NUVISTA ENERGY LTD

2016 ANNUAL INFORMATION FORM

MARCH 31, 2017

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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 24, 2017 evaluating as of December 31, 2016, 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	kilometers	1.609
kilometers	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 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 funds 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

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.

We disposed of various non-core assets throughout 2016 for aggregate gross proceeds of $76.0 million. Total average production associated with these assets was approximately 3,450 Boe/d. Included in divestitures in 2016 was the June 17, 2016 divestiture of our W6 Sweet Cretaceous (non-Montney) natural gas assets in the Wapiti area south of Grande Prairie in exchange for $70 million in cash (before adjustments) together with certain Wapiti area Montney lands. The proceeds from the dispositions were used to reduce bank indebtedness.

Equity Offerings

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.

On June 28, 2016, we completed a private offering of 3,252,411 Common Shares, for gross proceeds of approximately $21.5 million. The Common Shares were issued on a "flow-through" basis in respect of Canadian development expense at a price of $6.65 per Common Share. Of the total Common Shares issued, 92,000 Common Shares were acquired by certain directors, officers and employees of NuVista on a non-brokered, "flow through" basis on the same terms.

On October 28, 2016, we completed a public offering with a syndicate of underwriters of an aggregate of 15,111,000 Common Shares at $6.85 per share for gross proceeds of $103.5 million, which included 1,971,000 Common Shares issued pursuant to the full exercise of the over-allotment option granted to the underwriters.

Senior Unsecured Notes

On June 22, 2016, we completed a private placement of 9.875% five-year term unsecured senior notes in the amount of $70 million. The proceeds from the sale of the notes were used to reduce bank indebtedness.

Credit Facility

In October 2014, our lenders increased the borrowing base of our credit facility to $300 million. In November 2015, the borrowing base was reconfirmed at $300 million.

On June 13, 2016, we completed the annual redetermination of our borrowing base with our syndicate of lenders. After adjustments to account for the issuance of the 9.875% five-year term unsecured senior notes as well as the divestiture of W6 Sweet Cretaceous assets, our borrowing base was set at $200 million effective July 1, 2016.

Management and Board of Directors

On August 12, 2014, Mr. Brian Shaw joined our Board.

On August 29, 2014, Mr. Robert 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.

On August 9, 2016, Ms. Deborah Stein joined our Board. On November 14, 2016, Ms. Stein was appointed Chair of the Audit Committee.

On November 14, 2016, Mr. Peter Comber retired from our Board.

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 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 2016, 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 $10.8 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.

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 2017 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, 2017. See "*Risk Factors – Credit Facility Arrangements* ".

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, 2016, we employed 66 full-time employees, including 58 office and 8 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 24, 2017. The statement is effective as of December 31, 2016 and the preparation date of the statement is February 24, 2017. 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, 2016, 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, 2016 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, 2016
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	7	7	4,847	4,199	12,000	9,273	150,383	139,582
Developed Non-Producing	28	27	2,250	1,926	2,551	2,065	30,344	28,190
Undeveloped	29	25	1,245	1,161	28,036	23,610	357,977	324,648
TOTAL PROVED	65	59	8,343	7,285	42,587	34,948	538,704	492,420
PROBABLE	21	18	2,724	2,346	39,668	31,042	500,351	439,748
TOTAL PROVED PLUS PROBABLE	86	77	11,066	9,632	82,255	65,990	1,039,055	932,168

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	562,763	457,909	387,982	339,283	303,763	11.67	1.94
Developed Non-Producing	129,157	98,193	79,385	67,185	58,734	11.16	1.86
Undeveloped	746,885	396,404	207,449	99,762	35,198	2.66	0.44
TOTAL PROVED	1,438,805	952,506	674,815	506,231	397,695	5.70	0.95
PROBABLE	1,728,286	870,318	489,750	298,124	190,867	4.68	0.78
TOTAL PROVED PLUS PROBABLE	3,167,092	1,822,825	1,164,566	804,354	588,562	5.22	0.87

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	562,763	457,909	387,982	339,283	303,763
Developed Non-Producing	129,157	98,193	79,385	67,185	58,734
Undeveloped	596,404	322,494	168,542	78,073	22,516
TOTAL PROVED	1,288,325	878,596	635,909	484,541	385,014
PROBABLE	1,254,601	625,392	343,945	202,699	124,318
TOTAL PROVED PLUS PROBABLE	2,542,926	1,503,988	979,854	687,240	509,333

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2016
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	5,323,287	581,093	2,360,238	894,942	48,208	1,438,805	150,481	1,288,325
Total Proved plus Probable	10,859,478	1,383,212	4,602,139	1,624,203	82,833	3,167,092	624,166	2,542,926

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, 2016
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]	961	8.18	1.36
Conventional Natural Gas [2]	4,430	3.67	0.61
Shale Gas	669,425	5.72	0.95
Total Proved	674,815	5.70	0.95
Proved plus Probable			
Light and Medium Crude Oil [1]	1,440	8.37	1.40
Conventional Natural Gas [2]	6,510	3.98	0.66
Shale Gas	1,156,615	5.22	0.87
Total Proved Plus Probable	1,164,566	5.22	0.87

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 and including a very immaterial amount of coal bed methane.
(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 fuel 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 ($/Bbl)	Cromer Medium 29. 0° API ($/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										
2017	55.00	69.33	46.69	64.48	3.46	28.43	49.92	72.11	2.0	0.750
2018	59.00	72.26	50.40	67.20	3.10	26.74	54.19	74.79	2.0	0.775
2019	64.00	75.00	55.03	69.75	3.27	26.25	56.25	78.75	2.0	0.800
2020	67.00	76.36	56.96	71.02	3.49	26.73	57.27	79.80	2.0	0.825
2021	71.00	78.82	59.95	73.31	3.67	27.59	59.12	82.37	2.0	0.850
2022	74.00	82.35	63.43	76.59	3.86	28.82	61.76	86.06	2.0	0.850
2023	77.00	85.88	66.99	79.87	4.05	30.06	64.41	89.32	2.0	0.850
2024	80.00	89.41	70.48	83.15	4.16	31.29	67.06	92.99	2.0	0.850
2025	83.00	92.94	73.63	86.44	4.24	32.53	69.71	97.59	2.0	0.850
2026	86.05	95.61	77.54	88.92	4.32	33.46	71.71	99.91	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, 2017.
(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, 2016, excluding financial derivative commodity contracts were $3.54/Mcf for natural gas, $49.87/Bbl for condensate, $31.96/Bbl for light and medium crude oil and $10.43/Bbl for NGLs (excluding condensate).

