ATHABASCA
OIL CORPORATION

Annual Information Form

FOR THE YEAR ENDED DECEMBER 31, 2016

March 9, 2017

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INTRODUCTORY INFORMATION

Except as otherwise indicated, or unless the context otherwise requires, the terms the "**Company**", "**Athabasca**", "**we**", "**our**" and "**us**" refer to Athabasca Oil Corporation and one or more of Athabasca Oil Corporation's direct or indirect subsidiaries, collectively. Capitalized terms used herein and not otherwise defined have the meanings ascribed thereto in the Glossary of Defined Terms.

FORWARD LOOKING STATEMENTS

Certain statements contained in this Annual Information Form constitute forward looking statements. These statements relate to future events or Athabasca’s future performance. All statements other than statements of historical fact are forward looking statements. The use of any of the words "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "project", "should", "believe", "predict", "pursue" and "potential" and similar expressions are intended to identify forward looking statements. 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. No assurance can be given that these expectations will prove to be correct and such forward looking statements included in this Annual Information Form should not be unduly relied upon. These statements speak only as of the date of this Annual Information Form. In addition, this Annual Information Form may contain forward looking statements and forward looking information attributed to third party industry sources.

In particular, this Annual Information Form contains forward looking statements pertaining to, but not limited to, the following:

- the business strategy, objectives and business strengths of Athabasca;
- Athabasca’s growth strategy and opportunities;
- Athabasca’s 2017 exploration and development budget and Athabasca’s capital expenditure programs;
- realization of the anticipated benefits of acquiring the Acquired Assets;
- Athabasca’s expectations regarding its ability to raise capital;
- Athabasca’s plans to submit additional regulatory applications;
- the estimated quantity of Athabasca’s Proved Reserves, Probable Reserves and Contingent Resources and the Proved Reserves, Probable Reserves and Contingent Resources attributable to the Acquired Assets;
- Athabasca’s projections of commodity prices, costs and netbacks;
- the timing of certain of Athabasca’s operations and projects, including the commencement of its planned Thermal Oil Division development projects, the exploration and development of Athabasca’s Light Oil assets, and the levels and timing of anticipated production;
- the timing of the project activities related to the Hangingstone Project and the Hangingstone Expansion, included the timing of the ramp-up of the Hangingstone Project production to design capacity;
- the potential for future joint venture arrangements;
- the use of SAGD technology to produce bitumen from the Hangingstone Expansion, Dover West Sands and Birch assets;
- development plans, projected timelines and expected costs for the Company’s Hangingstone Expansion, Dover West Sands and Birch assets;
- expected or projected abandonment and reclamation obligation costs;
- expected receipt of insurance claim proceeds;
- Athabasca’s ability to comply with the covenants contained in the Amended Credit Facility, the LC Facility, the New Notes, transportation agreements and any other third party agreement to which Athabasca is party;
- expected timing and volume of Athabasca’s planned hedging program;
- supply and demand fundamentals for crude oil, bitumen blend, natural gas, and SCO and other diluents;
- Athabasca’s access to third-party infrastructure;
- industry conditions including with respect to project development;
- Athabasca’s drilling plans and plans and results regarding the completion of wells that have been drilled and other exploration and development activities;
- realization of the anticipated benefits of acquisitions and dispositions; and
- Athabasca’s treatment under governmental regulatory regimes and tax laws.

With respect to forward looking statements and forward looking information contained in this Annual Information Form, assumptions have been made regarding, among other things:

- the benefits expected to be realized by the Company from the Acquired Assets, including the impact on the Company's reserves and financial position;
- the benefits expected to be realized by the Company from the Murphy Transaction, including the impact on the Company's financial position;
- future sources of funding for Athabasca's capital programs and Athabasca's ability to obtain financing on acceptable terms;
- future crude oil, bitumen blend, natural gas, SCO and other diluent prices;
- Athabasca's ability to obtain qualified staff and equipment in a timely and cost-efficient manner;
- the regulatory framework governing royalties, taxes, environmental matters and foreign investment in the jurisdictions in which Athabasca conducts and will conduct its business;
- Athabasca's ability to transport and market production of bitumen blend, conventional crude oil, shale oil, conventional natural gas, shale gas and NGLs, successfully to customers;
- Athabasca's future production levels;
- the applicability of technologies for the recovery and production of Athabasca's reserves and resources;
- the recoverability of Athabasca's reserves and resources;
- full field development status, recovery of the Company's proved and probable reserves attributable to asset areas and project life-span in calculation of abandonment and reclamation estimates;
- Athabasca's ability to develop its oil and gas properties in the manner currently contemplated;
- operating costs;
- future capital expenditures to be made by Athabasca;
- Athabasca's future debt levels;
- potential benefit to be realized by the Company in securing access to the Trans Mountain Pipeline expansion;
- compliance of counterparties with the terms of contractual arrangements with Athabasca;
- success rates of future well drilling;
- well drainage areas;
- future well production rates;
- geological and engineering estimates in respect of Athabasca's reserves and resources being accurate in all material respects;
- the geography of the areas in which Athabasca is conducting exploration and development activities; and
- the impact of increasing competition on Athabasca.

Actual results could differ materially from those anticipated in these forward looking statements as a result of the risk factors set forth below and included elsewhere in this Annual Information Form, including, but not limited to:

- how the oil and gas industry may affect Athabasca's operations and financial results;
- how declines in oil and natural gas commodity prices may adversely affect Athabasca's operating results and the value of its reserves and resources;
- how adverse changes in general economic and market conditions could negatively impact demand for oil and natural gas, revenue, operating costs, results of financing efforts, timing and extent of capital expenditures or credit risk and counterparty risk;
- anticipated benefits of acquisitions and dispositions;
- Athabasca's reserves and the current market value of Athabasca's estimated reserves;
- Athabasca's ability to finance its capital expenditures;
- risks related to the early stage of development of certain of Athabasca's assets;
- regulations resulting from concerns regarding hydraulic fracturing that delay the development of oil and natural gas resources;
- the effect of new regulations or the modification of existing regulations on Athabasca's business, financial condition, results of operations and prospects;
- the effect of changes to applicable royalty regimes on Athabasca's earnings, future capital investments and operations;

- additional financing in order to carry out Athabasca's oil and natural gas acquisition, exploration and development activities;
- variations in foreign exchange rates and interest rates;
- the impact of climate change legislation, regulations and policies on Athabasca's exploration and production facilities and other operations and activities and the market for its products;
- risks related to the Asset Acquisition, including risks generally associated with oil sands operations and risks and uncertainties related to exploration properties;
- how political events may affect the marketability and price of oil and natural gas and Athabasca's net production revenue;
- quantities of oil, natural gas and natural gas liquids reserves and the future cash flows attributed to such reserves;
- dependence on assets operated by other companies;
- future acquisition and joint venture activities;
- crude oil and natural gas exploration, development and production;
- possible capital cost over-runs and project delays for Athabasca's oil sands projects;
- the availability of capacity of gathering, processing and pipeline systems;
- federal and provincial statutes and regulations regarding the protection of the environment;
- claims made by aboriginal peoples against Athabasca or its assets;
- key personnel and operators;
- compliance with financial assurance covenants contained within Athabasca's pipeline transportation agreements;
- the effect of the demand for equipment or access restrictions on Athabasca's exploration and development activities;
- the effect of operating costs on Athabasca's results of operations and financial condition;
- Athabasca's ability to sell bitumen blend profitably based on, among other things, availability of supply of natural gas and diluents and the cost of natural gas and the cost of diluent;
- Athabasca's ability to utilize the most advanced commercially available technology;
- demand for oil and natural gas products;
- the risks posed by the production or potential production of natural gas overlying bitumen resources to Athabasca's ability to recover the bitumen resources on its oil sands leases using SAGD technology;
- security that must be posted based on the ratio of Athabasca's deemed assets to deemed liabilities or the requirements of liability management programs;
- tax reassessments or changes to income tax laws;
- abandonment and reclamation costs to be incurred when reserves and resources have been extracted from projects;
- whether exploration activities will result in additional discoveries to replace reserves depleted by production;
- the effect of environmental and health and safety risks and hazards to Athabasca's development, costs and liabilities;
- management’s assessment of items such as fair values, income taxes, stock based compensation and asset retirement obligations;
- whether third parties will meet their contractual obligations;
- third parties provision of an adequate supply of services in a timely, cost efficient, reliable and effective manner;
- the effect on Athabasca's operations of seasonality and weather conditions;
- the risks to which potential future hedging arrangements of the Company may be subject;
- the effectiveness of Athabasca's internal controls to meet its reporting obligations;
- whether Athabasca's insurance will be sufficient to cover all liabilities;
- the Company’s involvement in litigation;
- the effect of competition on Athabasca's results of operations, financial condition, cash flows and prospects;
- possible defects to the chain of title for Athabasca's properties;
- the effect on Athabasca's future operational and financial conditions should it acquire or move into new industry related activities or new geographical areas;
- Athabasca's information and computer systems;

- the yield of oil, natural gas or NGLs in commercial quantities at Athabasca's well locations;
- the anticipated benefits of the Asset Acquisition and the diversion of management's attention;
- potential undisclosed liabilities associated with the Asset Acquisition;
- Athabasca's engineering, title, environmental and economic assessments of the Acquired Assets;
- the integration of the Acquired Assets into Athabasca's existing business;
- the current market value of the reserves attributable to the Acquired Assets;
- operational and reserves risks relating to the Acquired Assets;
- additional capital requirements following the completion of the Asset Acquisition;
- risks related to Athabasca's indebtedness; and
- risks related to the Common Shares.

In addition, information and statements in this Annual Information Form relating to "reserves" and "resources" are deemed to be forward looking information and statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and resources described exist in the quantities predicted or estimated, and that the reserves and resources described can be profitably produced in the future. Readers are cautioned that the foregoing list of risk factors should not be construed as exhaustive.

Although management of the Company believes that the assumptions underlying and the expectations reflected in the forward looking information are reasonable, significant risks and uncertainties are involved in such information. Management can give no assurances that its assumptions, estimates and expectations will prove to have been correct. Forward looking information should not be read as guarantees of future performance or results, and will not necessarily be accurate indications of whether or not, or the times at or by which, such performance or results will be achieved. Many factors that are beyond Athabasca's control could cause actual results to differ materially from the results discussed in the forward looking statements.

The forward looking statements included in this Annual Information Form are expressly qualified by this cautionary statement and are made as of the date of this Annual Information Form. The Company does not undertake any obligation to publicly update or revise any forward looking statements, except as required by applicable securities laws.

GLOSSARY OF DEFINED TERMS

The following terms, used in the preparation of this Annual Information Form, have the following meanings:

"**2010 RSU**" means a restricted share unit granted under the 2010 RSU Plan.

"**2010 RSU Plan**" means the restricted share unit plan of the Company originally dated effective as of February 25, 2010, as amended from time to time and which was replaced by the 2015 RSU Plan.

"**2015 RSU**" means a restricted share unit granted under the 2015 RSU Plan.

"**2015 RSU Plan**" means the restricted share unit plan of the Company dated effective as of March 11, 2015.

"**abandonment and reclamation costs**" means all costs associated with the process of restoring Athabasca's property that has been disturbed by oil and gas activities to a standard imposed by applicable government or regulatory authorities.

"**ABCA**" means the *Business Corporations Act,* R.S.A. 2000, c. B-9, as amended, including the regulations promulgated thereunder.

"**Acquired Assets**" has the meaning given to that term under "*General Development of the Business – Recent Developments*".

"**Acquisition Agreement**" has the meaning given to that term under "*General Development of the Business – Recent Developments*".

"**Acquisition Independent Report**" means a consolidation prepared by GLJ dated effective as of December 31, 2016 of the report of GLJ relating to the Acquired Assets dated January 5, 2017and the GLJ Report and the DMCL Report, assessing and evaluating the Contingent Resources, Proved Reserves and Probable Reserves attributable to the Company's assets, including the Acquired Assets.

"**Acquisition Royalty**" has the meaning given to that term under "*General Development of the Business – Recent Developments*".

"**AER**" means the Alberta Energy Regulator (the successor to the ERCB).

"**AER Decision**" means the AER's written decision in respect of a hearing with the AER that was requested by the Dover JV Operator in response to certain objections that were filed by the FMFN with respect to the Dover Oil Sands Project, which hearing began on April 23, 2013 and was completed on April 29, 2013.

"**Alberta Environment**" means the Ministry of Environment and Sustainable Resource Development of the Government of Alberta (formerly, the Department of Environment and Water).

"**Amended and Restated Credit Agreement**" has the meaning given to that term under "*Description of Capital Structure –Revolving Senior Secured Credit Facility*".

"**Amended Credit Facility**" has the meaning given to that term under "*General Development of the Business – Recent Developments*".

"**AOC (Dover)**" means AOC (Dover) Energy Inc., a wholly-owned subsidiary of the Company incorporated under the ABCA, which as at the closing date of the Dover Put Option Transaction held an undivided 40% interest in the Dover assets.

"**AOC (Dover) Shares**" means all of the issued and outstanding shares of AOC (Dover) Energy Inc.

"**AOSC Newco**" means 1487645 Alberta Ltd., a corporation incorporated under the ABCA, that: (a) prior to the closing of the PetroChina Share Purchase Agreement, was a wholly-owned subsidiary of the Company; and (b) following the closing of the PetroChina Share Purchase Agreement and prior to the amalgamation of AOSC Newco and Phoenix, was a wholly-owned subsidiary of Phoenix.

"**API**" means the American Petroleum Institute.

"**°API**" refers to an indication of the specific gravity of crude oil measured on the API gravity scale.

"**Asset Acquisition**" has the meaning given to that term under "*General Development of the Business – Recent Developments*".

"**Athabasca**" means Athabasca Oil Corporation and/or its wholly-owned subsidiaries, as the context requires.

"**Audit Committee**" means the audit committee of the Board.

"**Best Estimate**" has the meaning given to that term under "*Schedule A – Supplemental Disclosure- Contingent Resource Estimates*".

"**Birch assets**" means the interests of Athabasca in approximately 447,000 net acres of land as at December 31, 2016, located in northeastern Alberta (see map), that are more particularly described under "*Description of Athabasca's Business –Thermal Oil Division- Other Thermal Oil Exploration Area*s".

"**Birch Project**" means a staged development plan for a 170,000 bbls/d SAGD project, with an initial phase 1 of 12,000 bbls/d.

"**bitumen**" means a naturally occurring solid or semi-solid hydrocarbon, consisting mainly of heavier hydrocarbons with a viscosity greater than 10,000 milliPascal seconds (or centipoise) measured at the hydrocarbon's original temperature in the reservoir and atmospheric pressure, on a gas-free basis and is not primarily recoverable at economic rates through a well without the implementation of enhanced recovery methods. Crude bitumen may contain sulphur and other non-hydrocarbon compounds.

"**Board**" means the Board of Directors of the Company.

"**BOEs**" means barrels of oil equivalent.

"**Brion**" means Brion Energy Corporation the successor to Phoenix by amalgamation which occurred on August 29, 2014.

"**Burgess**" has the meaning given to that term under "*General Development of the Business – Three Year History – 2016*".

"**cap rock**" means a relatively impermeable rock, commonly shale, that forms a barrier or seal above reservoir rock so that injected or in-situ fluids cannot migrate beyond the reservoir.

"**carbonate**" means a class of sedimentary rock whose chief mineral constituents (95% or more) are calcite, aragonite and dolomite. Limestone, dolostone (or dolomite) and chalk are carbonate rocks. Although carbonate rocks can be clastic in origin, they are more commonly formed through processes of precipitation or the activity of organisms such as coral and algae. Carbonates form in shallow and deep marine settings, evaporitic basins, lakes and windy deserts. Carbonate rocks are common hydrocarbon reservoir rocks.

"**CCAA**" means the *Companies' Creditors Arrangement Act*, R.S.C. 1983, c. C-36.

"**CSS**" means cyclic steam stimulation, an in-situ oil extraction method where a well cycles through steam injection, soak and oil production phases.

"**clastic**" means sediment consisting of weathered fragments derived from pre-existing rocks and transported elsewhere and redeposited before forming another rock. Examples of common clastic sedimentary rocks include siliciclastic rocks such as conglomerate, sandstone, siltstone and shale.

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

"**Collateral Agent**" means Computershare Trust Company of Canada, the collateral agent, pursuant to the Collateral Agent Agreement.

"**Collateral Agent Agreement**" has the meaning given to that term under "*Description of Capital Structure – Senior Secured Notes*".

"**Common Shares**" means the common shares in the capital of the Company, as constituted on the date hereof.

"**Company Interest**" means Athabasca's total working interest share before deduction of royalties and without excluding any royalty interests.

"**Compensation and Governance Committee**" means the compensation and governance committee of the Board.

"**Computershare**" means Computershare Trust Company of Canada.

"**Contingent Resources**" has the meaning given to that term under "*Schedule A – Supplemental Disclosure-Contingent Resource Estimates*".

"**conventional natural gas**" means natural gas that has been generated elsewhere and has migrated as a result of hydrodynamic forces and is trapped in discrete accumulations by seals that may be formed by localized structural, depositional or erosional geological features.

"**Credit Facility**" means the amended and restated revolving senior secured first lien credit facility entered into by the Company on May 7, 2014 as more particularly described in "*Description of Capital Structure – Revolving Senior Secured Credit Facility*".

"**crude oil**" or "**oil**" means a mixture consisting mainly of pentanes and heavier hydrocarbons that exist in the liquid phase in reservoirs and remains liquid at atmospheric pressure and temperature. Crude oil may contain small amounts of sulphur and other non-hydrocarbons but does not include liquids obtained from the processing of natural gas. Classes of crude are reported on basis of density, acceptable ranges are as follows: Light: less than 870kg/m3 (greater than 31.1 degrees (symbol) API), Medium: 870-920 kg/m3 (31.1-22.3 degrees API), Heavy 920-1000 kg/m3 (22.3-10 degrees API).

"**DBRS**" means DBRS Limited.

"**developed non-producing reserves**" has the meaning given to that term under "*Independent Reserves Evaluations – Reserves Classifications – Development and Production Status*".

"**developed producing reserves**" has the meaning given to that term under "*Independent Reserves Evaluations – Reserves Classifications – Development and Production Status*".

"**developed reserves**" has the meaning given to that term under "*Independent Reserves Evaluations – Reserves Classifications – Development and Production Status*".

"**dilbit**" means a blend of condensate and bitumen.

"**diluent**" means lighter viscosity petroleum products that are used to dilute bitumen for transportation in pipelines.

"**DMCL**" means DeGolyer and MacNaughton Canada Limited, an independent qualified reserve and resource evaluator.

"**DMCL Report**" means the reports of DMCL dated effective as of December 31, 2016 assessing and evaluating the Proved Reserves, Probable Reserves and Contingent Resources of Athabasca, as applicable, located in the Birch and Hangingstone areas of Alberta.

"**Dover assets**" means the former interests of the Participants in approximately 150,000 acres of land primarily between townships 92 to 97, ranges 15 to 18 west of the fourth meridian in northeastern Alberta near the city of Fort McMurray which after the closing date of the Dover Put Option Transaction on August 29, 2014, were owned exclusively by Phoenix (now Brion).

"**Dover Put Option**" means the option granted to the Company by Phoenix to require Phoenix or an affiliate of Phoenix to acquire all of the shares or assets of AOC (Dover) (or a wholly-owned subsidiary of AOC (Dover)), as the case may be, pursuant to the Put/Call Option Agreement.

"**Dover Put Option Transaction**" means the exercise by the Company of the Dover Put Option (which is more particularly described under "*General Development of the Business –Three Year History - 2014*") and the sale by the Company of the AOC (Dover) Shares to Phoenix.

"**Dover West assets**" means the interests of Athabasca in approximately 233,000 net acres of land as at December 31, 2016 located within the Athabasca oil sands fairway in northeastern Alberta (see map) that are more particularly described under "*Description of Athabasca's Business – Thermal Oil Division – Other Thermal Oil Exploration Areas-Dover West assets*".

"**Dover West Sands**" means the clastic bitumen reservoirs contained within the McMurray Formation and the Wabiskaw member of the Clearwater Formation in the Dover West assets.

"**Dover West Sands Project 1**" means a SAGD project in the Dover West area with a planned production capacity of up to 12,000 bbls/d.

"**DSU**" means a deferred share unit granted under the Company's DSU Plan.

"**DSU Plan**" means the deferred share unit plan adopted by the Company and effective March 11, 2015 for directors of the Company.

"**Enbridge**" means Enbridge Inc.

"**EPAI**" means Enbridge Pipelines (Athabasca) Inc.

"**ERCB**" means the Energy Resources Conservation Board of Alberta (predecessor to the AER).

"**Established Technology**" means methods that have been proven to be successful in commercial applications, as such term is defined in the COGE Handbook.

"**FEED**" means front end engineering and design.

"**fines**" means fragments or particles of rock or mineral that are too minute to be treated as ordinary coarse material.

"**FMFN**" means the Fort McKay First Nation.

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

"**future net revenue**" means a forecast of revenue, estimated using forecast prices and costs or constant 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.

"**GHG**" means greenhouse gas.

"**GLJ**" means GLJ Petroleum Consultants Ltd., an independent qualified reserve and resource evaluator.

"**GLJ Report**" means the reports of GLJ dated effective as of December 31, 2016, assessing and evaluating the Contingent Resources of Athabasca, as applicable, located in the Dover West Sands area of Alberta and the Proved Reserves and Probable Reserves attributable to the Light Oil assets.

"**Greater Kaybob area**" has the meaning given to that term under "*The Company – Overview of Athabasca's Business – Light Oil Division*".

