2015 ANNUAL INFORMATION FORM

MARCH 29, 2016

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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 our Board of Directors.

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

Shareholders means holders of our Common Shares.

Reserves

COGE Handbook means the Canadian Oil and Gas Evaluation Handbook maintained by the Society of Petroleum Engineers (Calgary Chapter), as amended from time to time.

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 Reserve Report means the report of GLJ dated February 18, 2016 evaluating as of December 31, 2015, our crude oil, natural gas and natural gas liquids reserves.

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.

Other

Credit Facility means our extendible revolving term credit facility available from a syndicate of Canadian chartered banks.

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.

ABBREVIATIONS

Oil and Natural Gas Liquids		Natural Gas	
Bbl	barrel	Mcf	thousand cubic feet
Bbls	barrels	MMcf	million cubic feet
Bbls/d	barrels per day	Tcf	trillion cubic feet
Mbbls	thousand barrels	Mcf/d	thousand cubic feet per day
MMbbls	million barrels	MMcf/d	million cubic feet per day
Mstb	thousand stock tank barrels of oil	MMbtu	million British Thermal Units
NGLs	natural gas liquids	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 six Mcf of natural gas being equivalent to one barrel of oil
Boe/d	barrels of oil equivalent per day
Tcfe	trillion cubic feet equivalent
m^3	cubic metres
MBoe	thousand barrels of oil equivalent
Mcfe	thousand cubic feet of gas equivalent, using the conversion factor of six Mcf of natural gas being equivalent to one barrel of oil
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	28.317
cubic metres	cubic feet	35.315
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 or referred to herein, contains forward-looking information and statements (collectively, "**forward-looking statements**"). These forward-looking 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 statements. Such forward-looking statements 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 – Recent Developments*" as to our 2016 guidance including our proposed 2016 capital programs; "*General Description of Our Business – Stated Business Objectives and Strategy*" as to our business focus, plans and strategy; "*Statement of Reserves Data and Other Oil and Natural Gas Information – Disclosure of Reserves Data*" as to our reserves and future net revenue from our reserves, income taxes and pricing, exchange and inflation rates; "*Statement of Reserves Data and Other Oil and Natural Gas Information – Additional Information Relating to Reserves Data*" as to the development of our proved undeveloped reserves and probable undeveloped reserves, future developments costs, our ability to fund future developments costs through funds from operations and debt and equity issuances and anticipated funding costs; "*Statement of Reserves Data and Other Oil and Natural Gas Information – Other Oil and Natural Gas Information – Principal Oil and Natural Gas Properties*" as to our capital expenditure plans, facility and downstream infrastructure capacity and expansion plans, exploration and development activities and opportunities and plans, anticipated production and operating costs, anticipated land expiries, hedging and marketing policies and arrangements and benefits, processing and transportation arrangements and plans, reclamation and abandonment obligations, tax horizon, anticipated increases in our reserves and anticipated treatment under government royalty regimes and "*Description of our Capital Structure – Credit Facility"* as to the anticipated renewal of our Credit Facility.

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 statements are based on the estimates and opinions of our management at the time the statements were made. In addition, forward-looking 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 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;
- expectations of future production rates, volumes and product mixes;
- projected costs and plans and objectives;
- projections of market prices and trading liquidity;
- our capital expenditure program, the timing of expenditures and the sources of funding;
- our access to credit facilities, ability to raise capital and financial flexibility;
- supply and demand for oil, natural gas and natural gas liquids;
- commodity prices; and
- expected royalty rates and the anticipated benefits of royalty incentive programs.

Statements relating to "reserves" are also deemed to be forward-looking 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 or resources can be profitably produced in the future.

Forward-looking 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 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 statements contained herein include the following:

- volatility of commodity prices;
- liabilities inherent in oil and natural gas operations;
- imprecision of reserve and resource estimates;
- risks associated with refinancing our Credit Facility;
- competition from other industry participants;
- lack of processing and transportation infrastructure;
- 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;
- unforeseen title claims or defects;
- 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*".

With respect to forward-looking statements contained in this Annual Information Form, we have made assumptions regarding, among other things: the timing of obtaining regulatory approvals; commodity prices and royalty regimes; availability of skilled labour; timing and amount of capital expenditures; future exchange rates; the price of oil and natural gas; the impact of increasing competition; conditions in general economic and financial markets; access to capital; availability of drilling and related equipment; effects of regulation by governmental agencies; royalty rates and future operating costs. We have included the above summary of assumptions and risks related to forward-looking statements provided in this Annual Information Form in order to provide investors with a more complete perspective on our current and future operations and such information may not be appropriate for other purposes.

You are further cautioned that the preparation of financial statements requires management to make certain judgments and estimates that affect the reported amounts of assets, liabilities, revenues and expenses. Estimating reserves and resources 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. **The information contained in this Annual Information Form, including the documents incorporated by reference or referred to herein, identifies additional factors that could affect our operating results and performance. We urge you to carefully consider those factors.**

The forward-looking statements contained herein are expressly qualified in their entirety by this cautionary statement. The forward-looking 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 statements to reflect new information, subsequent events or otherwise unless required by applicable securities laws.

BARREL OF OIL EQUIVALENCY

We have adopted the standard of 6 Mcf:1 Bbl when converting natural gas to oil equivalent and 1 Bbl:6 Mcf when converting oil to natural gas equivalent. Boes, MMBoes, Mcfes and Tcfes may be misleading, particularly if used in isolation. A Boe conversion ratio of 6 Mcf:1 Bbl and an Mcfe conversion ratio of 1 Bbl:6 Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. **Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.**

NON-GAAP MEASURES

The term "netback" in this Annual Information Form is not a recognized measure under generally accepted accounting principles. We use "netback" as a key performance indicator and it is used by us to evaluate the operating performance of our petroleum and natural gas assets and is determined by deducting royalties, transportation charges and operating expenses from petroleum and natural gas revenue. Readers are cautioned; however, that this measure should not be construed as an alternative to net earnings or cash flow from operating activities determined in accordance with generally accepted accounting principles as an indication of our performance.

NUVISTA ENERGY LTD.

Summary Description of our Business

We are an independent oil and natural gas company engaged in the exploration for, and the development, production and acquisition of oil and natural gas reserves in the province of Alberta. Our primary focus is on the scalable and repeatable condensate-rich Montney formation in the Alberta Deep Basin (Wapiti Montney). See "*General Development of Our Business*", "*General Description of Our Business*" and "*Statement of Reserves Data and Other Oil and Natural Gas Information*" in this Annual Information Form.

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." and on June 24, 2003, we amended our Articles to create our performance shares and remove our private company restrictions.

On January 1, 2009, we amalgamated with Rider Resources Ltd. and immediately thereafter amalgamated with Roberts Bay Resources Ltd., a wholly-owned subsidiary.

On September 30, 2014, we completed an internal corporate restructuring, which through a series of transactions resulted in the dissolution of our three partnerships and the amalgamation of our three subsidiaries. As such, effective October 1, 2014, we have no subsidiaries and are not partner to any partnerships.

On May 12, 2015, we filed Articles of Amendment to remove the preferred shares from our share capital.

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 2400, 525 – 8th Avenue S.W., Calgary, Alberta, T2P 1G1.

GENERAL DEVELOPMENT OF OUR BUSINESS

History and Development

On July 2, 2003, we completed a plan of arrangement with Bonavista Petroleum Ltd. pursuant to which we acquired certain assets of Bonavista Petroleum Ltd. and our Common Shares were distributed to the former holders of common shares of Bonavista Petroleum Ltd. Since the completion of the plan of arrangement, we have grown our business through a combination of exploration, development and optimization of our assets.

The following provides a summary of how our business has developed over the last three years.

Asset Dispositions

On December 11, 2013, we announced the disposition of non-core assets in our W3/W4 operating areas for gross proceeds of approximately $30.2 million. The disposed assets included the Northwest Saskatchewan natural gas area and the West Central Saskatchewan Provost heavy oil areas. The proceeds from the disposition were used to reduce bank indebtedness and fund capital expenditures in our Wapiti operating area.

We disposed of various non-core assets throughout 2014. On June 17, 2014, we completed the disposition of oil and natural gas properties in Pine Creek, Alberta for net proceeds of approximately $8.6 million. On August 28, 2014, we completed the disposition of assets in Pembina, Alberta for net proceeds of approximately $3.6 million. In the fourth quarter of 2014, we completed the disposition of oil and natural gas properties in Northeast British Columbia and Fir and Wapiti (Cardium), Alberta for total proceeds, including closing adjustments, of $69.4 million. Proceeds from these dispositions were used to reduce bank indebtedness and fund capital expenditures in our Wapiti operating area.

We disposed of various non-core assets throughout 2015 for aggregate gross proceeds of $26.9 million. Total average production associated with these assets was approximately 345 boe/d.

Equity Offerings

On October 29, 2013, we completed a private placement and public offering of an aggregate of 5,129,000 "flow-through" Common Shares for gross proceeds of approximately $39.7 million. The offering consisted of: (i) a public offering of 3,200,000 Common Shares issued on a "flow-through" basis in respect of Canadian exploration expense through a syndicate of underwriters for gross proceeds of $25.6 million; and (ii) a private placement of 254,000 Common Shares issued on a "flow-through" basis in respect of Canadian exploration expense and 1,675,000 Common Shares issued on a "flow-through" basis with respect to Canadian development expense for aggregate gross proceeds of approximately $14.1 million.

On December 3, 2013, we completed a public offering of 11,000,000 Common Shares with a syndicate of underwriters for gross proceeds of $78.1 million.

On September 3, 2014, we completed a private offering of 2,400,000 Common Shares issued on a “flow-through” basis, with a syndicate of underwriters for gross proceeds of approximately $29.4 million. The offering consisted of 884,511 Common Shares issued on a "flow-through" basis in respect of Canadian exploration expense at a price of $13.19 per Common Share and 1,476,144 Common Shares issued on a "flow-through" basis with respect to Canadian development expense at a price of $11.99 per Common Share.

On April 29, 2015, we completed a public offering with a syndicate of underwriters of an aggregate of 11,465,000 Common Shares at $7.85 per Common Share and 2,313,000 Common Shares issued on a "flow-through" basis with respect to Canadian development expense at $8.65 per Common Share for gross proceeds of $110.0 million. In addition, we completed a non-brokered private placement of 231,040 Common Shares issued on a "flow-through" basis with respect to Canadian development expense at $8.65 per Common Share for gross proceeds of $2.0 million.

Credit Facility

In November 2013, our Credit Facility was reconfirmed by our lenders at a commitment amount of $240 million with a maximum borrowing amount of $220 million. In October 2014, our lenders increased our borrowing base to $300 million. In November 2015, the borrowing base was reconfirmed at $300 million.

Management and Board of Directors

On March 5, 2013, Mr. Ron Eckhardt and Mr. Sheldon Steeves joined our Board. On December 31, 2013, due to the cumulative effects of NuVista's property dispositions and their overall impact on our head office operations, Mr. Wayne Olmstead our Vice President, Human Resources and Office Administration left NuVista.

On August 12, 2014, Mr. Brian Shaw joined our Board. On August 29, 2014 Mr. Froese, our Chief Financial Officer and Vice President, Finance resigned and was succeeded by Mr. Andreachuk who was promoted to our Chief Financial Officer and Vice President, Finance.

On June 30, 2015, Mr. Craig Burton, our Vice President, Business Development & New Plays resigned. His position was not replaced and the business development role was transferred to the Vice President, Land.

GENERAL DESCRIPTION OF OUR BUSINESS

Stated Business Objectives and Strategy

Our primary focus is the development and delineation of our primary operating area, the Wapiti Montney. The Wapiti Montney is a condensate-rich natural gas resource play that provides us with significant profitable growth potential into the future. We continue to employ a disciplined approach to our business plan which focuses on strong economics to provide positive near and long-term operating and financial results.

We apply our technical and operating expertise within the Montney area with a disciplined approach based on the following principles:

- focus - establish technical expertise in key focus areas;
- invest in plays with scalability and repeatability, and strong economics;
- operate our production and hold a high working interest;
- create a culture of capital discipline, strong execution, and performance;
- attract and retain a talented team;
- control our business plan and be opportunity driven; and
- maintain financial flexibility.

We have created an organization in which operational and technical excellence and idea generation are encouraged in a culture that emphasizes accountability and performance. Our employees are all rewarded with an ownership stake in us, closely aligning their interests with those of our Shareholders. By focusing in an operating area, our teams become experts in identifying opportunities and improving economics. 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 funds from operations, 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 have successfully transitioned from a junior exploration and production company with a focus on shallow natural gas in eastern Alberta to a company with a focus on our longer-life condensate-rich natural gas Wapiti Montney play with significant scale, repeatability and upside.

