2009 Annual Information Form

March 31, 2010

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GLOSSARY OF TERMS

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

Entities

Board of Directors means the board of directors of NuVista.

Bonavista means Bonavista Petroleum Ltd.

Bonavista Group means collectively Bonavista, Bonavista Oil & Gas Ltd. and Bonavista Partnership.

Bonavista Trust means Bonavista Energy Trust.

Bonavista Partnership means Bonavista Petroleum, a general partnership.

NuVista, **we**, **us, our** or the **Corporation** means NuVista Energy Ltd. and, where the context requires, all its controlled entities on a consolidated basis.

NuVista 2009 Partnership means NuVista 2009 Energy Partnership, a general partnership.

NuVista Partnership means NuVista Energy, a general partnership.

NuVista Resources means NuVista Resources Ltd.

NuVista Resources Partnership means NuVista Resources, a general partnership.

Rider means Rider Resources Ltd.

Shareholders means holders of our Common Shares.

Independent Engineering

COGE Handbook means Canadian Oil and Gas Evaluation Handbook.

CSA 51-324 means Staff Notice 51-324 – *Glossary to NI 51-101 Standards of Disclosure for Oil and Gas Activities* of the Canadian Securities Administrators.

GLJ means GLJ Petroleum Consultants Ltd., independent petroleum consultants of Calgary, Alberta.

GLJ Report means the report prepared by GLJ dated February 19, 2010 evaluating the crude oil, natural gas, natural gas liquids and sulphur reserves attributable to all of our oil and natural gas assets as at December 31, 2009.

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

Securities

Common Shares means our common shares, as presently constituted.

Performance Shares means our Class B performance shares, as presently constituted.

CONVENTIONS

Certain terms used herein are defined in the "*Glossary of Terms*". Certain other terms used herein but not defined herein are defined in NI 51-101 and CSA 51-324 and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101 and CSA 51-324. Unless otherwise indicated, references herein to "$" or "dollars" are to Canadian dollars. All financial information herein has been presented in Canadian dollars in accordance with generally accepted accounting principles in Canada. All operational information contained in this Annual Information Form relates to our consolidated operations unless the context otherwise requires.

ABBREVIATIONS

Oil and Natural Gas Liquids

Bbl	barrel
Bbls	barrels
Bbls/d	barrels per day
Mbbls	thousand barrels
MMbbls	million barrels
Mstb	thousand stock tank barrels of oil
NGLs	natural gas liquids

Natural Gas

Mcf	thousand cubic feet
MMcf	million cubic feet
Bcf	billion cubic feet
Mcf/d	thousand cubic feet per day
MMcf/d	million cubic feet per day
MMbtu	million British Thermal Units
GJ	Gigajoule

Other

AECO	the natural gas storage facility located at Suffield, Alberta, connected to TransCanada's Alberta System
API	American Petroleum Institute
°API	an indication of the specific gravity of crude oil measured on the API gravity scale
BOE or Boe	barrel or barrels of oil equivalent, using the conversion factor of 6 Mcf of natural gas being equivalent to one barrel of oil
Boe/d	barrels of oil equivalent per day
$Cdn	Canadian dollars
m^3	cubic metres
MBoe	thousand barrels of oil equivalent.
MMBoe	million barrels of oil equivalent
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for the crude oil standard grade
$000s	thousands of dollars
$MM	millions of dollars

CONVERSIONS

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

FORWARD-LOOKING INFORMATION AND STATEMENTS

This Annual Information Form, including documents incorporated by reference herein, contains forward-looking information and statements. These statements relate to our future events or our future performance. All information and statements other than statements of historical fact contained in this Annual Information Form are forward-looking information and statements. Such statements and information may be identified by looking for words such as "about", "approximately", "may", "believe", "expects", "will", "intends", "should", "plan", "budget", "predict", "potential", "projects", "anticipates", "forecasts", "estimates", "continues" or similar words or the negative thereof or other comparable terminology. In addition, there are forward-looking statements in this Annual Information Form under the headings: "*General Development of our Business – History and Development*" as to our future payment of dividends and the timing thereof and our plans to implement a dividend re-investment plan; "*General Development of Our Business – Recent Developments – Capital Program*" as to the funding of our planned 2010 capital program from our expected funds from operations; "*General Description of Our Business – Stated Business Objectives and Strategy*" as to our business plan; "*Statement of Reserves Data and Other Oil and Gas Information – Disclosure of Reserves Data*" as to our reserves and future net revenue from our reserves and pricing and inflation rates; "*Statement of Reserves Data and Other Oil and Gas Information – Additional Information Relating to Reserves Data*" as to the development of our proved undeveloped reserves and probable undeveloped reserves, future developments costs and our ability to fund future developments costs through cash flow, equity issuances and debt; "*Statement of Reserves Data and Other Oil and Gas Information – Other Oil and Natural Gas Information*" as to our exploration and development activities and opportunities, testing, drilling and completion plans and the results therefrom, anticipated treatment under government royalty regimes, anticipated production and operating costs, anticipated land expiries, hedging policies, reclamation and abandonment obligations and tax horizon; and "*Dividend Policy*" as to our dividend policy and the time of payment of future dividends, if any. 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. Forward-looking information and statements are based on the estimates and opinions of our management at the time the statements were made. In addition, forward-looking information and statements may include statements attributable to third party industry sources. There can be no assurance that the plans, intentions or expectations upon which such forward-looking information and statements are based will occur.

In addition to the forward-looking statements identified above, this Annual Information Form contains forward-looking statements pertaining to the following:

- the performance characteristics of our oil and natural gas properties;
- expectation of future production rates, volumes and product mixes;
- projected costs and plans and objectives;
- projections of market prices and trading liquidity;
- our expenditure capital program, the timing of expenditures and the sources of funding;
- our access to credit facilities, ability to raise capital and financial flexibility;
- interest and other funding costs;
- supply and demand for oil and natural gas;
- capital and income taxes;
- commodity prices;
- projected funds from operations and earnings and the components thereof; and
- expected royalty rates and the anticipated benefits of royalty incentive programs.

Statements relating to "reserves" or "resources" are also 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.

Forward-looking information and statements are subject to risks, uncertainties and assumptions, including those discussed below and elsewhere in this Annual Information Form. Although we believe that the expectations represented in such forward-looking information and statements are reasonable, there can be no assurance that such expectations will prove to be correct. Some of the risks which could affect future results and could cause results to differ materially from those expressed in the forward-looking information and statements contained herein include the following:

- volatility of commodity prices;
- liabilities inherent in oil and natural gas operations;
- imprecision of reserve and resource estimates;
- competition from other industry participants;
- the lack of availability of qualified personnel or management or oilfield services;
- incorrect assessments of the value of acquisitions;
- geological, technical, drilling and processing problems;
- fluctuation in foreign exchange or interest rates;
- stock market volatility;
- general economic and industry conditions;
- environmental risks;
- the inability to access sufficient capital from internal and external sources;
- governmental regulation, applicable royalty rates and tax laws; and
- the other factors discussed under "*Risk Factors*".

This Annual Information Form also contains test results for various wells. Actual production from these wells could differ materially from these test results.

You are further cautioned that the preparation of financial statements in accordance with generally accepted accounting principles in Canada requires management to make certain judgments and estimates that affect the reported amounts of assets, liabilities, revenues and expenses. Estimating reserves is also critical to several accounting estimates and requires judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change, having either a negative or positive effect on net earnings as further information becomes available, and as the economic environment changes. Information and statements relating to "reserves" or "resources" are deemed to be forward-looking information and statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and resources described exist in the quantities predicted or estimated, and that the reserves can be profitably produced in the future. **The information contained in this Annual Information Form, including the documents incorporated by reference herein, identifies additional factors that could affect our operating results and performance. We urge you to carefully consider those factors.**

The forward-looking information and statements contained herein are expressly qualified in their entirety by this cautionary statement. The forward-looking information and statements included in this Annual Information Form are made as of the date of this Annual Information Form and we undertake no obligation to publicly update such forward-looking information and statements to reflect new information, subsequent events or otherwise unless required by applicable securities laws.

BARREL OF OIL EQUIVALENCY

The term "Boe" or barrels of oil equivalent may be misleading, particularly if used in isolation. A Boe conversion ratio of six thousand cubic feet per barrel (6 Mcf: 1 Bbl) of natural gas to barrels of oil equivalence is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

NON-GAAP MEASURES

Within this Annual Information Form, references are made to terms commonly used in the oil and natural gas industry. Management uses funds from operations to analyze operating performance and leverage. Funds from operations as presented does not have any standardized meaning prescribed by generally accepted accounting principles in Canada and therefore it may not be comparable with the calculation of similar measures for other entities. Funds from operations as presented is not intended to represent operating cash flow or operating profits for the period nor should it be viewed as an alternative to cash flow from operating activities, net income or other measures of financial performance calculated in accordance with generally accepted accounting principles in Canada.

For more information, see our "*Management's Discussion and Analysis*" for the year ended December 31, 2009, which includes a reconciliation of "funds from operations" to cash provided by operating activities, which has been filed on SEDAR at *www.sedar.com*.

NUVISTA ENERGY LTD.

General

We are an intermediate oil and natural gas company engaged in the exploration for, and the acquisition, development and production of oil and natural gas reserves in the Provinces of Alberta, British Columbia and Saskatchewan.

We were incorporated under the *Business Corporations* Act (Alberta) as 1040491 Alberta Ltd. on April 7, 2003. On May 20, 2003, we changed our name to "NuVista Energy Ltd.". On June 24, 2003, we amended our Articles to create our Performance Shares and removed the private company restrictions. On January 1, 2009, we amalgamated with Rider and thereafter amalgamated with Roberts Bay Resources Ltd., another of our wholly-owned subsidiaries.

We were originally formed as part of a plan of arrangement involving Bonavista, which resulted in the shareholders of Bonavista receiving one of our Common Shares for each common share of Bonavista held. Pursuant to this plan of arrangement, we acquired approximately 10% of the oil and natural gas properties of Bonavista, with the balance of the properties of Bonavista being acquired by Bonavista Trust.

Our head office is located at Suite 3500, 700 – 2nd Street S.W., Calgary, Alberta, T2P 2W2, and our registered office is located at Suite 1400, 350 – 7th Avenue S.W. Calgary, Alberta, T2P 3N9.

Inter-Corporate Relationships

The following table provides the name, the percentage of voting securities owned by us and the jurisdiction of incorporation, continuance or formation of our subsidiaries and partnerships either, direct and indirect, as at the date hereof.

	Percentage of voting securities (directly or indirectly)	**Nature of Entity**	**Jurisdiction of Incorporation/ Formation**
NuVista Partnership	75.78% (1)(2)	General Partnership	Alberta
NuVista Resources Partnership	75.79% (3)	General Partnership	Alberta
NuVista Resources	100%	Corporation	Alberta
NuVista 2009 Partnership	100%	General Partnership	Alberta
1364364 Alberta Ltd.	100%	Corporation	Alberta

Notes:

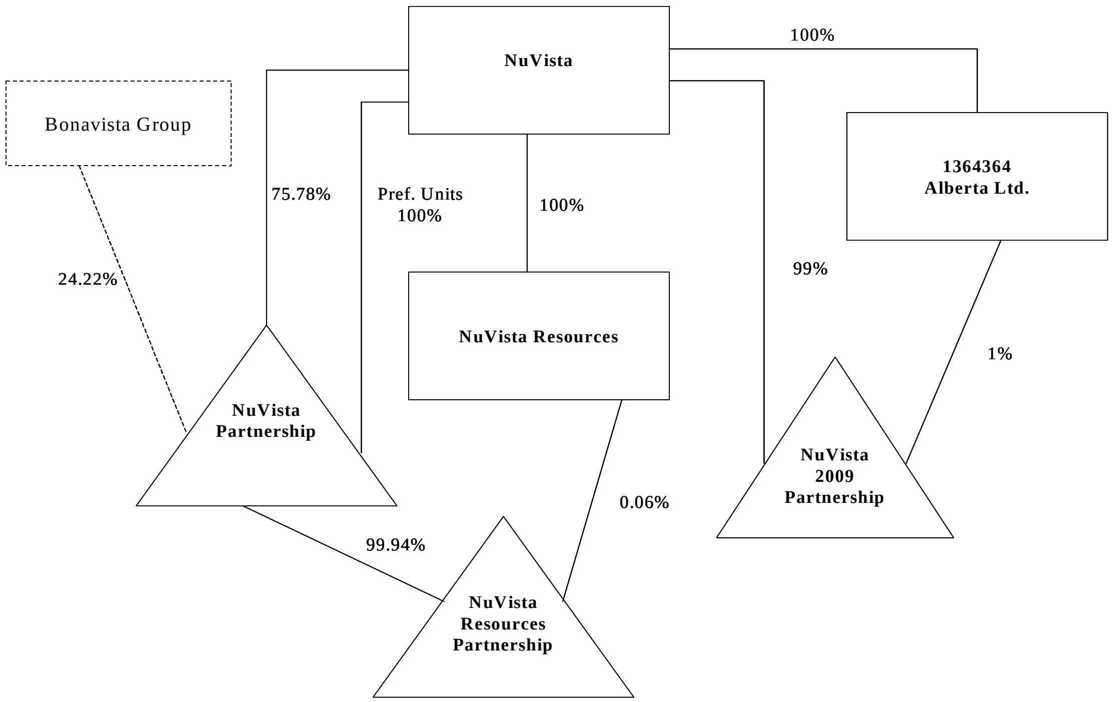
(1) As part of a plan of arrangement completed on July 2, 2003, all of Bonavista's eastern Alberta developed assets were conveyed to NuVista Partnership. We are the managing partner of the NuVista Partnership and the other partner is the Bonavista Group.