"**Greater Placid area**" has the meaning given to that term under "*The Company – Overview of Athabasca's Business – Light Oil Division*".

"**Grosmont assets**" refers to Athabasca's interest in approximately 112,000 net acres of land in the Grosmont (Mikwa) area located in northeastern Alberta in which Athabasca, as at December 31, 2016 (see map), as more particularly described under "*Description of Athabasca's Business – Thermal Oil Division – Other Thermal Oil Exploration Areas*".

"**Gross Reserves**" or "**Gross**" in relation to reserves means a 100% working interest share (operating or non-operating) before deduction of royalties and without including any royalty interests of Athabasca.

"**HAF**" means the Heater Assembly Facility constructed and owned by Athabasca and used for assembly of cable-based well heaters for TAGD applications.

"**Hangingstone assets**" means the interests of Athabasca in approximately 139,000 net acres of land located in the Athabasca oil sands fairway in northeastern Alberta (see map) as at December 31, 2016, that are more particularly described under "*Description of Athabasca's Business – Thermal Oil Division –Hangingstone assets*".

"**Hangingstone Expansion**" means an incremental expansion of the Hangingstone Project by an additional 70,000 bbls/d via three separate projects: Hangingstone Project 2A, Hangingstone Project 2B and Hangingstone Project 3 in respect of which a regulatory application was filed with the AER and Alberta Environment on May 17, 2013.

"**Hangingstone Project**" means a 12,000 bbl/d SAGD project in the Hangingstone area which received regulatory approval in October 2012 and which was sanctioned by the Board on November 27, 2012.

"**Hangingstone Project 2A** means an 8,000 bbl/d incremental debottleneck project in the Hangingstone area.

"**Hangingstone Project 2B**" means a project which is planned to have a production capacity of 32,000 bbl/d in the Hanginstone area.

"**Hangingstone Project 3**" means a project which is planned to have a production capacity of 30,000 bbl/d in the Hangingstone area.

"**Hangingstone Projects**" means the Hangingstone Project, the Hangingstone Expansion and any future proposed in-situ oil sands projects in respect of the Hangingstone assets.

"**HS CPF**" means the Hangingstone Project central processing facility.

"**hydrocarbon**" means a compound consisting of hydrogen and carbon, which, when naturally occurring, may also contain other elements such as sulphur.

"**Indenture Trustee**" means Olympia Trust Company, as trustee under the Note Indenture.

"**Independent Evaluators**" means, collectively, DMCL and GLJ.

"**Independent Reports**" means, collectively, the DMCL Report and the GLJ Report.

"**in-situ**" means "in place" and, when referring to oil sands, means a process for recovering bitumen from oil sands by means other than surface mining, such as SAGD, CSS or TAGD.

"**IPP**" means Inter Pipeline Polaris Inc.

"**KA**" has the meaning given to that term under "*Description of Athabasca's Business – Light Oil Division*".

"**Kaybob assets**" means the interests of Athabasca in approximately 97,350 net acres of land that are located primarily in northwestern Alberta (see map), as at December 31, 2016, as more particularly described under "*Description of Athabasca's Business – Light Oil Division*".

"**Kaybob Carry Commitment**" means a portion of the purchase price in the Murphy Transaction in the form of Murphy's obligation to fund 75% of Athabasca's share of Duvernay development capital up to $1 billion of gross investment over a period of up to four years ($75 million net capital exposure to Athabasca).

"**Kaybob Infrastructure Assets**" means the light oil transportation infrastructure assets located in the Kaybob area including a 63 kilometre, 12-inch pipeline, from the Kaybob and Placid areas to the Keyera Simonette Gas Plant and two oil batteries (the Kaybob West battery has a design capacity of 13,000 bbls/d of oil and 48 MMcf/d of natural gas and is located at 7-14-063-20-W5M and the Kaybob East battery has a design capacity of 13,000 bbls/d of oil and 24 MMcf/d of natural gas and is located at 16-03-065-18-W5M. Following completion of the Murphy Transaction, Athabasca now holds a non-operated 30% interest in the Greater Kaybob area as of December 31, 2016.

"**Kaybob JDA**" means the joint development agreement between AOC Simonette Partnership, AOC Kaybob Partnership and Murphy Oil Company Ltd. dated May 13 2017 as further described in "*General Development of the Business- Three year History- 2016*"

"**KKD Partnership**" means KKD Oil Sands Partnership.

"**LC Facility**" has the meaning given to that term under "*Description of Capital Structure – LC Facility*".

"**LIBOR**" means the London Interbank Offered Rate.

"**Light Crude Oil**" or "**light crude oil**" means crude oil with a relative density greater than 31.1 degrees API gravity.

"**Light Oil assets**" means the interests of Athabasca in approximately 233,480 net acres of land as at December 31, 2016, primarily located in northwestern Alberta, which includes the Kaybob, Placid and Light Oil Exploration Areas.

"**Light Oil Division**" means Athabasca's business unit which is primarily focused on the exploration for, and sustainable development and production of, light oil and liquids-rich natural gas.

"**Light Oil Exploration Areas**" means the interests of Athabasca in approximately 83,000 net acres of land that are located in the Grande Prairie, North Muskwa, South Muskwa, Caribou, Glenevis and Sawn Lake areas in northwestern Alberta as at December 31, 2016.

"**Medium Crude Oil**" or "**medium crude oil**" means crude oil with a relative density greater than 22.3 degrees API gravity and less than or equal to 31.1 degrees API gravity.

"**Murphy**" means Murphy Oil Canada Ltd., a wholly owned subsidiary of Murphy Oil Corporation.

"**Murphy Transaction**" has the meaning given to such term under the heading "*General Development of the Business- Three Year History - 2016*".

"**Murphy Transaction Assets**" means (a) 70% of the Company's WI in the Greater Kaybob area including approximately 200,000 acres of prospective Duvernay lands; and (b) 30% of the Company's WI in the Greater Placid area including approximately 60,000 acres of prospective Montney lands.

"**Murphy Purchase and Sale Agreement**" means the Agreement of Purchase and Sale dated January 27, 2016 entered into between AOC Simonette Partnership, AOC Kaybob Partnership and AOC Light Oil Partnership as vendors and Murphy Oil Canada Ltd. as purchaser.

"**M$**" means thousands of Canadian dollars.

"**MM$**" means millions of Canadian dollars.

"**natural gas**" means a naturally occurring mixture of hydrocarbon gases and other gases, which may contain sulphur or other non-hydrocarbon compounds.

"**Net Reserves**" means Athabasca's working interest (operating or non-operating) share after deduction of royalty obligations, plus Athabasca's royalty interests in reserves.

"**New Note Indenture**" means the indenture dated February 24, 2017, among the Company, the Company's subsidiary guarantors, the Bank of New York Mellon and the BNY Trust Company of Canada relating to the New Notes.

"**New Notes**" has the meaning given to such term under the heading "*General Development of the Business-Recent Developments*".

"**NGL**" or "**natural gas liquids**" means the hydrocarbon components that can be recovered from natural gas as liquids, including, but not limited to ethane, propane, butanes, pentanes plus and condensates.

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

"**NI 51-102**" means National Instrument 51-102 *Continuous Disclosure Obligations.*

"**Note Indenture**" means the indenture dated November 19, 2012, among the Company, the Company's subsidiary guarantors and the Indenture Trustee, relating to the Senior Secured Notes.

"**oil sands**" means deposits of sand, sandstone, carbonate or other mineral material containing bitumen.

"**Original Royalty Transaction**" has the meaning given to that term under "*General Development of the Business – Three Year History – 2016*".

"**Participant**" means a person that had a Participating Interest in the Dover Joint Venture and was a party to the Dover Joint Venture Agreement, in any case, as the context requires or permits.

"**Participating Interest**" means an undivided beneficial ownership interest in the Dover Joint Venture, the Dover assets and bitumen recovered from the lands underlying the Dover Oil Sands Leases, in any case, as the context requires or permits.

"**Performance Award**" means performance awards able to be granted to directors and other Company staff under the Company's Performance Plan which was adopted by the Company on March 18, 2014.

"**Performance Plan**" means the performance award plan of the Company dated effective March 18, 2014.

"**permeability**" is a measure of the ability of a rock to conduct a fluid through its interconnected pores when that fluid is at 100% saturation. A rock may be highly porous and yet impermeable if it has no interconnecting pore network (communication). Permeability is measured in darcies or millidarcies.

"**PetroChina**" means PetroChina Company Limited, a joint stock company with limited liabilities existing under the laws of the People's Republic of China.

"**PetroChina International**" means PetroChina International Investment Company Limited, a body corporate existing under the laws of the People's Republic of China and a wholly-owned subsidiary of PetroChina.

"**PetroChina Share Purchase Agreement**" means the agreement dated February 10, 2010 between the Company and Phoenix, pursuant to which Phoenix acquired the AOSC Newco shares from the Company.

"**Phoenix**" means Phoenix Energy Holdings Limited, a wholly-owned subsidiary of PetroChina International and the successor entity resulting from the amalgamation of AOSC Newco and Cretaceous Oilsands Holdings Limited.

"**PIIP**" means that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production. The recoverable portion of discovered petroleum initially-in-place includes production, reserves and Contingent Resources; the remainder is unrecoverable.

"**Placid JDA**" means the joint development agreement between AOC Simonette Partnership and Murphy Oil Company Ltd. dated May 13 2017 as further described in "*General Development of the Business- Three year History-2016*".

"**Plan of Arrangement**" means the plan of arrangement under the ABCA effective March 22, 2010.

"**porosity**" means the volume of a rock available to contain fluids; the ratio of void space to the bulk volume of rock containing that void space. Porosity can be expressed as a fraction or percentage of pore volume in a volume of rock.

"**Probable Reserves**" or "**probable reserves**" has the meaning given to that term under "*Independent Evaluations – Reserves Classifications – Reserves Categories*".

"**Promissory Notes**" means the three interest-bearing promissory notes issued by Phoenix (now Brion) to the Company pursuant to the closing of the Dover Put Option Transaction on August 29, 2014. The promissory notes were in the following amounts (exclusive of interest) and were due and paid on the following dates:$300 million due March 2, 2015; $150 million due August 28, 2015; and $134 million due August 29, 2016.

"**Prosperity Act**" has the meaning given to that term under "*Industry Conditions – Pricing and Marketing – Oil*".

"**Proved Reserves**" or "**proved reserves**" has the meaning given to that term under "*Independent Reserves Evaluations – Reserves Classifications – Reserves Categories*".

"**Put/Call Option Agreement**" means the amended and restated agreement dated March 15, 2012 setting forth the Dover Put/Call Option, among the Company, Phoenix, AOC (Dover) and AOC Dover Corp.

"**recovery factor**" means the percentage of PIIP in a reservoir that ultimately can be recovered at a specific point in time.

"**Reserves**" or "**reserves**" has the meaning given to that term under "*Independent Reserve and Resource Evaluations – Reserves and Resources Classifications – Reserves Categories*".

"**Reserves Committee**" means the reserves committee of the Board.

"**reservoir**" means a porous and permeable formation that contains a separate accumulation of petroleum that is confined by impermeable rock or water barriers and is characterized by a single pressure system.

"**Restricted Subsidiaries**" has the meaning given to that term under "*Description of Capital Structure – Senior Secured Term Loans*".

"**Rights Plan**" means the shareholder rights plan of the Company having the terms set forth in the shareholder rights plan agreement entered into between the Company and Olympia Trust Company, as rights agent, on April 8, 2010, as described under "*Description of Capital Structure – Shareholder Rights Plan*".

"**risked**" has the meaning given to that term under "*Schedule A – Supplemental Disclosure- Contingent Resource Estimates*".

"**Royalty**" has the meaning given to that term under "*General Development of the Business – Three Year History – 2016*".

"**Royalty Transaction**" has the meaning given to that term under "*General Development of the Business – Three Year History – 2016*".

"**RSU**" means either a 2010 RSU or a 2015 RSU or both, as the context requires.

"**S&P**" means Standard and Poor's Rating Services, a division of McGraw-Hill Companies (Canada) Corporation.

"**SAGD**" means steam assisted gravity drainage, an in-situ process used to recover bitumen from oil sands.

"**saturation**" is the fraction or percentage of the pore volume occupied by a specific fluid (e.g., oil, gas, water, etc.).

"**SCL**" means Statoil Canada Limited.

"**SCO**" or "**synthetic crude oil**" means a mixture of liquid hydrocarbons derived by upgrading bitumen, kerogen or other substances such as coal, or derived from gas to liquid conversion and may contain sulphur or other compounds.

"**Senior Secured Notes**" has the meaning given to that term under "*Description of Capital Structure – Senior Secured Notes*".

"**shale gas**" means natural gas contained in dense organic-rich rocks, including low permeability shales, siltstones and carbonates, in which the natural gas is primarily adsorbed on the kerogen or clay materials and that usually requires the use of hydraulic fracturing to achieve economic production rates.

"**Shareholders**" means the holders, from time to time, of the Common Shares, collectively or individually, as the context requires.

"**SOC**" means statement of concern.

"**SOR**" means steam to oil ratio.

"**Statoil**" means Statoil ASA.

"**Stock Option**" means a stock option granted under the Stock Option Plan.

"**Stock Option Plan**" means the stock option plan of the Company originally dated effective as of September 1, 2009, as amended from time to time.

"**TAGD**" means thermal assisted gravity drainage.

"**TCPL**" means TransCanada Pipelines Limited, a subsidiary of TransCanada Corporation.

"**Technology Under Development**" means a recovery process or process improvement project that has been determined to be technically viable via a field test and is being field tested further to determine its economic viability in the subject reservoir as such term is defined in the COGE Handbook.

"**Term Loans**" means the senior secured first lien term loans entered into by the Company on May 7, 2014 pursuant to the Term Loan Credit Agreement.

"**Term Loan Credit Agreement**" means the credit agreement with respect to the Term Loans dated May 7, 2014 between the Company, the lenders of the Term Loans and the Toronto Dominion Bank as agent for such lenders

"**Thermal Oil assets**" means the interests of Athabasca in over 1.24 million net acres of oil sands leases in the Athabasca region of northeastern Alberta, as at December 31, 2016.

"**Thermal Oil Division**" means Athabasca's business unit which is primarily focused on the exploration for, and sustainable development and production of, bitumen from oil sands.

"**tight oil**" means crude oil contained in dense organic-rich rocks, including low permeability shales, siltstones and carbonates, in which the natural gas is primarily contained in microscopic pore spaces that are poorly connected to one another and that usually requires the use of hydraulic fracturing to achieve economic production rates.

"**TSX**" means the Toronto Stock Exchange.

"**undeveloped reserves**" has the meaning given to that term under "Independent Reserves Evaluations – Reserves Classifications – Development and Production Status".

"**Upsized Royalty Transaction**" has the meaning given to that term under "*General Development of the Business – Three Year History – 2016*".

"**unrisked**" has the meaning given to that term under "*Schedule A – Supplemental Disclosure- Contingent Resource Estimates*".

"**WCS**" means Western Canadian Select.

"**WI**" means working interest.

"**WTI**" means West Texas Intermediate grade crude oil at a reference sales point in Cushing, Oklahoma, a common benchmark for crude oils.

ABBREVIATIONS

In this Annual Information Form, the abbreviations set forth below have the following meanings:

bbl	barrel
bbls	barrels
bbl/d	barrels per day
BOE or boe	barrels of oil equivalent
Boe/d	barrels of oil equivalent per day
MMboe	million barrels of oil equivalent
Mbbl	thousand barrels
MMbbl	million barrels
Mcf	thousand cubic feet
Mcfe	thousand cubic feet equivalent
MMcf	million cubic feet
MMcf/d	million cubic feet per day
Bcf	billion cubic feet

BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. As the value ratio between natural gas and crude oil based on the current prices of natural gas and crude oil 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.

CONVERSIONS

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

To Convert From	To	Multiply By
Mcf	cubic metres	28.174
cubic metres	cubic feet	35.315
Bbls	cubic metres	0.159
cubic metres	Bbls	6.290
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.500

CONVENTIONS

Words importing the singular number only include the plural, and vice versa, and words importing any gender include all genders.

All dollar amounts set forth in this Annual Information Form are in Canadian dollars, except where otherwise indicated.

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

THE COMPANY

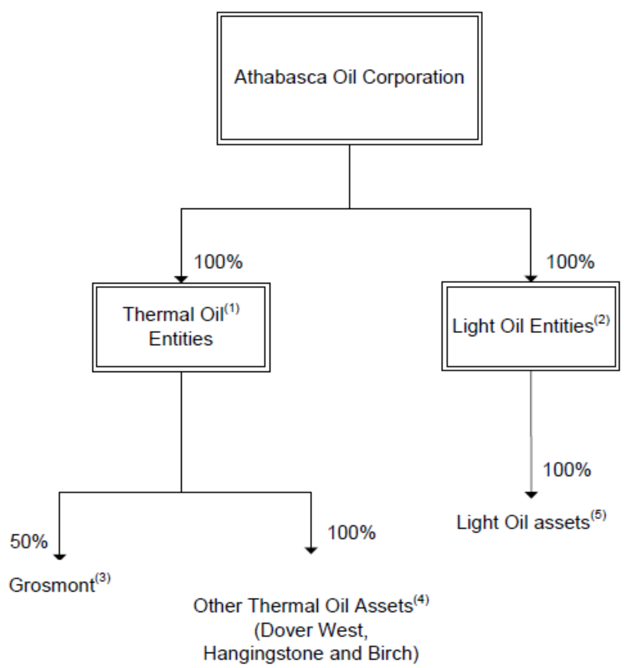
Name, Address and Incorporation

The Company was incorporated as "Athabasca Oil Sands Corp." under the ABCA on August 23, 2006. On September 1, 2006, the Company filed articles of amendment to remove its private company restrictions. On March 22, 2010, the Company filed articles of arrangement to give effect to the Plan of Arrangement and filed articles of amendment to create first preferred shares, issuable in series, and second preferred shares, issuable in series. On May 10, 2012, the Company filed articles of amendment to change its name from "Athabasca Oil Sands Corp." to "Athabasca Oil Corporation". On January 1, 2017, Athabasca amalgamated with its subsidiaries AOC Grande Prairie Corp., AOC Muskwa North Corp., AOC Muskwa South Corp., AOC Caribou Corp and AOC Dover Corp. to form "Athabasca Oil Corporation".

The Company's head office is located at Suite 1200, 215 – 9th Avenue S.W., Calgary, Alberta T2P 1K3, and its registered office is located at Suite 2400, 525 – 8th Avenue S.W., Calgary, Alberta T2P 1G1.

Intercorporate Relationships

The following simplified organizational chart and related notes illustrate the intercorporate relationships of the Company and its material subsidiaries, as at January 1, 2017, including the percentage of votes attaching to all voting securities of such entities that are beneficially owned, or controlled or directed, directly or indirectly, by the Company. Each of the Company's subsidiaries is incorporated or formed under the laws of the Province of Alberta.



Notes:

(1) The "Thermal Oil Entities" are corporations and partnerships that hold the Company's Thermal Oil assets and that are directly or indirectly wholly-owned by the Company: AOC Dover West Corp., AOC Grosmont Ltd., AOC Carbonates Ltd., AOC (ELE) Corp., AOC Birch Corp., AOC Dover West Partnership, AOC Grosmont Partnership, AOC Carbonates Partnership, AOC Hangingstone Partnership, AOC Birch Partnership, AOC Leismer Corner Partnership and 1686303 Alberta Ltd.

(2) The "Light Oil Entities" are corporations and partnerships that hold the Company's Light Oil assets and that are directly or indirectly wholly-owned by the Company: AOC Light Oil Corp., AOC Kaybob Corp., AOC Simonette Corp., AOC Light Oil Partnership, AOC Kaybob Partnership and AOC Simonette Partnership.

(3) See "*Description of Athabasca's Business – Thermal Oil Division – Other Thermal Oil Exploration Areas- Grosmont assets*" for a description of Athabasca's 50% working interest in the Grosmont area. ZAM Ventures Alberta Inc., a private Alberta company, holds the remaining 50% working interest in the Grosmont area.

(4) See "*Description of Athabasca's Business – Thermal Oil Division – Other Thermal Oil Exploration Areas- Dover West assets*", "*Description of Athabasca's Business – Thermal Oil Division – Hangingstone assets*" and "*Description of Athabasca's Business – Thermal Oil Division – Other Thermal Oil Exploration Areas- Birch assets*" for descriptions of Athabasca's 100% working interests in the Dover West assets, Hangingstone assets and Birch assets.

(5) See "*Description of Athabasca's Business – Light Oil Division*" for a description of Athabasca's interests in the Light Oil assets.