Cyclical and Seasonal Impact of Industry

Our operational results and financial condition are dependent on the prices we receive 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. To fulfill this commitment, our operating practices and procedures are consistent with the requirements established for the oil and gas industry. We support and endorse the Environmental Operating Procedures developed by the Canadian Association of Petroleum Producers. Key environmental considerations include air quality and climate change, water conservation, spill management, waste management plans, hydraulic fracturing, lease and right-of-way management, natural and historic resource protection, and liability management (including site assessment and remediation). These practices and procedures apply to our employees and we monitor all activities and make reasonable efforts to ensure that companies who provide services to us will operate in a manner consistent with our environmental policy.

We believe that we meet all existing environmental standards and regulations and include sufficient amounts in our capital expenditure budget to continue to meet current environmental protection requirements. These requirements apply to all operators in the oil and gas industry; therefore it is not anticipated that our competitive position within the industry will be adversely affected by changes in applicable legislation. We have internal procedures designed to ensure that detailed due diligence reviews to assess environmental liabilities and regulatory compliance are completed prior to proceeding with new acquisitions and developments.

Our environmental management plan and operating guidelines focus on minimizing the environmental impact of our operations while meeting regulatory requirements and corporate standards. Our environmental program includes: an internal environmental compliance audit and inspection program; a suspended well inspection program to support future development or eventual abandonment; appropriate reclamation and decommissioning standards for wells and facilities ready for abandonment; an effective surface reclamation program; a groundwater monitoring program; a spill prevention, response, and clean-up program; a fugitive emission survey and repair program, and an environmental liability assessment program.

We expect to incur abandonment and reclamation costs as existing oil and gas properties are abandoned. In 2015, expenditures for abandonment and reclamation costs, including costs to reclaim and abandon ownership interests in oil and natural gas assets including well sites, gathering systems and processing facilities, was $8.8 million.

We participate in both the Canadian federal and provincial regulated greenhouse gas emissions reporting programs and continue to quantify annual greenhouse gas emissions for internal reporting purposes. We also participate in the Canadian Association of Petroleum Producers Responsible Canadian Energy Program. Our participation in this program demonstrates a commitment to mitigate our environmental impact through monitoring metrics, identifying areas of improvement, and implementing new processes and procedures for key environmental consideration areas.

During the third quarter of 2015, we identified a leak in a remote pipeline carrying oil emulsion in the non-core area of Northwest Alberta. The pipeline was immediately shut down and our emergency response plan was activated. Our insurers have been notified and are currently evaluating to determine if this is an insurable event. We estimate that the total cost of remediation will be approximately $9.3 million, of which $4.5 million has been spent as of December 31, 2015. It is anticipated that the majority of the remaining remediation will occur throughout 2016.

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 2016 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 29, 2016. 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, 2015, we employed 75 full-time employees, including 66 office and 9 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 18, 2016. The statement is effective as of December 31, 2015 and the preparation date of the statement is February 18, 2016. 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, 2015, as contained in the GLJ Reserve 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 Reserve 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 Province of Alberta.

We determined the future net revenue and present value of future net revenue after income taxes by utilizing GLJ's before income tax future net revenue and our estimate of income tax. Our estimates of the after income tax value of future net revenue have been prepared based on before income tax reserves information and include assumptions and estimates of our tax pools and the sequences of claims and rates of claim thereon. The values shown may not be representative of future income tax obligations, applicable tax horizon or after-tax valuation. The after-tax net present value of our oil and gas properties reflects the tax burden of our properties on a stand-alone basis. It does not provide an estimate of the value of us as a business entity, which may be significantly different. Our financial statements for the year ended December 31, 2015 and the associated management's discussion and analysis should be consulted for additional information regarding our taxes.

Future net revenue is a forecast of revenue, estimated using forecast prices and costs, arising from the anticipated development and production of resources, net of the associated royalties, operating costs, development costs and abandonment and reclamation costs for our wells with attributable reserves. 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 Reserve 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 Resource 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, 2015
FORECAST PRICES AND COSTS

	RESERVES							
	LIGHT AND MEDIUM CRUDE OIL		CONVENTIONAL NATURAL GAS (1)		NATURAL GAS LIQUIDS		SHALE GAS	
RESERVES CATEGORY	Gross (Mbbls)	Net (Mbbls)	Gross (MMcf)	Net (MMcf)	Gross (Mbbls)	Net (Mbbls)	Gross (MMcf)	Net (MMcf)
PROVED:								
Developed Producing	21	43	45,140	41,283	11,267	8,592	111,525	104,770
Developed Non-Producing	22	21	7,318	6,641	1,506	1,158	14,548	13,610
Undeveloped	29	23	9,045	8,193	23,128	18,458	303,946	287,596
TOTAL PROVED	72	88	61,502	56,115	35,901	28,208	430,019	405,976
PROBABLE	63	67	55,998	52,526	41,295	31,318	504,851	472,396
TOTAL PROVED PLUS PROBABLE	135	154	117,500	108,641	77,196	59,526	934,870	878,372

Note:
(1) Includes solution gas and an immaterial amount of coal bed methane

	NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAXES DISCOUNTED AT (%/year)					UNIT VALUE BEFORE INCOME TAXES DISCOUNTED AT 10% (1)	
RESERVES CATEGORY	0 ($000s)	5 ($000s)	10 ($000s)	15 ($000s)	20 ($000s)	($/Boe)	($/Mcfe)
PROVED:							
Developed Producing	427,075	349,249	296,781	259,567	231,996	9.00	1.50
Developed Non-Producing	64,905	46,714	35,903	28,868	23,977	7.88	1.31
Undeveloped	665,202	360,081	191,431	93,590	34,240	2.82	0.47
TOTAL PROVED	1,157,182	756,044	524,114	382,025	290,214	4.98	0.83
PROBABLE	1,911,623	963,952	534,086	314,574	191,335	4.49	0.75
TOTAL PROVED PLUS PROBABLE	3,068,804	1,719,996	1,058,200	696,598	481,549	4.72	0.79

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

	NET PRESENT VALUES OF FUTURE NET REVENUE AFTER INCOME TAXES DISCOUNTED AT (%/year)				
RESERVES CATEGORY	0 ($000s)	5 ($000s)	10 ($000s)	15 ($000s)	20 ($000s)
PROVED:					
Developed Producing	427,075	349,249	296,781	259,567	231,996
Developed Non-Producing	64,905	46,714	35,903	28,868	23,977
Undeveloped	614,809	339,175	182,238	89,339	32,186
TOTAL PROVED	1,106,789	735,138	514,922	377,774	288,159
PROBABLE	1,388,785	700,671	384,887	222,738	131,374
TOTAL PROVED PLUS PROBABLE	2,495,574	1,435,809	899,810	600,512	419,533

**TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2015
FORECAST PRICES AND COSTS**

RESERVES CATEGORY	REVENUE[(1)] ($000s)	ROYALTIES[(2)] ($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	4,518,395	663,947	1,896,698	745,982	54,587	1,157,182	50,393	1,106,789
Total Proved plus Probable	10,536,007	1,644,603	4,112,368	1,617,498	92,733	3,068,804	573,230	2,495,574

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 PRODUCT TYPE
AS OF DECEMBER 31, 2015
FORECAST PRICES AND COSTS**

	NET PRESENT VALUE OF FUTURE NET REVENUE [(3)(4)] (before deducting Future Income Tax Expenses and Discounted at 10%/year)	UNIT VALUE [(5)] (before deducting Future Income Tax Expenses and Discounted 10%/year)	
	($000s)	($/Boe)	($/Mcfe)
Proved			
Light and Medium Crude Oil [(1)]	1,856	15.56	2.59
Conventional Natural Gas [(2)]	80,551	6.58	1.10
Shale Gas	441,690	4.75	0.79
Total Proved	524,098	4.98	0.83
Proved plus Probable			
Light and Medium Crude Oil [(1)]	3,590	17.29	2.88
Conventional Natural Gas [(2)]	116,755	4.77	0.79
Shale Gas	937,824	4.70	0.78
Total Proved Plus Probable	1,058,168	4.72	0.79

Notes:
(1) Including solution gas, other by-products as well as a very immaterial amount of heavy oil.
(2) Including by-products but excluding solution gas.
(3) Other company revenue and costs not related to a specific production group have been allocated proportionately to production groups.
(4) Columns may not add due to rounding.
(5) Unit values are based on net reserve volumes.

Definitions and Notes to Reserves Data Tables

In the tables set forth above in "*Statement of Reserves Data and Other Oil and Natural Gas Information*" 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. **"unproved property"** means a property or part of a property to which no reserves have been specifically attributed.

5. "**exploratory well**" means a well that is not a development well, a service well or a stratigraphic test well.

6. "**development costs**" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground draining, road building, and relocating public roads, gas lines and power lines, 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.

7. "**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.

8. "**exploration costs**" means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves,

including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property 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.

9. "**service well**" means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt water disposal, water supply for injection, observation or injection for combustion.

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

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.

Pricing Assumptions

The forecast cost and price assumptions in this Annual Information Form assume 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 Reserve Report were as follows:

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

	OIL				NATURAL GAS	NATURAL GAS LIQUIDS				
Year	**WTI Cushing Oklahoma ($US/Bbl)**	**Edmonton Par Price 40° API ($/Bbl)**	**Hardisty Heavy 12° API ($/Bbl)**	**Cromer Medium 29. 3° API ($/Bbl)**	**AECO Gas Price ($/MMbtu)**	**Edmonton Propane ($/Bbl)**	**Edmonton Butane ($/Bbl)**	**Edmonton C5+ Stream Quality ($/Bbl)**	**INFLATION RATES %/Year (2)**	**EXCHANGE RATE ($US/$Cdn)(3)**
Forecast										
2016	44.00	55.86	35.70	50.80	2.76	9.58	41.90	60.79	2.0	0.725
2017	52.00	64.00	45.02	59.52	3.27	16.00	48.00	68.48	2.0	0.750
2018	58.00	68.39	49.06	63.60	3.45	20.52	51.29	73.17	2.0	0.775
2019	64.00	73.75	54.42	68.59	3.63	25.81	55.31	78.91	2.0	0.800
2020	70.00	78.79	59.75	73.27	3.81	27.58	59.09	84.30	2.0	0.825
2021	75.00	82.35	63.56	76.59	3.90	28.82	61.76	88.12	2.0	0.850
2022	80.00	88.24	69.32	82.06	4.10	30.88	66.18	94.41	2.0	0.850
2023	85.00	94.12	74.62	87.53	4.30	32.94	70.59	100.71	2.0	0.850
2024	87.88	96.48	78.40	89.73	4.50	33.77	72.36	103.24	2.0	0.850
2025	89.63	98.41	79.99	91.52	4.60	34.44	73.81	105.30	2.0	0.850
2026+	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	2.0	0.850

Notes:
(1) As at January 1, 2016.
(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, 2015, excluding financial derivative commodity contracts were $3.64/Mcf for natural gas, $51.53/Bbl for condensate, $46.74/Bbl for light and medium crude oil and $9.96/Bbl for NGLs (excluding condensate).

Reserves Reconciliation

RECONCILIATION OF GROSS RESERVES
BY PRODUCT TYPE [1]
FORECAST PRICES AND COSTS

	LIGHT AND MEDIUM CRUDE OIL			CONVENTIONAL NATURAL GAS [2] [3]		
	Proved (Mbbls)	**Probable (Mbbls)**	**Proved Plus Probable (Mbbls)**	**Proved (MMcf)**	**Probable (MMcf)**	**Proved Plus Probable (MMcf)**
December 31, 2014	943	672	1,615	102,239	76,266	178,505
Discoveries	-	-	-	-	-	-
Extensions	-	-	-	-	5,507	5,507
Infill Drilling	-	-	-	-	-	-
Improved Recovery	-	-	-	-	-	-
Technical Revisions	(756)	(578)	(1,334)	(15,981)	(13,657)	(29,638)
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	(15,080)	(12,118)	(27,199)
Economic Factors	(82)	(31)	(113)	-	-	-
Production	(33)	-	(33)	(9,676)	-	(9,676)
December 31, 2015	72	63	135	61,502	55,998	117,500

	NATURAL GAS LIQUIDS			SHALE GAS [3]		
	Proved (Mbbls)	**Probable (Mbbls)**	**Proved Plus Probable (Mbbls)**	**Proved (MMcf)**	**Probable (MMcf)**	**Proved Plus Probable (MMcf)**
December 31, 2014	33,068	33,003	66,071	356,956	371,270	728,226
Discoveries	-	-	-	-	-	-
Extensions	7,749	9,628	17,377	107,946	128,553	236,500
Infill Drilling	-	-	-	-	-	-
Improved Recovery	236	35	272	3,578	488	4,066
Technical Revisions	(1,314)	409	(905)	(848)	40,339	39,491
Acquisitions	-	-	-	-	-	-
Dispositions	(633)	(567)	(1,201)	-	-	-
Economic Factors	(839)	(1,213)	(2,052)	(12,901)	(35,799)	(47,800)
Production	(2,366)	-	(2,366)	(24,713)	-	(24,713)
December 31, 2015	35,901	41,295	77,196	430,019	504,851	934,870

Notes:

(1) We held an immaterial amount of heavy crude oil reserves at December 31, 2014 which we divested of during the year ended December 31, 2015.