(2) As at December 31, 2009 and the date hereof, our general partnership interest in NuVista Partnership was 75.78%. The Bonavista Group holds the remaining 24.22%. We also own 100% of the non-voting preferred units. The preferred units in NuVista Partnership relate to certain producing assets contributed by us. The preferred units are allocated 100% of the economic and financial results of the assets contributed to NuVista Partnership.

(3) As at December 31, 2009 and the date hereof, NuVista Resources Partnership was owned 99.94% by NuVista Partnership and 0.06% by NuVista Resources resulting in our indirect ownership being 75.79%.

Our Organizational Structure

The following diagram describes the inter-corporate relationships among us and our material subsidiaries as of the date hereof:



GENERAL DEVELOPMENT OF OUR BUSINESS

History and Development

On July 2, 2003, we completed a plan of arrangement with Bonavista pursuant to which we acquired certain assets of Bonavista and our Common Shares were distributed to the former holders of common shares of Bonavista. Since the completion of the plan of arrangement on July 2, 2003, we have grown our business through a combination of exploration, development and optimization of our assets as well as the completion of a number of strategic acquisitions in western Canada.

On June 1, 2006, we completed the acquisition of certain natural gas properties in west central and northwest Saskatchewan. The acquisition was completed through a series of transactions, for a net acquisition cost, paid in cash, of approximately $82 million. With this acquisition we established a new operating area in west central Saskatchewan and increased our dominance in our northwest Saskatchewan operating area. The acquisition included natural gas production of approximately 13.3 MMcf/d (2,200 Boe/d). The assets acquired also included approximately 106,000 net acres of undeveloped lands. The acquisition was funded with bank debt.

On April 2, 2007, we completed the acquisition of certain natural gas properties located in our Kaybob/Waskahigan operating area. The acquisition cost, paid in cash, for these assets was approximately $34 million. Production from the acquired properties was approximately 800 Boe/d, with an 85% natural gas weighting.

On April 20, 2007 we completed an equity issue of 2,750,000 Common Shares on a bought deal basis at a price of $14.50 per share. The net proceeds of the offering were used to fund our ongoing capital program and for general corporate purposes.

On January 8, 2008, we closed the acquisition of certain oil properties located primarily in our Provost operating area, in close proximity to our existing Chauvin properties. The acquisition cost, paid in cash, for these assets was approximately $24.5 million. At the time of purchase, production from the acquired properties was approximately 650 Bbls/d of 23° API oil.

On March 4, 2008, we completed a plan of arrangement pursuant to which we acquired Rider on the basis of 0.3540 of a Common Share for each common share of Rider resulting in the issuance of approximately 19.8 million Common Shares. As a result of the arrangement with Rider, we acquired four new operating areas in liquids-rich natural gas prone regions of Alberta, characterized by high netbacks and long reserve life production and a high impact deep gas drilling inventory to our exploration and development program. We acquired approximately 11,500 Boe/d of production (approximately 77% natural gas) and approximately 33 million Boe of proved plus probable reserves (calculated as at December 31, 2007 and based upon our management's pro forma estimates) from Rider. We also acquired over 155,000 net acres of undeveloped land with an average working interest of approximately 77% and with 75 identified drilling locations. Mr. Craig W. Stewart, the former President and Chief Executive Officer of Rider, joined our Board of Directors upon the closing of the transaction.

Concurrently with the Rider acquisition, we also completed a private placement with the Ontario Teachers' Pension Plan pursuant to which they subscribed for 6.0 million units at a price of $14.00 per unit for proceeds of $84.0 million. Each unit was comprised of one Common Share and one-half of one common share purchase warrant. Each full warrant entitled the holder to purchase one Common Share for an exercise price of $15.50 on or before March 4, 2009, subject to the usual adjustment provisions. None of the warrants were exercised prior to their expiry on March 4, 2009. The proceeds of the private placement were used to reduce our aggregate outstanding indebtedness following completion of the arrangement with Rider.

On January 29, 2009, we completed the acquisition of 1,600 Boe/d of production, primarily in our Ferrier/Sunchild, Wapiti and Northwest Saskatchewan operating areas for approximately $55 million which was funded by cash flow from operations and bank debt. Total proved plus probable reserves acquired, based on management's internal estimates effective as of December 31, 2008, were 4.5 million Boe.

On June 15, 2009, we entered into an agreement to acquire certain properties located in the Martin Creek area of northeast British Columbia and in northwest Alberta for cash consideration of approximately $174 million. We closed the acquisition on July 27, 2009. The purchase price for the acquisition was funded through a combination of bank debt and the net proceeds from a public offering of 7,500,000 subscription receipts at a price of $11.00 per subscription receipt for gross proceeds of $82.5 million and a private placement to Ontario Teachers' Pension Plan of 1,500,000 subscription receipts at a price of $11.00 per subscription receipt for gross proceeds of $16.5 million. Upon completion of the acquisition, each subscription receipt was exchanged for one of our common shares for no additional consideration or further action. The acquisition is consistent with our strategy of acquiring assets with high working interests, operatorship, infrastructure and undeveloped land at times when commodity prices are at their cyclical lows. At the time of closing, the properties acquired were producing approximately 5,900 Boe/d with an 82% natural gas weighting. The majority of the liquids production was light oil production from Keg River pools in northwest Alberta. Approximately 96% of the production was operated with an average working interest of 77%. Included in the acquisition was approximately 140,000 net acres of undeveloped land with an average working interest of 71% with over 30 identified drilling opportunities.

Concurrent with the closing of the Martin Creek acquisition, our credit facility was increased from $450 million to $510 million. In November of 2009, we completed the semi-annual review of our borrowing base with our lenders. Our lenders approved a request for a credit facility totalling $510 million, comprised of a $480 million extendible revolving facility and a $30 million non-extendible, non-revolving acquisition facility. The acquisition facility is available subject to the approval of the lenders. The annual renewal date of our credit facility is April 30, 2010.

On November 12, 2009, Craig W. Stewart, who joined our Board of Directors upon the completion of our business combination with Rider, resigned as a director in order to pursue other business opportunities.

On March 8, 2010, our Board of Directors declared a quarterly dividend of $0.05 per Common Share. The first dividend payment will be on April 15, 2010, payable in cash to shareholders of record on March 31, 2010. We also expect to implement a dividend re-investment plan for Canadian Shareholders in the coming months, subject to regulatory approval.

Recent Developments

Capital Program

We anticipate that funds from operations will provide the flexibility to fund our planned 2010 capital program. In this period of low natural gas prices and continuing economic uncertainty, we will continue to diligently maintain our financial flexibility. At this time, we are forecasting capital spending for the first half of 2010 to be less than our forecast funds from operations. For the last half of 2010, we expect capital expenditures to approximate forecast funds from operations.

Significant Acquisitions

The completion of the Martin Creek acquisition on July 27, 2009 constituted a significant acquisition under Part 8 of National Instrument 51-102 - *Continuous Disclosure Obligations*. We filed a business acquisition report for the Martin Creek acquisition on SEDAR on October 8, 2009.

GENERAL DESCRIPTION OF OUR BUSINESS

Stated Business Objectives and Strategy

Our business plan is to deliver profitable growth to our Shareholders over the long term under varying business conditions. We employ an acquire and develop business model that currently includes operations in three core regions consisting of nine operating areas. We pursue strategic acquisitions that will result in a new core area or synergistic acquisitions that complement our properties in existing core regions. Once a property has been acquired, we pursue optimization and ongoing development and exploration opportunities. Our asset base provides the flexibility to pursue shallow natural gas, deep natural gas, light oil and heavy oil targets, both through exploration and development activities and acquisitions.

We apply our technical and operating expertise within our core regions with a disciplined approach based on seven principles:

- focus on operating areas, establish technical expertise in these areas;
- operate our production;
- hold a high working interest;
- attract and retain a talented team;
- maintain a low cost structure;
- control our business plan and be opportunity driven; and
- use strategic alliances to maintain financial flexibility.

We pursue strategic acquisition opportunities that would permit us to form a new core region or operating area in which to lever our expertise. Every opportunity, however, must be carefully evaluated to ensure it complements our defined business strategy. Ideally, each potential acquisition must offer us the opportunity to acquire undeveloped land and seismic, as well as a high working interest ownership and operatorship, in an area where infrastructure is underutilized and further optimization and development opportunities exist.

We are also looking for synergistic acquisitions in our existing operating areas. These types of acquisitions enable us to solidify our position in areas where we have technical expertise and reinforce barriers to competition that could affect the profitability of our projects.

We have created a team based organization in which operational and technical excellence and idea generation are encouraged. Each of our operating areas has a multi-disciplined team that is self-motivated and empowered to develop their ideas. They are all rewarded with an ownership stake in us, closely aligning their interests with those of our Shareholders. Together, they concentrate their efforts in our operating areas, where we can achieve a dominant land position, operate and control infrastructure, and therefore manage costs, as well as discourage encroachment by competitors. By focusing in an operating area, our team become experts in identifying opportunities. Over time, this intimate knowledge enables us to extract maximum value from the asset. Our goal is to operate with a high working-interest ownership. This enables us to control the pace of development, minimize costs and cycle times between ideas and cash flow, and allows us to accurately forecast the timing and magnitude of our efforts.

We continue to enforce stringent cost controls to maintain our financial flexibility throughout the commodity price cycles. We believe that stewardship of our capital spending over the long-term is the single biggest factor in our ability to grow profitably. We know that financial flexibility can enable a company to capitalize on the inevitable acquisition opportunities that occur at the bottom of the commodity price cycle. We are well positioned to capture these opportunities, if and when they arise.

We have successfully transitioned from a junior exploration and production company with a focus on shallow gas in eastern Alberta to a strong intermediate company with a focus on longer-life assets containing growth opportunities in the Deep Basin of central Alberta and northeast British Columbia. Our production has grown from 3,500 Boe/d in 2003 to approximately 29,000 Boe/d today. In 2010, we will be pursuing several scalable natural gas and oil resource plays that if successful could have a significant impact on our future growth.

Cyclical and Seasonal Impact of Industry

Our operational results and financial condition will be dependent on the prices received for oil and natural gas production. Oil and natural gas prices have fluctuated widely during recent years and are determined by supply and demand factors, including weather and general economic conditions, as well as conditions in other oil and natural gas regions. Any decline in oil and natural gas prices could have an adverse effect on our financial condition. We mitigate such price risk through closely monitoring the various commodity markets and establishing price risk management programs, as deemed necessary and through maintaining financial flexibility. See "*Risk Factors – Prices, Markets and Marketing*" and "*Risk Factors – Hedging*".

Environment Policies

We are committed to managing and operating in a safe, efficient, environmentally responsible manner in association with our industry partners and are committed to continually improving our environmental, health, safety and social performance.

Renegotiation or Termination of Contracts

As at the date hereof, we do not anticipate that any aspect of our business will be materially affected in the remainder of 2010 by the renegotiation or termination of contracts or subcontracts other than with respect to our credit facility which has an annual renewal date of April 30, 2010. See "*Risk Factors – Refinancing Risk and Increased Debt Service Charges*".

Competitive Conditions

We are a member of the petroleum industry, which is highly competitive at all levels. We compete with other companies for all of our business inputs, including exploration and development prospects, access to commodity markets, acquisition opportunities, available capital and staffing. See "*Risk Factors – Competition*".

We strive to be competitive by maintaining financial flexibility and by utilizing current technologies to enhance optimization, development and operational activities.

Human Resources

At December 31, 2009, we employed 132 full-time employees, including 105 office and 27 field employees.

STATEMENT OF RESERVES DATA AND OTHER OIL AND NATURAL GAS INFORMATION

The statement of reserves data and other oil and natural gas information set forth below is dated February 19, 2010. The statement is effective as of December 31, 2009 and the preparation date of the statement is February 16, 2010. 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 in Form 51-101F2 are attached as Appendices A and B to this Annual Information Form.

Disclosure of Reserves Data

The reserves data set forth below is based upon an evaluation by GLJ with an effective date of December 31, 2009 as contained in the GLJ Report. The reserves data summarizes our crude oil, natural gas liquids and natural gas reserves and the net present values of future net revenue for these reserves using forecast prices and costs, not including the impact of any price risk management activities. The GLJ Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101 and CSA 51-324. We engaged GLJ to provide an evaluation of our 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, British Columbia and Saskatchewan.

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. Readers should review the definitions and information contained in "*Definitions and Notes to Reserves Data Tables*" below in conjunction with the following tables and notes. The recovery and reserve estimates on our properties described herein are estimates only. The actual reserves on our properties may be greater or less than those calculated. See "*Risk Factors*".

