from terrorism.

Dilution

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

Management of Growth

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

Expiration of Licences and Leases

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

Dividends

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

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights to portions of western Canada. The Corporation is not aware that any claims have been made in respect of its properties and assets; however, if a claim arose and was successful such claim may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Seasonality

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

Third Party Credit Risk

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

Conflicts of Interest

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

Reliance on Key Personnel

The Corporation's success depends in large measure on certain key personnel. The loss of the services of such key personnel may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The Corporation does not have any key person insurance in effect for the Corporation. The contributions of the existing management team to the immediate and near term operations of the Corporation are

likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that the Corporation will be able to continue to attract and retain all personnel necessary for the development and operation of its business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the management of the Corporation.

ADDITIONAL INFORMATION

Additional information relating to us may be found on SEDAR at www.sedar.com. Additional information including remuneration of our directors and officers, principal holders of Common Shares and options to acquire Common Shares, will be contained in our Information Circular – Proxy Statement for our Annual Meeting of Shareholders to be held on May 20, 2010 and further information in respect of financial matters is provided in our Consolidated Financial Statements and Management's Discussion and Analysis for the years ended December 31, 2009 and 2008.

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

Midnight Oil Exploration Ltd.
Suite 2500, 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 OIL AND GAS DISCLOSURE

(FORM 51-101 F3)

Management of Midnight Oil Exploration Ltd. ("**Midnight**") is responsible for the preparation and disclosure of information with respect to Midnight's oil and natural gas activities in accordance with securities regulatory requirements. This information includes reserves data which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2009, estimated using forecast prices and costs.

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

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

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

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

- (a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information;
- (b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluator or auditor on the reserves data; and
- (c) the content and filing of this report.

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

(signed) "*Fred Woods*"

Fred Woods
President and Chief Executive Officer

(signed) "*Anthony Lambert*"

Anthony Lambert
Director and Chairman of the Reserves Committee

(signed) "*Dale Miller*"

Dale Miller
Vice President and Chief Operating Officer

(signed) "*Peter Harrison*"

Peter Harrison
Director and Member of the Reserves Committee

March 11, 2010

SCHEDULE B

REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

(FORM 51-101F2)

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

1. We have prepared an evaluation of the Company's reserves data as at December 31, 2009. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2009, estimated using forecast prices and costs.
2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "**COGE Handbook**") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.
4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2009, and identifies the respective portions thereof that we have evaluated and reported on to the Company's board of directors:

**Net Present Value of Future Net Revenue
(before income taxes, 10% discount rate - \$M)**

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 - \$M)			
			Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants	February 24, 2010	Canada	-	128,196	-	128,196

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook.
6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.
7. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material. However, any variation should be consistent with the fact that reserves are categorized according to the probability of their recovery.

Executed as to our report referred to above:

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

Calgary, Alberta, Canada, February 26, 2010

SCHEDULE C

MIDNIGHT OIL EXPLORATION LTD.

MANDATE AND TERMS OF REFERENCE OF THE AUDIT COMMITTEE

Role and Objective

The Audit Committee (the "**Committee**") is a committee of the board of directors (the "**Board**") of Midnight Oil Exploration Ltd. ("**Midnight**") to which the Board has delegated its responsibility for oversight of the nature and scope of the annual audit, management's reporting on internal accounting standards and practices, financial information and accounting systems and procedures, financial reporting and statements and recommending, for approval of the Board, the audited financial statements, interim financial statements and other mandatory disclosure releases containing financial information. The primary objectives of the Committee are as follows:

1. To assist directors on meeting their responsibilities in respect of the review and approval of the financial statements of Midnight and related documentation;
2. To provide a communication link between independent directors and external auditors;
3. To enhance the external auditor's independence;
4. To increase the credibility and objectivity of financial reports; and
5. To strengthen the role of the outside directors by facilitating in depth discussions between directors on the Committee, management and external auditors.

Membership of Committee

6. The Committee shall be comprised of at least three (3) directors of Midnight, none of whom are members of management of Midnight and all of whom are independent (as such term is used in Multilateral Instrument 52-110 — Audit Committees ("**MI 52-110**") unless the Board shall have determined that the exemption contained in Section 3.6 of MI 52-110 is available and has determined to rely thereon.
7. The Board shall appoint the Committee Chair, who shall be an independent director.
8. All of the members of the Committee shall be "financially literate" (as defined in MI 52-110) unless the Board shall determine that an exemption under MI 52-110 from such requirement in respect of any particular member is available and has determined to rely thereon in accordance with the provisions of MI 52-110.

Mandate and Responsibilities of Committee

9. The Committee shall provide oversight on the work of the external auditors, including resolution of disagreements between management and the external auditors regarding financial reporting.
10. The Committee shall satisfy itself on behalf of the Board with respect to Midnight's Internal Control Systems and its ability to:
 - identify, monitor and mitigate business risks; and
 - ensure compliance with legal, ethical and regulatory requirements.