(2) Includes solution gas, other associated by-products and an immaterial amount of coal bed methane.

(3) The December 31, 2014 shale gas reserve values were previously included in the December 31, 2014 conventional natural gas reserve values in our statement of reserves data effective December 31, 2014. The shale gas reserve values have been shown separately from conventional natural gas in this table to conform to NI 51-101 product types.

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 60% of the proved undeveloped reserves in the GLJ Reserve Report over the next three years and the significant majority of the probable undeveloped reserves over the next six 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 our most recent three financial years.

Year	Light and Medium Crude Oil (Mbbls)		Heavy Crude Oil (Mbbls)		Shale Gas [1] (MMcf)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
2013	719	719	218	218	-	-
2014	-	173	43	164	-	-
2015	-	29	-	-	72,522	303,946

Year	Conventional Natural Gas (MMcf)		Natural Gas Liquids (Mbbls)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
2013	173,124	173,124	13,406	13,406
2014	138,130	279,866	10,861	20,887
2015	-	9,045	5,192	23,128

Note:
(1) For 2013 and 2014, our shale gas volumes were included in conventional natural gas.

Of our total proved plus probable reserves, 75,322 MBoe or 30% are proved undeveloped reserves. These well locations are allocated reserves because they are within the defined distances to proved reserve accumulations. The Wapiti Montney play accounts for 73,240 MBoe or 97% of the proved undeveloped reserves. Subject to market conditions, capital expenditures of $50.6 million in 2016 and $147.3 million in 2017 will be invested in developing our proved undeveloped reserves. The remaining proved undeveloped reserves are planned to be mostly developed within an additional three year time period subject to capital availability and allocation and regulatory and gas processing considerations.

Probable Undeveloped Reserves

The following table discloses, for each product type, the volumes of probable undeveloped reserves that were first attributed in each of our most recent three financial years.

Year	Light and Medium Crude Oil (Mbbls)		Heavy Crude Oil (Mbbls)		Shale Gas [1] (MMcf)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
2013	1,090	1,090	516	516	-	-
2014	-	396	89	462	-	-
2015	-	12	-	-	136,609	461,758

Year	Conventional Natural Gas (MMcf)		Natural Gas Liquids (Mbbls)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
2013	184,674	184,674	14,142	14,142
2014	224,951	391,243	17,544	29,217
2015	5,507	38,105	10,218	36,905

Note:
(1) For 2013 and 2014, our shale gas volumes were included in conventional natural gas.

Of our total proved plus probable reserves, 120,227 MBoe or 48% are probable undeveloped reserves. These well locations are allocated reserves because they are within the defined distances to proved reserve accumulations. The Wapiti Montney play accounts for 110,874 MBoe or 92% of the probable undeveloped reserves. Subject to market conditions, capital expenditures of $97.2 million in 2016 and $248.6 million in 2017 will be invested developing our proved plus probable undeveloped reserves. The remaining proved undeveloped reserves are planned to be mostly developed within an additional four year time period subject to capital availability and allocation and regulatory and gas processing considerations.

Significant Factors or Uncertainties

Changes in future commodity prices relative to the forecasts provided under "*Pricing Assumptions*" above could have a negative impact on our reserves and in particular the development of our undeveloped reserves unless future development costs are adjusted in parallel. We are also committed to deliver certain amount of our production in accordance with various processing and transportation agreements. Any changes or disruptions to these agreements could have an effect on our reserves. See "*Marketing Arrangements*". Other than the foregoing and the factors disclosed or described above, 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*".

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, 2015, we had approximately 1,200 net wells for which we expect to incur abandonment and reclamation costs. We calculated our overall abandonment costs at $151 million (undiscounted) and $44.7 million (10% discount). Included in this calculation are the abandonment and reclamation costs for our proved plus probable properties as well as surface leases, facilities and pipelines. The future net revenues disclosed in this Annual Information Form based on the GLJ Reserve Report do not contain an allowance for abandonment and reclamation costs for surface leases, facilities and pipelines. The GLJ Reserve Report deducted $92.7 million (undiscounted) and $7.0 million (10% discount using forecast prices and costs) for abandonment costs of wells with booked reserves, in estimating the future net revenue disclosed in this Annual Information Form.

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)**
2016	57,374	97,218
2017	151,108	248,593
2018	217,972	337,640
2019	165,904	386,097
2020	152,111	347,701
Remaining	1,514	200,250
Total (Undiscounted)	745,982	1,617,498

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

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, 2015. Information in respect of current production is average production, net to our working interest, except where otherwise indicated.

Wapiti Operating Area

Wapiti, our largest operating area is located south of Grande Prairie, Alberta, approximately 520 kilometers northwest of Calgary. The stratigraphy underlying the Wapiti operating area falls largely within the deep basin gas window and is characterized as having multiple stacked prospective Cretaceous–Triassic gas bearing formations that lend themselves to horizontal drilling and multi-stage fracturing technology. The greater Wapiti area has a land base of approximately 344,960 gross acres (224,678 net acres) with an average working interest of 65%. This operating area is poised to play an important role in our future growth with substantially all of our projected 2016 capital budget expected to be spent in this region.

<u>Wapiti - Montney</u>

We hold rights in approximately 136,640 gross acres (117,760 net acres) of land with an approximate working interest of 86% that are prospective for the Triassic Montney zone resource play. This formation is typified by high rate condensate-rich natural gas. In 2014, we completed the construction of a 100% owned compressor and dehydration station in the Bilbo area. The facility and downstream third party infrastructure has a gross throughput capacity of up to 80 MMcf/d. A second compressor station was constructed in the Elmworth area and has 40 MMcf/d of initial throughput capacity and plans are underway to expand the facility to 65 MMcf/d in 2016. This compressor station became operational in June 2015. Production from the Wapiti Montney zone is currently processed at one of three large area processing plants: the SemCams K3 plant, the Keyera Simonette plant or the CNRL Gold Creek plant.

In 2015, we drilled and completed 19 (19.0 net) wells resulting in 18 (18.0 net) natural gas wells and 1 (1.0 net) planned disposal well. A combination of development pad drilling and delineation drilling took place in 2015. 2016 activity will focus on maintaining production volumes at Bilbo, building volumes to increase throughput for the new Elmworth compressor, and a modest amount of delineation drilling.

In 2015, Wapiti Montney production averaged approximately 16,735 Boe/d (68.1 MMcf/d of natural gas, 4,602 Bbls/d of condensate and 785 Bbls/d of natural gas liquids (excluding condensate)).

Wapiti - Sweet

In addition to the Montney formations, we have working interests in numerous other shallower potential productive zones including the Falher, Wilrich and Nikanassin. The Falher and Wilrich formations are Cretaceous targets that are seeing increasing development with the use of horizontal multi-stage fracturing. These wells are typically high-rate liquid-rich natural gas wells.

Our 2015 average production rate was 3,751 Boe/d (16.5 MMcf/d of natural gas, 186 Bbls/d of condensate and oil and 814 Bbls/d of natural gas liquids (excluding condensate)). In 2015, we did not drill any wells in the area. Sweet natural gas production in the Wapiti area is processed at third party operated facilities where we own a working interest, primarily at the CNRL South Wapiti 16-36-67-9W6 with a 3.7% working interest and the CNRL Elmworth Deep Cut 4-8-69-8W6 where we hold a 2.2% working interest. These large plants provide both favorable liquid recoveries and low operating costs for our production.

W5 Non-core Operating Area

Our Deep Basin operating area is located approximately 450 kilometers north of Calgary and includes our Kaybob/Waskahigan property in addition to other minor areas in the Pembina region. Currently, this operating area has a land base of approximately 46,938 gross acres (26,511 net acres) with an average working interest of 56%. Our 2015 average production rate was 1,018 Boe/d (4.8MMcf/d of natural gas and 219 Bbls/d of oil and natural gas liquids). We drilled no wells in the W5 operating area in 2015.

W3/W4 Non-core Operating Area

Our W3/W4 operating area is comprised primarily of our Oyen region. The Oyen core region is located approximately 250 kilometers southeast of Calgary. Currently, its primary product is dry shallow gas production. This operating area contains 325,485 gross acres (267,357 net acres) of land with an average working interest of 82%. We control the majority of the infrastructure in this region and have an extensive seismic database. Our 2015 average production rate was 469 Boe/d (2.7 MMcf/d of natural gas and 12 Bbls/d of oil and natural gas liquids). We did not drill any wells in this area in 2015.

Northwest Alberta Non-core Operating Area

Our 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 and Mississippian Debolt formations. We own and operate three 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 seven 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.

This operating region contains 220,240 gross acres (159,582 net acres) with an average working interest of 72%. Our 2015 production averaged 435 Boe/d (2.2 MMcf/d of natural gas and 73 Bbls/d of oil) from this region. We did not drill any wells in this area in 2015.

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, 2015.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing (2)		Producing		Non-Producing (2)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	57	15	140	101	590	333	1,025	777
Total (1)	57	15	140	101	590	333	1,025	777

Notes:
(1) The table does not include 3 gross (3 net) non-producing wells located in Saskatchewan.
(2) Included in the non-producing wells are 75 gross (56 net) oil wells and 574 gross (435 net) natural gas wells that are abandoned but not yet reclaimed.

Properties With No Attributed Reserves

As at December 31, 2015 we held 938,903 gross (678,368) net acres to which no reserves are currently attributed. Rights to explore, develop and exploit 28,026 net acres of these land holdings could expire by December 31, 2016 if not continued. We have no material work commitments other than abandonment obligations on these properties and the majority of this acreage is located in our non-core operating areas. When determining gross and net acreage for two or more leases covering the same lands but different rights, the acreage is reported for each lease. Where there are multiple discontinuous rights in a single lease, the acreage is reported only once.

Significant Factors or Uncertainties Relevant to Properties with no Attributed Reserves

We do not anticipate any significant economic factors or significant uncertainties will affect any particular components of our properties with no attributed reserves. There are no unusually significant abandonment and reclamation costs with our properties with no attributed reserves. See "*Significant Factors and Uncertainties Affecting Reserves Data – Abandonment and Reclamation Costs*" and "*Risk Factors*".

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, 2015 see Note 17 to our financial statements for the year ended December 31, 2015.

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 70% of our net after royalty production for the term January 1, 2016 to December 31, 2016 and up to 50% and 40% of our net after royalty production for 2017 and 2018, respectively. Our price risk management program is comprised of costless collars, differentials, 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. The integration and application of these strategies resulted in an average realized price (excluding financial derivative commodity contracts) of $3.64/Mcf for the year ended December 31, 2015.

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 and NGL markets and look for opportunities to enter into price risk management contracts for up to 60% of net after royalty production for 2016 and up to 50% and 40% of our net after royalty production for 2017 and 2018, respectively. In 2015, our average realized condensate & oil price (excluding financial derivative commodity contracts) was $51.34/Bbl and our average realized price for natural gas liquids (excluding condensate) was $9.96/Bbl.

For additional details on our price risk management program see Note 17 to our financial statements for the year ended December 31, 2015.

In March 2016, our Board of Directors approved an amendment to the commodity risk management program, amending the terms to secure minimum prices for up to 70% of our net after royalty production for the first 18 month forward period and up to 60% for the following 18 months forward period.

Processing and Transportation

Most of our natural gas and associated natural gas liquids production requires processing to meet sales quality specifications. We require pipeline transportation to deliver our raw natural gas and natural gas liquids to these processing facilities. Access to processing and pipeline transportation is critical to the development of our Wapiti Montney condensate-rich natural gas play. We have entered into long-term take-or-pay contracts to ensure access to processing and pipelines for current and future production. We have made the strategic decision to own most of the gathering and compression facilities required for production from our Wapiti Montney play but we rely on third-party owned infrastructure for the processing and transportation of our production.

We have committed to a five year firm take-or-pay transportation agreement with Semcams for 10 MMcf/d of raw natural gas production starting July 1, 2012, increasing to 17 MMcf/d starting July 1, 2013 and expiring in 2017. In May 2014, we entered into a 10-year processing and transportation agreement with Semcams for an additional 30 MMcf/d of raw natural gas starting in mid-2015 and extended the existing 17 MMcf/d for the same term. In October 2014, we entered into an agreement to increase these volumes a further 30 MMcf/d in mid-2016 for a total commitment of 77 MMcf/d of raw natural gas transportation and processing.

In April 2013, we entered into a 10-year processing, transportation and marketing agreement with Keyera Corp. for 35 MMcf/d of raw natural gas starting in the third quarter of 2014, increasing to 65 MMcf/d late in the fourth quarter of 2014. In early 2014, we entered into an agreement to increase these volumes to 80 MMcf/d in the third quarter of 2015. In addition to these raw natural gas processing and transportation arrangements, we have entered into agreements for the transportation and fractionation of our natural gas liquids produced from the above raw gas processing arrangements. We continue to pursue other processing and transportation agreements as we develop our Wapiti Montney play to provide line-of-sight to future capacity and production growth.