Reserves Data (Forecast Prices and Costs)

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

	RESERVES							
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS		NATURAL GAS LIQUIDS	
RESERVES CATEGORY	Gross (Mbbls)	Net (Mbbls)	Gross (Mbbls)	Net (Mbbls)	Gross (MMcf)	Net (MMcf)	Gross (Mbbls)	Net (Mbbls)
PROVED:								
Developed Producing	2,658	2,192	5,059	4,596	244,086	207,185	5,898	4,156
Developed Non-Producing	288	231	494	431	32,123	26,448	949	686
Undeveloped	312	253	752	690	28,403	24,889	665	522
TOTAL PROVED	3,257	2,676	6,306	5,716	304,611	258,522	7,513	5,364
PROBABLE	1,775	1,329	2,230	1,987	133,308	112,206	3,562	2,505
TOTAL PROVED PLUS PROBABLE	5,033	4,005	8,536	7,703	437,919	370,728	11,075	7,869

RESERVES CATEGORY	NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAXES DISCOUNTED AT (%/year) 0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)	UNIT VALUE BEFORE INCOME TAXES DISCOUNTED AT 10%(1) ($/Bbl)	($/Mcf)
PROVED:							
Developed Producing	1,547,521	1,197,530	988,310	848,526	748,106	21.73	3.62
Developed Non-Producing	202,007	138,957	107,525	88,218	74,920	18.68	3.11
Undeveloped	171,712	132,657	105,373	85,755	71,147	18.77	3.13
TOTAL PROVED	1,921,239	1,469,144	1,201,209	1,022,499	894,172	21.13	3.52
PROBABLE	964,902	565,996	384,789	284,218	221,285	15.69	2.62
TOTAL PROVED PLUS PROBABLE	2,886,142	2,035,139	1,585,998	1,306,716	1,115,457	19.49	3.25

Note:
(1) Unit values are based on net reserve volumes.

RESERVES CATEGORY	NET PRESENT VALUES OF FUTURE NET REVENUE AFTER INCOME TAXES DISCOUNTED AT (%/year) 0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)
PROVED:					
Developed Producing	1,358,243	1,050,393	867,297	745,124	657,339
Developed Non-Producing	150,490	102,277	78,309	63,591	53,459
Undeveloped	127,290	96,510	75,012	59,602	48,175
TOTAL PROVED	1,636,024	1,249,180	1,020,617	868,317	758,972
PROBABLE	720,413	420,063	283,519	207,664	160,179
TOTAL PROVED PLUS PROBABLE	2,356,437	1,669,244	1,304,137	1,075,980	919,152

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2009
FORECAST PRICES AND COSTS (1)(2)

RESERVES CATEGORY	REVENUE ($000s)	ROYALTIES ($000s)	OPERATING COSTS ($000s)	DEVELOPMENT COSTS ($000s)	ABANDONMENT AND RECLAMATION COSTS ($000s)	FUTURE NET REVENUE BEFORE INCOME TAXES ($000s)	INCOME TAXES ($000s)	FUTURE NET REVENUE AFTER INCOME TAXES ($000s)
Total Proved	3,718,940	580,088	1,072,474	93,326	51,813	1,921,239	285,215	1,636,024
Total Proved plus Probable	5,637,412	906,303	1,620,263	163,589	61,115	2,886,142	529,705	2,356,437

Notes:
(1) Total revenue includes company revenue before royalty and includes other income.
(2) Royalties include Crown, freehold and overriding royalties and mineral tax.

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) ($000s)	UNIT VALUE (1)	
			($/Bbl)	($/Mcf)
Proved	Light and Medium Crude Oil (including solution gas and other by-products)	90,004	27.58	4.60
	Heavy Oil (including solution gas and other by-products)	200,201	35.08	5.85
	Natural Gas (including by-products but excluding natural gas from oil wells)	911,004	19.03	3.17
	Total	1,201,209	21.13	3.52
Proved plus Probable	Light and Medium Crude Oil (including solution gas and other by-products)	126,852	25.75	4.29
	Heavy Oil (including solution gas and other by-products)	253,598	33.23	5.54
	Natural Gas (including by-products but excluding natural gas from oil wells)	1,205,547	17.52	2.92
	Total	1,585,998	19.49	3.25

Notes:
(1) Unit values are based on net reserve volumes.

Definitions and Notes to Reserves Data Tables

In the tables set forth above in "*Reserves Data (Forecast Prices and Costs)*" and elsewhere in this Annual Information Form the following definitions and other notes are applicable:

1. "Gross" means:

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

   (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.

2. "Net" means:

   (a) in relation to our interest in production and reserves, our interest (operating and non-operating) share after deduction of royalty obligations, plus our royalty interest 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 our working interest.

3. Definitions used for reserve categories are as follows:

Reserve Categories

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

(a) analysis of drilling, geological, geophysical and engineering data;

(b) the use of established technology; and

(c) specified economic conditions (see the discussion of "*Economic Assumptions*" below).

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

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

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

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

Development and Production Status

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

(a) Developed reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

  (i) Developed producing reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

  (ii) Developed non-producing reserves are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

(b) Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned.

Levels of Certainty for Reported Reserves

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

(a) at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and

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

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

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

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, pumping equipment and wellhead assembly;

(b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and wellhead assembly;

(c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and

(d) provide improved recovery systems.

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

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 and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies;

(b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence, and the maintenance of land and lease records;

(c) dry hole contributions and bottom hole contributions;

(d) costs of drilling and equipping exploratory wells; and

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

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. "Forecast Prices and Costs"

These are 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 NuVista is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

10. On March 11, 2010 the Alberta Government announced changes to Alberta's royalty system intended to increase Alberta's competitiveness in the oil and natural gas industry, which included a decrease in the maximum royalty rates for conventional oil and natural gas production effective for the January 2011 production month and certain temporary incentive programs currently in place being made permanent. See "*Industry Conditions*". Further details with respect to the changes to Alberta's royalty system are expected to be provided in the coming months. Reserves and net present values reflected in the above tables do not reflect the potential effect of these new changes to Alberta's royalty system and no sensitivities were provided by GLJ as to the potential impact of same.

11. Numbers may not add due to rounding.

12. The estimates of future net revenue presented in the tables above do not represent fair market value.

13. We do not have any synthetic oil or other products from non-conventional oil and gas activities.

Pricing Assumptions

The forecast cost and price assumptions in this statement assume primarily increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. Crude oil and natural gas benchmark reference pricing, inflation and exchange rates utilized in the GLJ Report were as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
FORECAST PRICES AND COSTS (1)

	OIL				NATURAL GAS	NATURAL GAS LIQUIDS	NATURAL GAS LIQUIDS		
Year	WTI Cushing Oklahoma ($US/Bbl)	Edmonton Par Price 40° API ($Cdn/ Bbl)	Hardisty Heavy 12° API ($Cdn/ Bbl)	Cromer Medium 29. 3° API ($Cdn/ Bbl)	AECO Gas Price ($Cdn/ MMbtu)	Edmonton Propane ($Cdn/Bbl)	Edmonton Butane ($Cdn/Bbl)	INFLATION RATES %/Year (2)	EXCHANGE RATE ($US/$Cdn)(3)
Forecast									
2010	80.00	83.26	64.99	76.60	5.96	52.46	64.11	2.0	0.95
2011	83.00	86.42	65.24	78.64	6.79	54.45	66.54	2.0	0.95
2012	86.00	89.58	65.33	80.62	6.89	56.43	68.98	2.0	0.95
2013	89.00	92.74	65.26	82.54	6.95	58.42	71.41	2.0	0.95
2014	92.00	95.90	67.52	85.35	7.05	60.42	73.84	2.0	0.95
2015	93.84	97.84	68.90	87.07	7.16	61.64	75.33	2.0	0.95
2016	95.72	99.81	70.32	88.83	7.42	62.88	76.85	2.0	0.95
2017	97.64	101.83	71.76	90.63	7.95	64.15	78.41	2.0	0.95
2018	99.59	103.88	73.22	92.46	8.52	65.45	79.99	2.0	0.95
2019	101.58	105.98	74.72	94.32	8.69	66.77	81.60	2.0	0.95
2020	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	2.0	0.95

Notes:
(1) As at January 1, 2010.
(2) Inflation rate for costs.
(3) Exchange rate used to generate the benchmark reference prices in this table.

Weighted average historical prices realized by us for the year ended December 31, 2009, including price risk management activities were $4.94/Mcf for natural gas, $73.32/Bbl for light and medium oil, $60.58/Bbl for heavy oil and $38.58/Bbl for NGLs. All price risk management activities are reflected in the realized light and medium oil price.

Reserves Reconciliation

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

	LIGHT AND MEDIUM OIL			HEAVY OIL		
	Gross Proved (Mbbls)	Gross Probable (Mbbls)	Gross Proved Plus Probable (Mbbls)	Gross Proved (Mbbls)	Gross Probable (Mbbls)	Gross Proved Plus Probable (Mbbls)
December 31, 2008	3,522	1,519	5,040	5,121	2,079	7,200
Discoveries	-	-	-	-	-	-
Extensions	51	22	73	77	(14)	63
Infill Drilling	15	5	20	561	148	709
Improved Recovery	-	-	-	-	-	-
Technical Revisions	(1,338)	(548)	(1,886)	1,234	(117)	1,117
Acquisitions	1,880	904	2,784	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	(466)	(126)	(592)	481	135	616
Production	(406)	-	(406)	(1,169)	-	(1,169)
December 31, 2009	3,257	1,775	5,033	6,306	2,230	8,536

	ASSOCIATED AND NON-ASSOCIATED GAS			NATURAL GAS LIQUIDS		
	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)	Proved (Mbbls)	Probable (Mbbls)	Proved Plus Probable (Mbbls)
December 31, 2008	229,555	110,099	339,653	5,805	2,851	8,656
Discoveries	-	-	-	-	-	-
Extensions	14,193	4,745	18,938	589	254	842
Infill Drilling	9,450	3,909	13,359	248	109	357
Improved Recovery	2,702	1,502	4,204	111	67	179
Technical Revisions	2,594	(12,157)	(9,562)	560	(82)	478
Acquisitions	90,179	25,578	115,757	1,384	364	1,747
Dispositions	-	-	-	-	-	-
Economic Factors	(1,646)	(369)	(2,015)	(21)	(1)	(22)
Production	(42,415)	-	(42,415)	(1,162)	-	(1,162)
December 31, 2009	304,611	133,308	437,919	7,513	3,562	11,075

Additional Information Relating to Reserves Data

Undeveloped Reserves

Undeveloped reserves are attributed by GLJ in accordance with standards and procedures contained in the COGE Handbook. Proved undeveloped reserves are those reserves that can be estimated with a high degree of certainty and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Probable undeveloped reserves are those reserves that are less certain to be recovered than proved reserves and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production.

In some cases, it will take longer than two years to develop these reserves. We plan to develop approximately 95% of the proved undeveloped reserves in the GLJ Report over the next two years and the significant majority of the probable undeveloped reserves over the next five years. There are a number of factors that could result in delayed or cancelled development, including the following: (i) changing economic conditions (due to pricing, operating and capital expenditure fluctuations); (ii) changing technical conditions (including production anomalies, such as water breakthrough or accelerated depletion); (iii) multi-zone developments (for instance, a prospective formation completion may be delayed until the initial completion is no longer economic); (iv) a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and (v) surface access issues (including those relating to land owners, weather conditions and regulatory approvals). For more information, see "*Risk Factors*".

Proved Undeveloped Reserves

The following table discloses, for each product type, the volumes of proved undeveloped reserves that were attributed in each of the most recent three financial years and, in the aggregate, before that time:

Year	Light and Medium Oil (Mbbls)		Heavy Oil (Mbbls)		Natural Gas (MMcf)		NGLs (Mbbls)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
Prior	-	-	29	29	81	81	2	2
2007	-	-	54	83	1,061	1,142	2	4
2008	-	-	-	83	2,979	4,121	45	49
2009	303	312	666	752	22,846	28,403	608	665

GLJ has assigned 6.5 MMboe of proved undeveloped reserves in the GLJ Report under forecast prices and costs, together with $59.6 million of associated undiscounted future capital expenditures to be spent in the first two forecast years. The majority of our proved undeveloped reserves evaluated in the GLJ Report are attributable to the Kaybob, Rainbow and Wapiti properties.

Probable Undeveloped Reserves

The following table discloses, for each product type, the volumes of probable undeveloped reserves that were first attributed in each of the most recent three financial years and, in the aggregate, before that time:

Year	Light and Medium Oil (Mbbls)		Heavy Oil (Mbbls)		Natural Gas (MMcf)		NGLs (Mbbls)	
	First Attributed	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**
Prior	-	-	47	47	869	869	2	2
2007	-	-	23	70	2,352	3,221	46	48
2008	181	181	25	95	10,972	14,193	233	281
2009	530	711	300	397	21,699	37,746	640	955

GLJ has assigned 8.4 MMboe of probable undeveloped reserves in the GLJ Report under forecast prices and costs, and $56.5 million in undiscounted future capital attributed to probable undeveloped reserves scheduled for the first five years.

Significant Factors or Uncertainties

We do not anticipate any significant economic factors or significant uncertainties will affect any particular components of our reserves data. However, our reserves can be affected significantly by fluctuations in product pricing, capital expenditures, operating costs, royalty regimes and well performance that are beyond our control. See "*Risk Factors*".

Future Development Costs

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

	FORECAST PRICES AND COSTS	
Year	**Proved Reserves ($000s)**	**Proved Plus Probable Reserves ($000s)**
2010	53,971	84,972
2011	27,492	51,390
2012	3,977	10,260
2013	71	192
2014	1,218	1,815
Remaining	6,597	14,960
Total (Undiscounted)	93,326	163,589

We expect to fund the development costs of our reserves through a combination of internally generated cash flow, debt and equity issuances. There can be no guarantee that funds will be available or that our Board of Directors will allocate funding to develop all of the reserves attributed in the GLJ Report. Failure to develop those reserves could have a negative impact on our future cash flow.

The interest or other costs of external funding are not included in our reserves and future net revenue estimates and would reduce reserves and future net revenue to some degree depending upon the funding sources utilized. We do not anticipate that interest or other funding costs would make development of any of our properties uneconomic.