Reserves Reconciliation

RECONCILIATION OF GROSS RESERVES
BY PRODUCT TYPE
FORECAST PRICES AND COSTS

	LIGHT AND MEDIUM CRUDE OIL			CONVENTIONAL NATURAL GAS [1]		
	Proved (Mbbls)	Probable (Mbbls)	Proved Plus Probable (Mbbls)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)
December 31, 2015	72	63	135	61,503	55,999	117,502
Discoveries	-	-	-	-	-	-
Extensions	-	-	-	-	-	-
Infill Drilling	-	-	-	-	-	-
Improved Recovery	-	-	-	-	-	-
Technical Revisions	-	(1)	-	(1,042)	(1,624)	(2,666)
Acquisitions	-	-	-	-	-	-
Dispositions	(5)	(22)	(27)	(47,261)	(49,632)	(96,894)
Economic Factors	-	(19)	(19)	(847)	(2,018)	(2,865)
Production	(3)	-	(3)	(4,011)	-	(4,011)
December 31, 2016	65	21	86	8,343	2,724	11,066

	NATURAL GAS LIQUIDS			SHALE GAS		
	Proved (Mbbls)	Probable (Mbbls)	Proved Plus Probable (Mbbls)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)
December 31, 2015	35,901	41,295	77,196	430,019	504,851	934,870
Discoveries	-	-	-	-	-	-
Extensions	11,576	1,292	12,868	137,859	217	138,076
Infill Drilling	-	-	-	-	-	-
Improved Recovery	-	-	-	-	-	-
Technical Revisions	1,576	1,072	2,647	4,271	(6,058)	(1,787)
Acquisitions	247	149	396	3,375	2,054	5,430
Dispositions	(3,403)	(4,018)	(7,422)	-	-	-
Economic Factors	(221)	(121)	(342)	(5,375)	(713)	(6,088)
Production	(3,089)	-	(3,089)	(31,445)	-	(31,445)
December 31, 2016	42,587	39,668	82,255	538,704	500,351	1,039,055

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

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 gross 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 (MMcf)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
2014	-	173	43	164	-	-
2015	-	29	-	-	72,522	303,946
2016	-	29	-	-	72,632	357,977

Year	Conventional Natural Gas (MMcf)		Natural Gas Liquids (Mbbls)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
2014	138,130	279,866	10,861	20,887
2015	-	9,045	5,192	23,128
2016	-	1,245	5,851	28,036

Of our total proved plus probable gross reserves, 87,936 MBoe or 34% 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 87,687 MBoe or virtually 100% of the proved undeveloped reserves. Subject to market conditions, capital expenditures of $102.2 million in 2017 and $161.1 million in 2018 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 gross 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 (MMcf)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
2014	-	396	89	462	-	-
2015	-	12	-	-	136,609	461,758
2016	-	12	-	-	60,889	436,348

Year	Conventional Natural Gas (MMcf)		Natural Gas Liquids (Mbbls)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
2014	224,951	391,243	17,544	29,217
2015	5,507	38,105	10,218	36,905
2016	-	389	6,300	34,599

Of our total proved plus probable reserves, 107,400 MBoe or 42% are probable undeveloped gross reserves. These well locations are allocated reserves because they are within the defined distances to proved reserve accumulations. The Wapiti Montney play accounts for 107,320 MBoe or approximately 100% of the probable undeveloped reserves. Subject to market conditions, capital expenditures of $61.9 million in 2017 and $122.1 million in 2018 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, 2016, we had approximately 1,000 net wells for which we expect to incur abandonment and reclamation costs. We calculated our overall abandonment costs at $128.8 million (undiscounted) and $40.5 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 $83 million (undiscounted) and $3 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)**
2017	122,210	184,130
2018	163,422	285,479
2019	252,068	354,543
2020	165,115	286,985
2021	192,126	290,325
Remaining	-	222,742
Total (Undiscounted)	894,942	1,624,203

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, 2016. Information in respect of current production is average production, net to our working interest, except where otherwise indicated.

Wapiti - Montney

Wapiti, our largest operating area is located south of Grande Prairie, Alberta, approximately 520 kilometers northwest of Calgary. This operating area is poised to play an important role in our future growth with substantially all of our projected 2017 capital budget expected to be spent in this region.

We hold Montney rights in approximately 137,280 gross acres (118,405 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 became operational in June 2015. The facility at Elmworth was expanded to 65 MMcf/d of throughput capacity in 2016. 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 2016, we drilled and completed 20 (20 net) wells resulting in 20 (20 net) natural gas wells. A combination of development pad drilling and delineation drilling took place in 2016. 2017 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 2016, Wapiti Montney production averaged approximately 21,877 Boe/d (83.9 MMcf/d of natural gas, 6,722 Bbls/d of condensate and 1,161 Bbls/d of natural gas liquids (excluding condensate)).

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 35,840 gross acres (20,199 net acres) with an average working interest of 56%. Our 2016 average production rate was 363 Boe/d (1.9 MMcf/d of natural gas and 42 Bbls/d of oil and natural gas liquids). We drilled no wells in the W5 operating area in 2016.

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 322,765 gross acres (265,179 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 2016 average production rate was 444 Boe/d (2.5 MMcf/d of natural gas and 24 Bbls/d of oil and natural gas liquids). We did not drill any wells in this area in 2016.

Northwest Alberta Non-core Operating Area

Our northwestern Alberta operating area is located 150 kilometers 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. This operating region contains 215,440 gross acres (155,287 net acres) with an average working interest of 72%. Our 2016 production averaged 237 Boe/d (1.4 MMcf/d of natural gas and 4 Bbls/d of oil and natural gas liquids) from this region. We did not drill any wells in this area in 2016.

Non-core Property Dispositions

In 2016 through the W6 Sweet and other noncore dispositions, production from properties sold in 2016 averaged 1,717 Boe/d (7.2 MMcf/d of natural gas and 515 Bbls/d of oil and natural gas liquids).

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, 2016.

	Oil Wells				**Natural Gas Wells**			
	Producing		**Non-Producing** (2)		**Producing**		**Non-Producing** (2)	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Alberta (1)	10.0	3.3	135.0	107.6	278.0	202.6	920.0	735.1

Notes:

(1) The table does not include 3 gross (2.2 net) non-producing natural gas wells located in Saskatchewan.

(2) Included in the non-producing wells are 74 gross (57.7 net) oil wells and 480 gross (373.3 net) natural gas wells that are abandoned but not yet reclaimed.

Properties With No Attributed Reserves

As at December 31, 2016 we held 408,284 gross (308,113 net acres) to which no reserves are currently attributed. Rights to explore, develop and exploit 83,077 net acres of these land holdings could expire by December 31, 2017 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, 2016 see Note 17 to our financial statements for the year ended December 31, 2016.

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 forecast net after royalty production for the term January 1, 2017 to June 30, 2018 and up to 60% for July 1, 2018 to December 31, 2019 and a further 50% for the following 24 months. 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 $2.62/Mcf for the year ended December 31, 2016.