Most of the condensate produced from our Wapiti Montney play is extracted in the field at compressor stations. These condensate volumes are either transported by pipeline or truck to sales points. We have entered into long-term condensate pipeline transportation agreements to access additional pipeline capacity and reduce the need for higher cost trucking transportation of condensate production.

Tax Horizon

Based on estimated 2016 funds from operations and capital expenditures, and existing tax pools, we do not expect to be cash taxable in 2016. Projecting taxability beyond 2016 is subject to many uncertainties including commodity prices, capital spending, acquisitions, divestments and government regulations and guidelines and, as a result, we are unable to predict taxability beyond the current year.

Costs Incurred

The following table summarizes the costs incurred related to our activities for the year ended December 31, 2015:

Expenditure	**Year Ended December 31, 2015 ($000s)**
Property acquisition costs – Unproved properties (1)	7,420
Property acquisition costs – Proved properties	-
Exploration costs (2)	9,737
Development costs (3)	262,197
Other	211
Total	279,565

Notes:
(1) Cost of land acquired and non-producing lease rentals on those lands.
(2) Geological and geophysical capital expenditures and drilling costs for exploration wells.
(3) 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, 2015:

	Development		**Exploratory**	
	Gross	**Net**	**Gross**	**Net**
Natural Gas	18.0	18.0	-	-
Oil	-	-	-	-
Disposal Well	1.0	1.0	-	-
Dry	-	-	-	-
Total	19.0	19.0	-	-

In 2016, we expect to drill approximately 10 to 11 condensate-rich natural gas wells within our Wapiti Montney resource play. See "*Statement of Reserves Data and Other Oil and Natural Gas Information – Other Oil and Natural Gas Information – Principal Oil and Natural Gas Properties*".

Production Estimates

The following table sets out the volumes of our working interest production estimated for the year ended December 31, 2016, which is reflected in the estimates of future net revenue disclosed in the forecast price tables contained above under the subheading "*Reserves Data (Forecast Prices and Costs)*":

	Light and Medium Oil (Bbls/d)	Conventional Natural Gas[1] (Mcf/d)	Natural Gas Liquids (Bbls/d)	Shale Gas (Mcf/d)	Total (BOE)
Total Proved	24	20,263	7,386	82,524	24,541
Total Proved plus Probable	26	20,946	8,418	96,463	28,012

Note:
(1) Includes an immaterial amount of coal bed methane.

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 2015				Year Ended
	Mar. 31	June 30	Sept. 30	Dec. 31	Dec. 31, 2015
Average Daily Production [1]					
Light and Medium Crude Oil (Bbls/d)	331	309	168	-	198
Natural Gas (Mcf/d)	98,608	91,070	91,257	96,359	94,309
NGLs (Bbls/d) [2]	1,794	1,512	1,413	1,864	1,648
Condensate (Bbls/d) [2]	4,656	4,448	4,831	5,432	4,844
Combined (Boe/d)	23,215	21,448	21,622	23,355	22,408
Average Net Production Prices Received					
Light and Medium Crude Oil ($/Bbl)	41.78	53.60	51.58	-	46.74
Natural Gas ($/Mcf)	3.83	3.61	3.55	3.55	3.64
NGLs ($/Bbl) [2]	14.87	7.17	8.42	8.76	9.96
Condensate ($/Bbl) [2]	48.47	62.05	51.58	45.52	51.53
Combined ($/Boe)	27.73	29.46	27.48	25.88	27.59
Royalties Paid					
Light and Medium Crude Oil ($/Bbl)	6.54	6.37	5.88	-	7.03
Natural Gas ($/Mcf)	0.24	0.17	0.22	0.19	0.20
NGLs ($/Bbl) [2]	1.54	0.75	1.19	1.16	1.18
Condensate ($/Bbl) [2]	3.77	4.92	3.63	4.64	4.25
Combined ($/Boe)	1.36	0.95	0.42	0.58	0.83
Production Costs [3][4]					
Light and Medium Crude Oil ($/Bbl)	0.16	0.19	0.10	-	0.11
Natural Gas ($/Mcf)	7.75	9.09	8.92	7.68	8.33
NGLs ($/Bbl) [2]	0.85	0.91	0.83	0.90	0.87
Condensate ($/Bbl) [2]	2.19	2.66	2.83	2.60	2.57
Combined ($/Boe)	10.94	12.84	12.68	11.17	11.88
Transportation					
Light and Medium Crude Oil ($/Bbl)	1.69	0.78	0.91	-	1.23
Natural Gas ($/Mcf)	0.12	0.11	0.13	0.28	0.16
NGLs ($/Bbl) [2]	-	-	-	-	-
Condensate ($/Bbl) [2]	13.39	0.64	2.13	0.35	3.95
Combined ($/Boe)	3.21	0.63	1.03	1.23	1.55
Netback Received [5]					
Light and Medium Crude Oil ($/Bbl)	33.39	46.26	44.69	-	38.37
Natural Gas ($/Mcf)	2.33	2.04	2.05	2.14	2.15
NGLs ($/Bbl) [2]	12.48	5.51	6.40	6.70	7.91
Condensate ($/Bbl) [2]	29.12	53.83	43.00	37.93	40.76
Combined ($/Boe)	12.22	15.04	13.35	12.90	13.33

Notes:
(1) Before deduction of royalties.
(2) For the purposes of this table condensate has been shown separately from natural gas liquids.
(3) Production costs are composed of direct costs incurred to operate wells that produce any one or more of the product types that are shown. Costs have been allocated to products based on production volumes on a pro-rata basis.
(4) Overhead recoveries associated with operated properties are charged to production costs and accounted for as a reduction to general and administrative costs.
(5) Netbacks are calculated by subtracting royalties, production costs and transportation from revenues.

The following table indicates our average daily production (including production from our major areas) for the year ended December 31, 2015:

	Light and Medium Crude Oil (Bbls/d)	Natural Gas Liquids (Bbls/d)	Condensate [1] (Bbls/d)	Natural Gas (Mcf/d)	Total (Boe/d)
Wapiti – Montney	-	785	4,602	68,091	16,735
Wapiti – Sweet	20	814	166	16,508	3,751
Non-core	179	49	76	9,710	1,922
Total	199	1,648	4,844	94,309	22,408

Note:
(1) For the purposes of this table condensate has been shown separately from natural gas liquids.

DIVIDENDS

On February 14, 2011, our Board of Directors determined that we will no longer pay a dividend to Shareholders but rather use these funds from operations to fund our drilling program and growth opportunities. We have not declared dividends on our Common Shares since November of 2010.

Any decision to pay dividends on the Common Shares will be made by our Board of Directors on the basis of our earnings, financial requirements and other conditions that the Board of Directors may consider appropriate in the circumstances. It is not intended that dividends will be paid in the foreseeable future.

DESCRIPTION OF OUR CAPITAL STRUCTURE

Credit Facility

We have a $300 million extendible revolving term Credit Facility from a syndicate of Canadian chartered banks. Borrowing under the Credit Facility may be made by prime loans, bankers' acceptances and/or US LIBOR advances. These advances bear interest at the bank's prime rate and/or at money market rates plus a borrowing margin. The Credit Facility is secured by a first floating charge debenture, general assignment of book debts and our oil and natural gas properties and equipment. The Credit Facility does not contain any financial covenants but we are subject to various non-financial covenants under our Credit Facility. Compliance with these covenants is monitored on a regular basis.

The Credit Facility has a 364-day revolving period and is subject to an annual review by the lenders, at which time a lender can extend the revolving period or can request conversion to a one-year term loan. During the revolving period, a review of the maximum borrowing amount occurs semi-annually on or before October 31. During the term period, no principal payments would be required until April 29, 2016.

During the revolving period, a determination of the maximum borrowing amount occurs semi-annually at approximately October 31. The annual renewal date of our Credit Facility is April 29, 2016. Although we have no reason to believe that we will be unable to extend our Credit Facility after April 29, 2016, if not renewed, the facility will be available on a non-revolving basis for a period of one year thereafter, at which time the facility would be due and payable. See "*Risk Factors – Refinancing Risk and Increased Debt Service Charges*".

Share Capital

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.

MARKET FOR OUR SECURITIES

Trading Price and Volume

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**
2015			
January	7.52	5.87	9,882,443
February	8.98	7.15	7,849,224
March	8.61	6.75	7,322,814
April	9.00	7.38	11,371,444
May	9.54	7.49	7,781,300
June	8.00	6.60	6,438,628
July	6.89	4.94	5,958,437
August	5.92	4.02	11,562,904
September	5.92	4.56	10,275,973
October	6.35	4.48	15,249,140
November	5.53	3.91	10,582,067
December	4.38	3.28	10,877,762
2016			
January	4.53	2.72	12,488,995
February	4.62	3.75	6,113,307
March (1 – 28)	5.50	4.33	9,161,247

Prior Sales

During the year ended December 31, 2015, we issued a total of 1,608,305 options pursuant to our stock option plan and 275,850 restricted share awards pursuant to our restricted share award plan. No funds are received by us until the options are exercised. On the payment date of the restricted share awards, we have the sole discretion as to whether the awards shall be paid in cash, Common Shares from treasury or Common Shares purchased on the Toronto Stock Exchange. See note 15 of our annual financial statements for a summary of stock option and restricted share award transactions.

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)(3)(5) Calgary, Alberta	Chairman and Director	May 2003	Our Chairman and Executive Chairman of Bonavista Energy Corporation.
W. Peter Comber (1)(3) Toronto, Ontario	Director	May 2004	Former Managing Director of Barrantagh Investment Management Inc. (an investment counselling firm).

Name and Municipality of Residence	Position with NuVista	Director or Officer Since	Principal Occupation
Ronald J. Eckhardt (2) Calgary, Alberta	Director	March 2013	Former Executive Vice-President, North American Operations for Talisman Energy Inc.
Pentti O. Karkkainen (1)(3)(6) Calgary, Alberta	Director	July 2003	Former General Partner, KERN Partners Ltd. (a private equity firm and partnership).
Ronald J. Poelzer (1)(4)(5) Calgary, Alberta	Director	May 2003	Executive Vice Chairman of Bonavista Energy Corporation.
Brian G. Shaw (1) Toronto, Ontario	Director	August 2014	Director of Encana Corp., Manulife Bank of Canada and Manulife Trust Company.
Sheldon B. Steeves (2)(4) Calgary, Alberta	Director	March 2013	Former CEO and Chairman of Echoex Ltd., a private oil and natural gas exploration and production company.
Grant A. Zawalsky (4)(5) Calgary, Alberta	Director	May 2003	Managing Partner of Burnet, Duckworth & Palmer LLP (barristers and solicitors).
Jonathan A. Wright (5) Calgary, Alberta	President and Chief Executive Officer and a Director	May 2011	Our President and Chief Executive Officer and a Director since May 2011. Prior thereto, Mr. Wright was Senior Vice-President of Talisman Energy Ltd.'s North American Conventional Production Division.
Ross L. Andreachuk Calgary, Alberta	Vice President, Finance and Chief Financial Officer and Corporate Secretary	May 2009	Our Vice President, Finance and Chief Financial Officer since September, 2014. Prior thereto, Mr. Andreachuk was our Vice President and Controller.
Kevin G. Asman Calgary, Alberta	Vice President, Marketing	January 2010	Our Vice President, Marketing.
Mike J. Lawford Calgary, Alberta	Vice President, Development	January 2012	Our Vice President, Development since January 2012. Prior thereto, Mr. Lawford was Executive Project Management Officer and Manager – New Plays at Talisman Energy Ltd.
D. Chris McDavid Calgary, Alberta	Vice President, Operations	August 2006	Our Vice President, Operations.
Joshua T. Truba Calgary, Alberta	Vice President, Land & Business Development	January 2009	Our Vice President, Land.

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) Member of our Executive Committee.
(6) Our Lead Director.

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

As at the date of this Annual Information Form our directors and officers, as a group, beneficially owned, or directed or controlled, directly or indirectly, approximately 7.1 million Common Shares or approximately 5% 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. 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 of Directors 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).

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, Mr. Poelzer and Mr. Shaw 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: *Independent Businessman*

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. From August 1999 to his retirement in May 2015, Mr. Comber had been a 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, Thornmark Capital Corporation, an investment holding company, and principal officer of Thornmark Capital Funding Corporation, merchant bank. Prior 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.

Pentti O. Karkkainen: *Independent Businessman*

Mr. Karkkainen has over 30 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 was a Co-Founder and General Partner of KERN Partners, a leading Canadian based energy focused capital markets and private equity firm, from September 2000 to July 2014 and was the firm's Senior Strategy Advisor from July, 2014 until his retirement from the firm in August, 2015. 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.