Other Oil and Natural Gas Information

Principal Oil and Natural Gas Properties

The following is a description of our principal oil and natural gas properties on production or under development as at December 31, 2009. Information in respect of current production is average production, net to our working interest, except where otherwise indicated.

Alberta Deep Basin Core Region

Wapiti

Wapiti, our largest operating area is located south of Grande Prairie, Alberta, approximately 520 kilometres northwest of Calgary. This operating area is expected to play an important role in our future growth. When Rider acquired Wapiti from a senior oil and gas company in May of 2007, the property was producing 2,800 Boe/d, primarily consisting of non-operated shallow decline Cadomin gas. Two and one-half years later at the end of 2009, Wapiti was producing approximately 6,000 Boe/d, with the increase in production resulting from the drilling activities completed during the year. Over the past year, we have invested a significant amount of capital in the area resulting in an increase in undeveloped land from 125,000 net acres to 143,000 net acres.

The Wapiti operating area falls largely within the deep basin gas window and is characterized as having multiple stacked prospective Cretaceous–Jurassic gas bearing formations that lend themselves both to vertical and horizontal drilling and multistage fracing technology. Our Wapiti operating area lies within the newly created ERCB Development Entity #2 which allows 4 wells per pool per section further expanding our already large development drilling portfolio. In addition to an annually renewable inventory of approximately 20 high working interest, multi-zone drilling prospects, which include the highly prolific Falher Channel sands, we have substantial interests in four resource prospects, with significant development potential. The Cadomin, the most mature of these plays is not operated by us, but may ultimately lead to over 100 development vertical and horizontal infill locations at a working interest of approximately 40%. The other emerging resource plays are operated by us. Following on our early vertical drilling successes in early 2010, we drilled our first successful Dunvegan Channel Sand using horizontal multi-stage fracing technology which tested at 4 MMcf/d. This success confirms the prospectivity of the Dunvegan as a resource play with significant repeatable development opportunities. We have extensive high working interest land holdings in the prospective Jurassic Nikanassin and the Triassic Montney formations. We expect to test these regional prospects in 2010 using horizontal drilling and multi-stage fracing technology.

We also intend to test a potential oil resource play in the Cardium in 2010, where we have a large land position. The zone is known to produce both oil and natural gas regionally, however to date it has not been developed using horizontal wells with multi-stage fracing completion technology.

In 2009, we drilled 10 (6.0 net) wells in the area and achieved a success rate of 100%, yielding 10 natural gas wells.

Pembina

The Pembina operating area is located approximately 230 kilometres north of Calgary, Alberta. Our properties in this operating area include Pembina, Pembina Units (including Pembina Keystone Cardium Unit No. 2), Buck Creek and Alsike. This area is characterized by mature production with gas and light oil development opportunities. We have a 100% interest in a 25 MMcf/d gas plant. This area contains 58,000 acres of undeveloped land with an average working interest of 74%.

Our 2009 average production rate was approximately 3,600 Boe/d (15.7 MMcf/d of natural gas and 970 Bbls/d of oil and liquids).

We have 34 net prospective sections of land within the Cardium oil resource fairway in the Central Pembina area. In late 2009, we drilled our first Cardium horizontal oil well using multi-stage fracing technology. The well came on-stream at approximately 170 Bbls/d. We intend to drill an additional 7 to 10 horizontal oil wells in 2010 which are expected to lead to a significant number of development locations for future years. In 2009, we drilled 5 (1.6 net) wells in the area and achieved a success rate of 100%, yielding 4 natural gas wells and 1 oil well.

Ferrier/Sunchild

The Ferrier/Sunchild operating area is approximately 200 kilometres northwest of Calgary, Alberta, and includes both the Ferrier and Sunchild properties. Natural gas production in the Ferrier/Sunchild area is processed at third party facilities, primarily the Keyera Nordegg and the Keyera Strachan gas plants. These large plants provide both favourable liquid recoveries and low operating costs for our production. This operating area has an undeveloped land base of approximately 18,000 acres with an average working interest of 88%.

Our production in this area comes from liquids-rich natural gas wells. The production is mature and possesses some of our lowest overall corporate declines. We recently acquired overlapping land and production interests in this area. The acquisition which closed on January 29, 2009, added approximately 800 Boe/d of low decline production to this operating area.

Our 2009 average production rate was approximately 3,200 Boe/d (15.7 MMcf/d of natural gas and 600 Bbls/d of oil and liquids). Our Ferrier/Sunchild large contiguous land base is also prospective for the emerging Notikewin gas resource play. During 2010, we plan to test the Notikewin formation using horizontal drilling and multi-stage fracing completion technology, with up to three wells planned for the second half of the year.

Our Ferrier/Sunchild operating area also lies to a large degree within the newly created ERCB Development Entity #2 which allows 4 wells per pool per section further expanding our portfolio of Cretaceous and Jurassic oil and gas prospects.

We did not drill any wells in the Ferrier/Sunchild area in 2009.

Kaybob/Waskahigan

The Kaybob/Waskahigan operating area is located approximately 100 kilometres southeast of Grande Prairie, Alberta. This operating area has an undeveloped land base of approximately 31,000 acres with an average working interest of 79%. Our 2009 average production rate was approximately 1,300 Boe/d (6.4 MMcf/d of natural gas and 215 Bbls/d of oil and liquids). Production from the Kaybob/Waskahigan operating area is characterized by multi-zone stacked oil and gas formations with hyperbolic production decline rates decreasing to less than 10% per year over time. This type of production profile is positive from a reserve life index and royalty perspective.

In 2009, we drilled our first Montney horizontal gas well (100%) which has been completion tested at 6.0 MMcf/d. A second Montney horizontal well was drilled and completed using a multi-stage frac in the first quarter of 2010 and tested at 11 MMcf/d. We have identified up to an additional 20 gross Montney horizontal well locations on our Kaybob Montney lands. We intend to drill 4 to 6 Montney horizontal wells in 2010.

In 2009, we drilled 5 (4.8 net) wells and achieved a success rate of 80%, yielding 4 natural gas wells.

Eastern Alberta and Saskatchewan Core Region

Provost

Our Provost operating area is located west of the Saskatchewan border approximately 350 kilometres northeast of Calgary, Alberta. In 2003, pursuant to the plan of arrangement with Bonavista, we obtained one minor oil property in this area. We have increased our operations in this area through exploration and development activities as well as by acquiring additional producing properties and undeveloped land. Our 2009 average production rate in the Provost area was 3,400 Boe/d consisting of approximately 2,500 Bbls/d of oil and 5.3 MMcf/d of natural gas. This operating area contains 63,000 acres of undeveloped land with an average working interest of 83%.

The northern portion of the Provost area has multi-zone potential and contains both Mannville medium-heavy oil and natural gas targets. The southern portion of this area contains ten prospective natural gas horizons at drill depths of less than 1,100 metres.

In 2009, we drilled 1 net oil well and anticipate a more active drilling program in 2010.

Oyen

Our Oyen operating area is located west of the Saskatchewan border approximately 175 kilometres east of Calgary, Alberta. This operating area produces primarily natural gas from more than ten different Cretaceous age horizons and our control of infrastructure provides a strategic advantage and a barrier to entry for our competitors. Our original operating area continues to provide new discoveries and trends that permit numerous follow-up locations.

Our 2009 average production rate in the Oyen operating area was 3,000 Boe/d (17.3 MMcf/d of natural gas and 135 Bbls/d of oil). Our operations in the area include six main processing facilities and a number of field compressors connected through an extensive network of gathering lines. Our dominant position in Oyen ensures a high degree of flexibility in operating the production and controlling the pace of development with the area.

This operating area contains 227,000 acres of undeveloped land with an average working interest of 85%. The Oyen operating area also contains over 200,000 acres of land that is considered to be developed but is included in the area that received downspacing approval from the Alberta Government in 2006. Our extensive 2D and 3D seismic database enhances the prospectivity of both our developed and undeveloped lands in the area.

In 2009, we drilled or re-entered 24 (21.3 net) wells resulting in 15 natural gas wells and 1 oil well.

For 2009, new wells in Oyen received substantial economic benefits from the royalty incentive programs originally announced by the Government of Alberta on March 3, 2009, where 1,000 metre wells costing between $225,000 and $250,000 to drill are expected to receive approximately a $200,000 drilling credit which can be applied against our 2009 crown royalties. See "*Industry Conditions*".

Northwest Saskatchewan

Our northwest Saskatchewan operating area is located 100 kilometres east of Cold Lake near the Alberta-Saskatchewan border. The region was established as an operating area in August 2005, when we acquired natural gas properties in northwest Saskatchewan for approximately $150 million. In June 2006, we acquired additional properties contiguous to our existing operations thereby increasing our dominance in the area. This area is natural gas prone and is characterized by larger, more mature pools with lower production decline rates. Parts of this operating area are restricted to winter access and therefore we typically conduct an active first quarter drilling program in this area. In the southern part of this operating area, we are currently evaluating several heavy oil prospects where access tends to be available year round.

Our 2009 average production rate was approximately 2,800 Boe/d (15.8 MMcf/d of natural gas and 200 Bbls/d of oil). We operate nearly all the production in this area and our facilities process over 95% of our production. Our operations in the area include seven main processing facilities connected through an extensive network of large diameter gathering lines.

We have 143,000 acres of undeveloped land with an average working interest of 75%. We have acquired over 4,500 kilometres of 2D seismic, most of which is proprietary.

This area contains a minimum of four prospective natural gas horizons at drill depths of less than 800 metres and is prospective for heavy oil in the southern portion. The Onion Lake Lower Mannville heavy oil pool was again the focus of our development drilling program in 2009 where we drilled 3 oil wells.

In 2009, we drilled 4 (3.3 net) wells, resulting in 4 oil wells, 3 of which were at Onion Lake.

West Central Saskatchewan

Our west central Saskatchewan operating area is located east of the Alberta border approximately 400 kilometres northeast of Calgary. This operating area was established in June 2006 when we acquired natural gas properties in west central and northwestern Saskatchewan. This area has multi-zone production from both Cretaceous natural gas and Cretaceous and Devonian heavy oil horizons.

In 2009, our daily average production was approximately 1,200 Boe/d (3.0 MMcf/d of natural gas and 730 Bbls/d of oil). We operate nearly all production in this operating area. Our operations in the area include six natural gas processing facilities and a number of field compressors connected through an extensive network of gathering lines. This operating area contains 54,000 acres of undeveloped land with an average working interest of 79%.

In 2009, we drilled 11 (8.6 net) wells yielding 10 oil wells. The 2009 drilling program focused on development and extension drilling at Hallam, where 7 Birdbear horizontal oil wells were drilled in 2009 increasing field production to over 800 Bbls/d. We have 12 additional horizontal locations identified in Hallam.

Northwest Alberta and British Columbia Core Region

Martin Creek, Black and Conroy, British Columbia

The Martin Creek, Black and Conroy properties are located approximately 100 kilometres northwest of Fort St. John, British Columbia. The property is operated with an average 76% overall working interest. This property is in the winter drilling area which requires all drilling, completion and tie in activities to occur essentially between January 1 and the end of March each season. In the latest winter program beginning in January 2009, 4 wells averaging 90% working interest were drilled in the Conroy/Black area. These wells were successful in multiple zones including the Cretaceous Bluesky Formation as well as reservoirs within the Triassic Charlie Lake and Baldonnel Formations. These zones occur at moderate depths between 800 to 1,300 metres. All 4 wells in the 2009 program were cased and completed with three being tied in this season.

Since July 27, 2009, production averaged 16.5 MMcf/d with 230 Bbls/d of oil and NGLs averaging 2,981 Boe/d. We own a 60% to 100% working interest in key facilities, including five compressor stations, one gas plant with 24 MMcf/d current throughput and over 290 kilometres of pipelines, which gives us a dominant infrastructure position in this portion of British Columbia.

We plan to drill 7 wells on our newly acquired Martin Creek properties in the first quarter of 2010. This program is expected to pave the way for future drilling programs in 2011 and beyond in this area.

Northwestern Alberta

The Northwestern Alberta operating area is located 150 kilometres south/southeast of the Northwest Territories/British Columbia/Alberta border near the town of Rainbow Lake. Productive zones on this property are primarily oil and gas from the Devonian Keg River, Sulphur Point and Slave Point formations as well as gas in the shallow Cretaceous Bluesky formation. Regionally, Keg River oil wells are characterized by prolific carbonate reefs. Bluesky sandstone reservoirs tend to provide lower deliverability, but longer-life sweet natural gas production. We own and operate two sour oil batteries, complete with treaters, tanks, oil-pumping station and solution gas compression. The area also has a number of gas-gathering systems comprised of 7 owned and operated compressors complete with a sour gas processing facility, two refrigeration plants, three dehydration facilities and numerous sales points. Additional processing and compression capacity is available for further development of our lands.

Since July 27, 2009, production averaged 2,047 Boe/d (8.6 MMcf/d of gas and 614 Bbls/d of oil and NGLs) from the Northwestern Alberta operating area.

No drilling is planned in this area for the 2009/2010 winter season. Operational activity will be focused on reactivations and workovers of existing wells.