Overview of Athabasca's Business

Athabasca is primarily focused on the exploration for, and sustainable development and production of, light oil and liquids-rich natural gas from regions in northwestern Alberta, Canada and bitumen from oil sands in the Athabasca region of northeastern Alberta, Canada. Athabasca is organized into the following two divisions:

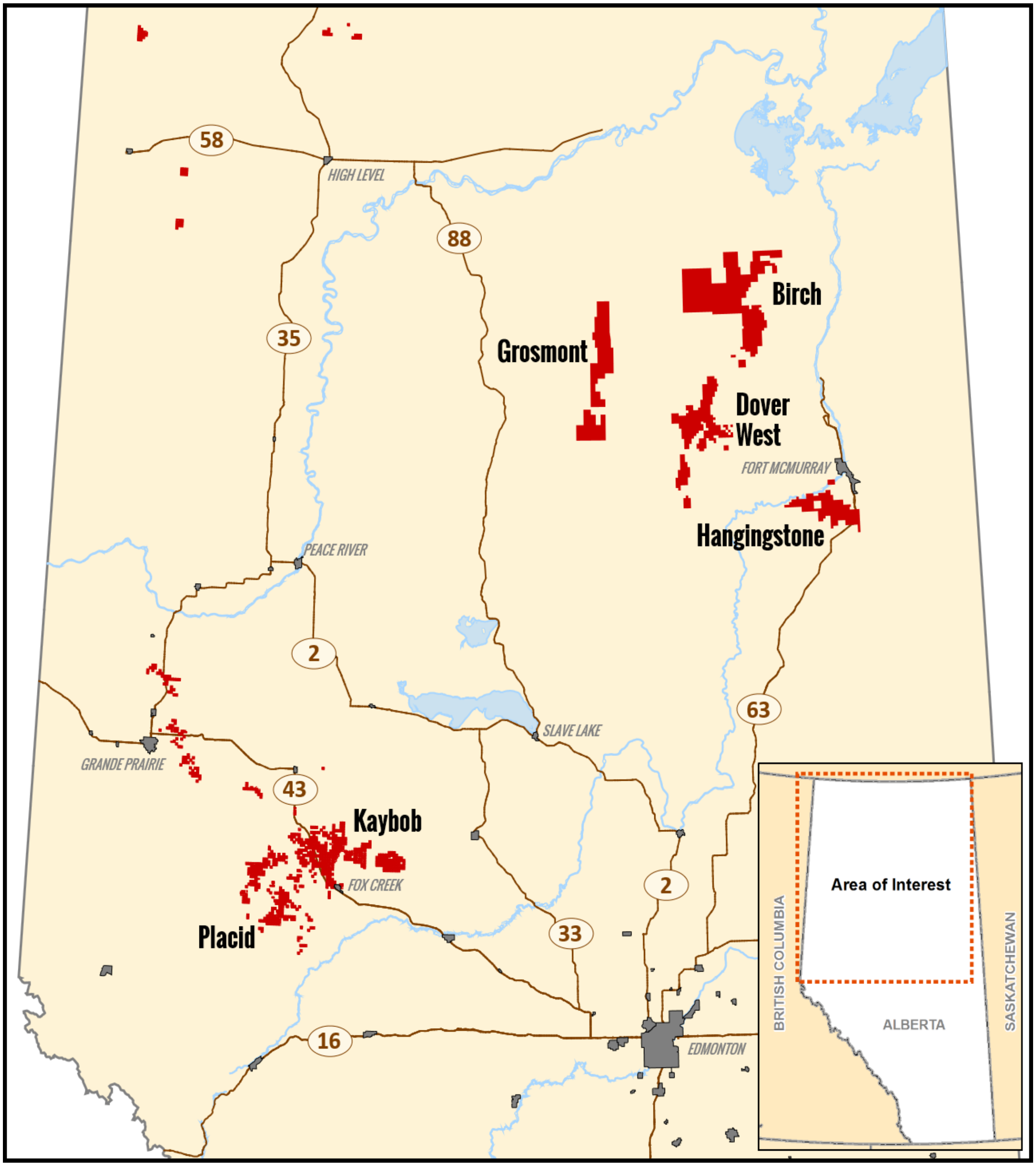
Light Oil Division

In the Light Oil Division, Athabasca produces light oil and liquids-rich natural gas from unconventional reservoirs utilizing horizontal drilling and multi-stage hydraulic fracturing technology. Developments have recently been focused on the Montney formation in Saxon/Placid (the "**Greater Placid area**") and the Duvernay formation in Kaybob (the "**Greater Kaybob area**") near the town of Fox Creek in northwestern Alberta. In the Greater Placid area, the Company had greater than 65,000 gross Montney acres at December 31, 2016, of which approximately 31,500 gross acres (approximately 21,500 net) are considered commercially prospective. In the Greater Kaybob area, the Company has a 30% non-operated interest in approximately 200,000 gross Duvernay acres as at December 31, 2016 with exposure to both liquids-rich gas and volatile oil opportunities. In the second quarter of 2016, the Company completed the Murphy Transaction to form a strategic joint venture to develop the Duvernay and Montney formations in the Greater Kaybob and Greater Placid areas, respectively. See "*General Development of the Business – Three Year History – 2016*" and "*Description of Athabasca's Business- Light Oil Division*".

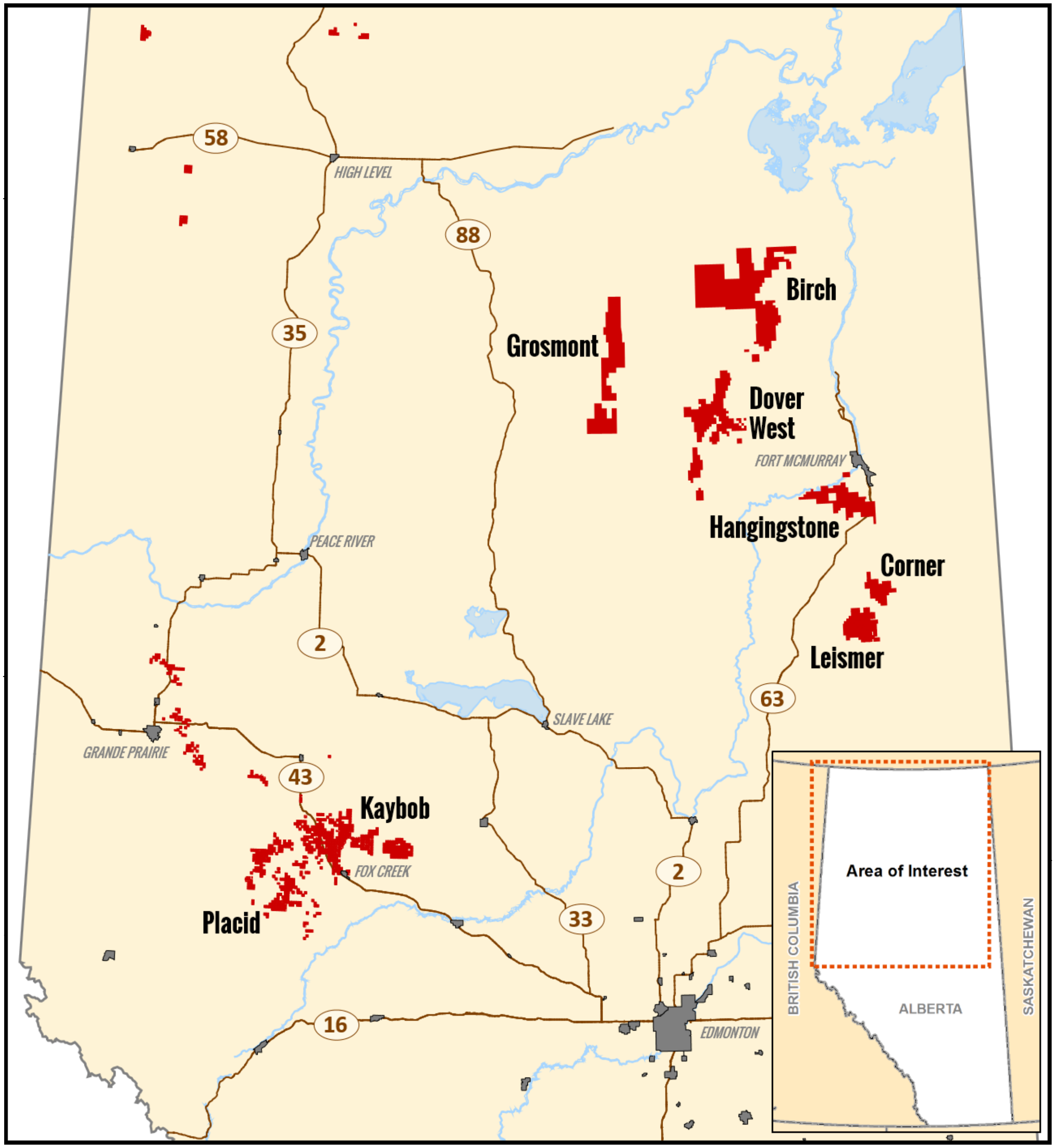
Thermal Oil Division

The Thermal Oil Division consists of several major project areas in the Athabasca region of Northeastern Alberta, where, as at December 31, 2016, Athabasca held over 1.24 million net acres of oil sands leases and following completion of the Asset Acquisition on January 31, 2017, the Company now holds approximately 1.4 million net acres of oil sands leases. On January 31, 2017, the Company completed the Asset Acquisition with SCL and KKD Partnership, subsidiaries of Statoil, to acquire their Canadian thermal oil assets, which include the operating Leismer thermal oil project, the delineated Corner lease and certain strategic infrastructure and related midstream agreements. See "*General Development of the Business – Recent Developments*", "*General Development of the Business – Significant Acquisitions*" and "*Description of Athabasca's Business- Acquired Assets*". The Company's other development focus in the Thermal Oil Division has been on the ramp-up of Athabasca's Hangingstone Project to design capacity. First production was achieved from the Hangingstone Project in July 2015 and the Company expects to achieve design capacity of 12,000 bbl/d in 2018. Limited capital expenditures are anticipated at Hangingstone over the next five years as the well pairs are early in their life cycle.

The following map illustrates the locations of Athabasca's Light Oil assets and Thermal Oil assets, as at December 31, 2016, prior to completion of the Asset Acquisition:



The following map illustrates the locations of Athabasca's Light Oil assets and Thermal Oil assets, as at March 9, 2017, following completion of the Asset Acquisition on January 31, 2017:



In conjunction with the New Notes, the Company established a $120 million reserve-based Amended Credit Facility with seven major financial institutions. The Amended Credit Facility is guaranteed on a senior secured first lien basis and is subject to the terms of the Collateral Agent Agreement. See "*Description of Capital Structure – Revolving Senior Secured Credit Facility*". The Company also amended and restated its LC Facility. See "*Description of Capital Structure – LC Facility*".

Trans Mountain Pipeline Capacity

On March 6, 2017, Athabasca acquired firm service on the Trans Mountain Pipeline Expansion (the "**TMX Pipeline**") by entering into a long-term transportation service agreement with Trans Mountain Pipeline L.P. to deliver up to 20,000 bbl/d of the Company's blended bitumen from Edmonton, Alberta to Burnaby, B.C. The TMX Pipeline is federally approved and is expected to be in-service in late 2019. The TMX Pipeline is expected to provide Athabasca with access to global oil demand growth.

Three Year History

The following is a summary description of the development of Athabasca's business over the last three completed financial years.

2016

On May 5, 2016, the Hangingstone Project was shut down due to the regional Fort McMurray wildfires. The decision to shut down the well sites and central facility was due to elevated safety risks from the fire's proximity to the Hangingstone Project. Operations resumed on May 24, 2016. There was no damage to the facility, field pipelines or well sites.

In the second quarter of 2016, the Company completed a transaction with Murphy to form a strategic joint venture to develop the Company's interests in the Duvernay and Montney Formations in the Greater Kaybob and Greater Placid areas. As part of the transaction, the Company sold an operated 70% interest in the Greater Kaybob area and a non-operated 30% interest in the Greater Placid area to Murphy for gross proceeds of $486 million, including closing adjustments. The Company received cash consideration of $267 million and an additional $219 million Kaybob Carry Commitment whereby Murphy will fund 75% of the Company's share of Duvernay development capital up to $1 billion of gross investment over the next four years ($75 million net capital exposure for Athabasca). Murphy has assumed operatorship of the Greater Kaybob area field assets and the Company retained operatorship of the Greater Placid area assets. Joint development agreements were entered into concurrently with the closing of the transaction that are intended to preserve the value of the Company's interests, ensure strategic alignment on Duvernay growth and provide flexibility to accelerate activity in Greater Placid area where the Company has established a core operated position (the "**Placid JDA**" and "**Kaybob JDA**", respectively).

On June 20, 2016, the Company granted a contingent bitumen royalty to Burgess Energy Holdings L.L.C. ("**Burgess**") on select Thermal assets (including Hangingstone, Dover West, Birch and Grosmont) (the "**Royalty**") for consideration of $128.5 million (the "**Original Royalty Transaction**"). On November 10, 2016, the amount of the Royalty was increased for additional cash consideration of $128.5 million (the "**Upsized Royalty Transaction**"). On December 22, 2016, the Company amended the terms of the Royalty such that the applicable royalty rate will be determined by a linear scale tied to US$ WCS benchmark prices, for incremental proceeds of $50 million (together with the Original Royalty Transaction and the Upsized Royalty Transaction, the "**Royalty Transaction**"). In total, the Royalty Transaction has generated $307 million of cash proceeds for the Company. The Royalty is determined based on US$ WCS benchmark prices and calculated on a linear scale ranging from 0 - 12% of Athabasca's realized bitumen price (C$), with the Royalty rate beginning at 2% when US$ WCS reaches US$60/bbl (estimated as a US$ WTI equivalent of US$75/bbl assuming a US$15/bbl WCS differential) in the case of Hangingstone, and US$70/bbl in the case of Dover West, Birch, and Grosmont. The realized bitumen price is determined net of diluent, transportation and storage costs and has been structured so that the assets will not be encumbered at lower pricing levels. The Royalty is not expected to materially impact the economics of future Hangingstone expansion phases or future other Thermal development projects and there are no associated commitments to develop future expansions or projects. The Royalty does not apply to the Leismer and Corner assets acquired in the Asset Acquisition, however, the Leismer and Corner assets are subject to the Acquisition Royalty. See "*General Development of the Business – Recent Developments*".

On June 20, 2016, the Company reduced its outstanding corporate debt by approximately $250 million through the repayment of its US$221 Term Loan and the concurrent unwind of its US dollar foreign exchange hedge.

On August 29, 2016, the final Promissory Note issued to Athabasca on the sale of the Company's 40% interest in the Dover Oil Sands Project matured and Athabasca received a cash payment of $138.5 million.

2015

On March 2, 2015, Brion paid to Athabasca $302.5 million, being the principal and interest payable under the first Promissory Note.

On March 23, 2015, the Company achieved a significant milestone with commencement of well pair steaming at its Hangingstone Project.

In July, 2015, the Hangingstone Project achieved first commercial oil production.

On August 28, 2015, Brion paid to the Company approximately $152.6 million, representing the principal and interest payable on the second Promissory Note.

During the third quarter of 2015, the Company commenced a drilling and completions program that achieved material cost reductions with the transition to pad style operations in the Duvernay and Montney formations.

The dilbit sales pipeline from the HS CPF to the EPAI Cheecham terminal was completed, started-up and operational in December 2015. The diluent supply line to the HS CPF had previously been completed and was operational in April 2015.

The Company conducted multiple rounds of staff reductions during 2015 in its head office and in its field locations, resulting in an overall reduction of staff of approximately 40% from year-end 2014 staff levels as part of a review and realignment of its cost structure, including annualized general and administrative expenses.

2014

On February 21, 2014, the Dover JV Operator entered into a Long Term Sustainability Agreement with the FMFN, resulting in the FMFN discontinuing its appeal of the AER Decision and withdrawing its concerns with respect to the Dover Oil Sands Project.

On March 13, 2014, the Dover JV Operator received the approval of the Lieutenant Governor in Council in respect of the Dover Oil Sands Project.

The Dover JV Operator received Alberta Environment approval of the Dover Oil Sands Project on April 16, 2014. The Company subsequently exercised its Dover Put Option on April 17, 2014 requiring Phoenix to purchase the Company's subsidiary AOC (Dover) which held a 40% interest in the Dover Oil Sands Project.

The Company entered into credit facilities on May 7, 2014 providing for approximately $425 million of funding. The credit facilities consisted of a US $225 million senior secured first lien term loan maturing on May 7, 2019 and an additional US $50 million senior secured first lien term loan which the Company could draw upon at any time up to May 7, 2016, subject to compliance with covenants (collectively the "**Term Loans**"). Concurrently, the Company entered into an amended and restated credit agreement with a syndicate of financial institutions for a $125 million senior secured first lien revolver with an initial maturity date of April 30, 2017.

On August 29, 2014, the Company closed the Dover Put Option Transaction completing the sale of its subsidiary AOC (Dover), which held a 40% interest in the Dover assets and was a Participant in the Dover Oil Sands Project, for net proceeds of $1.184 billion. Upon closing of the Dover Put Transaction, the Company received cash proceeds of $600 million and the Promissory Notes which were supported by unconditional, irrevocable letters of credit issued by HSBC Bank Canada and which matured and were paid as follows: March 2, 2015- $300 million, August 28, 2015- $150 million and August 29, 2016- $134 million.

The Light Oil Division 2014 drilling program in the Duvernay successfully continued approximately 95% of Athabasca's core land position into the intermediate term.

Reorganizations

Other than as disclosed above, Athabasca has not completed any material reorganization within the three most recently completed financial years or during the current financial year.

Significant Acquisitions

Athabasca did not complete any significant acquisitions during the year ended December 31, 2016 for which disclosure is required under Part 8 of NI 51-102.

On January 31, 2017, the Company completed the Asset Acquisition, which was a significant acquisition for which disclosure is required under Part 8 of NI 51-102. A business acquisition report in the form of Form 51-102F4 in respect of the Asset Acquisition will be filed by Athabasca in accordance with NI 51-102. See "*General Development of the Business – Recent Developments – Asset Acquisition*".

DESCRIPTION OF ATHABASCA'S BUSINESS

Athabasca's Development Strategy for its Principal Properties

Athabasca is focused on the exploration and development of unconventional resources plays in Alberta, Canada and is organized into two divisions, Light Oil Division and Thermal Oil Division. As at December 31, 2016, Athabasca's principal properties were its Kaybob and Placid asset areas located in northwestern Alberta in its Light Oil Division and the Hangingstone asset in its Thermal Oil Division.

In the Light Oil Division, during the year ended December 31, 2016, Athabasca produced light oil and liquids-rich natural gas from unconventional reservoirs. In May of 2016, the Company completed the Murphy Transaction to form a strategic joint venture to develop the Duvernay and Montney formations in the Greater Kaybob and Greater Placid areas, respectively. The Company's current focus in the Light Oil Division is on developing its Montney core acreage in the Greater Placid area and, through the Company's joint venture with Murphy ongoing appraisal and delineation of the Duvernay in the Greater Kaybob area. See "*General Development of the Business – Three Year History - 2016*" and "*Description of Athabasca's Business- Light Oil Division*".

In the Thermal Oil Division, on January 31, 2017 Athabasca completed the Asset Acquisition to acquire the Acquired Assets, which include a 100% working interest in the Leismer project, a SAGD thermal oil project with a capacity of 22,000-24,000 bbl/d and in the delineated Corner oil sands leases. Both the Leismer project and the Corner oil sands leases are located in northeastern Alberta. See "*General Development of the Business – Recent Developments*" and "*General Development of the Business – Significant Acquisitions*" and "*Description of Athabasca's Business- Thermal Oil Division*". During the year ended December 31, 2016, Athabasca's focus in the Thermal Oil Division was on the continued ramp-up of the Hangingstone Project to design capacity. During 2015, the Company completed construction and commissioning of the Hangingstone Project, which achieved first production in July 2015. Production ramp-up continued through 2016 and will continue throughout 2017 and is expected to achieve design capacity of 12,000 bbl/d in 2018. Limited capital expenditures are anticipated at Hangingstone over the next five years.

Athabasca's 2017 activities are expected to be funded with cash flow from operations, the Kaybob Carry Commitment and existing cash and cash-equivalents. Athabasca's current business plan for developing its properties beyond 2017 anticipates that Athabasca will fund its activities and other requirements through cash flow from operations and the Kaybob Carry Commitment. Any significant acceleration of Light Oil development activities or future expansion of Athabasca's thermal oil projects will potentially require additional funding which could include debt, equity, joint ventures or other external financing or a combination of these. The availability of any additional future funding will depend on, amongst other things, the current commodity price environment, operating performance, the Company's credit rating at the time and the current state of the equity and debt capital markets. See "*Risk Factors – Our ability to finance our capital expenditures depends on many factors*" for additional information.

Light Oil Division

As of December 31, 2016, Athabasca held approximately 233,000 net acres of petroleum and natural gas rights in its Light Oil Division, which primarily includes rights in the Duvernay, Montney and Nordegg formations. Production from the Light Oil Division, for the year ended December 31, 2016, averaged 4,597 boe/d, an 18% reduction compared to the prior year. The decrease was primarily due to the sale of the Murphy Transaction Assets, partially offset by production from four Duvernay wells brought on stream in the fourth quarter of 2015 and thirteen wells (seven Montney and six Duvernay) brought on stream during 2016.

The Company's current principal Light Oil Division development properties are located in the Greater Placid and Greater Kaybob areas. Athabasca holds a 70% operated working interest in the Greater Placid area and a 30% non-operated interest in the Greater Kaybob area. The Greater Placid and Greater Kaybob areas are near the town of Fox Creek in northwestern Alberta. To date, the Company has focused its drilling efforts in the Montney formation in the Greater Placid area and in the Duvernay formation in the Greater Kaybob area. Athabasca deployed approximately $117 million ($111 million net of the Kaybob Carry Commitment) of capital in the Light Oil Division in 2016, primarily related to: (a) the following in the Montney Formation: completing and bringing on-stream four (gross) wells that had been drilled in 2015; the initiation of a twenty (gross) well 2016 winter program of which 10 wells were rig-released, and three of those wells completed and brought on stream by year-end; and construction of infrastructure in the Greater Placid area; plus (b) the following in the Duvernay formation in the non-operated Greater Kaybob area: bringing two wells (gross) on stream which had been drilled and completed in 2015; completing and bringing on-stream a four-well (gross) pad; and commencement of drilling a two-well (gross) pad which is expected to be brought on-stream in the first quarter of 2017.