We have been contracting for export pipeline capacity to diversify our gas sales to other regional markets. We contracted for 20 MMcf/d of Alliance pipeline capacity to the Chicago market area that started December 2015. In 2016, we contracted for 40,000 GJ/d of delivery service on the Nova system to the Alberta/BC border which will allow for gas exports to northern California. This service is anticipated to commence in late 2018 after the Sundre Crossover project is completed by Nova. This capacity coupled with our existing Alliance Pipeline capacity to Chicago will provide for a more diverse portfolio of gas markets and prices beyond AECO. We will continue to evaluate other downstream gas marketing opportunities as they arise.

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 70% of forecast net after royalty production for the term January 1, 2017 to June 30, 2018, up to 60% for the next 18 months and up to 30% for the following 24 months. In 2016, our average realized condensate & oil price (excluding financial derivative commodity contracts) was $49.81/Bbl and our average realized price for natural gas liquids (excluding condensate) was $10.43/Bbl.

For additional details on our price risk management program see Note 17 to our financial statements for the year ended December 31, 2016.

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 ULC 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.

On October 11, 2016 we entered into an agreement as anchor tenant with SemCAMS ULC for firm processing of an additional 120 MMcf/d of raw gas from our condensate rich Montney play in the Wapiti area of Alberta. The processing capacity will be added in three incremental steps of 40 MMcf/d, commencing in 2019, 2020, and 2021 respectively. The agreement is underpinned by take-or-pay terms for a period of 15 years, and the 80% take-or-pay terms provide flexibility to produce above or below these firmly contracted amounts. The capacity will be provided via the new 200 MMcf/d gas plant at Gold Creek. With this agreement, we and SemCAMS have moved past Final Investment Decision. Both parties have received all board approvals needed to proceed with construction of the licensed gas plant. We will supply gas to this contract from the Gold Creek, Pipestone, Elmworth, and surrounding areas. Bilbo and adjacent southern lands will continue to be processed at the Keyera Simonette gas plant. When added to our existing capacity, this agreement will expand our total Wapiti area firm processing capacity to approximately 277 MMcf/d of raw gas by 2021.

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 2017 funds from operations and capital expenditures, and existing tax pools, we do not expect to be cash taxable in 2017. Projecting taxability beyond 2017 is subject to many uncertainties including commodity prices, capital spending, acquisitions, divestments and government regulations and guidelines. Within the context of current commodity prices and our capital spending plans, we do not expect to be taxable in the next five years.

Costs Incurred

The following table summarizes the costs incurred related to our activities for the year ended December 31, 2016:

Expenditure	**Year Ended December 31, 2016 ($000s)**
Property acquisition costs – Unproved properties [(1)]	3,850
Property acquisition costs – Proved properties	-
Exploration costs [(2)]	5,377
Development costs [(3)]	182,739
Other	228
Total	192,194

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

In 2016, we drilled 20 (100% interest) condensate-rich natural gas development wells within our Wapiti Montney resource play. We did not participate in any other exploratory or development wells in 2016.

In 2017, we expect to drill approximately 29 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, 2017, 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/d)**
Total Proved	6	2,493	9,645	108,153	28,092
Total Proved plus Probable	6	2,532	11,275	127,914	33,023

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 2016				Year Ended
	Mar. 31	**June 30**	**Sept. 30**	**Dec. 31**	**Dec. 31, 2016**
Average Daily Production [1]					
Light and Medium Crude Oil (Bbls/d)	12	43	17	19	23
Natural Gas (Mcf/d)	102,589	91,788	97,376	96,334	97,021
NGLs (Bbls/d) [2]	2,143	1,731	1,035	1,403	1,576
Condensate (Bbls/d) [2]	6,232	6,379	7,617	7,239	6,870
Combined (Boe/d)	25,484	23,451	24,898	24,716	24,638
Average Net Production Prices Received					
Light and Medium Crude Oil ($/Bbl)	(6.40)	31.86	49.12	39.83	31.96
Natural Gas ($/Mcf)	3.75	3.25	3.37	3.74	3.54
NGLs ($/Bbl) [2]	5.35	11.26	7.34	19.35	10.43
Condensate ($/Bbl) [2]	41.76	49.54	48.73	58.26	49.87
Combined ($/Boe)	25.75	27.10	28.44	32.78	28.53
Royalties Paid					
Light and Medium Crude Oil ($/Bbl)	(14.40)	(17.18)	1.14	51.57	1.10
Natural Gas ($/Mcf)	0.02	(0.51)	(0.23)	(0.17)	(0.22)
NGLs ($/Bbl) [2]	0.91	0.67	0.87	1.10	0.88
Condensate ($/Bbl) [2]	4.84	2.47	3.79	3.30	3.59
Combined ($/Boe)	1.32	(1.31)	0.28	0.42	0.21
Production Costs [3][4]					
Light and Medium Crude Oil ($/Bbl)	0.00	0.02	0.01	0.01	0.01
Natural Gas ($/Mcf)	1.18	1.05	1.23	1.13	1.15
NGLs ($/Bbl) [2]	0.89	0.71	0.47	0.59	0.67
Condensate ($/Bbl) [2]	2.59	2.63	3.46	3.06	2.93
Combined ($/Boe)	10.59	9.66	11.31	10.44	10.52
Transportation					
Light and Medium Crude Oil ($/Bbl)	(0.55)	(0.09)	0.70	1.02	0.33
Natural Gas ($/Mcf)	0.71	0.53	0.56	0.47	0.57
NGLs ($/Bbl) [2]	0.00	0.00	0.00	0.00	0.00
Condensate ($/Bbl) [2]	(0.49)	(0.10)	0.70	1.02	0.33
Combined ($/Boe)	2.74	2.07	2.39	2.14	2.34
Netback Received [5]					
Light and Medium Crude Oil ($/Bbl)	8.55	49.11	47.27	(12.77)	30.52
Natural Gas ($/Mcf)	1.84	2.18	1.81	2.31	2.04
NGLs ($/Bbl) [2]	3.55	9.88	6.00	17.66	8.88
Condensate ($/Bbl) [2]	34.82	44.54	40.78	50.88	43.02
Combined ($/Boe)	11.10	16.68	14.46	19.78	15.46

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, 2016:

	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	-	1,161	6,722	83,962	21,877
Non-core [2]	22	415	148	13,059	2,761
Total	22	1,576	6,870	97,021	24,638

Note:
(1) For the purposes of this table condensate has been shown separately from natural gas liquids.
(2) Included in the non-core category are the 2016 dispositions.

DIVIDENDS

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 $200 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 industry standard 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 October 31 and April 30. During the term period, no principal payments would be required until a year after the revolving period matures.

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, 2017. Although we have no reason to believe that we will be unable to extend our Credit Facility after April 29, 2017, 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 – Credit Facility Arrangements*".