11. The primary responsibility of the Committee is to review the annual and interim financial statements of Midnight and related management's discussion and analysis ("MD&A") prior to their submission to the Board for approval. The process should include but not be limited to:
- reviewing changes in accounting principles and policies, or in their application, which may have a material impact on the current or future years' financial statements;
 - reviewing significant accruals, reserves or other estimates such as the ceiling test calculation;
 - reviewing accounting treatment of unusual or non-recurring transactions;
 - reviewing disclosure requirements for commitments and contingencies;
 - reviewing adjustments raised by the external auditors, whether or not included in the financial statements;
 - reviewing unresolved differences between management and the external auditors; and
 - obtaining explanations of significant variances with comparative reporting periods.
12. The Committee is to review the financial statements, prospectuses, MD&A, annual information form ("AIF") and all public disclosure containing audited or unaudited financial information (including, without limitation, annual and interim press releases and any other press releases disclosing earnings or financial results) before release and prior to Board approval. The Committee must be satisfied that adequate procedures are in place for the review of Midnight's disclosure of all other financial information.
13. With respect to the appointment of external auditors by the Board, the Committee shall:
- recommend to the Board the external auditors to be nominated;
 - recommend to the Board the terms of engagement of the external auditor, including the compensation of the auditors and a confirmation that the external auditors shall report directly to the Committee;
 - on an annual basis, review and discuss with the external auditors all significant relationships such auditors have with the Corporation to determine the auditors' independence;
 - when there is to be a change in auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change; and
 - review and pre-approve any non-audit services to be provided to Midnight or its subsidiaries by the external auditors and consider the impact on the independence of such auditors. The Committee may delegate to one or more independent members the authority to pre-approve non-audit services, provided that the member report to the Committee at the next scheduled meeting such pre-approval and the member comply with such other procedures as may be established by the Committee from time to time.
14. Review with external auditors (and internal auditor if one is appointed by Midnight) their assessment of the internal controls of Midnight, their written reports containing recommendations for improvement, and management's response and follow-up to any identified weaknesses. The Committee shall also review annually with the external auditors their plan for their audit and, upon completion of the audit, their reports upon the financial statements of Midnight and its subsidiaries.

15. The Committee shall review risk management policies and procedures of Midnight (e.g. hedging, litigation and insurance).
16. The Committee shall establish a procedure for:
 - The receipt, retention and treatment of complaints received by Midnight regarding accounting, internal accounting controls or auditing matters; and
 - the confidential, anonymous submission by employees of Midnight of concerns regarding questionable accounting or auditing matters.
17. The Committee shall review and be apprised of any intent of Midnight regarding the hiring of partners and employees who work on Midnight's account and former partners and employees of the present and former external auditors of Midnight.
18. The Committee shall have the authority to investigate any financial activity of Midnight. All employees of Midnight are to cooperate as requested by the Committee.
19. The Committee may retain persons having special expertise and/or obtain independent professional advice to assist in fulfilling their responsibilities at the expense of Midnight without any further approval of the Board.

Meetings and Administrative Matters

20. At all meetings of the Committee every motion shall be decided by a majority of the votes cast. In case of an equality of votes, the Chair of the meeting shall not be entitled to a second or casting vote.
21. The Chair shall preside at all meetings of the Committee, unless the Chair is not present, in which case the members of the Committee present shall designate from among the members present the Chair for purposes of the meeting.
22. A quorum for meetings of the Committee shall be a majority of its members, and the rules for calling, holding, conducting and adjourning meetings of the Committee shall be the same as those governing the Board unless otherwise determined by the Board.
23. Meetings of the Committee should be scheduled to take place at least four times per year. Minutes of all meetings of the Committee shall be taken. The Chief Financial Officer shall attend meetings of the Committee, unless otherwise excused from all or part of any such meeting by the Chair.
24. The Committee shall meet with the external auditor at least once per year (in connection with the preparation of the year end financial statements) and at such other times as the external auditor and the Committee consider appropriate. At each of these meetings, the Committee will have an "in-camera" session with the external auditors.
25. Agendas, approved by the Chair, shall be circulated to Committee members along with background information on a timely basis prior to the Committee meetings.
26. The Committee may invite such officers, directors and employees of Midnight as it may see fit from time to time to attend at meetings of the Committee and assist thereat in the discussion and consideration of the matters being considered by the Committee.
27. Minutes of the Committee will be recorded and maintained and circulated to directors who are not members of the Committee or otherwise made available at a subsequent meeting of the Board.

28. The Committee may retain persons having special expertise and/or obtain independent professional advice to assist in fulfilling its responsibilities at the expense of Midnight.
29. Any members of the Committee may be removed or replaced at any time by the Board and shall cease to be a member of the Committee as soon as such member ceases to be a director. The Board may fill vacancies on the Committee by appointment from among its members. If and whenever a vacancy shall exist on the Committee, the remaining members may exercise all its powers so long as a quorum remains. Subject to the foregoing, each member of the Committee shall hold such office until the close of the next annual meeting of shareholders following appointment as a member of the Committee.
30. Any issues arising from these meetings that bear on the relationship between the Board and management should be communicated to the Chair of the Board by the Committee Chair.

Definitions – In this Charter:

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