The Company sells the majority of its oil produced from the Light Oil Division into the Pembina Pipeline system which transports and sells the product based on Edmonton prices. The majority of the Company's natural gas is sent to Keyera Corp.'s Simonette Gas Plant where it is processed and sold into the TransCanada Pipeline or Alliance Pipeline systems. In addition, Athabasca's Kaybob Infrastructure Assets are connected to SemCAM's Kaybob Amalgamated ("**KA**") gas plant via a flow-splitter ensuring that Athabasca's facilities are connected to a second large midstream plant in the Kaybob area, providing the Company with additional options for processing its production. As a result of an Alliance Pipeline contract, the bulk of the Company's natural gas produced in 2017 receives Chicago-based pricing, adjusted for energy content. Athabasca's NGLs that are separated at the Simonette Gas Plant are transported through the Pembina Pipeline system and receive Edmonton prices.

Greater Placid Area

Following the completion of the Murphy Transaction, the Company holds an operated 70% interest in the Greater Placid area, primarily targeting the development of the Montney formation. As of December 31, 2016, the Company held greater than 65,000 gross acres (45,500 net acres) of land in the Greater Placid area. Athabasca has high-graded approximately 31,500 gross acres (21,500 net acres) in the Greater Placid area for commercial Montney development.

GLJ has assigned approximately 12.7 MMboe of Proved Reserves and 23.0 MMboe of Total Proved plus Probable Reserves on a Gross Reserves basis to Athabasca's interests in the Greater Placid area, as at December 31, 2016. See "*Independent Reserves Evaluations*". (Please note the GLJ Report for the Greater Placid area reserves, as detailed in "*Independent Reserves Evaluations*" is based on the Placid operating area, not on the area defined in the Placid JDA and due to some of the Greater Placid area formations overlying the Greater Kaybob area formations, includes approximately 1.9 MMboe of Proved **(**Gross**)** Duvernay reserves and 4.1 MMboe of Total Proved plus Probable **(**Gross**)** Duvernay reserves which fall within the area defined in the Kaybob JDA area and are included in the description of the Greater Kaybob area below.)

In March 2016, Athabasca completed construction of and commissioned a pipeline inter-connect linking the Greater Placid area to the existing Kaybob Infrastructure Assets. In the third quarter of 2016, the Company began constructing a battery at Placid to accommodate future production growth. The Placid battery will utilize the pipeline for sales egress and is expected to be in operation in the second quarter of 2017.

During the year ended December 31, 2016, the Company spent approximately $103 million (net) in the Greater Placid area on a program that consisted of completing three (gross) wells and bringing on-stream four (gross) wells that had been drilled in 2015 and commencing a 20-well (gross) winter drilling program and commencing construction on the Placid battery. In respect of the 2016/2017 20-well winter drilling program, 10 wells had been rig released and three of those wells had been completed and brought on-stream by December 31, 2016, the 10 remaining wells are expected to be rig-released, and eight wells planned to be completed and brought on stream, during the first quarter of 2017. Eight wells are expected to be completed and brought on production in the third quarter of 2017.

Greater Kaybob Area

Following the completion of the Murphy Transaction, the Company holds a non-operated 30% interest in the Greater Kaybob area, primarily targeting the development of the Duvernay formation. Pursuant to the terms of the Murphy Transaction, Murphy will fund 75% of the Company's 30% share of development capital over the next four years, up to a maximum of $219 million. As at December 31, 2016, the remaining capital-carry receivable was $213.5 million.

As of December 31, 2016, the Company held approximately 200,000 gross acres (97,500 net acres) of land in the Greater Kaybob area. GLJ has assigned approximately 7.1 MMboe of Proved Reserves and 19.1 MMboe of Proved plus Probable Reserves on a Gross Reserves basis to Athabasca’s interests in the Kaybob Partnership Area, as at December 31, 2016. See "*Independent Reserves Evaluations*". (Please note the GLJ Report for the Greater Placid area reserves, as detailed in "*Independent Reserves Evaluations*" is based on the Placid operating area and not on the area defined in the Placid JDA and due to some of the Greater Placid area formations overlying the Greater Kaybob area formations, it includes approximately 1.9 MMboe of Proved (Gross) Duvernay reserves and 4.1 MMboe of Total Proved plus Probable (Gross) Duvernay reserves which fall within the Kaybob JDA area and are included in the description of the Greater Kaybob area above.)

The Company spent approximately $14 million ($8 million net of the capital-carry) on capital projects in the Greater Kaybob area during the year ended December 31, 2016, primarily to complete and bring on stream a 4-well (gross) Duvernay pad and to commence the drilling of a two-well (gross) pad in the Kaybob West area.

Thermal Oil Division

The Company's primary focus in its Thermal Oil Division in 2016 was on the continued ramp-up of its Hangingstone Project and the acquisition of the Acquired Assets. See "*General Development of the Business – Recent Developments - Asset Acquisition*".

First production was achieved from the Hangingstone Project in July 2015 and by year end 2016, 23 of 25 well pairs had been converted to bitumen production. In the Thermal Oil Division, the Company averaged 7,384 bbl/d of bitumen production during 2016. The Company expects to achieve design capacity of 12,000 bbl/d in 2018.

The Company does not have current plans and have not allocated any capital in its 2017 budget to develop the Thermal Oil exploration areas located at Dover West (Sands and Carbonates), Birch and Grosmont.

Acquired Assets

On January 31, 2017, Athabasca completed the Asset Acquisition pursuant to which the Company acquired the Acquired Assets. The Acquired Assets include approximately 77,750 acres (net) of land in the Leismer asset area, which includes a 100% working interest in the operating Leismer thermal oil project and approximately 44,000 acres (net) of land in the delineated Corner asset area. The Leismer and Corner asset areas are located in northeastern Alberta. The Acquired Assets include certain strategic infrastructure and related midstream agreements held by SCL (including dilbit and diluent pipelines between the Leismer thermal oil project and the Cheecham Terminal), 300,000 barrels of storage capacity at the Cheecham Terminal, access to multiple sales points with marketing agreements on the Enbridge Waupisoo pipeline, the Kettle River gravel pit, certain petroleum and natural gas rights that overlay the Leismer oil sands, and an indirect ownership interest in a regional airstrip servicing the Leismer area through the acquisition of common shares of Leismer Aerodrome Ltd. owned by SCL.

GLJ has assigned approximately 290 MMboe of Proved Reserves and 565 MMboe of Probable Reserves on a Gross Reserves basis to the Acquired Assets and 452 MMboe of risked (629 MMboe unrisked) Best Estimate Contingent

Resources on a Company Interest basis to the Acquired Assets as at December 31, 2016. See "*Changes to Reserves Data*" and "*Schedule A – Supplemental Disclosure- Contingent Resource Estimates*".

The Leismer thermal oil project is a SAGD project that was commissioned in 2010. The proved reserves production forecast in the Independent Acquisition Report is relatively flat for 30 years at an average rate of over 21,000 bbl/d. The Leismer and Corner assets have received regulatory approval for future development phases of up to a combined 80,000 bbl/d.

Hangingstone assets

Location and Size

The Hangingstone assets are located within the Athabasca oil sands fairway of northeastern Alberta. The Hangingstone assets are approximately 15 to 20 kilometres southwest of the city of Fort McMurray in northeastern Alberta and are comprised of a concentrated, contiguous land base of approximately 138,000 acres in which Athabasca owns a 100% working interest. The reservoir suitable for in-situ recovery is the McMurray Formation. A large portion of the assets remain unexplored.

DMCL has assigned approximately 92 MMboe of Proved Reserves and 130 MMboe of Probable Reserves on a Gross Reserves basis, and 586 MMboe of risked (788 MMboe unrisked) Best Estimate Contingent Resources on a Company Interest basis to the Hangingstone assets as at December 31, 2016. See "*Independent Reserves Evaluations*" and "*Schedule A – Supplemental Disclosure- Contingent Resource Estimates*".

The Company is developing the Hangingstone assets using SAGD with a staged development strategy with targeted future production capacity of up to approximately 80,000 bbl/d, subject to AER approval and contingent on a successful production ramp-up to design capacity for the Hangingstone Project, more favorable market conditions and securing project funding.

Project Development - the Hangingstone Project and Future Expansions

The Hangingstone Project is comprised of the HS CPF and twenty five SAGD well pairs on five well pads and has a planned annual production capacity of 12,000 bbl/d.

In 2015, Athabasca completed commissioning and start-up of the Hangingstone Project with steaming of well pairs commencing late in the first quarter of 2015. The Company achieved first production in July, 2015. Athabasca continued with the ramp-up of the Hangingstone Project throughout 2016 and averaged approximately 7,400 bbl/d of bitumen production for the year with production averaging approximately 8,700 bbl/d for December, 2016. Operations were impacted by a 19-day shutdown of the HS CPF in May 2016 as a result of the regional Fort McMurray wildfires. Athabasca resumed operations at the Hangingstone Project near the end of May. The fire caused no damage to the HS CPF, field pipelines, well sites or reservoir. During the year ended December 31, 2016, Athabasca filed an insurance claim of $8.7 million in respect of the business interruption and other incremental costs sustained as a result of the wildfires and anticipates that the claim will be recovered in 2017.

The Hangingstone Project is expected to reach 12,000 bbl/d design capacity in 2018. Minimal additional development and maintenance capital will be required during initial years of production to maintain a flat production profile as the project is early in its development life cycle.

Future asset development up to 80,000 bbl/d is expected to be completed in a staged process if sanctioned by the Board. The Company submitted its expansion application with the AER in May of 2013 and expects to receive approval in 2017. At this time future phases are not expected to be sanctioned by the Board and any future development will be contingent on a successful production ramp-up to design capacity for the Hangingstone Project, more favorable market conditions and securing project funding.

Other Thermal Oil Exploration Areas

The following are descriptions of Athabasca's other thermal oil exploration areas where GLJ has assigned approximately 2960 MMboe of risked (5107 MMboe unrisked) Best Estimate Contingent Resources on a Company Interest basis as at December 31, 2016.

Given current industry conditions, the Company has reduced activity and funding in these areas. See "*Schedule A – Supplemental Disclosure- Contingent Resource Estimates*".

Dover West Assets

Athabasca has a 100% working interest in its Dover West assets, which contain resources in the Dover West Sands. The Dover West assets are located within the Athabasca oil sands fairway in northeastern Alberta approximately 90 kilometres northwest of the city of Fort McMurray. As of December 31, 2016, the Dover West assets were comprised of a large contiguous land base of approximately 233,000 acres.

The Dover West assets are located in a geologically unique area which contains three primary bitumen reservoirs. The bitumen reservoirs are contained within the McMurray Formation and the Wabiskaw member of the Clearwater Formation (the Dover West Sands), and within the Leduc and Cooking Lake Formations of the Devonian Woodbend Group (the Dover West Carbonates).

Birch assets

The Company holds a 100% working interest in the Birch assets. The Birch assets are located within the Athabasca oil sands fairway of northeastern Alberta, approximately 95 kilometres northwest of the city of Fort McMurray and are comprised of an extensive contiguous land base of approximately 447,000 acres.

Grosmont assets

The Grosmont assets are located within the Athabasca oil sands fairway of northeastern Alberta and are prospective for development in the carbonate reservoirs. Athabasca has a 50% operated working interest in the Grosmont assets of approximately 112,000 net acres. ZAM Ventures Alberta Inc., a private Alberta company, holds the remaining 50% working interest in the Grosmont assets.

Specialized Skill and Knowledge

Athabasca employs individuals with various professional skills in the course of pursuing its business plan. These professional skills include, but are not limited to, geology, geophysics, engineering, financial and business skills. Drawing on significant experience in the oil and gas business, Athabasca believes its management team has a demonstrated track record of bringing together all of the key components to a successful exploration and production company: strong technical skills; expertise in planning and financial controls; the ability to execute on business development opportunities; capital markets expertise; and an entrepreneurial spirit that allows Athabasca to effectively identify, evaluate and execute on value added initiatives.

Personnel

As at December 31, 2016, Athabasca had 153 employees (comprised of 104 head office and 49 field employees).

As at March 8, 2017, Athabasca had 271 employees (comprised of 126 head office and 145 field employees), which includes the additional employees that accepted employment with Athabasca following competition of the Asset Acquisition.

INDEPENDENT RESERVES EVALUATIONS

Reserves Classifications

The reserves estimates presented in the Independent Reports are based upon the definitions and guidelines contained in the COGE Handbook. A summary of those definitions is set forth below:

Reserves Categories

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

- analysis of drilling, geological, geophysical, and engineering data;
- the use of established technology; and
- specified economic conditions, which are generally accepted as being reasonable and shall be disclosed.

Reserves are classified according to the degree of certainty associated with the estimates. The following terms when used herein have the following meanings:

- "**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.

- "**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 Reserves plus Probable Reserves.

  Other criteria that must be met for the classification of reserves are provided in the COGE Handbook.

Development and Production Status

Each of the Reserves categories (Proved Reserves and Probable Reserves) may be divided into "developed" and "undeveloped" categories:

- "**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.

  - "**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.

  - "**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.

- "**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 Reserves or Probable Reserves) 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 reserves 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 estimates are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

- at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated Proved Reserves; and

- at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated Proved Reserves plus Probable Reserves.

A quantitative 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 or probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods. Additional clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in the COGE Handbook.

Independent Reports

Athabasca engaged the Independent Evaluators to prepare the Independent Reports, which are independent assessments and evaluations of Athabasca's bitumen, light crude oil and medium crude oil, tight oil, conventional natural gas, shale gas and NGL reserves effective as at December 31, 2016.

The reserve estimates set out below reflect Athabasca's 100% working interests (as at December 31, 2016) in the Hangingstone assets and its interests in the Light Oil assets (but does not include the Acquired Assets which are set out on a proforma basis in "*Changes to Reserves Data*").

The information set forth below relating to Athabasca's reserves constitutes forward-looking information, which is subject to certain risks and uncertainties. See "*Forward-Looking Statements*" for additional information.

The effective date of the information provided below is December 31, 2016. The preparation date of the GLJ Report was January 27, 2017. The preparation date of the DMCL Report was January 12, 2017. The preparation and disclosure of the reported reserve estimates are the responsibility of Athabasca's management. The Independent Evaluators' responsibilities are to express opinions on the bitumen, light crude oil and medium crude oil, tight oil, conventional natural gas, shale gas and NGL reserves including the associated estimated net present values, based upon their respective evaluations. The Independent Evaluators carried out their evaluations in accordance with standards established by the Canadian Securities Administrators in NI 51-101. Those standards require that the bitumen, light crude oil and medium crude oil, shale oil, conventional natural gas, shale gas and NGL reserves be prepared in accordance with the COGE Handbook. Athabasca's properties are located in the Province of Alberta and are described under the heading "*Description of Athabasca's Business*".

GLJ's Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor and DMCL's Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor are each set forth in Schedule "C" to this Annual Information Form. Athabasca's Report of Management and Directors on Oil and Gas Disclosure in the form of National Instrument 51-101F3 is set forth in Schedule "B" to this Annual Information Form.

The evaluation procedures employed by GLJ and DMCL are in compliance with standards contained in the COGE Handbook.

The Independent Reports do not take into account taxes or other amounts that may be payable in the future by Athabasca pursuant to new or existing provincial and federal laws and regulations (including without limitation the

Climate Change and Emissions Management Act (Alberta) and the *Specified Gas Emitters Regulation*) that restrict or otherwise regulate GHG emissions.

The estimates of reserves and future net revenue for individual properties that are contained in this Annual Information Form may not reflect the same confidence level as estimates of reserves and future net revenue for all of Athabasca's properties, due to the effects of aggregation.

Reserve Estimates

As at December 31, 2016, Athabasca's bitumen reserves were contained in the Hangingstone assets. Proved Reserves were assigned by DMCL to the Hangingstone Project, and Probable Reserves were assigned by DMCL to the Hangingstone Expansion.

Athabasca's light crude oil and medium crude oil, tight oil, conventional natural gas, shale gas and NGL reserves are located in the Light Oil assets. Both Proved Reserves and Probable Reserves have been assigned by GLJ to Athabasca's Light Oil assets.

Set out below is a summary of Athabasca's reserves, as well as the estimated value of future net revenue of Athabasca from the reserves, as at December 31, 2016, as evaluated by GLJ in the GLJ Report, and as evaluated by DMCL in the DMCL Report. The pricing used in the forecast price evaluations for all assets is set forth below under "*GLJ Price Forecast*".

All evaluations of future net revenue are after the deduction of royalties, development costs, production costs and abandonment and reclamation costs but before consideration of indirect costs such as administrative, overhead and other miscellaneous expenses. The estimated future net revenues contained in the following tables do not represent the fair market value of Athabasca's reserves. There is no assurance that the forecast price assumptions that have been estimated by GLJ will be realized and variances could be material. Other assumptions have been made by GLJ and DMCL and qualifications relating to costs and other matters are included in the GLJ Report and DMCL Report. The recovery and reserves estimates of Athabasca's properties described herein are estimates only. The actual reserves of Athabasca's properties may be greater or less than those calculated.

Summary of Reserves Data – Forecast Prices and Costs as of December 31, 2016[(1)(2)]

Reserves Category	Bitumen		Tight Oil		Natural Gas	
	Gross (Mbbls)	Net (Mbbls)	Gross (Mbbls)	Net (Mbbls)	Gross (MMcf)	Net (MMcf)
PROVED RESERVES						
Developed Producing	47,953	45,115	314	252	449	413
Developed Non-Producing	0	0	6	6	716	675
Undeveloped	44,029	37,234	410	374	15	14
TOTAL PROVED RESERVES	91,982	82,349	730	632	1,180	1,102
TOTAL PROBABLE RESERVES	130,160	107,061	475	399	347	323
TOTAL PROVED PLUS PROBABLE RESERVES	222,142	189,410	1,205	1,031	1,527	1,425

Reserves Category	Shale Gas		Natural Gas Liquids		Oil Equivalent	
	Gross (MMcf)	Net (MMcf)	Gross (Mbbls)	Net (Mbbls)	Gross (Mboe)	Net (Mboe)
PROVED RESERVES						
Developed Producing	13,889	12,849	1,574	1,203	52,231	48,780
Developed Non-Producing	602	568	66	59	292	272
Undeveloped	51,557	47,636	6,374	5,645	59,408	51,195
TOTAL PROVED RESERVES	66,048	61,053	8,014	6,907	111,931	100,247
TOTAL PROBABLE RESERVES	71,548	64,508	9,901	8,314	152,519	126,578
TOTAL PROVED PLUS PROBABLE RESERVES	137,596	125,561	17,915	15,221	264,450	226,825

For notes please see the notes following the "*Reconciliation of Reserves by Principal Product Type*" table.

Summary of Net Present Values of Future Net Revenue – Forecast Prices and Costs as of December 31, 2016(1)(2)(3)(4))

	Before Income Tax Discounted at (%/year)					After Income Taxes Discounted at (%/year)					Unit Value Before Income Tax at 10% Discount/ Year	
RESERVES CATEGORY	**0% (M$)**	**5% (M$)**	**10% (M$)**	**15% (M$)**	**20% (M$)**	**0% (M$)**	**5% (M$)**	**10% (M$)**	**15% (M$)**	**20% (M$)**	**($/boe)**	**($/Mcfe)**
PROVED RESERVES												
Developed Producing	817,127	616,613	479,200	382,527	312,770	817,127	616,613	479,200	382,527	312,770	9.82	1.64
Developed Non- Producing	662	948	937	836	719	662	948	937	836	719	3.45	0.57
Undeveloped	801,616	421,623	234,431	137,772	85,012	801,616	421,623	234,431	137,772	85,012	4.58	0.76
TOTAL PROVED RESERVES	1,619,405	1,039,184	714,568	521,135	398,501	1,619,405	1,039,184	714,568	521,135	398,501	7.13	1.19
TOTAL PROBABLE RESERVES	2,881,695	1,171,430	552,933	289,062	159,364	2,202,871	928,185	455,833	246,769	139,603	4.37	0.73
TOTAL PROVED PLUS PROBABLE RESERVES	4,501,100	2,210,614	1,267,500	810,197	557,864	3,822,276	1,967,370	1,170,401	767,904	538,103	5.59	0.93

For notes please see the notes following the "*Reconciliation of Reserves by Principal Product Type*" table.

Future Net Revenue (Undiscounted) – Forecast Prices and Cost as of December 31, 2016(1)(2)(3)(4)

Reserves Category	**Revenue (M$)**	**Royalties (M$)**	**Operating Costs (M$)**	**Development Costs (M$)**	**Abandonment and Reclamation Costs (M$)**	**Future Net Revenue Before Future Income Tax Expenses (M$)**	**Future Income Tax Expenses (M$)**	**Future Net Revenue After Future Income Tax Expenses (M$)**
PROVED RESERVES	6,166,851	900,897	2,821,821	744,720	80,008	1,619,405	-	1,619,405
PROBABLE RESERVES	11,928,970	2,763,470	3,984,524	2,179,868	119,413	2,881,695	678,824	2,202,871
Proved Plus Probable RESERVES	18,095,822	3,664,368	6,806,345	2,924,588	199,421	4,501,100	678,824	3,822,276

For notes, please see the notes following the "*Reconciliation of Reserves by Principal Product Type*" table.