Oil And Natural Gas Wells

The following table sets forth the number and status of wells in which we had 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	1,003	694.2	484	306.5	666	418.6	773	533.9
British Columbia	84	52.4	42	21.3	369	269.7	391	267.7
Saskatchewan	-	-	1	1.0	100	77.6	63	45.9
Total	1,087	746.6	527	328.3	1,035	765.9	1,164	847.5

Of the non-producing wells, 2 (1.5 net) were oil wells and 17 (12.6 net) were natural gas wells drilled in 2009 that were capable of production and had reserves assigned to them. As of the date of this Annual Information Form, 2 (1.5 net) oil wells and 14 (9.7 net) natural gas wells have been placed on production.

Properties With No Attributed Reserves

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

	DEVELOPED ACRES		UNDEVELOPED ACRES		TOTAL ACRES	
	Gross	Net	Gross	Net	Gross	Net
Alberta	914,314	544,022	773,518	634,998	1,687,832	1,179,020
British Columbia	82,014	61,719	78,979	59,294	160,993	121,013
Saskatchewan	248,168	184,234	260,356	197,723	508,524	381,957
Total	1,244,496	789,975	1,112,853	892,015	2,357,349	1,681,990

Rights to explore, develop and exploit 217,482 net acres of these undeveloped land holdings could expire by December 31, 2010 if not continued.

Forward Contracts

We are exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. A variety of derivative instruments are used by us to reduce our exposure to fluctuations in commodity prices and foreign exchange rates. We are exposed to losses in the event of default by the counterparties to these derivative instruments. We manage this risk by diversifying our derivative portfolio amongst a number of financially sound counterparties. For information in relation to our marketing arrangements, see "*Marketing Arrangements*" below.

For details of our material commitments to sell natural gas and crude oil which were outstanding as at December 31, 2009 see Note 12 to our consolidated financial statements for the year ended December 31, 2009 which are incorporated herein by reference.

Marketing Arrangements

Natural Gas

We have established a natural gas transportation and sales portfolio, which will ensure receipt capacity at reasonable cost and provide an appropriate customer base. Our marketing objectives also include protecting or securing minimum prices for up to 60% of our net after royalty production for terms not exceeding two years. Our price risk management program is comprised of costless collars, fixed price and put option contracts. In order to control and manage credit risk and ensure competitive bids, we engage a number of reputable counterparties for our natural gas transactions. Our sales portfolio also includes sales to traditional aggregators. The integration and application of these strategies resulted in an average realized price of Cdn $4.94/Mcf for the year ended December 31, 2009.

Oil and NGLs

We sell our oil and liquids production to a variety of purchasers. This enables us to benefit from specific regional advantages, while maintaining price and delivery flexibility. We are continually monitoring global and regional crude oil markets and look for opportunities to enter into price risk management contracts for up to 60% of net after royalty production. In 2009, our average realized oil price was Cdn $63.22/Bbl and our average realized price for natural gas liquids was Cdn $38.58/Bbl.

Additional details on our price risk management program are shown in Note 12 of our consolidated financial statements for the year ended December 31, 2009 which are incorporated herein by reference.

Additional Information Concerning Abandonment and Reclamation Costs

Our overall abandonment and reclamation costs are based on well bore abandonment and reclamation costs and liability issues such as flare pit remediation, facility decommissioning, remediation, and reclamation costs. These costs were estimated using our experience conducting abandonment and reclamation programs. We review suspended or standing well bores for reactivation, recompletion or sale and conduct systematic abandonment programs for those well bores that do not meet our criteria. A portion of our liability issues are retired every year and facilities are decommissioned when all the wells producing to them have been abandoned. All of our liability reduction programs take into account seasonal access, high priority and stakeholder issues, and opportunities for multi-location programs to reduce costs.

As at December 31, 2009 we had 2,688 net wells for which we expect to incur abandonment and reclamation costs.

The total amount of abandonment and reclamation costs, net of estimated salvage values, that we expect to incur, are summarized in the following table:

Period	Abandonment and Reclamation Costs Escalated at 2% Undiscounted ($000s)	Abandonment and Reclamation Costs Escalated at 2% Discounted at 8% ($000s)
Total liability as at December 31, 2009	286,600	53,200
Anticipated to be paid in 2010	2,200	2,100
Anticipated to be paid in 2011	2,200	2,100
Anticipated to be paid in 2012	2,200	2,100

The future net revenues disclosed in this Annual Information Form based on the GLJ Report do not contain an allowance for abandonment and reclamation costs for surface leases, facilities and pipelines. The GLJ Report only deducted $51.8 million (undiscounted) and $21.2 million (10% discount using forecast prices and costs) for abandonment costs of wells with proved reserves, in estimating the future net revenue disclosed in this Annual Information Form.

Tax Horizon

Based on estimated 2010 cash flow and capital expenditures, we do not expect to be cash taxable in 2010.

Costs Incurred

The following table summarizes the costs incurred related to our activities for the year ended December 31, 2009:

Expenditure	Year Ended December 31, 2009 ($000s)
Property acquisition costs – Unproved properties [1] [2]	5,980
Property acquisition costs – Proved properties [2]	226,306
Exploration costs [3]	28,000
Development costs [4]	46,398
Other	3,226
Total	309,910

Notes:

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

(2) Net of dispositions.

(3) Geological and geophysical capital expenditures and drilling costs for exploration wells.

(4) Development costs include development drilling costs and equipping, tie-in and facility costs for all wells.

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells in which we participated during the year ended December 31, 2009:

	Development		Exploratory	
	Gross	Net	Gross	Net
Natural Gas	18	11.3	16	13.3
Heavy Oil	13	9.9	3	2.8
Dry	-	-	10	9.3
Total	31	21.2	29	25.4

In 2010, we expect to drill approximately 87 wells (68 gas, 19 oil) in Alberta. In Saskatchewan, we expect to drill 17 oil wells. In British Columbia, we are planning to drill six gas wells and one oil well.

Finding and Development Costs

The following table summarizes our finding and development costs for the periods indicated:

	2009		2008		Three Year Average	
($/Boe)	Proved	Proved plus Probable	Proved	Proved plus Probable	Proved	Proved plus Probable
Finding, development and acquisition cost [1]	14.18	11.79	24.29	18.51	20.08	16.06
Finding, development [1]	16.63	16.73	24.37	19.48	20.95	18.56
Acquisition costs	13.29	10.52	24.26	18.16	19.70	14.99

Notes:

(1) Including changes in future development capital expenditures.

(2) The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development capital expenditures generally will not reflect total finding and development costs related to reserves additions for that year.

Production Estimates

The following table sets out the volumes of our working interest production estimated for the year ended December 31, 2010, which is reflected in the estimate of future net revenue disclosed in the forecast price tables contained above under the subheading "*Disclosure of Reserves Data* ":

	Light and Medium Oil (Bbls/d)	Heavy Oil (Bbls/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	BOE (Boe/d)
Total Proved	1,488	3,174	129,103	3,361	29,541
Total Proved plus Probable	1,634	3,353	139,371	3,727	31,942

Production History

The following tables summarize certain information in respect of our production, product prices received, royalties paid, production costs and resulting netback for the periods indicated below:

	Quarter Ended 2009				Year Ended
	Mar. 31	**June 30**	**Sept. 30**	**Dec. 31**	**Dec. 31, 2009**
Average Daily Production [1]					
Light and Medium Oil (Bbls/d)	729	707	902	1,251	898
Heavy Oil (Bbls/d)	3,718	3,562	3,251	3,203	3,432
Gas (MMcf/d)	112.2	109.6	121.0	123.5	116.6
NGLs (Bbls/d)	3,029	3,247	3,181	3,312	3,193
Combined (Boe/d)	26,175	25,777	27,505	28,345	26,958
Average Net Production Prices Received					
Light and Medium Oil ($/Bbl)	81.52	80.74	62.05	72.63	73.32
Heavy Oil ($/Bbl)	50.17	60.85	67.32	65.26	60.58
Gas ($/Mcf)	6.53	4.52	3.99	4.82	4.94
NGLs ($/Bbl)	39.19	32.00	39.58	43.43	38.58
Combined ($/Boe)	41.94	33.86	32.13	36.67	36.09
Royalties Paid					
Light and Medium Oil ($/Bbl)	12.83	7.88	10.18	19.92	13.68
Heavy Oil ($/Bbl)	2.28	7.69	8.86	6.70	6.29
Gas ($/Mcf)	0.97	0.21	(0.02)	0.26	0.34
NGLs ($/Bbl)	14.22	10.51	14.38	16.34	13.88
Combined ($/Boe)	6.46	3.51	2.96	4.66	4.38
Production Costs [2][3]					
Light and Medium Oil ($/Bbl)	23.17	27.47	22.28	18.40	22.11
Heavy Oil ($/Bbl)	15.68	13.36	14.67	17.05	15.16
Gas ($/Mcf)	1.17	1.05	1.24	1.16	1.16
NGLs ($/Bbl)	7.02	6.30	7.44	6.96	6.96
Combined ($/Boe)	8.71	7.84	8.79	8.60	8.49
Transportation					
Light and Medium Oil ($/Bbl)	1.74	0.96	1.98	1.44	1.54
Heavy Oil ($/Bbl)	0.77	1.95	1.36	0.64	1.19
Gas ($/Mcf)	0.14	0.17	0.13	0.15	0.15
NGLs ($/Bbl)	0.01	-	-	-	-
Combined ($/Boe)	0.75	1.02	0.81	0.80	0.84
Netback Received [4]					
Light and Medium Oil ($/Bbl)	43.78	44.43	27.61	32.87	35.99
Heavy Oil ($/Bbl)	31.44	37.85	42.43	40.87	37.94
Gas ($/Mcf)	4.08	3.00	2.68	3.27	3.24
NGLs ($/Bbl)	17.94	15.19	17.76	20.13	17.74
Combined ($/Boe)	26.02	21.49	19.57	22.61	22.38

Notes:

(1) Before deduction of royalties.

(2) Production costs are composed of direct costs incurred to operate both oil and gas wells. A number of assumptions are required to allocate these costs between oil, natural gas and natural gas liquids production.

(3) Operating recoveries associated with operated properties are charged to production costs and accounted for as a reduction to general and administrative costs.
(4) Netbacks are calculated by subtracting royalties, production costs, transportation and losses/gains on commodity and foreign exchange contracts from revenues.

The following table indicates our average daily production (including production from our major areas) for the year ended December 31, 2009:

	Light and Medium Oil (Bbls/d)	**Heavy Oil (Bbls/d)**	**Natural Gas Liquids (Bbls/d)**	**Natural Gas (MMcf/d)**	**BOE (Boe/d)**
Central Saskatchewan	14	718	-	2,969	1,227
Ferrier	29	-	566	15,706	3,213
Kaybob/Waskahigan	47	-	169	6,396	1,282
Oyen	51	73	11	17,308	3,020
Provost	59	2,439	12	5,294	3,392
Pembina	386	-	585	15,710	3,589
Northwest Saskatchewan	3	202	-	15,779	2,835
Wapiti	5	-	1,749	25,555	6,013
British Columbia	33	-	63	6,873	1,242
Northwest Alberta	243	-	13	3,584	853
Other	28	-	25	1,434	292
Total	898	3,432	3,193	116,608	26,958

DESCRIPTION OF OUR CAPITAL STRUCTURE

The following is a description of the rights, privileges, restrictions and conditions attaching to our share capital.

Common Shares

We are authorized to issue an unlimited number of Common Shares without nominal or par value. Holders of our Common Shares are entitled to one vote per share at meetings of our Shareholders. Subject to the rights of the holders of preferred shares and any other shares having priority over the Common Shares, holders of Common Shares are entitled to dividends if, as and when declared by the Board of Directors and upon liquidation, dissolution or winding-up to receive, our remaining property.

Performance Shares

We are authorized to issue 1,200,000 Performance Shares without nominal or par value. The Performance Shares rank junior to the Common Shares and preferred shares, other than as set forth below. These were initially issued at the time we completed the plan of arrangement with Bonavista in 2003.

Each issued and outstanding Performance Share was initially issued at a price of $0.01 per share and was convertible into the fraction of a Common Share equal to the closing trading price of the Common Shares on the Toronto Stock Exchange or such other stock exchange on which the Common Shares are listed on the trading day prior to such conversion less $2.00, if positive, divided by such closing price. All of the issued and outstanding Performance Shares have been converted into Common Shares or cancelled and we no longer have any Performance Shares outstanding.

MARKET FOR OUR SECURITIES

Our Common Shares are listed and posted for trading on the Toronto Stock Exchange and trade under the symbol "NVA". The following sets forth the price range and trading volume of our Common Shares on the Toronto Stock Exchange for the periods indicated.

	Price Range		
	High	Low	Volume
2009			
January	9.43	6.68	3,609,681
February	7.95	5.11	4,815,623
March	6.60	4.90	10,468,723
April	8.23	5.85	10,165,088
May	11.88	7.98	11,187,930
June	11.50	10.05	6,081,280
July	10.06	8.85	5,330,600
August	10.40	9.20	5,257,662
September	12.50	9.35	8,925,608
October	14.00	11.35	5,921,562
November	12.64	10.42	5,315,319
December	12.50	10.70	5,933,532
2010			
January	12.91	11.55	6,182,410
February	14.56	12.53	9,015,955
March (1 – 22)	14.05	12.34	12,193,590

DIRECTORS AND OFFICERS

The names, municipalities of residence, any offices held with us, the period served as a director and principal occupations of our directors and officers are set out below.