Ronald J. Poelzer: *Bonavista Energy Corporation*

Mr. Poelzer has more than 30 years of experience in the oil and gas industry and is currently Executive Vice Chairman of Bonavista Energy Corporation. Prior thereto, Mr. Poelzer was Executive Vice President and Vice Chairman of Bonavista responsible for various strategic planning, business development, financial and capital market roles. Prior to joining Bonavista in 1997, Mr. Poelzer was with Poco Petroleum Ltd. as Vice President, Business Development. Prior thereto, Mr. Poelzer was in public accounting practice.

Mr. Poelzer is a Chartered Accountant and holds a Bachelor of Commerce (Distinction) degree from the University of Saskatchewan.

Mr. Poelzer is also a member of the board of directors of various private companies and a charitable foundation.

Brian G. Shaw: *Independent Businessman*

Mr. Shaw is an experienced financial industry executive with particular expertise in capital markets and investing activities. He is currently a director of Encana Corp., Manulife Bank of Canada and Manulife Trust Company.

Mr. Shaw is an alumni of CIBC World Markets Inc. (and its predecessor firm Wood Gundy) where he was employed for 23 years. He was Chairman and Chief Executive Officer of CIBC World Markets Inc. from 2005 through 2008 and prior to that managed the Global Equities Division for a number of years. Mr. Shaw is a Chartered Financial Analyst and holds a Masters of Business Administration from the University of Alberta and a Bachelor of Commerce from the University 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 $335,000 in 2015 and $295,000 in 2014.

Audit-Related Fees

The aggregate fees billed in each of the last two fiscal years for assurance and related services by our external auditor were $35,995 in 2015 and $95,000 in 2014.

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 $44,735 in 2015 and $39,570 in 2014.

All Other Fees

Our auditors did not provide any other products or services not reported above in 2015 and 2014.

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 up to the 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.

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 and upgrading, transportation, and marketing) as a result of legislation enacted by various levels of government with respect to the pricing and taxation of oil and natural gas through agreements among the governments of Canada and Alberta 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 in western Canada.

Pricing and Marketing

Oil

In Canada, producers of oil are entitled to negotiate sales contracts directly with oil purchasers, which results in the market determining the price of oil. Worldwide supply and demand factors primarily determine oil prices; however, prices are also influenced by regional market and transportation issues. The specific price depends in part on oil quality, prices of competing fuels, distance to market, availability of transportation, 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. 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 National Energy Board of Canada. The National Energy Board of Canada is currently undergoing a consultation process to update the current regulations governing the issuance of export licences. The updating process is necessary to meet the criteria set out in the federal *Jobs, Growth and Long-term Prosperity Act* which received Royal Assent on June 29, 2012. In this transitory period, the National Energy Board of Canada has issued, and is currently following an "Interim Memorandum of Guidance concerning Oil and Gas Export Applications and Gas Import Applications under Part VI of the *National Energy Board Act* (Canada)".

Natural Gas

Alberta's natural gas market has been deregulated since 1985. Supply and demand determine the price of natural gas and price is calculated at the sale point, being the wellhead, the outlet of a gas processing plant, on a gas transmission system such as the Alberta "NIT" (Nova Inventory Transfer), at a storage facility, at the inlet to a utility system or at the point of receipt by the consumer. Accordingly, the price for natural gas is dependent upon such producer's own arrangements (whether long or short term contracts and the specific point of sale). As natural gas is also traded on trading platforms such as the Natural Gas Exchange, Intercontinental Exchange or the New York Mercantile Exchange in the United States, spot and future prices can also be influenced by supply and demand fundamentals on these platforms. Natural gas exported from Canada is subject to regulation by the National Energy Board of Canada 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 National Energy Board of Canada 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 a National Energy Board of Canada 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 National Energy Board of Canada.

The North American Free Trade Agreement

The North American Free Trade Agreement among the governments of Canada, the United States and Mexico came into force on January 1, 1994. 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 the total supply of goods of the party maintaining the restriction as compared to 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 measures which only restrict the volume of exports); and (iii) disrupt normal channels of supply.

All three signatory countries are prohibited from imposing a minimum or maximum export price requirement in any circumstance where any other form of quantitative restriction is prohibited. The signatory countries are also prohibited from imposing a minimum or maximum import price requirement except as permitted in enforcement of countervailing and anti-dumping orders and undertakings. The North American Free Trade Agreement requires energy regulators to ensure the orderly and equitable implementation of any regulatory changes and to ensure that the application of those changes will cause minimal disruption to contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, all of which are important for Canadian oil and natural gas exports. The North American Free Trade Agreement contemplates the reduction of Mexican restrictive trade practices in the energy sector and prohibits discriminatory border restrictions and export taxes.

Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations that govern royalties, production rates and other matters. The royalty regime in a given province is a significant factor in the profitability of oil sands projects, 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 carved out of the working interest owner's interest, from time to time, 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.

The federal government has signaled it will, *inter alia*, phase out subsidies for the oil and gas industry, which include only allowing the use of the Canadian Exploration Expenses tax deduction in cases of successful exploration, implementing more stringent reviews for pipelines, and establishing a pan-Canadian framework for combating climate change within 90 days of the 2015 Paris Climate Conference which concluded on December 12, 2015. These changes could affect earnings of companies operating in the oil and natural gas industry.

Alberta

On January 29, 2016, the Government of Alberta released and accepted the Royalty Review Advisory Panel's recommendations, which outlined the implementation of a "Modernized Royalty Framework" for Alberta (the "**MRF**"). The MRF will take effect on January 1, 2017. Wells drilled prior to January 1, 2017 will continue to be governed by the current "Alberta Royalty Framework" for a period of 10 years until January 1, 2027. The MRF is structured in three phases: (i) Pre-Payout, (ii) Mid-Life, and (iii) Mature. During the Pre-Payout phase, a fixed 5% royalty will apply until the well reaches payout. Well payout occurs when the cumulative revenue from a well is equal to the Drilling and Completion Cost Allowance (determined by a formula that approximates drilling and completion costs for wells based on depth, length and historical costs). The new royalty rate will be payable on gross revenue generated from all production streams (oil, gas, and natural gas liquids), eliminating the need to label a well as "oil" or "gas". Post-payout, the Mid-Life phase will apply a higher royalty rate than the Pre-Payout phase. While the metrics for calculating the Mid-Life phase royalty have yet to be released, the rate will be determined based on commodity prices and are intended, on average, to yield the same internal rate of return as under the current Alberta Royalty Framework. In the Mature phase, once a well reaches the tail end of its cycle and production falls below a Maturity Threshold, currently estimated to be 20 bbl/d for oil and 200 mcf/d for gas, the royalty rate will move to a sliding scale (based on volume and price) with a minimum royalty rate of 5%. The downward adjustment of the royalty rate in the Mature phase is intended to account for the higher per-unit fixed cost involved in operating an older well. Details of the MRF, including the applicable royalty rates and formulas, are scheduled to be released by March 31, 2016.

Oil sands projects are also subject to Alberta's royalty regime. The MRF does not change the oil sands royalty framework, however, the method and figures by which the royalties are calculated will be released to the public. Prior to payout of an oil sands project, 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, determined using the average monthly price, expressed in Canadian dollars, for WTI crude oil at Cushing, Oklahoma. 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.

Currently, 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.

Royalties for wells drilled prior to January 1, 2017 are paid pursuant to "The New Royalty Framework" (implemented by the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*) and the "Alberta Royalty Framework", until January 1, 2027. 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. The maximum royalty payable under the royalty regime is 40%. Royalty rates for natural gas under the royalty regime are similarly determined using a single sliding rate formula with the maximum royalty payable under the royalty regime set at 36%.

Producers of oil and natural gas from freehold lands in Alberta are required to pay freehold mineral tax. The freehold mineral tax is a tax levied by the Government of Alberta on the value of oil and natural gas production from non-Crown lands and is derived from the *Freehold Mineral Rights Tax Act* (Alberta). The freehold mineral tax is levied on an annual basis on calendar year production using a tax formula that takes into consideration, among other things, the amount of production, the hours of production, the value of each unit of production, the tax rate and the percentages that the owners hold in the title. The basic formula for the assessment of freehold mineral tax is: revenue less allocable costs equals net revenue divided by wellhead production equals the value based upon unit of production. If payors do not wish to file individual unit values, a default price is supplied by the Crown. On average, the tax levied is 4% of revenues reported from fee simple mineral title properties.

The Government of Alberta has, from time to time, implemented drilling credits, incentives or transitional royalty programs to encourage oil and gas development and new drilling. For example, the Innovative Energy Technologies Program has the stated objectives of increasing recovery from oil and gas deposits, finding technical solutions to the gas over bitumen issue, improving the recovery of bitumen by in-situ and mining techniques and improving the recovery of natural gas from coal seams. The Innovative Energy Technologies Program provides royalty adjustments to specific pilot and demonstration projects that utilize new or innovative technologies to increase recovery from existing reserves.

In addition, the Government of Alberta has implemented certain initiatives intended to accelerate technological development and facilitate the development of unconventional resources (the "**Emerging Resource and Technologies Initiative**"). These initiatives apply to wells drilled before January 1, 2017, for a 10 year period until January 1, 2027. Specifically:

- Coalbed methane wells will receive a maximum royalty rate of 5% for 36 producing months on up to 750 MMcf of production, retroactive to wells that began producing on or after May 1, 2010;

- Shale gas wells will receive a maximum royalty rate of 5% for 36 producing months with no limitation on production volume, retroactive to wells that began producing on or after May 1, 2010;

- Horizontal gas wells will receive a maximum royalty rate of 5% for 18 producing months on up to 500 MMcf of production, retroactive to wells that commenced drilling on or after May 1, 2010; and

- Horizontal oil wells and horizontal non-project oil sands wells will receive a maximum royalty rate of 5% with volume and production month limits set according to the depth of the well (including the horizontal distance), retroactive to wells that commenced drilling on or after May 1, 2010.

While the MRF eliminates the various royalty credits and incentives, outlined above, for wells drilled after December 31, 2016, the Government of Alberta has committed to creating cost allowance programs to maintain a competitive royalty structure. Details of these programs are scheduled to be released simultaneously with the finalization of the MRF prior to April 21, 2016.

Land Tenure

The respective provincial governments predominantly own the rights to crude oil and natural gas located in the western provinces. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences, and permits for varying terms, and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. Private ownership of oil and natural gas also exists in such provinces 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. On March 29, 2007, British Columbia expanded its policy of deep rights reversion for new leases to provide for the reversion of both shallow and deep formations that cannot be shown to be capable of production at the end of their primary term.

Alberta also has a policy of "shallow rights reversion" which provides 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.

Production and Operation Regulations

The oil and natural gas industry in Canada is highly regulated and subject to significant control by provincial regulators. Regulatory approval is required for, among other things, the drilling of oil and natural gas wells, construction and operation of facilities, the storage, injection and disposal of substances and the abandonment and reclamation of well-sites. In order to conduct oil and gas operations and remain in good standing with the applicable provincial regulator, we must comply with applicable legislation, regulations, orders, directives and other directions (all of which are subject to governmental oversight, review and revision, from time to time). Compliance with such legislation, regulations, orders, directives or other directions can be costly and a breach of the same may result in fines or other sanctions.

Environmental Regulation

The oil and natural gas industry is currently subject to regulation pursuant to a variety of provincial and federal environmental legislation, all of which is subject to governmental review and revision from time to time. Such legislation provides for, among other things, restrictions and prohibitions on the spill, 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 sets out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites. 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 and the imposition of material fines and penalties.

Federal

Pursuant to the *Jobs, Growth and Long-term Prosperity Act*, the Government of Canada amended or repealed several pieces of federal environmental legislation and, in addition, created a new federal environment assessment regime that came in to force on July 6, 2012. The changes to the environmental legislation under the *Jobs, Growth and Long-term Prosperity Act* are intended to provide for more efficient and timely environmental assessments of projects that previously had been subject to overlapping legislative jurisdiction.

Alberta

The Alberta Energy Regulator is the single regulator responsible for all energy development in Alberta. The Alberta Energy Regulator ensures the safe, efficient, orderly, and environmentally responsible development of hydrocarbon resources including allocating and conserving water resources, managing public lands, and protecting the environment. The Alberta Energy Regulator's responsibilities exclude the functions of the Alberta Utilities Commission and the Surface Rights Board, as well as Alberta Energy's responsibility for mineral tenure. The objective behind a single regulator is an enhanced regulatory regime that is efficient, attractive to business and investors, and effective in supporting public safety, environmental management and resource conservation while respecting the rights of landowners.

The Government of Alberta relies on regional planning to accomplish its responsible resource development goals. The following frameworks, plans and policies form the basis of Alberta's Integrated Resource Management System. The Integrated Resource Management System method to natural resource management sets out to engage and consult with stakeholders and the public. While the Alberta Energy Regulator is the primary regulator for energy development, several governmental departments and agencies may be involved in land use issues, including Alberta Environment and Parks, Alberta Energy, the Alberta Energy Regulator, the Alberta Environmental Monitoring, Evaluation and Reporting Agency, the Policy Management Office, the Aboriginal Consultation Office, and the Land Use Secretariat.