Future Net Revenue by Product Type– Forecast Prices and Costs as of December 31, 2016)(1)(2)(3)(4)(5)(6)

		Future Net Revenue Before Income Taxes (Discounted at 10%/Year)		
RESERVES CATEGORY	**Product Type**	**M$**	**$/bbl**	**$/Mcfe**
PROVED RESERVES	Bitumen	516,351	6.27	1.05
	Tight Oil	29,910	24.13	4.02
	Conventional Natural Gas (5)	1,559	7.16	1.19
	Shale Gas	166,748	10.14	1.69
	TOTAL	**714,568**	**7.13**	**1.19**
PROVED PLUS PROBABLE RESERVES	Bitumen	770,943	4.07	0.68
	Tight Oil	58,455	24.74	4.12
	Conventional Natural Gas (5)	2,205	7.71	1.29
	Shale Gas	435,898	12.54	2.09
	TOTAL	**1,267,500**	**5.59**	**0.93**

For notes, please see the notes following the *"Reconciliation of Reserves by Principal Product Type"* table.

Reconciliation of Reserves by Principal Product Type – Forecast Prices and Costs as of December 31, 2016)(1)(2)(3)(5)(7)

The following table sets forth a reconciliation of the changes of Athabasca's reserves estimates, before royalties, of bitumen, tight oil, conventional natural gas, shale gas and NGL as at December 31, 2016, compared to such reserves as at December 31, 2015, based on the forecast price and cost assumptions that are described in Note 1 below.

FACTORS	Bitumen Gross Proved Reserves (MMbbls)	Bitumen Gross Probable Reserves (MMbbls)	Bitumen Gross Proved Plus Probable Reserves (MMbbls)	Light Crude Oil and Medium Crude Oil Gross Proved Reserves (MMbbls)	Light Crude Oil and Medium Crude Oil Gross Probable Reserves (MMbbls)	Light Crude Oil and Medium Crude Oil Gross Proved Plus Probable Reserves (MMbbls)
December 31, 2015	95.1	129.8	224.9	0.0	0.0	0.0
Discoveries	0.0	0.0	0.0	0.0	0.0	0.0
Extensions and Improved Recovery	0.0	0.0	0.0	0.0	0.0	0.0
Technical Revisions	(0.4)	0.3	(0.1)	0.0	0.0	0.0
Acquisitions	0.0	0.0	0.0	0.0	0.0	0.0
Dispositions	0.0	0.0	0.0	0.0	0.0	0.0
Economic Factors	0.0	0.0	0.0	0.0	0.0	0.0
Production	(2.7)	0.0	(2.7)	0.0	0.0	0.0
December 31, 2016	**92.0**	**130.2**	**222.1**	**0.0**	**0.0**	**0.0**

FACTORS	Conventional Natural Gas Gross Proved Reserves (Bcf)	Conventional Natural Gas Gross Probable Reserves (Bcf)	Conventional Natural Gas Gross Proved Plus Probable Reserves (Bcf)	Natural Gas Liquids Gross Proved Reserves (MMbbls)	Natural Gas Liquids Gross Probable Reserves (MMbbls)	Natural Gas Liquids Gross Proved Plus Probable Reserves (MMbbls)
December 31, 2015	1.7	0.5	2.2	2.8	4.9	7.7
Discoveries	0.0	0.0	0.0	0.0	0.0	0.0
Extensions and Improved Recovery	0.0	0.0	0.0	4.2	3.8	8.0
Technical Revisions	(0.1)	(0.1)	(0.2)	3.2	4.5	7.7
Acquisitions	0.0	0.0	0.0	0.0	0.0	0.0
Dispositions	(0.2)	(0.1)	(0.3)	(1.5)	(3.3)	(4.8)
Economic Factors	(0.0)	(0.0)	(0.1)	(0.0)	(0.0)	(0.0)
Production	(0.1)	0.0	(0.1)	(0.6)	0.0	(0.6)
December 31, 2016	**1.2**	**0.3**	**1.5**	**8.0**	**9.9**	**17.9**

FACTORS	Tight Oil Gross Proved Reserves (MMbbls)	Tight Oil Gross Probable Reserves (MMbbls)	Tight Oil Gross Proved Plus Probable Reserves (MMbbls)	Shale Gas Gross Proved Reserves (Bcf)	Shale Gas Gross Probable Reserves (Bcf)	Shale Gas Gross Proved Plus Probable Reserves (Bcf)
December 31, 2015	10.1	15.0	25.1	81.7	111.4	193.1
Discoveries	0.0	0.0	0.0	0.0	0.0	0.0
Extensions and Improved Recovery	0.1	(0.1)	0.0	32.7	29.3	62.0
Technical Revisions	(4.4)	(4.7)	(9.1)	(7.4)	0.7	(6.7)
Acquisitions	0.0	0.0	0.0	0.0	0.0	0.0
Dispositions	(4.9)	(9.7)	(14.6)	(35.9)	(69.8)	(105.7)
Economic Factors	(0.0)	(0.0)	(0.0)	(0.1)	(0.1)	(0.1)
Production	(0.2)	0.0	(0.2)	(4.9)	0.0	(4.9)
December 31, 2016	**0.7**	**0.5**	**1.2**	**66.0**	**71.5**	**137.6**

FACTORS	Oil Equivalent Gross Proved Reserves (MMboe)	Oil Equivalent Gross Probable Reserves (MMboe)	Oil Equivalent Gross Proved Plus Probable Reserves (MMboe)
December 31, 2015	121.9	168.4	290.3
Discoveries	0.0	0.0	0.0
Extensions and Improved Recovery	9.8	8.5	18.3
Technical Revisions	(2.9)	0.2	(2.7)
Acquisitions	0.0	0.0	0.0
Dispositions	(12.4)	(24.6)	(37.1)
Economic Factors	(0.0)	(0.0)	(0.1)
Production	(4.4)	0.0	(4.4)
December 31, 2016	**111.9**	**152.5**	**264.5**

Notes:

(1) Based on the Independent Reports. Future net revenue estimates were calculated by GLJ and DMCL using the pricing assumptions set forth below under "GLJ Price Forecast" to ensure for consistency and in accordance with the COGE Handbook.

(2) Totals may not add due to rounding.

(3) All evaluations of future net revenue are after the deduction of royalties, development costs, production costs and abandonment and reclamation costs but before consideration of indirect costs such as administrative, overhead and other miscellaneous expenses. For further detail on what is and isn't included in abandonment and reclamation costs, please see the "Abandonment and Reclamation Obligations for Properties with Reserves".

(4) The estimated tax burden included in the after-tax net present values of the Company's oil and gas properties is reflected at the corporate consolidation level and does not consider tax planning or provide an estimate of the tax burden at the business entity level which may be significantly different.

(5) Including by-products but excluding solution gas.

(6) Other company revenue and costs not related to a specific production group have been allocated proportionately to production groups. Unit values are based on Company Net Reserves.

(7) Infill drilling is included in the Extensions and Improved Recovery Category.

GLJ Price Forecast

The price forecasts that formed the basis for the revenue projections and net present value estimates that are contained herein are based on GLJ's January 1, 2017 pricing models. A summary of applicable selected price forecasts is set forth below.

								Natural Gas Liquids Edmonton		
Year	**Inflation**	**Bank of Canada Average Noon Exchange Rate**	**WTI Oil at Cushing Oklahoma Current**	**Light Sweet Crude Oil (40° API, 0.3%S) at Edmonton Current**	**WCS Stream Quality at Hardisty Current**	**Midwest price at Chicago Current**	**AECO/NIT Spot Current**	**Pentanes Plus**	**Propane**	**Butane**
	%	**($US/$Cdn)**	**($US/bbl)**	**($Cdn/bbl)**	**($Cdn/bbl)**	**($USD/MMBtu)**	**($Cdn/MMBtu)**	**($Cdn/bbl)**	**($Cdn/bbl)**	**($Cdn/bbl)**
2017	2.00	0.750	55.00	69.33	53.32	3.65	3.46	72.11	28.43	49.92
2018	2.00	0.775	59.00	72.26	56.79	3.25	3.10	74.79	26.74	54.19
2019	2.00	0.800	64.00	75.00	61.27	3.45	3.27	78.75	26.25	56.25
2020	2.00	0.825	67.00	76.36	63.00	3.65	3.49	79.80	26.73	57.27
2021	2.00	0.850	71.00	78.82	65.90	3.85	3.67	82.37	27.59	59.12
2022	2.00	0.850	74.00	82.35	69.42	4.05	3.86	86.06	28.82	61.76
2023	2.00	0.850	77.00	85.88	72.91	4.25	4.05	89.32	30.06	64.41
2024	2.00	0.850	80.00	89.41	76.45	4.36	4.16	92.99	31.29	67.06
2025	2.00	0.850	83.00	92.94	79.93	4.44	4.24	97.59	32.53	69.71
2026	2.00	0.850	86.05	95.61	83.47	4.53	4.32	99.91	33.46	71.71
2027+	Escalated oil, gas and product prices at 2.0% per year thereafter.									

The weighted average realized sales prices for Athabasca for the year ended December 31, 2016 were $23.58/bbl for bitumen, $47.07/bbl for tight oil, $2.10/Mcf for conventional natural gas, $20.03/bbl for NGL, and $2.03/Mcf for shale gas.

Undeveloped Reserves

The proved undeveloped bitumen reserves attributed the Hangingstone Project will transition to proved developed reserves with the drilling and start-up of sustaining wells. The probable undeveloped bitumen reserves attributed to the Hangingstone Expansion would transition to proved developed reserves with the sanctioning, construction, commissioning and start-up of the Hangingstone Expansion.

Once proved and/or probable undeveloped reserves are identified in respect of Athabasca's Light Oil assets, they are generally scheduled into Athabasca's development plans. Athabasca plans to develop the proved and probable undeveloped reserves that have been attributed to its Light Oil assets within the next five years. Athabasca's undeveloped bitumen reserves, which are considered to be longer term opportunities, are expected to be developed over a period of time exceeding two years. For additional information regarding the anticipated development of, the Hangingstone Expansion which is the project that has undeveloped bitumen reserves attributed to it, see "*Description of Athabasca's Business – Thermal Oil Division*".

A number of factors that could result in delayed or cancelled development plans are as follows:

- changing economic conditions (e.g. due to pricing, operating and capital expenditure fluctuations);
- changing technical conditions (e.g. production anomalies, such as water breakthrough or accelerated depletion);
- multi-zone developments (e.g. prospective formation completion may be delayed until the initial completion is no longer economic);
- availability and allocation of capital based on other opportunities available to Athabasca in any given year;
- a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization;
- surface access issues (e.g. landowner issues, weather conditions and receipt of required regulatory approvals); and
- changes in the legal & regulatory framework applicable to the assets (rendering it uneconomic, difficult or impossible to proceed with development).

The following tables set out the volumes of proved undeveloped reserves and probable undeveloped reserves that were attributed for each of Athabasca's product types for each of Athabasca's most recent three financial years using forecast prices and costs:

Proved Undeveloped Reserves[(1)(2)]

	Bitumen (MMbbls)		**Conventional Natural Gas (Bcf)**		**Natural Gas Liquids (MMbbls)**	
Year	First Attributed	Total at Year-end	First Attributed	Total at Year-end	First Attributed	Total at Year-end
2014	0.0	0.0	3.8	10.4	1.3	1.7
2015	44.4	44.4	0.0	0.3	0.8	1.9
2016	0.0	44.0	0.0	0.0	3.3	6.4

	Tight Oil (MMbbls)		**Shale Gas (Bcf)**		**Oil Equivalent (MMboe)**	
Year	First Attributed	Total at Year-end	First Attributed	Total at Year-end	First Attributed	Total at Year-end
2014	0.6	1.2	8.2	11.9	4.0	6.9
2015	5.5	7.2	43.3	60.0	57.9	63.4
2016	0.1	0.4	26.0	51.6	7.8	59.4

Probable Undeveloped Reserves[1][2]

	Bitumen (MMbbls)		Conventional Natural Gas (Bcf)		Natural Gas Liquids (MMbbls)	
Year	First Attributed	Total at Year-end	First Attributed	Total at Year-end	First Attributed	Total at Year-end
2014	0.0	261.3	5.7	52.2	3.2	7.6
2015	0.0	129.8	0.0	0.1	1.2	4.6
2016	0.8	130.6	0.0	0.0	5.1	9.3

	Tight Oil (MMbbls)		Shale Gas (Bcf)		Oil Equivalent (MMboe)	
Year	First Attributed	Total at Year-end	First Attributed	Total at Year-end	First Attributed	Total at Year-end
2014	9.5	9.6	50.9	59.7	22.2	297.7
2015	4.9	14.0	37.8	103.2	12.4	165.6
2016	0.0	0.3	37.9	66.0	11.5	150.0

Notes:
(1) "First Attributed" refers to reserves first attributed at year-end of the corresponding fiscal year.
(2) Based on the Independent Reports.

Significant Factors or Uncertainties

The process of evaluating reserves is inherently complex. It requires significant judgments and decisions based on available geological, geophysical, engineering, and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserves estimates contained herein are based on current production forecasts, prices and economic conditions and other factors and assumptions that may affect the reserves estimates and the present worth of the future net revenue therefrom. See "*Risk Factors –There are uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids reserves and the future cash flows attributed to such reserves*".

As circumstances change and additional data becomes available, reserve estimates may also change. Estimates made are reviewed and revised, either upward or downward, as warranted by new information. Revisions may be required as a result of a number of factors that are beyond Athabasca's control, including, among others, product pricing, economic conditions, access to markets, changes to royalty and tax regimes, governmental restrictions, changing operating and capital costs, surface access issues, the receipt of regulatory approvals, availability of services and processing facilities and technical issues affecting well performance. Although every reasonable effort is made to ensure that reserves estimates are accurate, reserve estimation is an inferential science and revisions to reserve estimates based upon the foregoing factors may be either positive or negative.

Abandonment and Reclamation Obligations for Properties with Reserves

In connection with Athabasca's operations, Athabasca will incur abandonment and reclamation costs for surface leases, wells, facilities and pipelines. Athabasca budgets for and recognizes as a liability the estimated present value of the future decommissioning liabilities associated with its property, plant and equipment. Athabasca's overall abandonment and reclamation costs include all costs associated with the process of restoring a property that has been disturbed by oil and gas activities to the standard imposed by the applicable government or regulatory authorities. These costs were estimated using amongst other things, Athabasca's experience conducting abandonment and reclamation programs, previous actual costs incurred and published industry information. Athabasca reviews suspended or standing wells for reactivation, recompletion or sale and conduct systematic abandonment programs for those wells that do not meet its criteria. A portion of Athabasca's liability issues are retired every year and facilities are decommissioned when all the wells producing to them have been abandoned. All of Athabasca's liability reduction programs take into account seasonal access, high priority and stakeholder issues, and opportunities for multi-location programs to reduce costs. There are no unusually significant abandonment and reclamation costs associated with our properties with attributed reserves. See "*Other Oil and Gas Information – Properties with no Attributable Reserves - Liege Area Abandonment and Reclamation Obligations*" for a discussion of certain abandonment and reclamation liabilities associated with properties with no attributed reserves.

The future net revenues disclosed in this Annual Information Form are based on the Independent Reports and contain an allowance for abandonment and reclamation costs for facilities associated with the Hangingstone assets; however such amount did not include an allowance for facilities associated with Light Oil assets, any pipelines or wells without reserves. The future net revenue disclosures by the Independent Reports however did include reclamation and abandonment costs associated with future development wells and infrastructure which were not included in the Company’s consolidated financial statements. The Independent Reports deducted an aggregate of $199 million (undiscounted) and $7 million (10% discount) for abandonment and reclamation costs of wells with proved and probable reserves.

As at December 31, 2016, Management estimates that there was $141.8 million (uninflated and undiscounted) in total reclamation and abandonment costs associated with the Company’s existing wells and the associated sites, facilities and pipelines in the Light Oil and Thermal Oil Divisions. Applying an estimated inflation rate of 2% and a discount rate of 10%, based on the current anticipated timing of the reclamation expenditures, Management estimates that the value of these reclamation and abandonment costs is $65.3 million.

Future Development Costs

The following table sets forth the undiscounted development costs deducted in the estimation of future net revenue attributable to each of the following reserves categories contained in the Independent Reports.

Year	**Total Proved Reserves Future Development Costs Using Forecast Dollar Costs** **(M$)**	**Total Proved Plus Probable Reserves Future Development Costs Using Forecast Dollar Costs** (M$)
2017	69,475	90,716
2018	52,706	101,752
2019	58,217	164,890
2020	23,423	240,667
2021	5,544	162,825
Total for all remaining years	535,355	2,163,738
Total Undiscounted	**744,720**	**2,924,588**

Note:
(1) Totals may not add due to rounding.

Athabasca’s 2017 activities are expected to be funded with cash flow from operations, the Kaybob Carry Commitment and existing cash and cash-equivalents. Athabasca’s current business plan for developing its properties beyond 2017 anticipates that Athabasca will fund its activities and other requirements through cash flow from operations and the Kaybob Carry Commitment. Any significant acceleration of Light Oil development activities or future expansion of Athabasca’s thermal oil projects will potentially require additional funding which could include debt, equity, joint ventures or other external financing or a combination of these. The availability of any additional future funding will depend on, amongst other things, the current commodity price environment, operating performance, the Company’s credit rating at the time and the current state of the equity and debt capital markets. See "*Risk Factors – Our ability to finance our capital expenditures depends on many factors*" for additional information.

OTHER OIL AND GAS INFORMATION

Oil & Gas Properties

As at December 31, 2016, Athabasca held approximately 1,474,603 net acres of mineral resource leases and permits, including over 1.24 million net acres of oil sands leases and permits in the Athabasca region of northeastern Alberta and 233,480 net acres of petroleum and natural gas leases in northwestern Alberta.

Oil sands leases in the Athabasca oil sands area carry a primary term of 15 years with an additional 2 year extension, and petroleum and natural gas leases carry a primary term of 5 years, after which time the leases can be continued if certain activity and/or production levels are satisfied. Oil sands permits have a primary term of 5 years and petroleum and natural gas licenses have a primary term of 4 years. Depending on the level of activity and/or production, both oil sands permits and petroleum and natural gas licenses can be converted into leases at the end of their primary terms. A vast majority of Athabasca's oil sands reserves and resources are held under oil sands leases (15 year initial terms), and those lands held under oil sands permits have met all requirements to convert to leases at the end of their initial terms.

See "*General Development of the Business – Thermal Oil Division*" and "*General Development of the Business – Light Oil Division*". Athabasca's oil sands leases and permits are large and generally contiguous, which management expects will allow for scale efficiency and simpler development planning.

As at December 31, 2016, Athabasca had an interest in approximately 156.00 Gross Wells (83.8 Net Wells), as set forth below, all of which are located in Alberta:

	Producing		**Non-Producing[3]**		**Total**	
	Gross Wells[1]	**Net Wells[2]**	**Gross Wells[1]**	**Net Wells[2]**	**Gross Wells[1]**	**Net Wells[2]**
Bitumen	23	23.0	3	3.0	26	26.0
Crude Oil Wells	30	9.0	46	21.5	76	30.46
Natural Gas Wells	36	17.3	18	10.0	54	27.36
TOTAL	**89**	**49.3**	**67**	**34.5**	**156**	**83.8**

Notes:

(1) "**Gross Wells**" means the total number of producing or non-producing bitumen, oil or gas wells in which Athabasca had an interest as of December 31, 2016.

(2) "**Net Wells**" means the aggregate number of producing or non-producing bitumen, oil or gas wells obtained by multiplying each Gross Well by Athabasca's percentage working interest therein.

(3) "**Non-Producing**" wells include stratigraphic test wells, wells awaiting completion as at December 31, 2016, and wells that are capable of production but were not producing as at December 31, 2016, due to facility limitations or were waiting to be tied-in. All non-producing wells considered to be capable of producing are located near existing transportation infrastructure. Athabasca has not included the following type of wells in its Non-Producing well count above: wells in the Liege area that are suspended or permanently shut-in either due to a lack of existing functional proximate transportation infrastructure or a permanent shut-in order issued by the AER, its HAF, water source, steam injection, disposal wells or wells that have been abandoned.

Properties with No Attributed Reserves

The following table is a summary of properties in which Athabasca has an interest to which no reserves have been attributed, and also the number of net acres for which Athabasca's rights to explore, develop or exploit will, absent further action, expire within one year, as at December 31, 2016:

	Gross Acres(1)(2)	Net Acres(1)(2)	Net Acres Expiring Within One Year(1)(2)
Alberta	1,373,223	1,185,023	8,832
Total	**1,373,223**	**1,185,023**	**8,832**

Notes:

(1) "**Gross**" means the total area of properties in which Athabasca has a working interest. "**Net**" means the total area in which Athabasca has an interest multiplied by the working interest owned by Athabasca.

(2) Excludes certain non-oil sands acreage held by Athabasca in formations under and adjacent to the same surface area as Athabasca's oil sands leases. Athabasca measures its land acreage based on the leases, licenses and permits granted by the Crown, as specified within the applicable legal documentation.

No capital expenditures were approved for the development of the Light Oil Exploration areas as part of Athabasca's 2017 capital budget. As a result the Company expects the full 8,832 ac. of expiries to occur during 2017.

Impairment Conducted in 2016

In the fourth quarter of 2016, Athabasca identified indicators of impairment over its Hangingstone assets primarily due to the pending acquisition of the Leismer Corner assets by the Company pursuant to the Asset Acquisition which implied that the recoverable value could be below its carrying value. In response, Athabasca performed an impairment test on its Hangingstone assets and recognized an impairment loss. For further details relating to this impairment loss, please see Athabasca's Consolidated Financial Statements and Management Discussion &Analysis for the year ended December 31, 2016.