Name and Municipality of Residence	Position with NuVista	Director or Officer Since	Principal Occupation
Keith A. MacPhail (2) Calgary, Alberta	Chairman and Director	May 2003	Our Chairman and Chairman and Chief Executive Officer of Bonavista.
W. Peter Comber (1)(3)(4) Toronto, Ontario	Director	May 2004	Managing Director of Barrantagh Investment Management Inc. (an investment counselling firm).
Pentti O. Karkkainen (1)(2)(3)(5) Calgary, Alberta	Director	July 2003	General Partner, KERN Partners Ltd. (a private equity firm and partnership).
Ronald J. Poelzer Calgary, Alberta	Director	May 2003	Executive Vice President and Vice Chairman of Bonavista.
Alex G. Verge Calgary, Alberta	President, Chief Executive Officer and Director	July 2003	Our President and Chief Executive Officer since July 2003.

Name and Municipality of Residence	Position with NuVista	Director or Officer Since	Principal Occupation
Clayton H. Woitas (1)(2)(4) Calgary, Alberta	Director	July 2003	Chairman, President and Chief Executive Officer of Range Royalty Management Ltd., general partner of Range Royalty Limited Partnership (an oil and gas royalty limited partnership) since July 2006; prior thereto President, Chief Executive Officer and a Director of Profico Energy Management Ltd. (a private oil and gas company) from February 2000 to June 2006.
Grant A. Zawalsky (3)(4) Calgary, Alberta	Director	May 2003	Partner of Burnet, Duckworth & Palmer LLP (barristers and solicitors).
Robert F. Froese Calgary, Alberta	Vice President, Finance, Chief Financial Officer and Corporate Secretary	May 2006	Our Vice President, Finance and Chief Financial Officer since May 2006 and our Corporate secretary since March 2010. Prior thereto, Mr. Froese was our Vice President, Finance commencing March 2006. Prior thereto, he was Treasurer at Suncor Energy Inc.
Ross L. Andreachuk Calgary, Alberta	Vice President and Controller	May 2009	Our Vice President and Controller since May 2009. Prior thereto, Mr. Andreachuk was our Controller commencing August 2006. Prior thereto, he was the Controller at Petrofund Energy Trust and Ultima Energy Trust.
Kevin G. Asman Calgary, Alberta	Vice President, Marketing	January 2010	Our Vice President, Marketing since January 2010. Prior thereto, Mr. Asman was our Marketing Manager commencing July 2008. Prior thereto, he was Marketing Manager at TAQA North Ltd. (formerly, Northrock Resources Ltd.).
Kevin J. Christie Calgary, Alberta	Vice President, Exploration	June 2008	Our Vice President, Exploration since June 2008. Prior thereto, Mr. Christie was Vice President Exploration at TAQA North Ltd. (formerly Northrock Resources Ltd.) since July, 1999.
Steven J. Dalman Calgary, Alberta	Vice President, Business Development	January 2006	Our Vice President, Business Development since January 2008. Prior thereto, Mr. Dalman was our Vice President Engineering since January 2006. Mr. Dalman joined us as Manager, Engineering in January 2005. Prior thereto, he was a Senior Exploitation Engineer at Bonavista.
D. Chris McDavid Calgary, Alberta	Vice President, Operations	August 2006	Our Vice President, Operations since August 2006. Mr. McDavid joined us as Production Manager in January 2005. Prior thereto, he was a Production Engineer at Bonavista.

Name and Municipality of Residence	Position with NuVista	Director or Officer Since	Principal Occupation
Daniel B. McKinnon Calgary, Alberta	Vice President, Engineering	January 2008	Our Vice President, Engineering since January 2008. Prior thereto, Mr. McKinnon was a Senior Exploitation Engineer with us commencing in January 2005 and then our Manager, Business Planning since July 2007. Prior thereto, Mr. McKinnon was a Senior Exploitation Engineer with Bonavista between August 2003 and January 2005.
Joshua T. Truba Calgary, Alberta	Vice President, Land	January 2009	Our Vice President, Land since January 2009. Mr. Truba joined NuVista in February 2005 as Area Landman, was promoted to Land Manager in May 2008. Prior thereto, Mr. Truba was employed by Addison Energy Inc. as Area Landman.

Notes:
(1) Member of our audit committee.
(2) Member of our reserves committee.
(3) Member of our compensation committee.
(4) Member of our governance and nominating committee.
(5) Our Lead Director.

The term of office of each of our directors expires at the next annual meeting of our Shareholders.

As at March 26, 2010 our directors and officers, as a group, beneficially owned, or directed or controlled, directly or indirectly, 8.0 million Common Shares or approximately 9.0% of our issued and outstanding Common Shares.

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, other than Mr. Zawalsky who was a former director of Efficient Energy Resources Ltd. (a private electrical generation company) which agreed to the voluntary appointment of a receiver in 2005 and Mr. MacPhail who was formerly a director of The Resort at Copper Point Ltd. (a private real estate development company) which was placed in receivership in February 2009.

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, 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

Our directors and officers may, from time to time, be involved with the business and operations of other oil and natural gas issuers, in which case a conflict may arise. See "*Risk Factors*".

Circumstances may arise where members of our Board of Directors serve as directors or officers of corporations which are in competition to our interests. No assurances can be given that opportunities identified by such board members will be provided to us.

The *Business Corporations Act* (Alberta) provides that in the event a director has an interest in a contract or proposed contract or agreement, the director shall disclose his interest in such contract or agreement and shall refrain from voting on any matter in respect of such contract or agreement unless otherwise provided under the *Business Corporations Act* (Alberta). To the extent that conflicts of interests arise, such conflicts will be resolved in accordance with the provisions of the *Business Corporations Act* (Alberta).

Our partners in NuVista Partnership may have interests in oil and natural gas properties or carry on other business of any nature, including interests and business that compete with ours, and pursuant to the partnership agreement governing NuVista Partnership, no partner is required to account to NuVista Partnership for profits earned from the holding of such interests and/or the carrying on of such business. In the event that the interests of a partner are in conflict with those of NuVista Partnership, the partner shall make decisions acting in good faith and shall advise NuVista Partnership of any material conflict; provided, however, that all decisions involving or affecting NuVista Partnership assets will be made in NuVista Partnership's best interest. In addition, each partner will have the right to contract or otherwise deal with or for the sale or lease of property, the provision of management, administrative or executive services and other services, and to receive payments and fees from NuVista Partnership in connection therewith as the manager shall determine to be in NuVista Partnership's best interest, provided that such payments or fees are no greater than the payments or fees that would be paid to persons with whom NuVista Partnership deals with at arm's length (as that term is defined in and construed under the *Income Tax Act* (Canada)).

AUDIT COMMITTEE INFORMATION

Audit Committee Charter

The full text of our Audit Committee charter is included in Appendix C of this Annual Information Form.

Composition of the Audit Committee

The members of our Audit Committee are Mr. Comber (Chair), Mr. Karkkainen and Mr. Woitas, each of whom are independent and financially literate. We have adopted the definition of "independence" as set out in Section 1.4 of National Instrument 52-110 – *Audit Committees*. The relevant education and experience of each Audit Committee member is outlined below:

W. Peter Comber: *Barrantagh Investment Management Inc.*

Mr. Comber has more than 40 years experience in various aspects of the financial services industry. Mr. Comber is a chartered accountant and has worked in corporate finance and investment management both in Toronto and Calgary. Since August 1999, Mr. Comber has been managing director of Barrantagh Investment Management Inc., investment counsellors based in Toronto, Ontario. Mr. Comber was the President of Newtonhouse Investment Management Ltd., investment counsellors located in Toronto, Ontario from May 1993 to August 1999. Between June 1989 and December 1991, Mr. Comber was Senior Vice President, Thommark Capital Corporation, an investment holding company, and principal officer of Thommark Capital Funding Corporation, merchant bank. Prior to thereto, Mr. Comber was Senior Vice President and Managing Director of Prudential - Bache Securities Canada Limited, an investment dealer in Toronto, Ontario.

Mr. Comber is a chartered accountant and holds a Bachelor of Arts degree from the University of Toronto and a Masters of Business Administration from York University.

Mr. Comber is also a director of Sure Energy Inc. and Exshaw Oil Corporation.

Pentti O. Karkkainen: *KERN Partners Ltd.*

Mr. Karkkainen has 24 years of investment management, energy sector research and investment banking experience, as well as four years of industry experience with Gulf Canada Resources. Mr. Karkkainen is a founding and a General Partner of KERN Partners Ltd. – a Calgary based energy sector private equity firm that was established in late 2000. KERN Partners has $1.1 billion of capital under management from a variety of North American and European pension funds, endowments, family offices and other financial institutions. Prior to establishing KERN Partners, Mr. Karkkainen was Managing Director and Head of Oil and Gas Equity Research at RBC Capital Markets.

Mr. Karkkainen holds a Bachelor of Science (Honours) degree in Geology from Carleton University in Ottawa and a Masters of Business Administration degree from Queen's University in Kingston.

Mr. Karkkainen is also a director of several Calgary based private energy infrastructure and oil and gas exploration and development companies including Altex Energy Ltd., Connaught Energy Ltd., Dolomite Energy Inc. and Peloton Exploration Inc.

Clayton H. Woitas: *Range Royalty Management Ltd.*

Mr. Woitas has more than 35 years experience in the oil and gas industry and is currently President and CEO of Range Royalty Management Ltd., general partner of Range Royalty Limited Partnership (an oil and gas royalty limited partnership). Mr. Woitas was President and CEO of Profico Energy Management Ltd. (a private oil and gas company) from February 2000 to June 2006. Prior thereto, Mr. Woitas was President and CEO of Renaissance Energy Ltd.

Mr. Woitas is also a director of AspenAir Corp., EnCana Corporation, EnerMark Inc. (the administrator of Enerplus Resources Fund), Flagstone Energy Inc., Chairman and a director of Spur Resources Ltd. (a private oil and gas company).

Mr. Woitas holds a Bachelor of Science degree in Civil Engineering from the University of Alberta and is a member of the Association of Professional Engineers, Geologists & Geophysicists of Alberta.

Pre-Approval of Policies and Procedures

Our Audit Committee must pre-approve all non-audit services to be provided to us by our external auditors. The Audit Committee may delegate to one or more members the authority to pre-approve non-audit services, provided that the member reports to the Audit Committee at the next scheduled meeting such pre-approval and the member complies with such other procedures as may be established by our Audit Committee from time to time.

External Auditor Service Fees

Audit Fees

The aggregate fees billed by our external auditor in each of the last two fiscal years for audit services were $160,000 in 2009 and $145,000 in 2008.

Audit-Related Fees

The aggregate fees billed in each of the last two fiscal years for assurance and related services by our external auditor that are reasonably related to the performance of the audit or review of our financial statements that are not reported under "*Audit Fees*" above were $58,500 in 2009 and $56,000 in 2008. Fees billed for prospectus review in each of the last two fiscal years were $55,000 in 2009 and $95,000 in 2008.

Tax Fees

The aggregate fees billed in each of the last two fiscal years for professional services rendered by our external auditor for tax compliance, tax advice, tax planning and review of tax returns were $126,833 in 2009 and $18,750 in 2008.

All Other Fees

The aggregate fees billed in each of the last two fiscal years for products and services provided by our auditors, other than services reported above, were nil in 2009 and $7,500 in 2008 in connection with a business acquisition report relating to an acquisition.

Reliance on Exemptions

At no time since the commencement of our most recently completed financial year have we relied on any of the exemptions contained in National Instrument 52-110 – *Audit Committees* with respect to independence or composition of our Audit Committee.

Audit Committee Oversight

At no time since the commencement most recently completed financial year has a recommendation of the Audit Committee to nominate or compensate an external auditor not been adopted by our Board of Directors.

DIVIDEND POLICY

We have not paid any dividends to date on our outstanding Common Shares.

We recently established a dividend policy of paying quarterly cash dividends to Shareholders, and the initial quarterly dividend of $0.05 per Common Share is expected to be paid on April 15, 2010 to Shareholders of record on March 31, 2010.

We currently intend to maintain dividend levels between 5% and 15% of our cash flow, preferably at the lower end of this range. However, the amount of future cash dividends, if any, is not assured and will be subject to the discretion of our Board of Directors and may vary depending on a variety of factors, including fluctuations in commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens and foreign exchange rates. See "*Risk Factors*".

Our credit facility permits us to pay dividends provided that (i) the aggregate of all dividends made by in a fiscal quarter in aggregate with all dividends made over the immediately prior three fiscal quarters, is not in excess of 25% of earnings before interest, income taxes and depletion, depreciation and amortization for the immediately prior four fiscal quarters, (ii) no default, event of default or borrowing base shortfall has occurred and is continuing, and (iii) no default, event of default or borrowing base shortfall would result due to any such dividend.

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 our 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 we are unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry.

Pricing and Marketing

Oil

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 the vast majority of natural gas produced in Western Canada is now determined through the liquid market established at the Alberta "NIT" hub rather than through direct 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 m^3/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

As a result of pipeline expansions over the past several years, there is ample pipeline capacity to accommodate current production levels of oil and natural gas in Western Canada and pipeline capacity does not generally limit the ability to produce and market such production.

The North American Free Trade Agreement

The North American Free Trade Agreement, or NAFTA as it is often referred to, 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. On March 11, 2010, the Government of Alberta announced changes to Alberta's royalty system intended to increase Alberta's competitiveness in the upstream oil and natural gas sectors; specifically, the maximum royalty rates for conventional oil and natural gas production will be decreased effective for the January 2011 production month and certain temporary incentive programs currently in place will be made permanent. Further details with respect to the changes to Alberta's royalty system are expected to be provided in the coming months.

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 maximum rates of 30-35% depending on the vintage of the oil, and rate caps are set at $120 per barrel. Effective January 1, 2011, the maximum royalty payable under the NRF will be reduced to 40%.