Senior Unsecured Notes

We have $70 million of 9.875% senior unsecured notes ("**Notes**") with a 5 year term which were issued by way of private placement. Interest is payable in equal quarterly installments in arrears. The Notes are fully and unconditionally guaranteed as to the payment of principal and interest, on a senior unsecured basis. There are no maintenance financial covenants. The Notes are non-callable prior to the two and a half year anniversary of the closing date.

At any time on or after December 22, 2018, we may redeem all or part of the Notes at the redemption prices set forth below plus any accrued and unpaid interest:

12 month period ended:	Percentage
December 22, 2019	104.938%
December 22, 2020	102.469%
December 22, 2021	100.00%

If a "change of control" (as defined in the note indenture governing the Notes) occurs at any time prior to June 22, 2017, each holder of the Notes will have the right to require us to purchase all or any part of that holder's Notes for an amount in cash equal to 110% of the aggregate principal repurchased plus accrued and unpaid interest. If a change of control occurs after June 22, 2017, each holder of Notes will have the right to require us to purchase all or any part of that holder's Notes for an amount in cash equal to 101% of the aggregate principal repurchased plus accrued and unpaid interest.

Share Capital

We are authorized to issue an unlimited number of Common Shares without nominal or par value and no other shares. 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**
2016			
January	4.53	2.72	12,488,995
February	4.62	3.75	6,113,307
March	5.50	4.33	10,219,671
April	6.12	4.50	7,957,380
May	7.13	5.30	12,502,633
June	7.18	5.74	11,608,598
July	7.10	5.94	9,746,149
August	7.41	6.28	10,146,862
September	7.64	6.17	14,140,950
October	7.80	6.55	15,102,190
November	7.24	6.28	14,815,106
December	7.61	6.51	13,285,236
2017			
January	7.15	6.38	9,190,792
February	6.83	5.82	8,837,879
March (1 – 30)	6.39	5.33	10,144,786

Prior Sales

During the year ended December 31, 2016, we issued a total of 2,043,450 options pursuant to our stock option plan and 355,500 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.
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	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.
Deborah S. Stein (1) DeWinton, Alberta	Director	August 2016	Former Executive Vice President at AltaGas Ltd. From 2008 to 2015. Ms. Stein was Senior Vice President Finance and Chief Financial Officer of AltaGas Ltd.
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.

Name and Municipality of Residence	Position with NuVista	Director or Officer Since	Principal Occupation
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 7.2 million Common Shares or approximately 4.2% 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 and Mr. Zawalsky who was a former director of Endurance Energy Ltd. (a private oil and gas company) which filed for creditor protection under the *Companies Creditors' Agreement Act* on May 30, 2016.

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 Deborah Stein (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.

Deborah Stein: *Independent Businesswoman*

Ms. Stein has over 30 years of industry experience, including 17 years of direct experience in the oil and gas business, most recently having held the position of Chief Financial Officer at AltaGas Ltd. Prior to joining AltaGas in 2005, Ms. Stein held various positions at TransCanada Corporation. Ms. Stein also led the finance functions of Wendy's Restaurants of Canada and Paramount Canada's Wonderland. She is currently a director of Parkland Fuel Corporation, Trican Well Service Ltd., CEDA and Past Chair of Financial Executives Canada.

Ms. Stein is a Chartered Accountant, holds a designation from the Institute of Corporate Directors and obtained her Bachelor of Arts degree from York University, majoring in Economics.

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 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

The following table summarizes the fees paid by us to our auditors, KPMG LLP, for external audit and other services during the periods indicated.

Year	Audit Fees (1) ($)	Audit Related Fees (2) ($)	Tax Fees (3) ($)	All Other Fees (4) ($)
2016	314,000	55,000	9,205	-
2015	335,000	35,995	44,735	-

Notes:

(1) Represents fees billed by our external auditor for audit services.

(2) Represents fees billed for assurance related services by our external auditor that are reasonably related to the performance of the audit or review of our financial statements that are not reported under audit fees.

(3) Represents fees billed for professional services rendered by our external auditor for tax compliance, tax advice and tax planning.

(4) Represents fees billed for products and services provided by our auditors other than the other services reported.

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 Alberta.

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, regional market and transportation issues also influence prices. 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 (the "**NEB**"). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB. The NEB underwent a consultation process to update the regulations governing the issuance of export licences. The updating process was necessary to meet the criteria set out in the federal *Jobs, Growth and Long-term Prosperity Act* (Canada) (the "**Prosperity Act**") which received Royal Assent on June 29, 2012. The Regulations Amending the National Energy Board Act Part VI (Oil and Gas) Regulations came into effect on July 31, 2015 and provides the requirements for obtaining long-term licences.

Natural Gas

Canada'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, 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 NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m^3 per day) must be made pursuant to an NEB order. Natural gas export contracts of a longer duration (to a maximum of 40 years) or that deal with larger quantities of natural gas requires an exporter to obtain an export licence from the NEB.

The North American Free Trade Agreement

The North American Free Trade Agreement ("**NAFTA**") 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. NAFTA 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. NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector and prohibits discriminatory border restrictions and export taxes. The new administration in the United States has indicated an intention to seek renegotiation of NAFTA, the impact of which on the oil and gas industry is uncertain.

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 where the Crown does not hold the mineral rights 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 Canadian federal government has signaled that 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 stringent reviews for pipelines and establishing a pan-Canadian framework for combating climate change. These changes could affect earnings of companies operating in the oil and natural gas industry.

Alberta

In Alberta, the Crown owns 81% of the province's mineral rights. The remaining 19% are 'freehold' mineral rights owned by the federal government on behalf of First Nations or in National Parks, and by individuals and companies. Provincial government royalty rates apply to Crown-owned mineral rights. 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 formally took effect on January 1, 2017 for wells drilled after this date. Wells drilled prior to January 1, 2017 will continue to be governed by the "New Royalty Framework" (implemented by the Mines and Minerals (*New Royalty Framework) Amendment Act, 2008*) (the "**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 total depth, length, and proppant placed). The new royalty rate for Pre-Payout under the MRF 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. Depending on the commodity price of the substance the well is producing, the royalty rate could range from 5% - 40%. The metrics for calculating the Mid-Life phase royalty are based on commodity prices and are intended, on average, to yield the same internal rate of return as under the Alberta Royalty Framework. In the Mature phase of the MRF, once a well reaches the tail end of its cycle and production falls below a Maturity Threshold, currently the equivalent of 194 m^3 (40 Boe/d or 345,500 m^3 of gas per month), 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.

On July 11, 2016, the Government of Alberta released details of the Enhanced Hydrocarbon Recovery Program and the Emerging Resources Program. These programs, that came into effect on January 1, 2017, are a part of the MRF and account for the higher costs associated with enhanced recovery methods and with developing emerging resources in an effort to make difficult investments economically viable and to increase royalties. Certain eligibility criteria must be satisfied in order for a proposed project to fall under each program. Enhanced recovery scheme applications can be submitted to the Alberta Energy Regulator ("**AER**").