In the fourth quarter of 2015, given continued deterioration in commodity prices and the value of the Light Oil assets implied by the pending Murphy Transaction and recent federal and provincial governance initiatives surrounding climate change and pipeline development which could impact the long-term development of thermal oil projects, Athabasca determined that indicators of impairment were present over all its oil and gas assets. In response, Athabasca performed an impairment test on each of its cash generating units. The impairment tests resulted in an impairment loss relating to Athabasca's Light Oil assets and its Dover West assets. For further details relating to this impairment loss, please see Athabasca's Consolidated Financial Statements and Management Discussion & Analysis for the year ended December 31, 2015.

Liege Area Abandonment and Reclamation Obligations

In November 2010, Athabasca acquired 259 shut-in gas wells from Perpetual Energy Inc. in the Liege area, which were located in proximity to its oil sands assets including oil sand assets that were part of the Dover assets. These wells were the subject of a permanent gas over bitumen shut-in order issued by the ERCB (now AER) pursuant to shut-in orders *ERCB 2011-035* and *ERCB 2011-002*. 61 of these wells are now operated by other companies. Athabasca has assumed the responsibility for its proportionate share of any abandonment and reclamation associated with the remaining 198 wells. Other items also acquired as part of the transaction and for which Athabasca is now responsible for the associated environmental liability include gas plants, gathering pipelines, several compressor stations, boosters, camps, airstrips and storage areas. Athabasca has budgeted approximately $40 million over the next 5-7 years for the abandonment and reclamation of the remaining assets in the Liege area.

Tax Horizon

For the fiscal year ended December 31, 2016, the Company paid no income tax. The Company does not expect to pay Canadian income taxes during the next five years. This estimate would be affected by, among other factors, the Company's other business activities such as any joint venture arrangements, acquisitions or asset sales. Changes in these factors from estimates used by the Company could result in the Company paying income taxes earlier or later than expected. For additional information concerning the Company's tax horizon see "*Risk Factors – Income Tax Matters*".

Costs Incurred During the Year Ended December 31, 2016

Division	Proved Property Acquisition Costs MM($)	Unproved Property Acquisition Costs MM($)	Exploration Costs MM($)	Development Costs MM($)
Light Oil	-	$ 7.0	-	$ 110.1
Thermal Oil	-	-	$ 6.3	$ 4.7
Total	**-**	**$ 7.0**	**$ 6.3**	**$ 114.8**

Exploration and Development Activities

The following table summarizes the gross and net exploratory and development wells that were completed by Athabasca during the year ended December 31, 2016:

	Exploratory		Development		Total	
	Gross	Net	Gross	Net	Gross	Net
Oil wells	-	-	-	-	-	-
Bitumen wells	-	-	-	-	-	-
Gas wells	-	-	14	7.4	14	7.4
Service wells	-	-	-	-	-	-
Stratigraphic test wells	-	-	-	-	-	-
Dry holes	-	-	-	-	-	-
Total	**-**	**-**	**14**	**7.4**	**14**	**7.4**

For a description of the Company's current and likely exploration and development activities see "*Description of Athabasca's Business*".

Production Estimates[1]

The following table sets out the volumes of Athabasca's working interest production estimated by GLJ and DMCL for the year ending December 31, 2017, which is reflected in the estimates of future net revenue disclosed in the tables contained under the headings "*Summary of Net Present Values of Future Net Revenue – Forecast Prices and Costs as of December 31, 2016*", "*Future Net Revenue (Undiscounted) – Forecast Prices and Costs as of December 31, 2016*" and " *Future Net Revenue by Product Type– Forecast Prices and Costs as of December 31, 2016*".

Reserve Category	Bitumen (bbl/d)	Conventional Natural Gas (Mcf/d)	NGLs (bbl/d)	Tight Oil (bbl/d)	Shale Gas (Mcf/d)	Oil Equivalent (Boe/d)
Gross Proved Reserves						
Hangingstone	10,102	-	-	-	-	10,102
Saxon/Placid Area **[Greater Placid Area?]**	-	223	1385	25	11134	3,303
Other Properties	-	-	828	357	4836	1,991
Total Gross Proved Reserves	**10,102**	**223**	**2,213**	**382**	**15,970**	**15,396**

Reserve Category	Bitumen (bbl/d)	Conventional Natural Gas (Mcf/d)	NGLs (bbl/d)	Tight Oil (bbl/d)	Shale Gas (Mcf/d)	Oil Equivalent (Boe/d)
Gross Probable Reserves						
Hangingstone	243	-	-	-	-	243
Saxon/Placid Area **[Greater Placid Area?]**	-	7	383	2	2914	872
Other Properties	-	-	155	119	925	428
Total Gross Probable Reserves	**243**	**7**	**538**	**121**	**3,839**	**1,543**

Note:

(1) Totals may not add due to rounding.

The Hangingstone and Placid assets are estimated to account for greater than 20% of Athabasca's 2017 production volumes. As is shown above, estimated 2017 production volumes for the Hangingstone assets are 10,100 boe/d on a Gross Proved Reserves basis and 10,345 boe/d on a Gross Proved plus Probable Reserves basis and estimated 2017 production volumes for the Placid assets are 3,303 boe/d on a Gross Proved Reserves basis and 4,175 boe/d on a Gross Proved plus Probable Reserves basis.

Production History

The following table sets forth on a quarterly basis for the year ended December 31, 2016, certain information in respect of production, product prices received, royalties paid, production costs and the resulting netbacks.

	Quarter Ended 2016				**Year Ended**
	Mar. 31	**June 30**	**Sept. 30**	**Dec. 31**	**Dec. 31, 2016**
Average Daily Production[(1)]					
Bitumen (bbls/d)	7,029	5,358	8,830	8,293	7,384
Tight Oil (bbls/d)	2,532	2,431	1,126	1,542	1,904
Conventional Natural Gas (Mcf/d)	373	416	340	337	366
NGLs (bbls/d)	622	407	252	252	383
Shale Gas (Mcf/d)	18,621	17,014	9,501	8,923	13,491
Total (Boe/d)	13,348	11,101	11,848	11,630	11,981
Average Prices Received[(2)]					
Bitumen ($/bbl)	7.27	24.51	28.56	31.46	23.58
Tight Oil ($/bbl)	36.86	48.49	53.01	57.09	47.07
Conventional Natural Gas ($/Mcf)	1.74	1.56	2.28	2.99	2.10
NGLs ($/bbl)	20.41	21.55	15.29	21.41	20.03
Shale Gas ($/Mcf)	1.65	1.61	2.71	2.88	2.03
Total ($/boe)	14.04	25.87	28.86	32.79	25.00
Royalties Paid					
Bitumen ($/bbl)	(0.04)	(0.28)	(0.17)	(0.37)	(0.21)
Tight Oil ($/bbl)	(2.65)	(3.07)	(4.67)	(4.77)	(3.51)
Natural Gas ($/Mcf)	(0.00)	(0.04)	0.08	0.15	0.04
NGLs ($/bbl)	(4.48)	(0.62)	(4.17)	(7.62)	(3.93)
Shale Gas ($/Mcf)	0.19	0.14	0.43	0.35	0.24
Total ($/boe)	(0.47)	(0.64)	(0.30)	(0.80)	(0.54)
Production Costs[(3)(4)]					
Bitumen ($/bbl)	(42.57)	(53.56)	(35.19)	(37.50)	(40.38)
Tight Oil ($/bbl)	(12.21)	(12.17)	(9.32)	(14.18)	(12.08)
Conventional Natural Gas ($/Mcf)	(1.95)	(2.19)	(1.61)	(2.34)	(2.01)
NGLs ($/bbl)	(12.29)	(12.58)	(9.47)	(14.10)	(12.08)
Shale Gas ($/Mcf)	(2.04)	(2.03)	(1.53)	(2.34)	(2.01)
Total ($/boe)	(28.36)	(30.29)	(29.05)	(30.62)	(29.50)
Netback Received[(5)]					
Bitumen ($/bbl)	(35.34)	(29.33)	(6.80)	(6.41)	(17.01)
Tight Oil ($/bbl)	22.00	33.25	39.02	38.15	31.47
Conventional Natural Gas ($/Mcf)	(0.21)	(0.67)	0.75	0.80	0.14
NGLs ($/bbl)	3.64	8.35	1.65	(0.31)	4.02
Shale Gas ($/Mcf)	(0.21)	(0.28)	1.61	0.88	0.26
Total ($/boe)	(14.79)	(5.06)	(0.49)	1.37	(5.04)

Notes:

(1) Production and netback figures have been presented by accounting month. The netback figures on a per barrel basis have been calculated on sales volumes.
(2) Average realized price received for bitumen has been presented net of the cost of the blended diluent sold.
(3) For wells producing multiple products, production costs have been allocated based on barrels of oil equivalent.
(4) Production costs are presented net of midstream revenues.
(5) Netbacks are calculated by subtracting royalties and operating and transportation costs from revenues.

The following table sets forth the average daily production from each of the Company's producing fields for the year ended December 31, 2016:

	Bitumen (bbls/d)	Tight Oil (bbls/d)	Conventional Natural Gas (Mcf/d)	NGLs (bbls/d)	Shale Gas (Mcf/d)	Oil Equivalent (boe/d)
Hangingstone Area	7,384	-	-	-	-	7,384
Greater Kaybob Area	-	994	-	232	7,469	2,470
Greater Placid Area	-	910	336	151	6,023	2,121
Light Oil Exploration Areas	-	-	31	0	-	6
Total	7,384	1,904	367	383	13,492	11,981

Environmental Considerations

The environmental issues and stakeholder concerns to be managed by Athabasca in developing its assets are similar to those currently being managed by other oil and gas companies, and by communities, and encompass the health of local and regional residents and employees, surface disturbance on the terrestrial ecosystem, effects on traditional land use and historical resources, local and regional air quality, GHG emissions, water quality, monitoring seismic activity levels, health of the aquatic ecosystem in rivers and cumulative effects on wildlife populations and aquatic resources. Athabasca has committed to both site-specific and regional monitoring programs to track the effects of its projects and the cumulative effects of regional development on environmental components and ecosystems.

Athabasca is committed to operating its projects to achieve compliance with applicable statutes, regulations, codes, regulatory approvals and, to the extent practicable, government guidelines. Where the applicable laws are not clear or do not address all environmental concerns, management intends to apply appropriate internal standards and guidelines to address such concerns. In addition to complying with applicable statutes, regulations, codes and regulatory approvals and exercising due diligence, Athabasca strives to continuously improve its operations to address environmental concerns.

CHANGES TO RESERVES DATA

On January 31, 2017, Athabasca completed the Asset Acquisition. Athabasca engaged GLJ to prepare the Acquisition Independent Report, which is an independent assessment and evaluation of Athabasca's consolidated pro forma bitumen, light crude oil and medium crude oil, tight oil, conventional natural gas, shale gas and NGL reserves as at December 31, 2016 and the net present values of future net revenue for these reserves using forecast prices and costs as at December 31, 2016 after giving effect the Asset Acquisition and assuming that the Asset Acquisition was completed on December 31, 2016. Although Athabasca did not acquire the Acquired Assets until January 31, 2017, and therefore did not beneficially own the bitumen, light crude oil and medium crude oil, tight oil, conventional natural gas, shale gas and NGL reserves attributable to the Acquired Assets until such date, the information presented herein is shown for convenience of reference, on a pro-forma basis, effective December 31, 2016.

The reserves data set forth below is based upon a consolidation of the reports prepared by: (i) GLJ dated January 5, 2017 relating to the Acquired Assets ; (ii) GLJ dated February 9, 2017 relating to the Company's other assets excluding the Acquired Assets with an effective date of December 31, 2016: and (iii) the DMCL Report and represents: (1) Athabasca's bitumen, light crude oil and medium crude oil, tight oil, conventional natural gas, shale gas and NGL reserves as at December 31, 2016 before giving effect to the Asset Acquisition and the net present values of future net revenue for these reserves; and (2) the bitumen, light crude oil and medium crude oil, tight oil, conventional natural gas, shale gas and NGL reserves attributable to the Acquired Assets as at December 31, 2016 and the net present values of future net revenue for these reserves. The Acquisition Independent Report was prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101 and the COGE Handbook.

All of the reserves at contained in the Acquisition Independent Report are located in Canada and specifically in the Province of Alberta.

All evaluations of future net revenue are after the deduction of royalties, development costs, production costs and abandonment and reclamation costs but before consideration of indirect costs such as administrative, overhead and other miscellaneous expenses. The estimated future net revenues contained in the following tables do not represent the fair market value of the reserves. There is no assurance that the forecast price assumptions that have been estimated by GLJ will be realized and variances could be material. Other assumptions have been made by GLJ and qualifications relating to costs and other matters are included in the Acquisition Independent Report. The recovery and reserves estimates of the described herein are estimates only. The actual reserves may be greater or less than those calculated.

Summary of Reserves Data – Forecast Prices and Costs as of December 31, 2016

Reserves Category	**Bitumen**		**Tight Oil**		**Conventional Natural Gas**	
	Gross (Mbbls)	**Net (Mbbls)**	**Gross (Mbbls)**	**Net (Mbbls)**	**Gross (MMcf)**	**Net (MMcf)**
PROVED RESERVES						
Developed Producing	77,804	73,747	314	252	449	413
Developed Non-Producing	0	0	6	6	716	675
Undeveloped	304,428	256,911	410	374	15	14
TOTAL PROVED RESERVES	382,232	330,658	730	632	1,180	1,102
TOTAL PROBABLE RESERVES	695,222	566,090	475	399	347	323
TOTAL PROVED PLUS PROBABLE RESERVES	1,077,454	896,748	1,205	1,031	1,527	1,425

Reserves Category	**Shale Gas**		**Natural Gas Liquids**		**Oil Equivalent**	
	Gross (MMcf)	**Net (MMcf)**	**Gross (Mbbls)**	**Net (Mbbls)**	**Gross (Mboe)**	**Net (Mboe)**
PROVED RESERVES						
Developed Producing	13,889	12,849	1,574	1,203	82,082	77,413
Developed Non-Producing	602	568	66	59	292	272
Undeveloped	51,557	47,636	6,374	5,645	319,808	270,872
TOTAL PROVED RESERVES	66,048	61,053	8,014	6,907	402,182	348,557
TOTAL PROBABLE RESERVES	71,548	64,508	9,901	8,314	717,581	585,607
TOTAL PROVED PLUS PROBABLE RESERVES	137,596	125,561	17,915	15,221	1,119,763	934,164

Summary of Net Present Values of Future Net Revenue – Forecast Prices and Costs as of December 31, 2016(1)(2)(3)(4)

	Before Income Tax Discounted at (%/year)					**After Income Taxes Discounted at (%/year)**					**Unit Value Before Income Tax at 10% Discount/ Year**	
RESERVES CATEGORY	**0% (M$)**	**5% (M$)**	**10% (M$)**	**15% (M$)**	**20% (M$)**	**0% (M$)**	**5% (M$)**	**10% (M$)**	**15% (M$)**	**20% (M$)**	**($/boe)**	**($/Mcfe)**
PROVED RESERVES												
Developed Producing	1,302,788	1,066,750	892,433	761,797	662,082	1,302,788	1,066,750	892,433	761,797	662,082	11.53	1.92
Developed Non-Producing	662	948	937	836	719	662	948	937	836	719	3.45	0.57
Undeveloped	6,934,131	2,807,813	1,360,963	732,190	411,908	5,339,993	2,209,315	1,093,869	597,812	338,472	5.02	0.84
TOTAL PROVED RESERVES	8,237,581	3,875,511	2,254,333	1,494,823	1,074,709	6,643,443	3,277,013	1,987,239	1,360,445	1,001,273	6.47	1.08
TOTAL PROBABLE RESERVES	16,387,714	5,135,296	1,727,194	410,486	-177,532	11,884,705	3,505,159	987,708	24,300	-398,294	2.95	0.49
TOTAL PROVED PLUS PROBABLE RESERVES	24,625,295	9,010,807	3,981,528	1,905,309	897,177	18,528,149	6,782,172	2,974,947	1,384,746	602,979	4.26	0.71

Future Net Revenue (Undiscounted) – Forecast Prices and Cost as of December 31, 2016(1)(2)(3)(4))

Reserves Category	Revenue (M$)	Royalties (M$)	Operating Costs (M$)	Development Costs (M$)	Abandonment and Reclamation Costs (M$)	Future Net Revenue Before Future Income Tax Expenses (M$)	Future Income Tax Expenses (M$)	Future Net Revenue After Future Income Tax Expenses (M$)
PROVED RESERVES	28,729,537	4,458,668	9,138,160	6,513,776	381,352	8,237,581	1,594,138	6,643,443
PROBABLE RESERVES	58,833,794	12,048,485	16,638,077	13,148,733	610,785	16,387,714	4,503,009	11,884,705
PROVED PLUS PROBABLE RESERVES	87,563,331	16,507,153	25,776,237	19,662,509	992,137	24,625,295	6,097,146	18,528,149

Future Net Revenue by Product Type– Forecast Prices and Costs as of December 31, 2016(1)(2)(3)(5)(6)

		Future Net Revenue Before Income Taxes (Discounted at 10%/Year)		
RESERVES CATEGORY	**Production Group**	**M$**	**$/BOE**	**$/Mcfe**
PROVED RESERVES	Bitumen	2,050,444	6.20	1.03
	Tight Oil	30,766	24.82	4.14
	Conventional Natural Gas [5]	1,604	7.37	1.23
	Shale Gas	171,520	10.43	1.74
	TOTAL	**2,254,334**	**6.47**	**1.08**
PROVED PLUS PROBABLE RESERVES	Bitumen	3,471,970	3.87	0.65
	Tight Oil	59,986	25.38	4.23
	Conventional Natural Gas [5]	2,262	7.91	1.32
	Shale Gas	447,310	12.87	2.14
	TOTAL	**3,981,527**	**4.26**	**0.71**

Notes:

(1) Based on the Acquisition Independent Report. Future net revenue estimates were calculated by GLJ using the pricing assumptions set forth below under "GLJ Price Forecast" to ensure for consistency and in accordance with the COGE Handbook.

(2) Totals may not add to rounding.

(3) All evaluations of future net revenue are after the deduction of royalties, development costs, production costs and abandonment and reclamation costs but before consideration of indirect costs such as administrative, overhead and other miscellaneous expenses. For further detail on what is and isn’t included in abandonment and reclamation costs, please see the "Abandonment and Reclamation Obligations for Properties with Reserves".

(4) The estimated tax burden included in the after-tax net present values of the Company’s oil and gas properties is reflected at the corporate consolidation level and does not consider tax planning or provide an estimate of the tax burden at the business entity level which may be significantly different.

(5) Including by-products but excluding solution gas.

(6) Other company revenue and costs not related to a specific production group have been allocated proportionately to production groups. Unit values are based on Company Net Reserves.

GLJ Price Forecast

The price forecasts that formed the basis for the revenue projections and net present value estimates that are contained herein are based on GLJ’s January 1, 2017 pricing models. A summary of applicable selected price forecasts is set forth below.

Year	Inflation	Bank of Canada Average Noon Exchange Rate	WTI Oil at Cushing Oklahoma Current	Light Sweet Crude Oil (40° API, 0.3%S) at Edmonton Current	WCS Stream Quality at Hardisty Current	Midwest price at Chicago Current	AECO/NIT Spot Current	Natural Gas Liquids Edmonton Pentanes Plus	Propane	Butane
	%	($US/$Cdn)	($US/bbl)	($Cdn/bbl)	($Cdn/bbl)	($USD/MMBtu)	($Cdn/MMBtu)	($Cdn/bbl)	($Cdn/bbl)	($Cdn/bbl)
2017	2.00	0.750	55.00	69.33	53.32	3.65	3.46	72.11	28.43	49.92
2018	2.00	0.775	59.00	72.26	56.79	3.25	3.10	74.79	26.74	54.19
2019	2.00	0.800	64.00	75.00	61.27	3.45	3.27	78.75	26.25	56.25
2020	2.00	0.825	67.00	76.36	63.00	3.65	3.49	79.80	26.73	57.27
2021	2.00	0.850	71.00	78.82	65.90	3.85	3.67	82.37	27.59	59.12
2022	2.00	0.850	74.00	82.35	69.42	4.05	3.86	86.06	28.82	61.76
2023	2.00	0.850	77.00	85.88	72.91	4.25	4.05	89.32	30.06	64.41
2024	2.00	0.850	80.00	89.41	76.45	4.36	4.16	92.99	31.29	67.06
2025	2.00	0.850	83.00	92.94	79.93	4.44	4.24	97.59	32.53	69.71
2026	2.00	0.850	86.05	95.61	83.47	4.53	4.32	99.91	33.46	71.71
2027+	Escalated oil, gas and product prices at 2.0% per year thereafter.									

The weighted average realized sales prices for Athabasca for the year ended December 31, 2016 were $23.58/bbl for bitumen, $47.07/bbl for tight oil, $2.10/Mcf for conventional natural gas, $20.03/bbl for NGL and $2.03/Mcf for shale gas.