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 maximum rates of 5-35%, and rate caps are set at $17.75/GJ. Effective January 1, 2011, the maximum royalty payable under the NRF will be reduced to 36%.

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. Pursuant to the changes made to Alberta's royalty structure announced on March 11, 2010, producers will only be able to elect to adopt the transitional royalty rates prior to January 1, 2011 and producers that have already elected to adopt the transitional royalty rates as of that date will be permitted to switch to Alberta's conventional royalty structure. On December 31, 2013, all producers operating under the transitional royalty rates will automatically become subject to Alberta's conventional royalty structure.

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 initially applied to wells that began producing conventional oil or natural gas between April 1, 2009 and March 31, 2010 and provided for a maximum 5% royalty rate for the first 12 months of production on 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. On March 11, 2010, the Government of Alberta announced that the incentive program rate of 5% for the first 12 months of production would be made permanent, with the same volume limitations.

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 m^3 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 kilometres 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 m^3 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 m^3 during the first 12 production months and average daily production less than 23 m^3 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 metres, average monthly production under 60,000 m^3 during the first 12 production months and average daily production less than 11.5 m^3 (development wells) or 17 m^3 (exploratory wildcat wells) for every 100 metres of marginal well depth; and

- *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 m^3 of production, whichever comes first.

On March 2, 2009, the Government of British Columbia announced the 2009 Infrastructure Royalty Credit Program which allocates $120 million in royalty credits for oil and gas companies. The 2009 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. The Government of British Columbia has recently announced the same level of funding for the 2010 Infrastructure Royalty Credit Program.

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. 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 metres. Wells spud between September 1, 2009 and June 30, 2010 may qualify for both the stimulus package 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.

Saskatchewan

In Saskatchewan, the amount payable as a royalty in respect of oil depends on the type and vintage of oil, the quantity of oil produced in a month, the value of the oil produced and specified adjustment factors determined monthly by the provincial government. For Crown royalty and freehold production tax purposes, conventional oil is classified as "heavy oil", "southwest designated oil" or "non-heavy oil other than southwest designated oil". The conventional royalty and production tax classifications ("fourth tier oil", "third tier oil", "new oil" and "old oil") depend on the finished drilling date of a well and are applied to each of the three crude oil types slightly differently. Heavy oil is classified as third tier oil (having a finished drilling date on or after January 1, 1994 and before October

1, 2004), fourth tier oil (having a finished drilling date on or after October 1, 2002) or new oil (not classified as either third tier oil or fourth tier oil). Southwest designated oil uses the same definitions of third and fourth tier oil but new oil is defined as conventional oil produced from a horizontal well having a finished drilling date on or after February 9, 1998 and before October 1, 2002. For non-heavy oil other than southwest designated oil, the same classification is used but new oil is defined as conventional oil produced from a vertical well completed after 1973 and having a finished drilling date prior to 1994, whereas old oil is defined as conventional oil not classified as third or fourth tier oil or new oil.

Base prices are used to establish lower limits in the price-sensitive royalty structure for conventional oil. Where average wellhead prices are below the established base prices of \$100 per m^3 for third and fourth tier oil and \$50 per m^3 for new oil and old oil, base royalty rates are applied. Base royalty rates are 5% for all fourth tier oil, 10% for heavy oil that is third tier oil or new oil, 12.5% for southwest designated oil that is third tier oil or new oil, 15% for non-heavy oil other than southwest designated oil that is third tier or new oil, and 20% for old oil. Where average wellhead prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base oil price. Marginal royalty rates are 30% for all fourth tier oil, 25% for heavy oil that is third tier oil or new oil, 35% for southwest designated oil that is third tier oil or new oil, 35% for non-heavy oil other than southwest designated oil that is third tier or new oil, and 45% for old oil.

The amount payable as a royalty in respect of natural gas production is determined by a sliding scale based on a reference price (which is the greater of the amount obtained by the producer and a prescribed minimum price), the quantity produced in a given month, the type of natural gas, and the vintage of the natural gas. Like conventional oil, natural gas is classified as "non-associated gas" or "associated gas" and royalty rates are determined according to the finished drilling date of the respective well. As an incentive for the production and marketing of natural gas which may have been flared, the royalty rate on natural gas produced in association with oil is less than on non-associated natural gas. Non-associated gas is classified as new gas (having a finished drilling date before February 9, 1998 with a first production date on or after October 1, 1976), third tier gas (having a finished drilling date on or after February 9, 1998 and before October 1, 2002), fourth tier gas (having a finished drilling date on or after October 1, 2002) and old gas (not classified as either third tier, fourth tier or new gas). A similar classification is used for associated gas except that the classification of old gas is not used, the definition of fourth tier gas also includes production from oil wells with a finished drilling date prior to October 1, 2002, where the individual oil well has a gas-oil production ratio in any month of more than 3,500 m^3 of gas for every m^3 of oil, and new gas is defined as oil produced from a well with a finished drilling date before February 9, 1998 that received special approval, prior to October 1, 2002, to produce oil and gas concurrently without gas-oil ratio penalties.

As with conventional oil production, base prices are used to establish lower limits in the price-sensitive royalty structure for natural gas. Where average field-gate prices are below the established base prices of \$50 per thousand m^3 for third and fourth tier gas and \$35 per thousand m^3 for new gas and old gas, base royalty rates are applied. Base royalty rates are 5% for all fourth tier gas, 15% for third tier or new gas, and 20% for old gas. Where average well-head prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base gas price. Marginal royalty rates are 30% for all fourth tier gas, 35% for third tier and new gas, and 45% for old gas**.**

The Government of Saskatchewan currently provide a number of targeted incentive programs. These include both royalty reduction and incentive volume programs, including the following:

- *Royalty/Tax Incentive Volumes for Vertical Oil Wells Drilled on or after October 1, 2002* providing reduced Crown royalty and freehold tax rates on incentive volumes of 8,000 m^3 for deep development vertical oil wells, 4,000 m^3 for non-deep exploratory vertical oil wells and 16,000 m^3 for deep exploratory vertical oil wells (more than 1,700 metres or within certain formations);

- *Royalty/Tax Incentive Volumes for Exploratory Gas Wells Drilled on or after October 1, 2002* providing reduced Crown royalty and freehold tax rates on incentive volumes of 25,000,000 m^3 for qualifying exploratory gas wells;

- *Royalty/Tax Incentive Volumes for Horizontal Oil Wells Drilled on or after October 1, 2002* providing reduced Crown royalty and freehold tax rates on incentive volumes of 6,000 m^3 for non-deep horizontal oil wells and 16,000 m^3 for deep horizontal oil wells (more than 1,700 metres or within certain formations);

- *Royalty/Tax Regime for Incremental Oil Produced from New or Expanded Waterflood Projects Implemented on or after October 1, 2002* treating incremental production from waterflood projects as fourth tier oil for the purposes of royalty calculation;

- *Royalty/Tax Regime for Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing prior to April 1, 2005* providing Crown royalty and freehold tax determinations based in part on the profitability of enhanced recovery projects pre- and post-payout; and

- *Royalty/Tax Regime for Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing on or after April 1, 2005* providing a Crown royalty of 1% of gross revenues on enhanced oil recovery projects pre-payout and 20% post-payout and a freehold production tax of 0% on operating income from enhanced oil recovery projects pre-payout and 8% post-payout.

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

Land Tenure

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

Each of the provinces of Alberta, British Columbia and Saskatchewan has implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or license.

In Alberta, the NRF includes a policy of "shallow rights reversion" which provides, for the first time in western Canada, for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for all leases and licenses. For leases and licenses issued subsequent to January 1, 2009, shallow rights reversion will be applied at the conclusion of the primary term of the lease or license. Holders of leases or licences that have been continued indefinitely prior to January 1, 2009 will receive a notice regarding the reversion of the shallow rights, which will be implemented three years from the date of the notice. The order in which these agreements will receive the reversion notice will depend on their vintage and location, with the older leases and licenses receiving reversion notices first beginning in January 2011. Leases and licences that were granted prior to January 1, 2009 but continued after that date will not be subject to shallow rights reversion until they reach the end of their primary term and are continued (at which time deep rights reversion will be applied); thereafter, the holders of such agreements will be served with shallow rights reversion notices based on vintage and location similar to leases and licences that were already continued as of January 1, 2009.

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 which 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* 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 Alberta Land Use Framework. Regional plans established pursuant to this act 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, this act 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 *Alberta Land Stewardship Act* 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 act 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 act, 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 *Alberta Land Stewardship Act* 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, 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 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" 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. 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 of 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 Unites 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 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 CO_2 equivalents per facility per year for natural gas pipelines; (ii) 3,000 tonnes of CO_2 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 governed 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 CO_2 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* on July 1, 2007, amending it through the *Climate Change and Emissions Management Amendment Act* which received royal assent on November 4, 2008. This act 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 *Climate Change and Emissions Management Act*. Similarly to the updated action plan, this act 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, this act does not contain any provision for continuous annual improvements beyond the 12% emissions intensity required.

The *Climate Change and Emissions Management Act* 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 at a rate of $15 per tonne of CO_2 equivalent. Unlike the updated action plan, this act 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, this act does not contemplate a linkage to external compliance mechanisms such as the Kyoto Protocol's Clean Development Mechanism.

We do not operate any facilities in Alberta that emit greater than 100,000 tonnes of GHG per year but do have a 2.2% working interest in a third party operated Wapiti gas plant that emitted 120,145 tonnes of CO_2 equivalent in 2008. We will continue to carefully monitor the emission requirements in Alberta and will strive to ensure all facilities, which we have interest in, comply with the emission targets outlined. For those facilities that may exceed the targets, we expect to trade for and or purchase emission credits as economically available. Currently, any potential costs under this option would not be material to us.

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 CO_2 equivalent and rose to $15 per tonne of CO_2 equivalent on July 1, 2009. It is scheduled to further increase at a rate of $5 per tonne of CO_2 equivalent on July 1 of every year until it reaches $30 per tonne of CO_2 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* 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 CO_2 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 came into force requiring all British Columbia facilities emitting over 10,000 tonnes of CO_2 equivalents per year to begin reporting their emissions. Facilities reporting emissions greater than 25,000 tonnes of CO_2 equivalents per year are required to have their emissions reports verified by a third party.

We operate two facilitates in British Columbia that individually emit greater than 10,000 tonnes CO_2 equivalents per year and therefore each of these facilities must be registered with the province and report their emissions. In addition, our total emissions from all operations in British Columbia in 2008 exceeded the 25,000 tonnes CO_2 equivalents per year and therefore we must have our emissions verified by a third party. For 2008 we reported a total of 35,345 tonnes of CO_2 equivalents from all of our operations in British Columbia. We will carefully monitor the emissions reporting requirements in British Columbia and we plan to participate in the cap and trade plan as economically available. Currently, any potential costs under the cap and trade program would not be material to us.

Saskatchewan

On May 11, 2009, the Government of Saskatchewan announced *The Management and Reduction of Greenhouse Gases Act* to regulate greenhouse gas emissions in the province. Although this act has only passed first reading in the Saskatchewan legislature and the specific details of the legislation have not yet been determined, it is expected that it will adopt the goal of a 20% reduction in greenhouse gas emissions by 2020 and permit the use of technology fund contributions and emissions offsets in compliance, similar to both the federal and Alberta climate change initiatives. It remains unclear whether the scheme implemented will be based on emissions intensity or an absolute cap on emissions.

RISK FACTORS

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

Prices, Markets and Marketing

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

The prices of oil and natural gas prices may be volatile and subject to fluctuation. Any material decline in prices could result in a reduction of our net production revenue. The economics of producing from some wells may change as a result of lower prices, which could result in reduced production of oil or gas and a reduction in the volumes of our reserves. We might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in our expected net production revenue and a reduction in our oil and gas acquisition, development and exploration activities. Prices for oil and gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond our control. These factors include economic conditions, in the United States and Canada, the actions of 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 carrying value of our reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on our 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 us may, in part, be determined by our borrowing base. A sustained material decline in prices from historical average prices could reduce our borrowing base, therefore reducing the bank credit available to us which could require that a portion, or all, of our bank debt be repaid.

Exploration, Development and Production Risks

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

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

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, cratering, sour gas releases and spills, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or personal injury. In particular, we may explore for and produce sour natural gas in certain areas. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to us. In accordance with industry practice, we are not fully insured against all of these risks, nor are all such risks insurable. Although we maintain liability insurance in an amount that we consider consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits, in which event we could incur significant costs. 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 our 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. Our actual production, revenues, taxes and development and operating expenditures with respect to our reserves will vary from estimates thereof and such variations could be material.

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

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

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

Project Risks

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

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;

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

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

Refinancing Risk and Increased Debt Service Charges

We have a credit facility totalling $510 million, comprised of a $480 million extendible revolving facility and a $30 million non-extendible, non-revolving acquisition facility. The $480 million revolving facility is subject to a request for an extension of the revolving period for a further 364 days and an annual review by the lenders, at which time a lender can provide an extension of the revolving period or request conversions to a one year term loan. Under the term period, no principal payments would be required until April 2011.

The annual renewal date of our credit facility is April 30, 2010. Although we have no reason to believe that we will be unable to extend our credit facility after April 30, 2010, if not renewed, the facility will be available on a non-revolving basis for a period of 364 days thereafter, at which time the facility would be due and payable.