Oil sands projects are also subject to Alberta's royalty regime. The MRF does not change the oil sands royalty framework, however, the Government of Alberta plans to increase transparency in the method and figures by which the royalties are calculated. 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% and 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 between 1% and 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, 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 Alberta Royalty Framework until January 1, 2027. Royalty rates for conventional oil are set by a single sliding scale 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 depends on the price of each of the components of the gas stream, the productivity of the well, its acid gas factor and the depth of the producing zone. These factors are employed on a sliding scale formula to determine the natural gas royalty rate per well with the maximum royalty payable under the royalty regime set at 36% and a minimum royalty rate of 5%.

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 lands where the Crown does not hold the rights to mines and minerals 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 freehold 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 (the "**IETP**") 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 IETP 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 ten-year period, until January 1, 2027. Specifically:

- Coalbed methane wells will receive a maximum royalty rate of 5% for 36 producing months 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 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.

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.

Alberta 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 licence. 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 licences issued after January 1, 2009 at the conclusion of the primary term of the lease or licence.

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, producers 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 environmental regulation under a variety of Canadian federal, provincial, territorial and municipal laws and regulations, 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. The regulatory regimes set 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 licences and authorizations, civil liability and the imposition of material fines and penalties. In addition to these specific, known requirements, future changes to environmental legislation, including anticipated legislation for air pollution and greenhouse gas ("**GHG**") emissions, may impose further requirements on operators and other companies in the oil and natural gas industry.

Federal

Canadian environmental regulation is the responsibility of the federal government and provincial governments. Where there is a direct conflict between federal and provincial environmental legislation in relation to the same matter, the federal law will prevail, however, such conflicts are uncommon. The federal government has primary jurisdiction over federal works, undertakings and federally regulated industries such as railways, aviation and interprovincial transport. The *Canadian Environmental Protection Act, 1999* and the *Canadian Environmental Assessment Act, 2012* provide the foundation for the federal government to protect the environment and cooperate with provinces to do the same.

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

On June 20, 2016, the Federal Government launched a review of current environmental and regulatory processes with a focus on rebuilding trust in the environmental assessment processes, modernizing the NEB, and introducing modernized safeguards to both the *Fisheries Act* and the *Navigation Protection Act*. An Expert Panel has been convened and is expected to complete its work by mid-2017. At such time, the Minister of Environment and Climate Change will consider the recommendations in the Panel's report and identify next steps to improve federal environmental processes, which is expected to take place during the summer/fall of 2017. Until this process is complete, the Federal Government's interim principles released January 27, 2016 will continue to guide decision-making authorities for projects currently undergoing environmental assessment. The Federal Government has not provided any indication on what changes, if any, will be implemented or when, but increased delays and uncertainty surrounding the environmental assessment process should be expected for large projects.

In a further development, on November 29, 2016, the Government of Canada announced that it would introduce legislation by spring 2017 to formalize a moratorium for crude oil tankers on British Columbia's north coast. It is unclear how the proposed moratorium may affect ongoing liquid natural gas export projects currently under consideration and development. On the same day, the Government of Canada also approved, subject to a number of conditions, the Trans Mountain Pipeline system expansion backed by Kinder Morgan Canada as well as the replacement of Enbridge Inc.'s plan to replace its Line 3 pipeline system, while also rejecting Enbridge Inc.'s proposed Northern Gateway project. On January 11, 2017, the Government of British Columbia confirmed that the conditions to the approval of the Trans Mountain Pipeline have been satisfied. Additionally, the new administration in the United States has indicated a willingness to revisit other pipeline projects that had been previously rejected.

Alberta

The AER is the single regulator responsible for all energy development in Alberta. The AER 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 AER'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 ("**IRMS**"). The IRMS method to natural resource management provides for engagement and consultation with stakeholders and the public and examines the cumulative impacts of development on the environment and communities, by incorporating the management of all resources, including energy, minerals, land, air, water and biodiversity. While the AER is the primary regulator for energy development, several other governmental departments and agencies may be involved in land use issues, including Alberta Environment and Parks, Alberta Energy, 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 "**ALUF**"). The ALUF sets out an approach to manage public and private land use and natural resource development in a manner that is consistent with the long-term economic, environmental and social goals of the province. It calls for the development of 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* (the "**ALSA**") provides the legislative authority for the Government of Alberta to implement the policies contained in the ALUF. Regional plans established under the ALSA 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 ALSA requires local governments, provincial departments, agencies and administrative bodies or tribunals to review their regulatory instruments and make any appropriate changes to ensure that they comply with an adopted regional plan. The ALSA also contemplates the amendment or extinguishment of previously issued statutory consents such as regulatory permits, licences, 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 ALSA are conservation easements, which can be granted for the protection, conservation and enhancement of land; and conservation directives, which are explicit declarations contained in a regional plan to set aside specified lands in order to protect, conserve, manage and enhance the environment.

On August 22, 2012, the Government of Alberta approved the Lower Athabasca Regional Plan ("**LARP**") which came into force on September 1, 2012. The LARP is the first of seven regional plans developed under the ALUF. LARP covers a region in the northeastern corner of Alberta that is approximately 93,212 square kilometers 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.

LARP 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 ("**SSRP**") which came into force on September 1, 2014. The SSRP is the second regional plan developed under the ALUF. The SSRP covers approximately 83,764 square kilometers and includes 44% of the provincial population.

The SSRP creates four new and four expanded conservation areas, and two new and six expanded provincial parks and recreational areas. Similar to LARP, the SSRP 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.

Phase 1 Consultation of the North Saskatchewan Region Plan ("**NSRP**") has been completed and the Regional Advisory Council is currently preparing its Recommendation to Government report. The NSRP is located in central Alberta and is approximately 85,780 square kilometers in size and affects activities in central Alberta, and encompasses an area between the province's borders with British Columbia and Saskatchewan. The Upper Peace Region Plan, Lower Peace Region Plan, Red Dear Region Plan and Upper Athabasca Region Plan have not been started.

Liability Management Rating Programs

Alberta

In Alberta, the AER administers the Licensee Liability Rating Program (the "**AB LLR Program**"). The AB LLR Program is a liability management program governing most conventional upstream oil and gas wells, facilities and pipelines. Alberta's *Oil and Gas Conservation Act* ("**OGCA**") 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 AB LLR Program if a licensee or working interest participant ("**WIP**") becomes defunct or is unable to meet its obligations. The Orphan Fund is funded by licensees in the AB LLR Program through a levy administered by the AER. The AB LLR Program is designed to minimize the risk to the Orphan Fund posed by unfunded liability of licensees and to prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines. The AB LLR Program requires a licensee whose deemed liabilities exceed its deemed assets to provide the AER with a security deposit. The ratio of deemed assets to deemed liabilities is assessed once each month and failure to post the required security deposit may result in the initiation of enforcement action by the AER. The AER publishes the liability management rating for each licensee on a monthly basis.