Undeveloped Reserves

The following tables set out the volumes of proved undeveloped reserves and probable undeveloped reserves that were attributed the Company's assets, including the Acquired Assets, for each of the three most recent financial years using forecast prices and costs:

Proved Undeveloped Reserves[1][2]

	Bitumen (MMbbls)		Conventional Natural Gas (Bcf)		Natural Gas Liquids (MMbbls)	
Year	First Attributed	Total at Year-end	First Attributed	Total at Year-end	First Attributed	Total at Year-end
2014	0.0	0.0	3.8	10.4	1.3	1.7
2015	44.4	44.4	0.0	0.3	0.8	1.9
2016	260.4	304.4	0.0	0.0	3.3	6.4

	Tight Oil (MMbbls)		Shale Gas (Bcf)		Oil Equivalent (MMboe)	
Year	First Attributed	Total at Year-end	First Attributed	Total at Year-end	First Attributed	Total at Year-end
2014	0.6	1.2	8.2	11.9	4.0	6.9
2015	5.5	7.2	43.3	60.0	57.9	63.4
2016	0.1	0.4	26.0	51.6	268.2	319.8

Probable Undeveloped Reserves[(1)(2)]

Year	Bitumen (MMbbls) First Attributed	Bitumen (MMbbls) Total at Year-end	Conventional Natural Gas (Bcf) First Attributed	Conventional Natural Gas (Bcf) Total at Year-end	Natural Gas Liquids (MMbbls) First Attributed	Natural Gas Liquids (MMbbls) Total at Year-end
2014	0.0	261.3	5.7	52.2	3.2	7.6
2015	0.0	129.8	0.0	0.1	1.2	4.6
2016	557.6	686.9	0.0	0.0	5.1	9.3

Year	Tight Oil (MMbbls) First Attributed	Tight Oil (MMbbls) Total at Year-end	Shale Gas (Bcf) First Attributed	Shale Gas (Bcf) Total at Year-end	Oil Equivalent (MMboe) First Attributed	Oil Equivalent (MMboe) Total at Year-end
2014	9.5	9.6	50.9	59.7	22.2	297.7
2015	4.9	14.0	37.8	103.2	12.4	165.6
2016	0.0	0.3	37.9	66.0	569.1	707.6

Notes:

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

(2) Based on the Acquisition Independent Report.

Significant Factors or Uncertainties

The process of evaluating reserves is inherently complex. It requires significant judgments and decisions based on available geological, geophysical, engineering, and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserves estimates contained herein are based on current production forecasts, prices and economic conditions and other factors and assumptions that may affect the reserves estimates and the present worth of the future net revenue therefrom. See "*Risk Factors –There are uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids reserves and the future cash flows attributed to such reserves*".

As circumstances change and additional data becomes available, reserve estimates may also change. Estimates made are reviewed and revised, either upward or downward, as warranted by new information. Revisions may be required as a result of a number of factors that are beyond Athabasca's control, including, among others, product pricing, economic conditions, access to markets, changes to royalty and tax regimes, governmental restrictions, changing operating and capital costs, surface access issues, the receipt of regulatory approvals, availability of services and processing facilities and technical issues affecting well performance. Although every reasonable effort is made to ensure that reserves estimates are accurate, reserve estimation is an inferential science and revisions to reserve estimates based upon the foregoing factors may be either positive or negative.

Abandonment and Reclamation Obligations For Properties with Reserves

In connection with the operations associated with the Acquired Assets, Athabasca will incur abandonment and reclamation costs for wells and associated pads with proved and probable reserves, interconnecting flowlines, trunk lines, central processing facility and all related inbounds facilities and infrastructure. The expected total project abandonment and reclamation costs, net of estimated salvage value, included in the proved plus probable category of the Acquisition Independent Report is an aggregate of $793 million (undiscounted) and $40 million (10% discount). These abandonment and reclamation cost estimates assume a full field development of the Acquired Assets with attributable proved and probable reserves representing approximately 2.1% of the undiscounted future production revenue of approximately $37,655 million (revenue net of royalties and operating costs) from the Acquired Assets proved and probable reserves (or approximately 0.6% of $7,297 million discounted future production revenue net of royalties and operating costs, 10% discount).

Including the impact of the Acquired Assets, as at December 31, 2016, Management estimates that there was $266.0 million (proforma, uninflated and undiscounted) in total reclamation and abandonment costs associated with the wells and associated sites, facilities and pipelines in the Light Oil and Thermal Oil Divisions. Applying an estimated inflation rate of 2% and a discount rate of 10%, based on the current anticipated timing of the reclamation expenditures, Management estimates that the proforma value of the Company's decommissioning obligations is $101.3 million.

Forward Contracts

Athabasca may from time to time use financial derivatives to manage its exposure to fluctuations in commodity prices, foreign exchange and interest rates. As at December 31, 2016, the Company did not have any forward contracts in place.

The following table is a summary of forward contracts entered into subsequent to December 31, 2016.

Subject of Contract	Volume (bbl/d)	Term	Reference	Strike Price	Option Traded
Oil	1,000	Feb-Dec 2017	CAD WCS	CAD $52.50	Fixed Price Swap
Oil	1,000	Feb-Dec 2017	CAD WCS	CAD $52.75	Fixed Price Swap
Oil	1,000	Feb-Dec 2017	CAD WCS	CAD $52.55	Fixed Price Swap
Oil	3,000	Feb-Dec 2017	CAD WTI	CAD $73.52	Fixed Price Swap
Oil	1,000	Feb-Dec 2017	CAD WTI/WCS Differential	CAD -$20.60	Fixed Price Swap
Oil	2,000	Feb-Dec 2017	CAD WTI/WCS Differential	CAD -$20.65	Fixed Price Swap
Oil	1,000	Feb-Dec 2017	CAD WCS	CAD $52.60	Fixed Price Swap
Oil	1,000	Feb-Dec 2017	CAD WTI	CAD $71.50	Fixed Price Swap
Oil	1,000	Feb-Dec 2017	CAD WTI/WCS Differential	CAD -$19.10	Fixed Price Swap
Oil	1,000	Feb-Dec 2017	CAD WCS	CAD $52.60	Fixed Price Swap
Oil	1,000	Feb-Dec 2017	CAD WCS	CAD $52.80	Fixed Price Swap
Oil	1,000	Feb-Dec 2017	CAD WCS	CAD $52.90	Fixed Price Swap
Oil	1,000	Feb-Dec 2017	CAD WCS	CAD $52.61	Fixed Price Swap

Future Development Costs

The following table sets forth the undiscounted development costs deducted in the estimation of future net revenue attributable to each of the following reserves categories contained in the Acquisition Independent Report.

Year	Total Proved Reserves Future Development Costs Using Forecast Dollar Costs (M$)	Total Proved Plus Probable Reserves Future Development Costs Using Forecast Dollar Costs (M$)
2017	289,638	243,678
2018	92,501	715,607
2019	196,926	1,237,672
2020	58,436	1,350,921
2021	129,591	383,530
Total for all remaining years	5,746,684	15,731,102
Total Undiscounted	6,513,776	19,662,510

Note:

(1) Totals may not add due to rounding.

Athabasca's 2017 activities are expected to be funded with cash flow from operations, the Kaybob Carry Commitment and existing cash and cash-equivalents. Athabasca's current business plan for developing its properties beyond 2017 anticipates that Athabasca will fund its activities and other requirements through cash flow from operations and the Kaybob Carry Commitment. Any significant acceleration of Light Oil development activities or future expansion of Athabasca's thermal oil projects will potentially require additional funding which could include debt, equity, joint ventures or other external financing or a combination of these. The availability of any additional future funding will depend on, amongst other things, the current commodity price environment, operating performance, the Company's credit rating at the time and the current state of the equity and debt capital markets. See "*Risk Factors – Our ability to finance our capital expenditures depends on many factors*" for additional information.

Oil and Gas Wells

The following table sets forth the number and status of wells as at December 31, 2016 in which the Company has a working interest on a pro forma basis, including the Acquired Assets, all of which are located in the Province of Alberta:

	Producing		**Non-Producing**[3]		**Total**	
	Gross Wells[1]	**Net Wells**[2]	**Gross Wells**[1]	**Net Wells**[2]	**Gross Wells**[1]	**Net Wells**[2]
Bitumen	66	66	4	4	70	70
Crude Oil Wells	30	9.0	46	21.5	76	30.46
Natural Gas Wells	36	17.3	18	10.0	54	27.36
TOTAL	132	92.3	68	35.5	200	127.8

Notes:

(1) "**Gross Wells**" means the total number of producing or non-producing bitumen, oil or gas wells in which Athabasca had an interest as of December 31, 2016.

(2) "**Net Wells**" means the aggregate number of producing or non-producing bitumen, oil or gas wells obtained by multiplying each Gross Well by Athabasca's percentage working interest therein.

(3) "**Non-Producing**" wells include stratigraphic test wells, wells awaiting completion as at December 31, 2016, and wells that are capable of production but were not producing as at December 31, 2016, due to facility limitations or were waiting to be tied-in. All non-producing wells considered to be capable of producing are located near existing transportation infrastructure. Athabasca has not included the following type of wells in its Non-Producing well count above: wells in the Liege area that are suspended or permanently shut-in either due to a lack of existing functional proximate transportation infrastructure or a permanent shut-in order issued by the AER, its HAF, water source, steam injection, disposal wells or wells that have been abandoned.

Properties with No Attributed Reserves

The following table sets out the properties (including the Acquired Assets) as at December 31, 2016 which have no reserves attributable, and also the number of net acres for which Athabasca's rights to explore, develop or exploit will, absent further action, expire within one year:

	Gross Acres[1][2]	**Net Acres**[1][2]	**Net Acres Expiring Within One Year**[1][2]
Alberta	1,373,223	1,185,023	8,832
Total	**1,373,223**	**1,185,023**	**8,832**

Notes:

(1) "**Gross**" means the total area of properties in which Athabasca has a working interest. "**Net**" means the total area in which Athabasca has an interest multiplied by the working interest owned by Athabasca.

(2) Excludes certain non-oil sands acreage held in formations under and adjacent to the same surface area as oil sands leases. Athabasca measures its land acreage based on the leases, licenses and permits granted by the Crown, as specified within the applicable legal documentation.

Exploration and Development Activities

The following table summarizes the gross and net exploratory and development wells that were completed on the Acquired Assets during the year ended December 31, 2016:

	Exploratory		**Development**		**Total**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Oil wells	-	-	-	-	-	-
Bitumen wells	-	-	-	-	-	-
Gas wells	-	-	14	7.4	14	7.4
Service wells	-	-	-	-	-	-
Stratigraphic test wells	-	-	-	-	-	-
Dry holes	-	-	-	-	-	-
Total	-	-	**14**	**7.4**	**14**	**7.4**

For a description of the Company's current and likely exploration and development activities see "*Description of Athabasca's Business*".

Production Estimates

The following table sets out the volumes of production estimated by GLJ for the year ending December 31, 2017 (including the Acquired Assets) which is reflected in the estimates of future net revenue disclosed in the tables contained under the headings "*Summary of Net Present Values of Future Net Revenue – Forecast Prices and Costs as of December 31, 2016*", "*Future Net Revenue (Undiscounted) – Forecast Prices and Costs as of December 31, 2016*" and " *Future Net Revenue by Product Type– Forecast Prices and Costs as of December 31, 2016*".

Reserve Category	**Bitumen (bbl/d)**	**Conventional Natural Gas (Mcf/d)**	**NGLs (bbl/d)**	**Tight Oil (bbl/d)**	**Shale Gas (Mcf/d)**	**Oil Equivalent (Boe/d)**
Gross Proved Reserves						
Hangingstone	10,102	0	0	0	0	10,102
Leismer	21,028	0	0	0	0	21,028
Greater Placid Area	0	223	1385	25	11134	3,303
Greater Kaybob Area	0	0	828	357	4836	1,991
Total Gross Proved Reserves	**31,130**	**223**	**2,213**	**382**	**15,970**	**36,425**

Reserve Category	**Bitumen (bbl/d)**	**Conventional Natural Gas (Mcf/d)**	**NGLs (bbl/d)**	**Tight Oil (bbl/d)**	**Shale Gas (Mcf/d)**	**Oil Equivalent (Boe/d)**
Gross Probable Reserves						
Hangingstone	243	0	0	0	0	243
	2,075	0	0	0	0	2075
Greater Placid area	0	7	383	2	2914	872
Greater Kaybob Area	0	0	155	119	925	428
Total Gross Probable Reserves	**2,318**	**7**	**538**	**121**	**3,839**	**3,618**

Reserve Category	**Bitumen**	**Conventional Natural Gas**	**NGLs**	**Tight Oil**	**Shale Gas**	**Oil Equivalent**
Gross Proved + Probable Reserves	**(bbl/d)**	**(Mcf/d)**	**(bbl/d)**	**(bbl/d)**	**(Mcf/d)**	**(Boe/d)**
Hangingstone	10,345	0	0	0	0	10,345
	23,103	0	0	0	0	23,103
Greater Placid area	0	231	1768	27	14047	4,175
Greater Kaybob Area	0	0	983	476	5761	2,419

Total Gross Proved + Probable Reserves	**33,448**	**231**	**2,751**	**503**	**19,808**	**40,043**

Note:
(1) Totals may not add due to rounding.

Production History

The following table sets forth on a quarterly basis for the year ended December 31, 2016, certain information in respect of production, product prices received, royalties paid, production costs and the resulting netbacks in respect of the Athabasca's assets as at December 31, 2016. The following table does not include the Acquired Assets.

	Quarter Ended 2016				**Year Ended**
	Mar. 31	**June 30**	**Sept. 30**	**Dec. 31**	**Dec. 31, 2016**
Average Daily Production[1]					
Bitumen (bbls/d)	7,029	5,358	8,830	8,293	7,384
Tight Oil (bbls/d)	2,532	2,431	1,126	1,542	1,904
Conventional Natural Gas (Mcf/d)	373	416	340	337	366
NGLs (bbls/d)	622	407	252	252	383
Shale Gas (Mcf/d)	18,621	17,014	9,501	8,923	13,491
Total (Boe/d)	13,348	11,101	11,848	11,630	11,981
Average Prices Received					
Bitumen ($/bbl)	7.27	24.51	28.56	31.46	23.58
Tight Oil ($/bbl)	36.86	48.49	53.01	57.09	47.07
Conventional Natural Gas ($/Mcf)	1.74	1.56	2.28	2.99	2.10
NGLs ($/bbl)	20.41	21.55	15.29	21.41	20.03
Shale Gas ($/Mcf)	1.65	1.61	2.71	2.88	2.03
Total ($/boe)	14.04	25.87	28.86	32.79	25.00
Royalties Paid					
Bitumen ($/bbl)	(0.04)	(0.28)	(0.17)	(0.37)	(0.21)
Tight Oil ($/bbl)	(2.65)	(3.07)	(4.67)	(4.77)	(3.51)
Conventional Natural Gas ($/Mcf)	(0.00)	(0.04)	0.08	0.15	0.04
NGLs ($/bbl)	(4.48)	(0.62)	(4.17)	(7.62)	(3.93)
Shale Gas ($/Mcf)	0.19	0.14	0.43	0.35	0.24
Total ($/boe)	(0.47)	(0.64)	(0.30)	(0.80)	(0.54)

	Quarter Ended 2016				**Year Ended**
	Mar. 31	**June 30**	**Sept. 30**	**Dec. 31**	**Dec. 31, 2016**
Production Costs[2]					
Bitumen ($/bbl)	(42.57)	(53.56)	(35.19)	(37.50)	(40.38)
Tight Oil ($/bbl)	(12.21)	(12.17)	(9.32)	(14.18)	(12.08)
Conventional Natural Gas ($/Mcf)	(1.95)	(2.19)	(1.61)	(2.34)	(2.01)
NGLs ($/bbl)	(12.29)	(12.58)	(9.47)	(14.10)	(12.08)
Shale Gas ($/Mcf)	(2.04)	(2.03)	(1.53)	(2.34)	(2.01)
Total ($/boe)	(28.36)	(30.29)	(29.05)	(30.62)	(29.50)
Netback Received[3]					
Bitumen ($/bbl)	(35.34)	(29.33)	(6.80)	(6.41)	(17.01)
Tight Oil ($/bbl)	22.00	33.25	39.02	38.15	31.47
Conventional Natural Gas ($/Mcf)	(0.21)	(0.67)	0.75	0.80	0.14
NGLs ($/bbl)	3.64	8.35	1.65	(0.31)	4.02
Shale Gas ($/Mcf)	(0.21)	(0.28)	1.61	0.88	0.26
Total ($/boe)	(14.79)	(5.06)	(0.49)	1.37	(5.04)

Notes:

(1) Production and netback figures have been presented by accounting month. The Netback figures on a per barrel basis have been calculated on sales volumes.
(2) Average realized price received for bitumen has been presented net of the cost of the blended diluent sold.
(3) For wells producing multiple products, production costs have been allocated based on barrels of oil equivalent.
(4) Production costs are presented net of midstream revenues.
(5) Netbacks are calculated by subtracting royalties and operating and transportation costs from revenues.

The following table sets forth the average daily production from each of the Company's producing fields for the year ended December 31, 2016. The following table does not include the Acquired Assets.

	Bitumen (bbls/d)	Tight Oil (bbls/d)	Natural Gas (Mcf/d)	NGLs (bbls/d)	Shale Gas (Mcf/d)	Oil Equivalent (boe/d)
Hangingstone Area	7,384	-	-	-	-	7,384
Greater Kaybob Area	-	994	-	232	7,469	2,470
Greater Placid area	-	910	336	151	6,023	2,121
Light Oil Exploration Areas	-	-	31	0	-	6
Total	7,384	1,904	367	383	13,492	11,981

DIVIDENDS

The Company has not declared or paid any cash dividends on its Common Shares in any of the three most recently completed financial years. The Company does not currently anticipate paying any cash dividends on its Common Shares in the foreseeable future but will review that policy from time to time as circumstances warrant. The Company currently intends to retain future earnings, if any, for future operations, expansion and debt repayment. Any decision to declare and pay dividends in the future will be made at the discretion of the Board and will depend on, among other things, the Company's results of operations, current and anticipated cash requirements and surplus, financial condition, solvency tests imposed by corporate law, contractual restrictions and financing agreement covenants, including those contained in the New Note Indenture, Amended Credit Facility and the LC Facility and other factors that the Board may deem relevant.

Under the terms of the New Note Indenture, Amended Credit Facility and the LC Facility, the Company and certain of its subsidiaries are prohibited from making certain restricted payments, including the payment of dividends, unless at the time of and immediately after giving effect to such a proposed restricted payment, certain financial tests (as set forth in the respective applicable agreements) are met, and no default or event of default under the New Note Indenture, Amended Credit Facility or LC Facility, as applicable, has occurred and is continuing.

DESCRIPTION OF CAPITAL STRUCTURE

General

The Company's authorized share capital consists of an unlimited number of Common Shares without nominal or par value, an unlimited number of first preferred shares, issuable in series, and an unlimited number of second preferred shares, issuable in series, each of which are described below. The Company has also issued the New Notes and has the ability to utilize the Amended Credit Facility and LC Facility that are described below.

As at December 31, 2016, 406,490,101 Common Shares were issued and outstanding and no first preferred shares or second preferred shares were issued and outstanding. In addition, 9,369,885 Stock Options and 9,235,490 RSUs (2010 and 2015), 2,691,300 Performance Awards and 1,132,727 DSUs were issued and outstanding on December 31, 2016.

As at February 28, 2017, 506,644,327 Common Shares were issued and outstanding and no first preferred shares or second preferred shares were issued and outstanding. In addition, 8,572,219 Stock Options and 10,358,244 RSUs (2010 and 2015), 2,426,500 Performance Awards and 1,132,727 DSUs were issued and outstanding on February 28, 2017.

Common Shares

Each Common Share entitles the holder thereof to: (a) vote at any meeting of Shareholders of the Company; (b) receive any dividend on the Common Shares declared by the Company; and (c) receive the remaining property of the Company upon dissolution. For a description of the Company's dividend policy, see "*Dividends*".

First Preferred Shares

Subject to the filing of articles of amendment in accordance with the ABCA, the Board may at any time and from time to time issue first preferred shares in one or more series, each series to consist of such number of shares as may, before the issuance thereof, be determined by the Board. Subject to the filing of articles of amendment in accordance with the ABCA, the Board may from time to time fix, before issuance, the designation, rights, privileges, restrictions and conditions attaching to each series of first preferred shares including, without limiting the generality of the foregoing: the amount, if any, specified as being payable preferentially to such series on a Distribution (as defined below); the extent, if any, of further participation on a Distribution; voting rights, if any; and dividend rights (including whether such dividends are preferential, cumulative or non-cumulative), if any.

In the event of the voluntary or involuntary liquidation, dissolution or winding up of the Company, or any other distribution of its assets among its Shareholders for the purpose of winding up its affairs (such event referred to herein as a "**Distribution**"), holders of each series of first preferred shares shall be entitled, in priority to holders of Common Shares, second preferred shares and any other shares of the Company ranking junior to the first preferred shares from time to time with respect to payment on a Distribution, to be paid rateably with holders of each other series of first preferred shares the amount, if any, specified as being payable preferentially to the holders of such series on a Distribution.

The holders of each series of first preferred shares shall be entitled, in priority to holders of Common Shares, second preferred shares and any other shares of the Company ranking junior to the first preferred shares from time to time with respect to the payment of dividends, to be paid rateably with holders of each other series of first preferred shares, the amount of accumulated dividends, if any, specified as being payable preferentially to the holders of such series.

Under the terms of the New Note Indenture, Amended Credit Facility and the LC Facility, the Company is prohibited from issuing preferred shares, unless certain financial tests (as set forth in the respective applicable agreements) are met, and no default or event of default under the New Note Indenture, Amended Credit Facility or LC Facility, as applicable, has occurred and is continuing.

Second Preferred Shares

Subject to the filing of articles of amendment in accordance with the ABCA, the Board may at any time and from time to time issue second preferred shares in one or more series, each series to consist of such number of shares as may, before the issuance thereof, be determined by the Board. Subject to the filing of articles of amendment in accordance with the ABCA, the Board may from time to time fix, before issuance, the designation, rights, privileges, restrictions and conditions attaching to each series of second preferred shares including, without limiting the generality of the foregoing: the amount, if any, specified as being payable preferentially to such series on a Distribution; the extent, if any, of further participation on a Distribution; voting rights, if any; and dividend rights (including whether such dividends are preferential, cumulative or non-cumulative), if any.