There is also a risk that the credit facility will not be renewed for the same amount or on the same terms. Variations in interest rates and scheduled principal repayments could result in significant changes in the amount required to be applied to debt service. Furthermore, any of these events could affect our ability to fund ongoing operations.

We are required to comply with covenants under the credit facility. In the event that we do not comply with covenants under the credit facility, our access to capital could be restricted or repayment could be required on an accelerated basis by our lender. The lender has security over substantially all of our assets. If we become unable to pay our debt service charges or otherwise commit an event of default such as breach of our financial covenants, the lender may foreclose on or sell our working interests in our properties.

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.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

We make acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner as well as our ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with ours. The integration of acquired business may require substantial management effort, time and resources and may divert management's focus from other strategic opportunities and operational matters.

There may be liabilities associated with an acquisition that we fail to discover or are unable to quantify in our due diligence and we may not be indemnified for some or all of these liabilities.

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 we can focus our efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain of our non-core assets, if disposed of, could be expected to realize less than their carrying value on our financial statements.

Substantial Capital Requirements

We anticipate making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. If our revenues or reserves decline, we may not have access to the capital necessary to undertake or complete future drilling programs. In addition, uncertain levels of near term industry activity coupled with the present global credit crisis exposes us 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 us. Our inability to access sufficient capital for our operations could have a material adverse effect on our business financial condition, results of operations and prospects.

Additional Funding Requirements

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

Dividends

We have not paid any dividends on our outstanding shares. We recently established a dividend policy of paying quarterly cash dividends to Shareholders, and the initial quarterly dividend of $0.05 per Common Share is expected to be paid on April 15, 2010 to Shareholders of record on March 31, 2010.

We currently intend to maintain dividend levels between 5% and 15% of our cash flow, preferably at the lower end of this range. However, the amount of future cash dividends, if any, is not assured and will be subject to the discretion of our Board of Directors and may vary depending on a variety of factors, including fluctuations in commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens and foreign exchange rates. See "*Risk Factors*".

Operational Dependence

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

Competition

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

Regulatory

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

Environmental

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require us to incur costs to remedy such discharge. Although we believe that we are in material compliance with current applicable environmental regulations, no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on our 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. Our exploration and production facilities and other operations and activities emit greenhouse gases and require us to comply with Alberta's greenhouse gas emissions legislation contained in the *Climate Change and Emissions Management Act* and the *Specified Gas Emitters Regulation*. We will also be required 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 our business, financial condition, results of operations and prospects. The future implementation or modification of greenhouse gases 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 ours. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact on us and our operations and financial condition. See "*Industry Conditions – 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 impacts our production revenues. Future Canadian/United States exchange rates could accordingly impact the future value of our reserves as determined by our independent evaluators.

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

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

Issuance of Debt

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

Hedging

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

Availability of Drilling Equipment and Access

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment (typically leased from third parties) in the particular areas where such activities will be conducted.

Demand for such limited equipment or access restrictions may affect the availability of such equipment to us and may delay exploration and development activities.

Title to Assets

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

Insurance

Our involvement in the exploration for and development of oil and natural gas properties may result in us becoming subject to liability for pollution, blow outs, leaks of sour natural gas, property damage, personal injury or other hazards. Although we maintain insurance in accordance with industry standards to address certain of these risks, such insurance has limitations on liability and may not be sufficient to cover the full extent of such liabilities. In addition, such risks are not, in all circumstances, insurable or, in certain circumstances, we may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of any uninsured liabilities would reduce the funds available to us. The occurrence of a significant event that we are not fully insured against, or the insolvency of the insurer of such event, may have a material adverse effect on our 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 us is and will continue to be affected by political events throughout the world that cause disruptions in the supply of oil. Conflicts, or conversely peaceful developments, arising in the Middle-East, and other areas of the world, have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and therefore result in a reduction of our net production revenue.

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

Dilution

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

Management of Growth

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

Expiration of Licences and Leases

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

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights to portions of western Canada and have also made claims that certain developments, including oil and gas exploration development, may have been proceeding without the Crown carrying out appropriate consultations in the course of allowing such developments to proceed. An action has been commenced on behalf of the Sunchild First Nation against the Provincial Crown, various provincial ministries, the Energy Resources Conservation Board and numerous respondent oil and gas companies. Although we have not been named in the action, we have interests in the area in question. Sunchild First Nation seeks judicial review of various Crown and Energy Resources Conservation Board decisions issued since June 30, 2008 in relation to what is claimed to be their traditional land, and which appears to include a significant portion of the foothills area of Alberta, on the basis that the Crown failed to properly consult and accommodate Sunchild First Nation, in the context of issuing licences to the oil and gas companies, forestry and coal companies within Sunchild First Nation's reserve and claimed foothills traditional lands area since the end of June, 2008. While the proceedings could result in a change in the consultative and decision-making processes with respect to the granting of Crown rights and other licences in respect of the area or some portion of it, it is too early to assess the likelihood of such a possibility or its impact on our future operations in this area.

Seasonality

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

Third Party Credit Risk

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

Conflicts of Interest

Certain of our directors 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 *Business Corporations Act* (Alberta). See "*Directors and Officers – Conflicts of Interest*".

Reliance on Key Personnel

Our 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 our business, financial condition, results of operations and prospects. We do not have any key person insurance in effect. The contributions of the existing management team to our immediate and near term operations are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that we will be able to continue to attract and retain all personnel necessary for the development and operation of our business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of our management.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

There are no legal proceedings that we are or were a party to, or that any of our property is or was the subject of, during our 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.

INTEREST 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 completed within the last three years or in any proposed transaction during the current financial year which have materially affected or are reasonably expected to materially affect us, other than as disclosed herein.

AUDITORS

KPMG LLP, Suite 2700, Bow Valley Square II, 205 – 5th Avenue S.W., Calgary, Alberta, T2P 4B9, is our auditor.

TRANSFER AGENT AND REGISTRAR

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

MATERIAL CONTRACTS

The only material contract entered into by us within the most recently completed financial year and which is presently material other than in the ordinary course of business, is the credit agreement in respect of our $510 million credit facility with a syndicate of Canadian chartered banks, which agreement is described in Note 8 to our consolidated financial statements for the year ended December 31, 2009, which note is incorporated by reference herein. A copy of this agreement is available on SEDAR at *www.sedar.com*.

INTERESTS OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a report, valuation, statement or opinion described or included in a filing, or referred to in a filing, made under National Instrument 51-102 by us during, or related to, our most recently completed financial year other than GLJ, our independent engineering evaluator and KPMG LLP, our independent auditors.

We used KPMG LLP for external audit and tax advisory services for the fiscal year ended December 31, 2009. KPMG LLP has advised us that they are independent with respect to us within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

None of the designated professionals of GLJ have any registered or beneficial interests, direct or indirect, in any of our securities or other property or of our associates or affiliates either at the time they prepared the statement, report or valuation prepared by it, at any time thereafter or to be received by them.

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 of our associates or affiliates, except for Grant A. Zawalsky, one of our directors, is a partner at Burnet, Duckworth & Palmer LLP, which law firm renders legal services to us.

ADDITIONAL INFORMATION

Additional information relating to us can be found on SEDAR at *www.sedar.com* and on our website at *www.nuvistaenergy.com*. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of our securities and securities issued and authorized for issuance under our equity compensation plans is contained in our proxy materials relating to our annual and special shareholders meeting held on May 5, 2009 and will be contained in our proxy materials relating to our annual and special shareholders meeting to be held on May 13, 2010. Additional financial information is contained in our consolidated financial statements for the year ended December 31, 2009 and the related management's discussion and analysis.

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

NuVista Energy Ltd.
Suite 3500, 700 – 2nd Street S.W.
Calgary, Alberta, T2P 2W2
Tel: (403) 538-8500
Fax: (403) 538-8505

APPENDIX A

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

Management of NuVista Energy Ltd. ("**NuVista**") is responsible for the preparation and disclosure of information with respect to NuVista'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 NuVista's reserves data. The report of the independent qualified reserves evaluator is presented below.

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

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

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

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

The Reserves Committee of the Board of Directors has reviewed NuVista'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 51-101F2 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 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) "*Keith A. MacPhail*"
Keith A. MacPhail
Chairman

(signed) "*Alex G. Verge*"
Alex G. Verge
President and Chief Executive Officer

(signed) "*Clayton H. Woitas*"
Clayton H. Woitas
Director and Chairman of the Reserves Committee

(signed) "*Pentti O. Karkkainen*"
Pentti O. Karkkainen
Director and Member of the Reserves Committee

February 19, 2010

APPENDIX B

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

To the board of directors of NuVista Energy Ltd. (the "**Company**"):

1. We have evaluated 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:

Independent Qualified Reserves Evaluator	Description and Preparation Date of Evaluation Report	Location of Reserves (County or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate – $000s)			
			Audited	**Evaluated**	**Reviewed**	**Total**
GLJ Petroleum Consultants	Corporate Summary February 16, 2010	Canada	-	1,585,998	-	**1,585,998**

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 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., Calgary, Alberta, Canada, February 19, 2010.

"ORIGINALLY SIGNED BY"

Myron J. Hladyshevsky, P. Eng.
Vice-President

APPENDIX C

NUVISTA ENERGY LTD.

MANDATE OF THE AUDIT COMMITTEE

Role and Objective

The Audit Committee (the "**Committee**") is a committee of the board of directors (the “**Board**”) of NuVista Energy Ltd. ("**NuVista**") to whom the Board has delegated 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 Board approval, the audited financial statements and other mandatory disclosure releases containing financial information. The objectives of the Committee, with respect to NuVista and its subsidiaries, partnership and other controlled entities are as follows:

- To assist the directors in meeting their responsibilities (especially for accountability) in respect of the preparation and disclosure of the financial statements of NuVista and related matters;
- To provide better communication between directors and external auditors;
- To enhance the external auditor's independence;
- To increase the credibility and objectivity of financial reports; and
- 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

- The Committee shall be comprised of at least three directors, all of whom are "independent" (as such term is used in Multilateral Instrument 52-110 — Audit Committees ("MI 52-110").
- The Board shall have the power to appoint the Committee Chair and other members of the Committee.
- All of the members of the Committee shall be "financially literate". The Board has adopted the definition for "financial literacy" used in MI 52-110.

Meetings

- At all meetings of the Committee every question shall be decided by a majority of the votes cast. In case of an equality of votes, the Committee Chair shall not be entitled to a second or casting vote.
- 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.
- 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 CEO and CFO shall attend meetings of the Committee, unless otherwise excused from all or part of any such meeting by the Committee Chair.
- The Committee shall forthwith report the results of meetings and reviews undertaken and any associated recommendations to the board.

- 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.

Mandate and Responsibilities of Committee

- It is the responsibility of the Committee to oversee the work of the external auditors, including resolution of disagreements between management and the external auditors regarding financial reporting.

- It is the responsibility of the Committee to monitor, on behalf of the Board, NuVista's internal control systems, including:

  - identifying, monitoring and mitigating business risks; and

  - ensuring compliance with legal, ethical and regulatory requirements including the certification process.

- It is a primary responsibility of the Committee to review the annual financial statements of NuVista prior to their submission to the Board for approval. The process should include but not be limited to:

  - reviewing the appropriateness of significant accounting principles and any changes in accounting principles, or in their application, which may have a material impact on the current or future years' quarterly unaudited and annual audited financial statements;

  - reviewing significant accruals, reserves or other estimates such as the ceiling test calculation;

  - reviewing accounting treatment of unusual or non-recurring transactions;

  - ascertaining compliance with covenants under loan agreements;

  - reviewing the adequacy of the asset retirement obligation in the financial statements;

  - 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;

  - reviewing non-recurring transactions;

  - reviewing related party transactions; and

  - obtaining explanations of significant variances with comparative reporting periods.

- The Committee is to review the financial statements, prospectuses, management discussion and analysis (MD&A), annual information forms (AIF) and all public disclosure containing audited or unaudited financial information before release and prior to Board approval. The Committee must be satisfied that adequate procedures are in place for the review of NuVista's disclosure of all other financial information and shall periodically access the accuracy of those procedures.

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

  - recommend to the Board the appointment of the external auditors;

  - 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;

  - 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 approve any non-audit services to be provided by the external auditors' firm and consider the impact on the independence of the auditors.

- The Committee shall review with external auditors (and internal auditor if one is appointed by NuVista) their assessment of the internal controls of NuVista, 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 NuVista and its subsidiaries.

- The Committee must pre–approve all non–audit services to be provided to NuVista or its subsidiaries by the external auditors. The Committee may delegate to one or more 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.

- The Committee shall review financial risk management policies and procedures of NuVista (i.e. hedging, litigation and insurance).

- The Committee shall establish a procedure for:

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

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

- The Committee shall review and approve NuVista's hiring policies regarding employees and former employees of the present and former external auditors of NuVista.

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

- The Committee shall meet periodically with the external auditors, independent of management. The issues for consideration should include, but are not limited to:

  - obtaining feedback on competencies, skill sets and performance of key members of the financial reporting team;

  - enquiring as to significant differences from prior year period audits or reviews;

  - enquiring as to transactions accounted for in an acceptable manner but on a basis which in the opinion of the external auditor, was not the preferable accounting treatment;

  - enquiring as to any differences between management and the external auditor;

  - enquiring as to material differences in accounting policies, disclosures or presentation from prior periods;

    - enquiring as to deficiencies in internal controls identified in the course of the performance of the procedures by the external auditors; and

    - enquiring as to any other matters or observations that the external auditors would like to bring to the attention of the Committee.

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

Approved by the Board: March 6, 2008