Made effective in three phases, from May 1, 2013 to August 1, 2015, the AER implemented important changes to the AB LLR Program (the "**Changes**") 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 assets to deemed liabilities under the AB LLR 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.

On June 20, 2016, the AER issued Bulletin 2016-16, Licensee Eligibility—Alberta Energy Regulator Measures to Limit Environmental Impacts Pending Regulatory Changes to Address the Redwater Decision ("**Bulletin 16**") in an urgent response to a decision from the Alberta Court of Queen's Bench, which is currently under appeal with the Court of Appeal of Alberta. In Redwater Energy Corporation (Re), 2016 ABQB 278 ("**Redwater**"), Chief Justice Wittman found that there was an operational conflict between the abandonment and reclamation provisions of the OGCA and the *Bankruptcy and Insolvency Act* ("**BIA**"), and that receivers and trustees have the right to renounce assets within insolvency proceedings. Such a conflict renders the AER's legislated authority unenforceable to impose abandonment orders against licensees or to require a licensee to pay a security deposit before approving a transfer when such a licensee is insolvent. Effectively, this means that abandonment costs will be borne by the industry-funded Orphan Well Fund or the province in these instances because any resources of the insolvent licensee will first be used to satisfy secured creditors under the BIA. Bulletin 16 provides interim rules to govern while the case is appealed and while the Government of Alberta can develop appropriate regulatory measures to adequately address environmental liabilities. Three changes were implemented to minimize the risk to Albertans:

- The AER will consider and process all applications for licence eligibility under Directive 067: Applying for Approval to Hold EUB Licences as non-routine and may exercise its discretion to refuse an application or impose terms and conditions on a licencee eligibility approval if appropriate in the circumstances.

- For holders of existing but previously unused licence eligibility approvals, prior to approval of any application (including licence transfer applications), the AER may require evidence that there have been no material changes since approving the licence eligibility. This may include evidence that the holder continues to maintain adequate insurance and that the directors, officers, and/or shareholders are substantially the same as when licence eligibility was originally granted.
- As a condition of transferring existing AER licences, approvals, and permits, the AER will require all transferees to demonstrate that they have a liability management rating ("**LMR**"), being the ratio of a licensee's assets to liabilities, of 2.0 or higher immediately following the transfer.

In order to clarify and revise the interim rules in Bulletin 16, the AER issued Bulletin 2016-21: Revision and Clarification on Alberta Energy Regulator's Measures to Limit Environmental Impacts Pending Regulatory Changes to Address the Redwater Decision ("**Bulletin 21**") on July 8, 2016 and reaffirmed its position that an LMR of 1.0 is not sufficient to ensure that licensees will be able to address their obligations throughout the life cycle of energy development, and 2.0 remains the requirement for transferees. However, Bulletin 21 did provide the AER with additional flexibility to permit licensees to acquire additional AER-licensed assets if:

- The licensee already has an LMR of 2.0 or higher;
- The acquisition will improve the licensee's LMR to 2.0 or higher; or
- The licensee is able to satisfy its obligations, notwithstanding an LMR below 2.0, by other means.

The AER provided no indication of what other means would be considered. In the short term the interim measures caused delays in completing transactions and reduced the pool of possible purchasers, however, transactions have been approved following a more rigorous review by the AER, despite a transferee's LMR not meeting the interim requirement. The Alberta Court of Appeal heard the appeal of the Redwater decision on October 11, 2016, with the Court reserving its decision.

The AER implemented the Inactive Well Compliance Program (the "**IWCP**") to address the growing inventory of inactive wells in Alberta and to increase the AER's surveillance and compliance efforts under Directive 013: Suspension Requirements for Wells ("**Directive 013**"). The IWCP 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 IWCP 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 by 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 IWCP is available on the AER's Digital Data Submission system. The AER has announced that from April 1, 2015 to April 1, 2016, the number of noncompliant wells subject to the IWCP fell from 25,792 to 17,470, with 76% of licensees operating in the province having met their annual quota.

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.

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 GHGs 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.

As a signatory to the United Nations Framework Convention on Climate Change (the "**UNFCCC**") and a participant to the Copenhagen Accord (a non-binding agreement created by the UNFCCC), the Government of Canada announced on January 29, 2010 that it will seek a 17% reduction in GHG emissions from 2005 levels by 2020; however, the GHG emission reduction targets are not binding. In May 2015, Canada submitted its Intended Nationally Determined Contribution ("**INDC**") to the UNFCCC. INDCs were communicated prior to the 2015 United Nations Climate Change Conference, held in Paris, France, which led to the Paris Agreement that came into force November 4, 2016 (the "**Paris Agreement**"). Among other items, the Paris Agreement constitutes the actions and targets that individual countries will undertake to help keep global temperatures from rising more than 2° Celsius and to pursue efforts to limit below 1.5° Celsius. The Government of Canada ratified the Paris Agreement on December 12, 2016, and pursuant to the agreement, Canada's INDC became its Nationally Determined Contributions ("**NDC**"). As a result, the Government of Canada replaced its INDC of a 17% reduction target established in the Copenhagen Accord with an NDC of 30% reduction below 2005 levels by 2030.

On June 29, 2016, the North American Climate, Clean Energy and Environment Partnership was announced among Canada, Mexico and the United States, which announcement included an action plan for achieving a competitive, low-carbon and sustainable North American economy. The plan includes setting targets for clean power generation, committing to implement the Paris Agreement, setting out specific commitments to address certain short-lived climate pollutants, and the promotion of clean and efficient transportation.

Additionally, on December 9, 2016, the Government of Canada formally announced the Pan-Canadian Framework on Clean Growth and Climate Change. As a result, the federal government will implement a Canada-wide carbon pricing scheme beginning in 2018. This may be implemented through either a cap and trade system or a carbon tax regime at the option of each province or territory. The federal government will impose a price on carbon of $10 per tonne on any province or territory which fails to implement its own system by 2018. This amount will increase by $10 annually until it reaches $50 per tonne in 2022 at which time the program will be reviewed.

In general, there is some uncertainty with regard to the impacts of federal or provincial climate change and environmental laws and regulations, as it is currently not possible to predict the extent of future requirements. Any new laws and regulations, or additional requirements to existing laws and regulations, could have a material impact on our operations and funds from operations.

Alberta

As part of its efforts to reduce GHG emissions, Alberta introduced legislation to address GHG emissions: the *Climate Change and Emissions Management Act* (the "**CCEMA**") 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 ("**SGER**"), which imposes GHG limits, and the Specified Gas Reporting Regulation, which imposes GHG emissions reporting requirements. Alberta is the first jurisdiction in North America to impose regulations requiring large facilities in various sectors to reduce their GHG emissions. The SGER applies to facilities emitting more than 100,000 tonnes of GHG emissions in 2003 or any subsequent year ("**Regulated Emitters**"), and requires reductions in GHG emissions intensity (e.g. the quantity of GHG emissions per unit of production) from emissions intensity baselines established in accordance with the SGER.