In December 2008, the Government of Alberta released a new land use policy for surface land in Alberta, the Alberta Land Use Framework. The Alberta Land Use Framework 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 seven 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.

Proclaimed in force in Alberta on October 1, 2009, the *Alberta Land Stewardship Act* provides the legislative authority for the Government of Alberta to implement the policies contained in the Alberta Land Use Framework. Regional plans established under the *Alberta Land Stewardship Act* are deemed to be legislative instruments equivalent to regulations and will be binding on the Government of Alberta and provincial regulators, including those governing the oil and gas industry. In the event of a conflict or inconsistency between a regional plan and another regulation, regulatory instrument or statutory consent, the regional plan will prevail. Further, the *Alberta Land Stewardship 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, registrations, approvals and authorizations 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 *Alberta Land Stewardship 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.

On August 22, 2012, the Government of Alberta approved the Lower Athabasca Regional Plan which came into force on September 1, 2012. The Lower Athabasca Regional Plan is the first of seven regional plans developed under the Alberta Land Use Framework. Lower Athabasca Regional Plan covers a region in the northeastern corner of Alberta that is approximately 93,212 square kilometres in size. The region includes a substantial portion of the Athabasca oil sands area, which contains approximately 82% of the province's oil sands resources and much of the Cold Lake oil sands area.

The Lower Athabasca Regional Plan establishes six new conservation areas and nine new provincial recreation areas. In conservation and provincial recreation areas, conventional oil and gas companies with pre-existing tenure may continue to operate. Any new petroleum and gas tenure issued in conservation and provincial recreation areas will include a restriction that prohibits surface access. In contrast, oil sands companies' tenure has been (or will be) cancelled in conservation areas and no new oil sands tenure will be issued. While new oil sands tenure will be issued in provincial recreation areas, new and existing oil sands tenure will prohibit surface access.

In July 2014, the Government of Alberta approved the South Saskatchewan Regional Plan which came into force on September 1, 2014. The South Saskatchewan Regional Plan is the second regional plan developed under the Alberta Land Use Framework. The South Saskatchewan Regional Plan covers approximately 83,764 square kilometres and includes 44% of the provincial population.

The South Saskatchewan Regional Plan creates four new and four expanded conservation areas, and two new and six expanded provincial parks and recreational areas. Similar to Lower Athabasca Regional Plan, the South Saskatchewan Regional Plan will honour existing petroleum and natural gas tenure in conservation and provincial recreational areas. However, any new petroleum and natural gas tenures sold in conservation areas, provincial parks, and recreational areas will prohibit surface access. However, oil and gas companies must minimize impacts of activities on the natural landscape, historic resources, wildlife, fish and vegetation when exploring, developing and extracting the resources. Freehold mineral rights will not be subject to this restriction.

Liability Management Rating Programs

Alberta

In Alberta, the Alberta Energy Regulator implements the Licensee Liability Rating Program. The Licensee Liability Rating Program is a liability management program governing most conventional upstream oil and gas wells, facilities and pipelines. The *Oil and Gas Conservation Act* establishes an orphan fund (the "**Orphan Fund**") to pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline included in the Licensee Liability Rating Program if a licensee or working interest participant becomes defunct. The Orphan Fund is funded by licensees in the Licensee Liability Rating Program through a levy administered by the Alberta Energy Regulator. The Licensee Liability Rating Program is designed to minimize the risk to the Orphan Fund posed by unfunded liability of licences and prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines. The Licensee Liability Rating Program requires a licensee whose deemed liabilities exceed its deemed assets to provide the Alberta Energy Regulator with a security deposit. The ratio of deemed liabilities to deemed assets is assessed once each month and failure to post the required security deposit may result in the initiation of enforcement action by the Alberta Energy Regulator.

Made effective in three phases, from May 1, 2013 to August 1, 2015, the Alberta Energy Regulator implemented important changes to the Licensee Liability Rating Program that resulted in a significant increase in the number of oil and gas companies in Alberta that are required to post security. The changes affect the deemed parameters and costs used in the formula that calculates the ratio of deemed liabilities to deemed assets under the Licensee Liability Rating Program, increasing a licensee's deemed liabilities and rendering the industry average netback factor more sensitive to asset value fluctuations. The changes stem from concern that the previous regime significantly underestimated the environmental liabilities of licensees.

The Alberta Energy Regulator implemented the inactive well compliance program to address the growing inventory of inactive wells in Alberta and to increase the Alberta Energy Regulator's surveillance and compliance efforts under *Directive 013: Suspension Requirements for Wells.* The inactive well compliance program applies to all inactive wells that are noncompliant with Directive 013 as of April 1, 2015. The objective is to bring all inactive noncompliant wells under the inactive well compliance program into compliance with the requirements of Directive 013 within 5 years. As of April 1, 2015, each licensee is required to bring 20% of its inactive wells into compliance every year, either by reactivating or suspending the wells in accordance with Directive 013 or by abandoning them in accordance with *Directive 020: Well Abandonment*. The list of current wells subject to the inactive well compliance program is available on the Alberta Energy Regulator's digital submission system.

Climate Change Regulation

Federal

Climate change regulation at both the federal and provincial level has the potential to significantly affect the regulatory environment of the oil and natural gas industry in Canada. Such regulations, surveyed below, impose certain costs and risks on the industry.

The Government of Canada is a signatory to the *United Nations Framework Convention on Climate Change* and a participant to the Copenhagen Accord (a non-binding agreement created by the *United Nations Framework Convention on Climate Change* which represents a broad political consensus and reinforces commitments to reducing greenhouse gas emissions). On January 29, 2010, Canada inscribed in the Copenhagen Accord its 2020 economy-wide target of a 17% reduction of greenhouse gas emissions from 2005 levels. This target is aligned with the United States target. In a report dated October 2013, the Government stated that this target represents a significant challenge in light of strong economic growth (Canada's economy is projected to be approximately 31% larger in 2020 compared to 2005 levels).

On April 26, 2007, the Government of Canada released "Turning the Corner: An Action Plan to Reduce Greenhouse Gases and Air Pollution" (the "**Action Plan**") which set forth a plan for regulations to address both greenhouse gas and air pollution. An update to the Action Plan, "Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions" was released on March 10, 2008 (the "**Updated Action Plan**"). The Updated Action Plan outlines emissions intensity-based targets, for application to regulated sectors on a facility-specific basis, sector-wide basis or company-by-company basis. Although the intention was for draft regulations aimed at implementing the Updated Action Plan to become binding on January 1, 2010, the only regulations being implemented are in the transportation and electricity sectors. The federal government indicates that it is taking a sector-by-sector regulatory approach to reducing greenhouse gas emissions and is working on regulations for other sectors. Representatives of the Government of Canada have 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. In June 2012, the second US-Canada Clean Energy Dialogue Action Plan was released. The plan renewed efforts to enhance bilateral collaboration on the development of clean energy technologies to reduce greenhouse gas emissions.

On December 12, 2015, the *United Nations Framework Convention on Climate Change* adopted the Paris Agreement, to which Canada is a participant. The Paris Agreement mandates that all countries must work together to limit global temperature rise resulting from green house gas emissions to a goal of less than 2° Celsius and to pursue efforts to limit below 1.5° Celsius, through implementing successive nationally determined contributions. Technical details remain unreleased, but the Government of Canada is expected to announce a plan within 90 days of the Paris Agreement, which will significantly increase Canada's green house gas emission reduction targets.

Alberta

As part of its efforts to reduce greenhouse gas emissions, Alberta introduced legislation to address greenhouse gas emissions: the *Climate Change and Emissions Management Act* enacted on December 4, 2003 and amended through the *Climate Change and Emissions Management Amendment Act*, which received royal assent on November 4, 2008. The accompanying regulations include the *Specified Gas Emitters Regulation*, which imposes greenhouse gas limits, and the *Specified Gas Reporting Regulation*, which imposes greenhouse gas emissions reporting requirements. Alberta is the first jurisdiction in North America to impose regulations requiring large facilities in various sectors to reduce their greenhouse gas emissions.

The *Specified Gas Emitters Regulation*, effective July 1, 2007, applies to facilities emitting more than 100,000 tonnes of greenhouse gases in 2003 or any subsequent year ("**Regulated Emitters**"), and requires reductions in greenhouse gas emissions intensity (e.g. the quantity of greenhouse gas emissions per unit of production) from emissions intensity baselines established in accordance with the *Specified Gas Emitters Regulation*. The *Specified Gas Emitters Regulation* distinguishes between "Established Facilities" and "New Facilities".

On June 25, 2015, the Government of Alberta renewed the *Specified Gas Emitters Regulation* for a period of two years with significant amendments while Alberta's newly formed Climate Advisory Panel conducted a comprehensive review of the province's climate change policy. In 2015, Regulated Emitters are required to reduce their emissions intensity by 2% from their baseline in the fourth year of commercial operation, 4% of their baseline in the fifth year, 6% of their baseline in the sixth year, 8% of their baseline in the seventh year, 10% of their baseline in the eighth year, and 12% of their baseline in the ninth or subsequent years. These reduction targets will increase, meaning that Regulated Emitters in their ninth or subsequent years of commercial operation must reduce their emissions intensity from their baseline by 15% in 2016 and 20% in 2017.

Regulated Emitters can meet their emissions intensity targets through a combination of the following: (1) producing its products with lower carbon inputs, (2) purchasing emissions offset credits from non-regulated emitters (generated through activities that result in emissions reductions in accordance with established protocols), (3) purchasing emissions performance credits from other Regulated Emitters that earned credits through the reduction of their emissions below the 100,000 tonne threshold, (4) cogeneration compliance adjustments, and (5) by contributing to the Climate Change and Emissions Management Fund. Contributions to the fund are made at a rate of $15 per tonne of greenhouse gas emissions, increasing to a rate of $20 per tonne of greenhouse gas emissions in 2016 and $30 per tonne of greenhouse gas emissions in 2017. Proceeds from the fund are directed at testing and implementing new technologies for greening energy production.

On November 22, 2015, as a result of the Climate Advisory Panel's Climate Leadership report, the Government of Alberta announced its Climate Leadership Plan which proposes to introduce a carbon tax on all emitters. An economy-wide levy $30 per tonne of greenhouse gas emissions will be phased in, starting in January 2017 at $20 per tonne, and increasing to $30 per tonne in January 2018. An oil sands specific approach was proposed to replace the $30 per tonne of GHG emissions to further reduce emissions and promote carbon competitiveness rather than rewarding past intensity levels. A 100 megatonne per year limit for greenhouse gas emissions was proposed for oil sands operations, which currently emit roughly 70 megatonnes per year. This cap exempts new upgrading and cogeneration facilities, which are allocated a separate 10 megatonne limit. The existing *Specified Gas Emitters Regulation* will be replaced for large industrial facilities with a Carbon Competitiveness Regulation in which sector specific output-based carbon allocations will be used to ensure competitiveness.

Alberta is also the first jurisdiction in North America to direct dedicated funding to implement carbon capture and storage technology across industrial sectors. Alberta has committed $1.24 billion over 15 years to fund two large-scale carbon capture and storage projects that will begin commercializing the technology on the scale needed to be successful. On December 2, 2010, the Government of Alberta passed the *Carbon Capture and Storage Statutes Amendment Act, 2010*. It deemed the pore space underlying all land in Alberta to be, and to have always been, the property of the Crown and provided for the assumption of long-term liability for carbon sequestration projects by the Crown, subject to the satisfaction of certain conditions.

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. The risks set out below are not an exhaustive list, nor should be taken as a complete summary or description of all the risks associated with our business and the oil and natural gas business generally.

Prices, Markets and Marketing

Numerous factors beyond our control do, and will continue to affect the marketability and price of oil and natural gas acquired or discovered by us. 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 or contract for the delivery of crude oil by rail. Deliverability uncertainties related to the distance of our reserves are from pipelines, railway lines, processing and storage facilities, operational problems affecting pipelines, railway lines and facilities as well as government regulation relating to prices, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business may also affect us.

Prices for oil and natural gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors beyond our control. These factors include economic conditions in the United States, Canada, Europe, China and emerging markets, the actions of the Organization of the Petroleum Exporting Countries ("**OPEC**"), governmental regulation, political stability in the Middle East, Northern Africa and elsewhere, the foreign supply and demand of oil and natural gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Prices for oil and natural gas are also subject to the availability of foreign markets and our ability to access such markets. Oil prices are expected to remain volatile and may decline further in the near future as a result of global excess supply due, in part, to the increased growth of shale oil production in the United States, the decline in global demand for exported cure oil commodities and the Organization of the Petroleum Exporting Countries recent decisions pertaining to the oil production of member countries. Declines in oil prices result in a reduction of our net production revenue. The economics of producing from some wells may change because of lower prices, which could result in reduced production of oil or natural gas and a reduction in the volumes and the value 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 its oil and natural gas acquisition, development and exploration activities. Any substantial and extended decline in the price of oil and natural gas would have an adverse effect on the carrying value of our reserves, borrowing capacity, revenues, profitability and funds from operations and may have a material adverse effect on our business, financial condition, results of operations and prospects.