On June 25, 2015, the Government of Alberta renewed the SGER 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. As of 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.

A Regulated Emitter can meet its 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 (the "**Fund**"). Contributions to the Fund are made at a rate of $15 per tonne of GHG emissions, increasing to a rate of $20 per tonne of GHG emissions in 2016 and $30 per tonne of GHG 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. On June 7, 2016, the *Climate Leadership Implementation Act* ("**CLIA**") was passed into law. The CLIA enacted the *Climate Leadership Act* ("**CLA**") introducing a carbon tax on all sources of GHG emissions, subject to certain exemptions. An initial economy-wide levy of $20 per tonne was implemented on January 1, 2017, increasing to $30 per tonne in January of 2018. All fuel consumption - including gasoline and natural gas -will be subject to the levy, with certain exemptions, and directors of a corporation may be held jointly and severally liable with a corporation when the corporation fails to remit an owed carbon levy. Regulated Emitters will remain subject to the SGER framework until the end of 2017 and are exempt from paying the carbon levy on fuels used in operations until this time. Upon the expiry of the SGER, the Government of Alberta intends to transition to a proposed Carbon Competitiveness Regulation, in which sector specific output-based carbon allocations will be used to ensure competitiveness. A 100 megatonne per year limit for GHG emissions was implemented 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.

There are certain exemptions to the carbon levy imposed by the CLA. Until 2023, fuels consumed, flared or vented in a production process by conventional oil and gas producers will be exempt from the carbon levy. An exemption also applies for biofuels and fuels sold for export. In addition, marked fuels used in farming operations as well as personal and band uses by First Nations are exempt.

The passing of the CLIA is the first step towards executing the Climate Leadership Plan (other legislation is still pending). In addition to enacting the CLA, the CLIA also enacted the *Energy Efficiency Alberta Act*, which enables the creation of Energy Efficiency Alberta, a new Crown corporation to support and promote energy efficiency programs and services for homes and businesses.

The Government of Alberta also signaled its intention through its Climate Leadership Plan to implement regulations that would lower methane emissions by 45% by 2025. Regulations are planned to take effect in 2020 to ensure the 2025 target is met.

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, produced or discovered by us. Our ability to market our oil and natural gas may depend upon our ability to acquire capacity 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 and 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 and political conditions, in the United States, Canada, Europe, China and emerging markets the actions of 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 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 crude oil commodities, OPEC's recent decisions pertaining to the oil production of OPEC member countries and non-OPEC member countries' decisions on production levels, among other factors. A material decline in oil prices could 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 these factors could result in a material decrease in our expected net production revenue and a reduction in our oil and natural gas production, 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, political uncertainties, sanctions imposed on certain oil producing nations by other countries and 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. See "*Weakness in the Oil and Gas Industry*".

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 the OPEC, slowing growth in emerging economies, market volatility and disruptions in Asia, sovereign debt levels and political upheavals 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 the case of Alberta, at the provincial level, and the resultant uncertainty surrounding regulatory, tax, royalty changes and environmental regulation that have been announced or 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 downward price pressure on oil and gas produced in Western Canada and 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, rendering certain reserves uneconomic. In addition, lower commodity prices have restricted, and are anticipated to continue to restrict, our funds from operations resulting in a reduced capital expenditure budget. Consequently, 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 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 funds from operations may not be sufficient to continue to fund our operations and to satisfy our obligations when due and our may require additional equity or debt financing and/or proceeds or reduction in liabilities 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 or reduction in liabilities from asset sales to discharge our obligations.

Political Uncertainty

In the last several years, the United States and certain European countries have experienced significant political events that have cast uncertainty on global financial and economic markets. During the recent presidential campaign, in the United States, a number of election promises were made and the new American administration has begun taking steps to implement certain of these promises. Included in the actions that the administration has discussed are the renegotiation of the terms of NAFTA, withdrawal of the United States from the Trans-Pacific Partnership, imposition of a tax on the importation of goods into the United States, reduction of regulation and taxation in the United States, and introduction of laws to reduce immigration and restrict access into the United States for citizens of certain countries. It is presently unclear exactly what actions the new administration in the United States will implement, and if implemented, how these actions may impact Canada and in particular the oil and gas industry. Any actions taken by the new United States administration may have a negative impact on the Canadian economy and on the businesses, financial conditions, results of operations and the valuation of Canadian oil and gas companies, including us.

In addition to the political disruption in the United States, the citizens of the United Kingdom recently voted to withdraw from the European Union and the Government of the United Kingdom has begun taken steps to implement such withdrawal. Some European countries have also experienced the rise of anti-establishment political parties and public protests held against open-door immigration policies, trade and globalization. To the extent that certain political actions taken in North America, Europe and elsewhere in the world result in a marked decrease in free trade, access to personnel and freedom of movement it could have an adverse effect on our ability to market our products internationally, increase costs for goods and services required for our operations, reduce access to skilled labour and negatively impact our business, operations, financial conditions and the market value of our Common Shares.

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 have 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 reimbursement 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, we potentially becoming subject to additional liabilities relating to such assets and may have difficulty collecting revenue due from such operators or recovering amounts owing to us from such operators for their share of abandonment and reclamation obligations. Any of these factors could have a material adverse affect on our financial and operational results

Risks Associated with Forecast Prices

Our reserves as at December 31, 2016 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 participation 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 ensure 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, shut ins of wells resulting from extreme weather conditions, insufficient storage or transportation capacity or 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, spills and 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, pipeline systems and, in certain circumstances, 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, 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 transport produced oil and gas to market. 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 or because of actions taken by regulators could also affect our production, operations and financial results. As a result, 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 or uncertainty in constructing new infrastructure systems and facilities could harm our business and, in turn, our financial condition, operations and funds from operations. In addition, the federal government has signaled that it plans to review the NEB approval process for large federally regulated projects. This may cause the timeframe for project approvals to increase for current and future applications.

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 and 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 adds additional costs to the transportation of crude oil by rail. On July 13, 2016, the Minister of Transport (Canada) issued Protective Direction No. 38, which directed that the shipping of crude oil on DOT-111 tank cars end by November 1, 2016. Tank cars entering Canada from the United States will be monitored to ensure they are compliant with Protective Direction No. 38.

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 by third parties 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 may realize less on disposition 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 have 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 reimbursement 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 or recovering amounts owing to us from such operators for their share of abandonment and reclamation obligations. Any of these factors could have a material adverse affect on 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 overruns 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 oil and gas industry operations. 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 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 compliance requirements 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 revenues 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 and political 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.