Oil and natural gas prices are expected to remain volatile for the near future because of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies, OPEC actions, and sanctions imposed on certain oil producing nations by other countries and the ongoing credit and liquidity concerns. Volatile oil and natural gas prices make it difficult to estimate the value of producing properties for acquisitions and often cause disruption in the market for oil and natural 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.

A prolonged period of low and/or volatile commodity prices, may negatively impact our ability to meet our guidance targets, maintain our business and meet all of our financial obligations as they come due, and could also result in a delay or cancellation of existing or future drilling, development or construction programs, unutilized long-term transportation commitments and a reduction in the value and amount of our reserves. We conduct assessments of the carrying value of our assets in accordance with Canadian generally accepted accounting principles. If crude and natural gas forecast prices decline, it could result in downward revisions to the carrying value of our assets and our net earnings could be adversely affected.

Weakness in the Oil and Gas Industry

Recent market events and conditions, including global excess oil and natural gas supply, recent actions taken by OPEC, slowing growth in China and other emerging economies, market volatility and disruptions in Asia, and sovereign debt levels in various countries, have caused significant weakness and volatility in commodity prices. These events and conditions have caused a significant decrease in the valuation of oil and gas companies and a decrease in confidence in the oil and gas industry. These difficulties have been exacerbated in Canada by the recent changes in government at a federal level and, in case of Alberta, the provincial level and the resultant uncertainty surrounding regulatory, tax and royalty changes that may be implemented by the new governments. In addition, the inability to get the necessary approvals to build pipelines and other facilities to provide better access to markets for the oil and gas industry in western Canada has led to additional uncertainty and reduced confidence in the oil and gas industry in western Canada. Lower commodity prices may also affect the volume and value of our reserves especially as certain reserves become uneconomic. In addition, lower commodity prices have restricted, and are anticipated to continue to restrict, our cash flow resulting in a reduced capital expenditure budget. As a result, we may not be able to replace our production with additional reserves and both our production and reserves could be reduced on a year over year basis. Any decrease in value of our reserves may reduce the borrowing base under our credit facilities, which, depending on the level of the our indebtedness, could result in having to repay a portion of our indebtedness. Given the current market conditions and the lack of confidence in the Canadian oil and gas industry, we may have difficulty raising additional funds or if we are able to do so, it may be on unfavourable and highly dilutive terms. If these conditions persist, our cash flow may not be sufficient to continue to fund our operations and to satisfy our obligations when due and may require additional equity or debt financing and/or proceeds from asset sales. There can be no assurance that such equity or debt financing will be available on terms that are satisfactory or at all. Similarly, there can be no assurance that we will be able to realize any or sufficient proceeds from asset sales to discharge our obligations.

Risks Associated with Forecast Prices

Our reserves as at December 31, 2015 are estimated using forecast pricing escalating prices as set forth under "*Statement of Reserves Data and Other Oil and Natural Gas Information – Disclosure of Reserves Data – Pricing Assumptions*". These prices are substantially above current oil and natural gas prices. If oil and gas prices stay at current levels our reserves may be substantially reduced as economic limits of developed reserves are reached earlier and undeveloped reserves become uneconomic at such prices. Even if some reserves remain economic at lower price levels, sustained low prices may compel us to re-evaluate our development plans and reduce or eliminate various projects with marginal economics.

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, our existing reserves, and the production from them, will decline over time as we produce from such reserves. A future increase in our reserves will depend on both our ability to explore and develop our existing properties and on our ability to select and acquire suitable producing properties or prospects. There is no assurance that we will be able continue to find satisfactory properties to acquire or participate in. Moreover, our management may determine that current markets, terms of acquisition, participation or pricing conditions make potential acquisitions or participations uneconomic. There is also no assurance that we will discover or acquire further commercial quantities of oil and natural gas.

Future oil and natural gas exploration may involve unprofitable efforts from dry wells as well as from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, completing (including hydraulic fracturing), operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs.

Drilling hazards, environmental damage and various field operating conditions could greatly increase the cost of operations and adversely affect the production from successful wells. Field operating conditions include, but are not limited to, delays in obtaining governmental approvals or consents, and 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, it is not possible to eliminate production delays and declines from normal field operating conditions, which can negatively affect revenue and funds from operations 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, but not limited to, fire, explosion, blowouts, cratering, sour gas releases, and spills or other environmental hazards. These typical risks and hazards could result in substantial damage to oil and natural gas wells, production facilities, other property, the environment and personal injury. Particularly, 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.

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.

As is standard industry practice, we are not fully insured against all risks, nor are all risks insurable. Although we maintain liability insurance in an amount that we consider consistent with industry practice, liabilities associated with certain risks could exceed policy limits or not be covered. In either event, we could incur significant costs.

Gathering and Processing Facilities, Pipeline Systems and Rail

We deliver our products through gathering, processing facilities and pipeline systems some of which we do not own and by rail. The amount of oil and natural gas that we can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities, pipeline systems and railway lines. The lack of availability of capacity in any of the gathering and processing facilities, pipeline systems and railway lines, and in particular the processing facilities, could result in our inability to realize the full economic potential of our production or in a reduction of the price offered for our production. The lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to produce and to market oil and natural gas production. In addition, the pro-rationing of capacity on inter-provincial pipeline systems also continues to affect the ability to export oil and natural gas. Unexpected shut downs or curtailment of capacity of pipelines for maintenance or integrity work because of actions taken by regulators could also affect our production, operations and financial results. Furthermore, producers are increasingly turning to rail as an alternative means of transportation. In recent years, the volume of crude oil shipped by rail in North America has increased dramatically. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities could harm our business and, in turn, our financial condition, results of operations and cash flows. The Federal Government has signaled that it plans to review the National Energy Board approval for large projects. This may base the timeframe for project approvals for current and future applications to increase.

Following major accidents in Lac-Megantic, Quebec and North Dakota, the Transportation Safety Board of Canada and the U.S. National Transportation Board have recommended additional regulations for railway tank cars carrying crude oil. In June 2015, as a result of these recommendations, the Government of Canada passed the Safe and Accountable Rail Act which increased insurance obligations on the shipment of crude oil by rail, imposed a per tonne levy of $1.65 on crude oil shipped by rail to compensate victims and for environmental cleanup in the event of a railway accident. In addition to this legislation, new regulations have implemented the TC-117 standard for all rail tank cars carrying flammable liquids which formalized the commitment to retrofit, and eventually phase out DOT-111 tank cars carrying crude oil. The increased regulation of rail transportation may reduce the ability of railway lines to alleviate pipeline capacity issues and add additional costs to the transportation of crude oil by rail.

A portion of our production may, from time to time, be processed through facilities owned by third parties and over which we do not have control. From time to time these facilities may discontinue or decrease operations either as a result of normal servicing requirements or as a result of unexpected events. A discontinuation or decrease of operations could have a material adverse effect on our ability to process our production and to deliver the same for sale.

Market Price of our Common Shares

The trading price of our securities is subject to substantial volatility often based on factors related and unrelated to our financial performance or prospects. Factors unrelated to our performance could include macroeconomic developments nationally, within North America or globally, domestic and global commodity prices or current perceptions of the oil and gas market. Similarly, the market price of our Common Shares could be subject to significant fluctuations in response to variations in our operating results, financial condition, liquidity and other internal factors. Accordingly, the price at which our Common Shares will trade cannot be accurately predicted.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

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

Operational Dependence

Other companies operate some of the assets in which we have an interest. 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 depends upon a number of factors that may be outside of our control, including, but not limited to, 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.

In addition, due to the current low and volatile commodity prices, many companies, including companies that may operate some of the assets in which we has an interest, may be in financial difficulty, which could impact their ability to fund and pursue capital expenditures, carry out their operations in a safe and effective manner and satisfy regulatory requirements with respect to abandonment and reclamation obligations. If companies that operate some of the assets in which we have an interest fail to satisfy regulatory requirements with respect to abandonment and reclamation obligations we may be required to satisfy such obligations and to seek recourse from such companies. To the extent that any of such companies go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in such assets being shut-in, the potential of us becoming subject to additional liabilities relating to such assets and us having difficulty collecting revenue due from such operators. Any of these factors could materially adversely affect our financial and operational results.

Project Risks

We manage a variety of small and large projects in the conduct of our business. Project delays may delay expected revenues from operations. Significant project cost over-runs could make a project uneconomic. Our ability to execute projects and market oil and natural gas 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 availability of, and the ability to acquire, water supplies needed for drilling and hydraulic fracturing, or our ability to dispose of water used or removed from strata at a reasonable cost and in accordance with applicable environmental regulations;
- 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;
- regulatory changes;
- 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 be unable to market the oil and natural gas that we produce effectively.

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 the spill, release or emission of various substances produced in association with certain oil and gas industry operations. In addition, such legislation sets out the requirements with respect to oilfield waste handling and storage, wildlife habitat production and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites.

Compliance with environmental 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 legislation, 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.

Hydraulic Fracturing

Hydraulic fracturing involves the injection of water, sand and small amounts of additives under pressure into rock formations to stimulate the production of oil and natural gas. Specifically, hydraulic fracturing enables the production of commercial quantities of oil and natural gas from reservoirs that were previously unproductive. Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to operational delays, increased operating costs, third party or governmental claims, and could increase our costs of compliance and doing business as well as delay the development of oil and natural gas resources from shale formations, which are not commercial without the use of hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

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. As future capital expenditures will be financed out of cash generated from operations, borrowings and possible future equity sales, our ability to do so is dependent on, among other factors:

- the overall state of the capital markets;
- our credit rating (if applicable);
- commodity prices;
- interest rates;
- royalty rates;
- tax burden due to current and future tax laws; and
- investor appetite for investments in the energy industry and our securities in particular.

Further, if our revenues or reserves decline, we may not have access to the capital necessary to undertake or complete future drilling programs. The current conditions in the oil and gas industry have negatively impacted the ability of oil and gas companies to access additional funding. 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. We may be required to seek additional equity financing on terms that are highly dilutive to existing shareholders. 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 and from time to time, we may require additional financing in order to carry out our oil and natural gas acquisition, exploration and development activities. Failure to obtain 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. Due to the conditions in the oil and gas industry and/or global economic volatility, we may from time to time have restricted access to capital and increased borrowing costs. The current conditions in the oil and gas industry have negatively impacted the ability of oil and gas companies to access additional financing.

Continued depressed oil and natural gas prices have caused decreases, and may cause further decreases, in our revenues from reserves, which may affect our ability to expend the necessary capital to replace our reserves or to maintain our production. To the extent that external sources of capital become limited, unavailable, or available on onerous terms, our ability to make capital investments and maintain existing assets may be impaired, and our assets, liabilities, business, financial condition and results of operations may be affected materially and adversely as a result. In addition, the future development of our petroleum properties may require additional financing and there are no assurances that such financing will be available or, if available, will be available upon acceptable terms. Failure to obtain any financing necessary for our capital expenditure plans may result in a delay in development or production on our properties.

Reserve and Resource Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids reserves and the future net revenue attributed to such reserves. The reserve and associated future net revenue information set forth in this Annual Information Form are estimates only. Generally, estimates of economically recoverable oil and natural gas reserves and the future net revenue from such estimated reserves 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 natural gas;
- royalty rates; and
- 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.

The estimation 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. 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 revenue as summarized herein. Actual future net revenue 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 future net revenue derived from our oil and natural 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 future net revenue to be derived therefrom and 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, except as may be specifically stated, has not been updated and thus does not reflect changes in our reserves since that date.

Competition

The petroleum industry is competitive in all of its phases. We compete with numerous other entities 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, methods, and reliability of delivery and storage.

Cost of New Technologies

The petroleum industry is characterized by rapid and significant technological advancements and introductions of new products and services utilizing new technologies. Other companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before us. There can be no assurance that we will be able to respond to such competitive pressures and implement such technologies on a timely basis or at an acceptable cost. One or more of the technologies currently utilized by us or implemented in the future may become obsolete. In such cases, our business, financial condition and results of operations could be materially adversely affected. If we are unable to utilize the most advanced commercially available technology, our business, financial condition and results of operations could be materially adversely affected.

Alternatives to and Changing Demand for Petroleum Products

Full conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, and technological advances in fuel economy and energy generation devices could reduce the demand for oil, natural gas and other liquid hydrocarbons. We cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on our business, financial condition, results of operations and funds from operations.

Regulatory

Various levels of governments impose extensive controls and regulations on oil and natural gas operations (including exploration, development, production, pricing, marketing and transportation). Governments may regulate or intervene with respect to exploration and production activities, prices, taxes, royalties and the exportation of oil and natural gas. Amendments to these controls and regulations may occur from time to time in response to economic or political conditions. See: "*Industry Conditions*". The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for crude oil and natural gas and increase our costs, either of which may have a material adverse effect on our business, financial condition, results of operations and prospects. In order to conduct oil and natural gas operations, we require regulatory permits, licenses, registrations, approvals and authorizations from various governmental authorities. There can be no assurance that we will be able to obtain all of the permits, licenses, registrations, approvals and authorizations that may be required to conduct operations that we may wish to undertake. In addition to regulatory requirements pertaining to the production, marketing and sale of oil and natural gas mentioned above, our business and financial condition could be influenced by federal legislation affecting, in particular, foreign investment, through legislation such as the *Competition Act* (Canada) and the *Investment Canada Act* (Canada).

Royalty Regimes

There can be no assurance that the federal government and the provincial governments of the western provinces will not adopt a new royalty regime or modify the existing royalty regimes which may have an impact on the economics of our projects. An increase in royalties would reduce our earnings and could make future capital investments, or our operations, less economic. On January 29, 2016, the Government of Alberta adopted a new royalty regime which will take effect on January 1, 2017. Details of the new regime are scheduled to be finalized and released before March 31, 2016.

Liability Management

Alberta and Saskatchewan have developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder becomes defunct. These programs generally involve an assessment of the ratio of a licensee's deemed assets to deemed liabilities. If a licensee's deemed liabilities exceed its deemed assets, a security deposit is required. Changes of the ratio of our deemed assets to deemed liabilities or changes to the requirements of liability management programs may result in significant increases to the security that must be posted. In addition, the liability management system may prevent or interfere with our ability to acquire or dispose of assets as both the vendor and the purchaser of oil and gas assets must be in compliance with the liability management programs (both before and after the transfer of the assets) for the applicable regulatory agency to allow for the transfer of such assets. See, "*Industry Conditions – Liability Management Rating Programs*".

Climate Change

Our exploration and production facilities and other operations and activities emit greenhouse gases and which may require us to comply with greenhouse gas emissions legislation at the provincial or federal level. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place. As a signatory to the *United Nations Framework Convention on Climate Change* and as a participant to the Copenhagen Agreement (a non-binding agreement created by the *United Nations Framework Convention on Climate Change*), the Government of Canada announced on January 29, 2010 that it will seek a 17% reduction in greenhouse gas emissions from 2005 levels by 2020 however, these greenhouse gas emission reduction targets are not binding. Although it is not the case today, some of our significant facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage greenhouse gas emissions. The Government of Canada is expected to announce a plan to further reduce greenhouse gas emission targets by March 11, 2016. The direct or indirect costs of compliance with these regulations may have a material adverse effect on our business, financial condition, results of operations and prospects. In addition, concerns about climate change have resulting in a number of environmental activists and members of the public opposing the continued exploitation and development of fossil fuels. 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 natural gas prices are quoted in United States dollars. The Canadian/United States dollar exchange rate, which fluctuates over time, consequently affects the price received by Canadian producers of oil and natural gas. Material increases in the value of the Canadian dollar relative to the United States dollar will negatively affect our production revenues. Although a low value of the Canadian dollar relative to the United States dollar may positively affect the price we receive for our oil and natural gas production, it could also result in an increase in the price for certain goods used for our operations, which may have a negative impact on our financial results.

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, resulting in a reduced amount available to fund our exploration and development activities, and if applicable, the cash available for dividends and could negatively impact the market price of our Common Shares.

Credit Facility Arrangements

The amount authorized under our Credit Facility is dependent on the borrowing base determined by our lenders. We are required to comply with covenants under our Credit Facility which may, in certain cases, include certain financial ratio tests, which from time to time either affect the availability, or price, of additional funding and in the event that we do not comply with these covenants, our access to capital could be restricted or repayment could be required. Events beyond our control may contribute to our failure to comply with such covenants. A failure to comply with covenants could result in the default under the Credit Facility, which could result in us being required to repay amounts owing thereunder. The acceleration of our indebtedness under one agreement may permit acceleration of indebtedness under other agreements that contain cross default or cross-acceleration provisions. In addition, our Credit Facility may impose operating and financial restrictions on us that could include restrictions on, the payment of dividends, repurchase or making of other distributions with respect to our securities, incurring of additional indebtedness, the provision of guarantees, the assumption of loans, making of capital expenditures, entering into of amalgamations, mergers, take-over bids or disposition of assets, among others.

Our lenders use our reserves, commodity prices, applicable discount rate and other factors, to periodically determine our borrowing base. Commodity prices continue to be depressed and have fallen dramatically since 2014. There remains a substantial amount of uncertainty as to when and if commodity prices will recover. Depressed commodity prices could reduce our borrowing base, reducing the funds available to us under our Credit Facility which could result in the requirement to repay a portion, or all, of our bank indebtedness.

Issuance of Debt

From time to time, we may enter into transactions to acquire assets or 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 debt financing that may not be available or, if available, may not be available on favorable 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, to the extent that we engage in price risk management activities to protect us from commodity price declines, we may also be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to manage price risk. In addition, our hedging arrangements may expose us to the risk of financial loss in certain circumstances, including instances in which:

- production falls short of the hedged volumes or prices fall significantly lower than projected;
- there is a widening of price-basis differentials between delivery points for production and the delivery point assumed in the hedge arrangement;
- the counterparties to the hedging arrangements or other price risk management contracts fail to perform under those arrangements; or
- a sudden unexpected event materially impacts oil and natural gas prices.

Similarly, from time to time we may enter into agreements to fix the exchange rate of Canadian to United States or dollars or other currencies in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to other currencies. However, if the Canadian dollar declines in value compared to such currencies, 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. Our actual interest in properties may vary from our records. If a title defect does exist, it is possible that we may lose all or a portion of the properties to which the title defect relates, which may have a material adverse effect on our business, financial condition, results of operations and prospects. There may be valid challenges to title, or proposed legislative changes which affect title to the oil and natural gas properties we control that, if successful or made into law, could impair our activities on them and result in a reduction of the revenue received by us.

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, certain 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.

Geopolitical Risks

Political events throughout the world that cause disruptions in the supply of oil continue to affect the marketability and price of oil and natural gas acquired or discovered by us. Conflicts, or conversely peaceful developments, arising outside of Canada have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and 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.

Litigation

In the normal course of our operations, we may become involved in, named as a party to, or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions, related to personal injuries, property damage, property tax, land rights, the environment and contract disputes. The outcome of outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to us and as a result, could have a material adverse effect on our assets, liabilities, business, financial condition and results of operations.

Aboriginal Claims

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

Breach of Confidentiality

While discussing potential business relationships or other transactions with third parties, we may disclose confidential information relating to our business, operations or affairs. Although confidentiality agreements are signed by third parties prior to the disclosure of any confidential information, a breach could put us at competitive risk and may cause significant damage to our business. The harm to our business from a breach of confidentiality cannot presently be quantified, but may be material and may not be compensable in damages. There is no assurance that, in the event of a breach of confidentiality, we will be able to obtain equitable remedies, such as injunctive relief, from a court of competent jurisdiction in a timely manner, if at all, in order to prevent or mitigate any damage to its business that such a breach of confidentiality may cause.

Income Taxes

We file all required income tax returns and believe that we are in full compliance with the provisions of the *Income Tax Act* (Canada) and all other applicable provincial tax legislation. However, such returns are subject to reassessment by the applicable taxation authority. In the event of a successful reassessment of us, whether by re-characterization of exploration and development expenditures or otherwise, such reassessment may have an impact on current and future taxes payable.

Income tax laws relating to the oil and natural gas industry, such as the treatment of resource taxation or dividends, may in the future be changed or interpreted in a manner that adversely affects us. Furthermore, tax authorities having jurisdiction over us may disagree with how we calculate our income for tax purposes or could change administrative practices to our detriment.

Seasonality

The level of activity in the Canadian oil and natural 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. In addition, certain oil and natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding decreases in the demand for our goods and services.

Third Party Credit Risk

We may be exposed to third party credit risk through our contractual arrangements with our current or future joint venture partners, marketers of our petroleum and natural gas production and other parties. In the event such entities fail to meet their contractual obligations to us, such failures 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. To the extent that any of such third parties go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in us being unable to collect all or portion of any money owing from such parties. Any of these factors could materially adversely affect our financial and operational results.

Conflicts of Interest

Certain of our directors or officers may also be directors or officers of other oil and natural gas companies and as such may, in certain circumstances, have a conflict of interest. Conflicts of interest, if any, will be subject to and governed by procedures prescribed by the *Business Corporations Act* (Alberta) which require a director of officer of a corporation who is a party to, or is a director or an officer of, or has a material interest in any person who is a party to, a material contract or proposed material contract with us to disclose his or her interest and, in the case of directors, to refrain from voting on any matter in respect of such contract unless otherwise permitted under the *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.

Expansion into New Activities

Our operations and the expertise of our management are currently focused primarily on oil and gas production, exploration and development in the Western Canada Sedimentary Basin. In the future we may acquire or move into new industry related activities or new geographical areas, may acquire different energy related assets, and as a result may face unexpected risks or alternatively, significantly increase our exposure to one or more existing risk factors, which may in turn result in our future operational and financial conditions being adversely affected.

Forward-Looking Information May Prove Inaccurate

Shareholders and prospective investors are cautioned not to place undue reliance on our forward-looking information. By its nature, forward-looking information involves numerous assumptions, known and unknown risk and uncertainties, of both a general and specific nature, that could cause actual results to differ materially from those suggested by the forward-looking information or contribute to the possibility that predictions, forecasts or projections will prove to be materially inaccurate.

Additional information on the risks, assumption and uncertainties are found under the heading "*Forward-Looking Statements*" of this Annual Information Form.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

In January 2013, a casing failed at one of our wells and we suffered approximately $14 million dollars in damages, $10.5 million in drilling/completion costs and an estimated $3.5 million in lost production. We commenced an action in the Alberta Court of Queen's Bench against the supplier of the casing, Alberta Tubular Products Ltd. ("**ATP**") and the manufacturer of the casing, Welded Tube of Canada Corp. ("**WTC**") on December 5, 2014. ATP filed its Statement of Defence on January 22, 2015. WTC filed its Statement of Defence and brought a cross-claim against ATP on February 20, 2015. No counterclaim was filed by either ATP or WTC against us.

On April 1, 2015, ATP filed third party claims against all of companies down the casing supply chain. All of the third parties have filed their third party Statements of Defence and the pleadings are now closed. We are currently scheduled to file our affidavit of records on May 1, 2016 and have requested that the remainder of the parties file their affidavits of records by August 1, 2016.

On November 10, 2015, one of the third parties noted by ATP obtained a favourable jury verdict against two other third parties included in the claim by ATP in a related lawsuit in the US District Court for the Southern District of Texas. We are not a party to the Texas action. We are reviewing the jury verdict and trial transcripts to determine whether they will support a summary judgment application in our Alberta action.

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 Computershare Trust Company of Canada 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 Credit Facility. 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.

KPMG LLP are our auditors and have confirmed that they are independent with respect to the Company within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulations.

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 the managing partner of Burnet, Duckworth & Palmer LLP, the law firm which 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 will be contained in our proxy materials relating to our annual Shareholder meeting to be held on May 11, 2016. Additional financial information is contained in our financial statements for the year ended December 31, 2015 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, 2015, 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 51-101F1 containing reserves data and other oil and gas information;

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

(c) the content and filing of this report.

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

(signed) "*Ronald J. Eckhardt*"
Ronald J. Eckhardt
Director and Chairman of the Reserves Committee

(signed) "*Jonathan A. Wright*"
Jonathan A. Wright
President and Chief Executive Officer

(signed) "*Keith MacPhail*"
Keith MacPhail
Chairman

(signed) "*Mike Lawford*"
Mike Lawford
Vice President, Development

March 8, 2016

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, 2015. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2015, 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.

3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "**COGE Handbook**") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).

4. 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.

5. 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, 2015, and identifies the respective portions thereof that we have evaluated and reported on to the Company's Board of Directors:

Independent Qualified Reserves Evaluator	Effective 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	12/31/2015	Canada	-	1,058,200	-	1,058,200

6. 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, consistently applied. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

7. We have no responsibility to update our reports referred to in paragraph 5 for events and circumstances occurring after the effective date of our reports.

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

Executed as to our report referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, February 18, 2016.

"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 Directors**") of NuVista Energy Ltd. ("**NuVista**") to whom the Board of Directors 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 of Directors 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 of Directors 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 of Directors 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 of Directors.
- 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 of Directors.

- 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 of Directors, 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 of Directors 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 of Directors 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 of Directors, the Committee shall:
    - recommend to the Board of Directors the appointment of the external auditors;
    - recommend to the Board of Directors 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 of Directors.

Reviewed and re-approved by the Board of Directors: March 8, 2016