As a result of global economic and political volatility, we may from time to time have restricted access to capital and increased borrowing costs. Failure to obtain such financing on a timely basis could cause us to forfeit our interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If our revenues from our reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect our ability to expend the necessary capital to replace our reserves or to maintain our production. 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 crude oil, natural gas and natural gas liquids reserves and the future revenues 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 revenues 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 is often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Recovery factors and drainage areas are often 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 revenues as summarized herein. Actual future net revenues 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 revenues derived from our crude 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 revenues 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. Some of these companies not only explore for, develop and produce oil and natural gas, but also carry on refining operations and market oil and natural gas on an international basis. As a result of these complementary activities, some of these competitors may have greater and more diverse competitive resources to draw on than we do. 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.

Information Technology Systems and Cyber-Security

We have become increasingly dependent upon the availability, capacity, reliability and security of our information technology infrastructure and our ability to expand and continually update this infrastructure, to conduct daily operations. We depend on various information technology systems to estimate reserve quantities, process and record financial data, manage our land base, analyze seismic information, administer our contracts with our operators and lessees and communicate with employees and third-party partners.

Further, we are subject to a variety of information technology and system risks as a part of our normal course operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of our information technology systems by third parties or insiders. Unauthorized access to these systems by employees or third parties could lead to corruption or exposure of confidential, fiduciary or proprietary information, interruption to communications or operations or disruption to our business activities or our competitive position. Further, disruption of critical information technology services, or breaches of information security, could have a negative effect on our performance and earnings, as well as on our reputation. We apply technical and process controls in line with industry-accepted standards to protect our information assets and systems; however, these controls may not adequately prevent cyber-security breaches. The significance of any such event is difficult to quantify, but may in certain circumstances be material and could have a material adverse effect on our business, financial condition and results of operations.

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. If we do implement such technologies, there is no assurance that we will do so successfully. One or more of the technologies currently utilized by us or implemented in the future may become obsolete. In such case, 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, or we are unsuccessful in implementing certain technologies, 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 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, licences, registrations, approvals and authorizations from various governmental authorities at the provincial and federal level. There can be no assurance that we will be able to obtain all of the permits, licences, registrations, approvals and authorizations that may be required to conduct operations that we may wish to undertake. In addition, certain federal legislation such as the *Competition Act* (Canada) and the *Investment Canada Act* (Canada) could negatively affect our business, financial condition and the market value of our Common Shares or our assets, particularly when undertaking, or attempting to undertake, acquisition or disposition activity.

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 took effect on January 1, 2017. See "*Industry Conditions - Royalties and Incentives*".

Liability Management

Alberta has developed a 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 is unable to satisfy its obligation. This program 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 to the required ratio of our deemed assets to deemed liabilities or other changes to the requirements of liability management programs may result in significant increases to our compliance requirements. 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. The Redwater decision, found an operational conflict between the *Bankruptcy and Insolvency Act* and the AER's abandonment and reclamation powers when the licensee is insolvent. The AER appealed this decision and issued interim rules to administer the liability management program and until the Alberta Government can develop new regulatory measures to adequately address environmental liabilities. The decision from this appeal has not been released. There remains a great deal of uncertainty as to what new regulatory measures will be developed or what the impact of the court decision will have on other provinces. See, "*Industry Conditions – Liability Management Rating Programs*".

Climate Change

Our exploration and production facilities and other operations and activities emit GHGs and which may require us to comply with GHG 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 UNFCCC and as a participant to the Copenhagen Agreement (a non-binding agreement created by the UNFCCC), the Government of Canada announced on January 29, 2010 that it would seek a 17% reduction in GHG emissions from 2005 levels by 2020; however, these GHG emission reduction targets were not binding. As a result of the UNFCCC adopting the Paris Agreement on December 12, 2015, which Canada ratified on October 3, 2016, the Government of Canada implemented new GHG emission reduction targets of a 30% reduction from 2005 levels by 2030. In addition, the Government of Canada announced it would implement a Canada wide price on carbon to further reduce its GHG emissions. In addition, on January 1, 2017 the CLA come into effect in the Province of Alberta introducing a carbon tax on almost all sources of GHG emissions at a rate of $20 per tonne, increasing to $30 per tonne in January 2018. 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. Some of our significant facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage GHG emissions. In addition, concerns about climate change have resulted 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 GHGs 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. Accordingly, exchange rates between Canada and the United States could accordingly affect the future value of our reserves as determined by independent evaluators. 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 could negatively impact the market price of our Common Shares.

Credit Facility Arrangements

The amount authorized under our Credit Facility is determined by our lenders. We are required to comply with certain non-financial covenants under our Credit Facility 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, 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 improved in the second half of 2016 however they have fallen dramatically since 2014. There is a significant amount of uncertainty as to when and if commodity prices will fully 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 entities. 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 favourable terms. Neither our articles nor our by-laws limit the amount of indebtedness that we may incur. The level of our indebtedness from time to time, could impair our ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

Hedging

From time to time, we may enter into agreements to receive fixed prices on our oil and natural gas production to offset the risk of revenue losses if commodity prices decline. However, 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) as well as skilled personnel trained to use such equipment in the areas where such activities will be conducted. Demand for such limited equipment and skilled personnel, or access restrictions, may affect the availability of such equipment and skilled personnel 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 a defect in the chain of title will not arise. Our actual interest in properties may accordingly 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 continuously affect the marketability and price of oil and natural gas acquired or discovered by us. Conflicts, or conversely peaceful developments, arising outside of Canada, including changes in political regimes or the parties in power, 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 the subject of 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, relating to personal injuries, including resulting from exposure to hazardous substances, property damage, property taxes, land and access rights, environmental issues, including claims relating to contamination or natural resource damages and contract disputes. The outcome with respect to 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. Even if we prevail in any such legal proceedings, the proceedings could be costly and time-consuming and may divert the attention of management and key personnel from business operations, which could have an adverse effect on our financial condition.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights in 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. In addition, the process of addressing such claims, regardless of the outcome, is expensive and time consuming and could result in delays which could have a material adverse effect on our business and financial results.

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 generally 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 our 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, 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. 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. In addition, extreme cold weather, heavy snowfall and heavy rainfall may restrict our ability to access our properties and cause operational difficulties. 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 addition, we may be exposed to third party credit risk from operators of properties in which we have a working interest or royalty interest. 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 or officer of a corporation who is a party to, or is a director or an officer of, or has a material interest in any person who is a party to, a material contract or proposed material contract with us 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 personnel 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 Information and 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 filed an 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 3100, 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 and the note indenture in respect of our Notes. Copies of these agreements are available on SEDAR at *www.sedar.com*.

INTERESTS OF EXPERTS

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

KPMG LLP are our auditors and have confirmed that they are independent with respect to us 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 10, 2017. Additional financial information is contained in our financial statements for the year ended December 31, 2016 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, 2016, 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 7, 2017

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, 2016. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2016, 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, 2016, 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	12/31/2016	Canada	-	1,164,566	-	1,164,566

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 24, 2017.

"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 impairment 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 7, 2017.