In the event of a Distribution, holders of each series of second preferred shares shall be entitled, subject to the preference accorded to holders of first preferred shares but in priority to holders of Common Shares and any other shares of the Company ranking junior to the second preferred shares from time to time with respect to payment on a Distribution, to be paid rateably with holders of each other series of second preferred shares the amount, if any, specified as being payable preferentially to the holders of such series on a Distribution.

The holders of each series of second preferred shares shall be entitled, subject to the preference accorded to the holders of first preferred shares but in priority to holders of Common Shares and any other shares of the Company ranking junior to the second preferred shares from time to time with respect to the payment of dividends, to be paid rateably with holders of each other series of second preferred shares, the amount of accumulated dividends, if any, specified as being payable preferentially to the holders of such series.

Shareholder Rights Plan

Effective April 8, 2010 (the "**Effective Date**"), the Company adopted the Rights Plan, which was originally approved by Shareholders at a special meeting held on April 21, 2012 and was subsequently amended and restated by the Shareholders at the annual general and special meeting that was held on May 10, 2015 (the "**Amended Rights Plan**"). Pursuant to the Amended Rights Plan, the Shareholders also approved an extension to the term of the Amended Rights Plan until the close of business on the first business day following the annual general meeting of the Shareholders to be held in 2018, unless at such meeting the Shareholders reconfirm the Amended Rights Plan for an additional period of time or the Amended Rights Plan is otherwise terminated in accordance with its terms prior thereto.

The objectives of the Amended Rights Plan are to provide adequate time for the Board and Shareholders to assess an unsolicited take-over bid for the Company, to provide the Board with sufficient time to explore and develop alternatives for maximizing Shareholder value if a take-over bid is made, and to provide Shareholders with an equal opportunity to participate in a take-over bid. The Amended Rights Plan encourages a potential acquirer who makes a take-over bid to proceed either by way of a "Permitted Bid" (as defined in the Amended Rights Plan), which generally requires a take-over bid to satisfy certain minimum standards designed to promote fairness, or with the concurrence of the Board. If a take-over bid fails to meet these minimum standards, the Amended Rights Plan provides that holders of Common Shares, other than the acquirer, will be able to purchase additional Common Shares at a significant discount to market, thus exposing the acquirer to substantial dilution of its holdings.

Pursuant to the Amended Rights Plan, effective on the Effective Date, one right ("**Right**") was issued and attached to each outstanding Common Share and one Right is also issued and attached to each Common Share issued after the Effective Date. If a person, or a group acting jointly or in concert, acquires (other than pursuant to an exemption available under the Amended Rights Plan including by way of a Permitted Bid) beneficial ownership of 20 percent or more of the Common Shares, Rights (other than those held by such acquiring person) will permit the holder to purchase that number of Common Shares having an aggregate market price (determined in accordance with the Amended Rights Plan) equal to two times the exercise price of the Rights for an amount in cash equal to the exercise price. The exercise price of the Rights is $100.00 per Right.

A copy of the Amended Rights Plan is available on the Company's SEDAR profile at www.sedar.com.

Senior Secured Notes

On November 19, 2012, the Company completed a private placement offering of $550 million aggregate principal amount of senior secured second lien notes, which bear interest at 7.50% per annum and mature on November 19, 2017 (the "**Senior Secured Notes**"). The Company was required to pay interest on the Senior Secured Notes at a rate of 7.50% per year on May 19 and November 19 of each year. On February 24, 2017, the Company completed a balance sheet refinancing transaction pursuant to which Athabasca issued the New Notes in the amount of US$450 million. Athabasca used the net proceeds from the New Notes to repurchase for cash $439 million principal amount of the Senior Secured Notes pursuant to a cash tender offer that was made by the Company on February 9, 2017 and will redeem the remaining $111 million principal amount of the Senior Secured Notes on March 27, 2017. See "*General Development of the Business – Recent Developments*".

The New Notes, due February 24, 2022 will bear interest at a rate of 9.875% per year, payable semi-annually, and are not subject to maintenance or financial covenants. The New Notes are guaranteed on senior secured basis by the Company's material subsidiaries. The New Notes and the guarantees are secured by second-priority security interests (subject to certain liens that are permitted pursuant to the terms of the New Note Indenture) in substantially all of the assets of the Company and the guarantors, with the exception of certain assets that are excluded pursuant to the terms of the New Note Indenture. The New Notes are also subject to the terms of a collateral agent and intercreditor agreement among the Company, the guarantors, the Indenture Trustee and the Collateral Agent dated February 24, 2017 (the "**Collateral Agent Agreement**").

Subject to certain exceptions and qualifications which are set forth in the New Note Indenture, the New Notes limit the ability of the Company and certain of its subsidiaries that are considered to be "restricted subsidiaries" pursuant to the New Note Indenture ("**Restricted Subsidiaries**") to, among other things: make restricted payments; incur additional indebtedness; issue disqualified or preferred stock; create or permit liens to exist; create or permit to exist restrictions on the ability of the Restricted Subsidiaries to make payments and distributions; make certain dispositions and transfers of assets; engage in amalgamations, mergers or consolidations; and engage in certain transactions with affiliates. The New Notes require the Company to hedge a minimum of 20,000 boe/d of production for the remainder of 2017 within 90 days of closing of the New Notes offering. In the first quarter of 2017, Athabasca hedged 12,000 bbl/d of WCS of production at an average price of $52.70.

A copy of the New Note Indenture is available on the Company's SEDAR profile at www.sedar.com

Revolving Senior Secured Credit Facility

On May 7, 2014, the Company entered into a $125 million amended and restated credit agreement with a syndicate of financial institutions to replace its existing credit facilities. The amended and restated credit facility (the "**Credit Facility**") was available on a revolving basis until April 30, 2017, and effective June 17, 2016 was reduced to a principal amount of $44.5 million. As of December 31, 2016, Athabasca had no amounts drawn under the Credit Facility. The Credit Facility was guaranteed on a senior secured first lien basis by the Company's material subsidiaries. The Credit Facility and the guarantees were secured by first-priority security interests (subject to certain liens that are permitted pursuant to the terms of the Credit Agreement) in substantially all of the assets of the Company and the guarantors, with the exception of certain assets that are excluded pursuant to the terms of the Credit Agreement. The Credit Facility was also subject to the terms of the Collateral Agent Agreement.

Concurrently with issuance of the New Notes, the Company amended and restated the Credit Agreement to provide for a $120 million borrowing base credit facility consisting of a $110 million syndicated revolving facility and a $10 million revolving operating facility (the "**Amended Credit Facility**"). The Amended Credit Facility has a term of 364 days and, with the consent of the lenders, may be extended for a period of up to 364 days. The current term date for the Amended Credit Facility is February 23, 2018. If not extended, the Amended Credit Facility will cease to revolve, the margins thereunder will increase by 0.50% and all outstanding advances thereunder will become repayable in one year from the current term date. The available lending limits of the Amended Credit Facility are reviewed semi-annually and are based on the lenders' assessment of the Company's reserves and future commodity prices.

Amounts borrowed under the Amended Credit Facility bear interest at a floating rate based on the applicable Canadian prime rate, U.S. base rate, LIBOR or bankers' acceptance rate, plus a margin of between 1.0% and 4.50% depending on the type of borrowing and the Company's indebtedness to EBITDA ratio. The Company will pay issuance fees for letters of credit between 2.0% and 4.50% depending on the Company's indebtedness to EBITDA ratio. The Company incurs a standby fee on the undrawn portion of the Amended Credit Facility of between 0.50% and 1.125% based on the Company's indebtedness to EBITDA ratio.

The Amended Credit Facility does not have any financial covenants and is subject to customary borrowing base provisions. The amended and restated credit agreement in respect of the Amended Credit Facility (the "**Amended and Restated Credit Agreement**") contains customary negative covenants including those that limit the Company's ability to among other things: incur additional indebtedness, create or permit liens to exist and make certain restricted payments, dispositions and transfers of assets. The Amended and Restated Credit Agreement requires the Company to hedge a minimum of 12,000 boe/d of 2017 production. In the first quarter of 2017, Athabasca hedged 12,000 bbl/d of WCS of production at an average price of $52.70.

The Amended and Restated Credit Agreement contains customary positive covenants including, but not limited to, delivery of financial and other information to the lenders, maintenance of existence, payment of taxes and other claims, maintenance of properties and insurance, access to books and records by the lenders, compliance with applicable laws and regulations, including environmental laws, and further assurances and provision of additional collateral and guarantees. The Amended Credit Facility is guaranteed on a senior secured first lien basis and subject to the terms of the Collateral Agent Agreement in the same manner as the Credit Facility.

LC Facility

On June 17, 2016, the Company entered into a demand credit facility (the "**LC Facility**") which provides for the issuance of letters of credit in a principal amount of up to $110,000,000. Effective on that date all letters of credit then issued and outstanding under the Credit Facility were deemed to be outstanding under the LC Facility. The LC Facility is guaranteed on a senior secured first lien basis by the Company's material subsidiaries.

The LC Facility was amended and restated concurrently with the issuance of the New Notes such that it is no longer subject to the Collateral Agent Agreement and the LC Facility lender is no longer party to the Collateral Agent Agreement. The Company provided a cash collateral security agreement that created in favour of the LC Facility lender a perfected security interest in cash collateral of $110,000,000 as security for its obligations under the LC Facility.

The Company pays a fee of 0.25% per annum for letters of credit issued under the LC Facility, subject to a minimum fee of $350.

CREDIT RATINGS

The following information relating to the Company’s credit ratings is provided as it relates to the Company’s financing costs, liquidity and cost of operations. Specifically, credit ratings impact the Company’s ability to obtain short-term and long-term financing and the cost of such financings. Changes in the Company’s current credit ratings by the rating agencies, particularly downgrades below the current ratings or negative changes in the ratings outlooks, could adversely affect the Company’s cost of borrowing and/or access to sources of liquidity and capital. In addition, changes in credit ratings may affect the Company’s ability to: (a) enter into, or the associated costs of entering into hedging transactions or other ordinary course contracts on acceptable terms and may require the Company to post additional collateral under certain of its contracts; and (b) enter into and maintain ordinary course contracts with customers and suppliers on acceptable terms. The Company has engaged two rating agencies, DBRS and S&P, to provide their opinion of the Company’s ability to satisfy financial obligations related to debt issuances.

The following table outlines the credit ratings received by the Company as of December 31, 2016:

	S&P Ratings Services	DBRS
Corporate Credit Rating	CCC+	B(low)
Senior Secured Notes	B	B(low)
Outlook/Trend	Stable	Negative

On February 10, 2017 S&P upgraded the Company’s corporate credit rating to B- with a "Stable" outlook, and upgraded the Senior Secured Notes and the New Notes issue-level rating to B+.

DBRS and S&P provide credit ratings of debt securities for commercial entities. A credit rating generally provides an indication of the risk that the borrower will not fulfill its full obligations in a timely manner with respect to both interest and principal commitments.

DBRS’ credit ratings are on a long-term debt rating scale that ranges from AAA to D, which represents the range from highest to lowest quality of such securities rated. A reference to "high" or "low" reflects the relative strength within the rating category, while the absence of either a "high" or "low" designation indicates the rating is placed in the middle category. According to DBRS, the "negative" trend helps give investors an understanding of DBRS’ opinion regarding the outlook for the rating.

S&P’s credit ratings are on a long-term debt rating scale that ranges from AAA to D, which represents the range from highest to lowest quality of such securities rated. The ratings from AA to CCC may be modified by the addition of a plus (+) or a minus (-) sign to show relative standing within the major rating categories. In addition, S&P may add a rating outlook of "positive", "negative" or "stable" which assesses the potential direction of a long-term credit rating over the intermediate term (typically six months to two years).

Credit ratings are intended to provide investors with an independent measure of credit quality of an issue of securities. Credit ratings are not recommendations to purchase, hold or sell securities and do not address the market price or suitability of a specific security for a particular investor. There is no assurance that any rating will remain in effect for any given period of time or that any rating will not be revised or withdrawn entirely by a rating agency in the future if, in its judgment, circumstances so warrant. A rating can be revised, suspended or withdrawn at any time by the rating agency.

The Company paid a fee for service to S&P to provide ratings in respect of the New Notes. The Company has not formally asked DBRS to rate the New Notes and have not paid DBRS any fees in respect of the New Notes. Otherwise, no service fees other than annual maintenance fees in respect of the existing credit ratings were paid by the Company to these organizations during the last two years.

MARKET FOR SECURITIES

Trading Price and Volume

The Common Shares have been listed and posted for trading on the TSX under the symbol "ATH" since April 8, 2010. The following table sets forth the price range and trading volume for the Common Shares on the TSX as reported by the TSX for the periods indicated.

	Price Range		
	High $/share	**Low $/share**	**Volume**
2017			
March (1 to 8)	$1.74	$1.51	6,841,414
February	$1.92	$1.65	32,827,544
January	$2.14	$1.62	28,217,605
2016			
December	$2.10	$1.37	53,794,872
November	$1.38	$1.18	40,919,328
October	$1.37	$1.24	51,237,690
September	$1.35	$1.11	28,552,789
August	$1.34	$1.20	18,460,755
July	$1.48	$1.17	35,625,125
June	$1.53	$1.19	48,846,255
May	$1.50	$1.04	59,590,777
April	$1.43	$0.94	57,879,403
March	$1.34	$0.91	73,289,312
February	$1.58	$0.93	28,012,266
January	$1.95	$1.16	39,379,153

Prior Sales

The following is a description of securities of the Company that were issued in the financial year ended December 31, 2016 that are not listed or quoted on a marketplace:

- the Company granted an aggregate of 3,850,675 2015 RSUs to acquire an aggregate of 3,850,675 Common Shares, each with no exercise price;
- the Company granted an aggregate of 3,102,100 Stock Options to acquire an aggregate of 3,102,100 Common Shares with a weighted average exercise price of $1.34;
- the Company granted an aggregate of 1,454,000 Performance Awards; and
- the Company granted an aggregate of 537,212 Deferred Share Units;

ESCROWED COMMON SHARES AND COMMON SHARES SUBJECT TO A CONTRACTUAL RESTRICTION ON TRANSFER

As at December 31, 2016, the Common Shares of the Company that continued to be held in trust to the Company's knowledge were immaterial, representing less than 0.01% of the Company's issued and outstanding Common Shares.

On January 31, 2017 the Company completed the Asset Acquisition. A portion of the consideration for the Acquired Assets was comprised of 100 million Common Shares issued to SCL. After giving effect to the completion of the Asset Acquisition, SCL holds approximately 19.7% of the issued and outstanding Common Shares. Subject to certain exceptions, SCL has agreed for a period of six months from January 31, 2017, not to offer, sell, contract to sell, pledge or otherwise dispose of, directly or indirectly, any of the Common Shares without the prior written consent of Athabasca. See "*General Development of the Business – Recent Developments*".

DIRECTORS AND OFFICERS

As at the date of filing of this Annual Information Form, the names, provinces (or states) and countries of residence, positions held with the Company, and principal occupation of the directors and executive officers of the Company during the past five years are set out below, and in the case of directors, the period each has served as a director of the Company is also set forth below.

Name and Place of Residence	Office	Principal Occupation	Director Since
Ronald J. Eckhardt(3) Alberta, Canada	Chairman(1)	Mr. Eckhardt is currently retired. Prior thereto, Executive Vice President, North American Operations of Talisman Energy Inc. from October 2003 to September 2009.	April 1, 2012
Marshall McRae(2) Alberta, Canada	Director(1)	Mr. McRae has been an independent financial and management consultant since August 2009. Prior thereto, Mr. McRae was Chief Financial Officer of CCS Inc., administrator of CCS Income Trust and its successor corporation, CCS Corporation since August 2002. Mr. McRae is a director and the Chair of the audit committee of Gibson Energy Inc. and a director of Black Diamond Group Limited. Mr. McRae served as interim Executive Vice President and CFO of Black Diamond Group Limited from October 16, 2013 to August 8, 2014 and as its Executive Vice President to December 31, 2014.	October 30, 2009
Carlos Fierro(2)(4) Washington D.C., U.S.A.	Director(1)	Mr. Fierro is an independent investor and serves on public and private corporate boards. From May 2016, Mr. Fierro has served as a senior advisor to Guggenheim Securities, the investment banking arm of Guggenheim Partners. Mr. Fierro serves on the board of directors, audit and conflicts committee of Shell Midstream Partners. From September 2008 to June 2013, Mr. Fierro was the Managing Director and Global Head of the Natural Resources Group for Barclays PLC. Prior thereto, Mr. Fierro spent 11 years at Lehman Brothers, where his last role was the Global Head of the National Resources Group. Before joining Lehman Brothers, Mr. Fierro was a transactional lawyer with Baker Botts LLP., where he practiced corporate, M&A and securities law.	January 7, 2015

Name and Place of Residence	Office	Principal Occupation	Director Since
Bryan Begley(3)(4) Texas, U.S.A	Director(1)	Mr. Begley is currently a Managing Director and Partner at 1901 Partners, a private equity firm formed in 2014 to make private investments in the energy sector. From 2007 to 2014, Mr. Begley served as a Managing Director of ZBI Ventures, LLC, a private equity firm focused on the energy sector. Prior to joining ZBI Ventures, Mr. Begley was a Partner at McKinsey & Co. in the Houston and Dallas offices where he advised clients across the global energy sector. He began his career as an engineer with Phillips Petroleum Company.	March 10, 2016
Robert Rooney, QC(2)(4) Alberta, Canada	Director(1)	Mr. Rooney is currently the Chief Legal Officer and Executive Vice President at Enbridge Inc. since February 1, 2017. Prior thereto he was a co-founder and a Managing Director of RimRock Oil and Gas, a private Calgary based company. Mr. Rooney was previously Executive Vice President and General Counsel at Talisman Energy Inc. prior to its acquisition by Repsol S.A. Prior thereto, Mr. Rooney was a partner at Bennett Jones LLP in Calgary with over 20 years of experience in corporate M&A and international oil and gas law.	May 4, 2016
Robert Broen(3) Alberta, Canada	Director(1), President & Chief Executive Officer	Mr. Broen has been a director and President and Chief Executive Officer of the Company since April 21, 2015. Prior thereto, he was Chief Operating Officer of the Company since October 12, 2013. Prior thereto, he was Senior Vice President, Light Oil of the Company from November 26, 2012 to October 12, 2013. Mr. Broen was the Senior Vice-President, North American Shale at Talisman Energy Inc. from April 2012 to November 2012, and prior thereto he was the President and a director of Talisman Energy USA Inc. from 2009 to April 2012.	April 21, 2015
Kim Anderson Alberta, Canada	Chief Financial Officer	Ms. Anderson has been Chief Financial Officer of the Company since February 18, 2014. Prior thereto, she was the Chief Financial Officer of KANATA Energy Group Ltd. from January 9, 2013 until February 14, 2014. Prior thereto, Ms. Anderson held various roles at Provident Energy Ltd. between June 2009 and April 2012, including Vice President, Finance & Investor Relations, Director, Finance & Investor Relations, Director, Finance & Information Services and Director, Finance Midstream.	N/A
Anne Schenkenberger Alberta, Canada	Vice President, General Counsel and Corporate Secretary	Ms. Schenkenberger has been Vice President, General Counsel and Corporate Secretary of the Company since August 18, 2010. Prior thereto, she was General Counsel and Corporate Secretary of the Company from May 2008 to August 18, 2010. Prior thereto, Ms. Schenkenberger was legal counsel at ConocoPhillips Canada, a subsidiary of ConocoPhillips from April 2000 to April 2008.	N/A

Name and Place of Residence	Office	Principal Occupation	Director Since
Don Verdonck Alberta, Canada	Vice President, Thermal Oil	Mr. Verdonck was appointed Vice President, Thermal Oil on January 9, 2017. Prior to a brief two-year retirement, he was Vice President, Development and Operations of the Company from 2007 to 2014, during which time he also served as Executive Vice President of the Dover Joint Venture operating entity (which is now Brion Energy Corporation). Prior thereto, Mr. Verdonck held senior roles with Total E&P Canada, Deer Creek Energy and Murphy Oil.	N/A
Kevin Smith Alberta, Canada	Vice President, Light Oil	Mr. Smith has been Vice President, Light Oil of the Company since January 6, 2014. Prior thereto, he was the Business Unit, Vice President at Encana Corporation from October 2008 until November 2013.	N/A
Dave Stewart Alberta , Canada	Vice President, Operations	Mr. Stewart became Vice President, Operations of the Company in November 2016 and now leads the Company’s Light Oil and Thermal Oil field operations, HSE, transportation and marketing. Prior thereto he was Director, Light Oil Operations of the Company since December 2013 and Director HSE from April 2013. Prior to joining Athabasca, Mr. Stewart held a number of senior roles at Talisman Energy including Vice President Operations North American Western District portfolio and Vice President of HSE & Operational Integrity supporting Talisman’s U.S. country office.	N/A
Matthew Taylor Alberta, Canada	Vice President, Capital Markets and Communications	Mr. Taylor has been Vice President, Capital Markets and Communications of the Company since May 4, 2014. Prior thereto he was the Director of Energy Equity Research at National Bank from July 2010 to April 2014, and held positions in equity research and investment banking at GMP Securities and CIBC World Markets from August 2007 to June 2010.	N/A
Rod Sousa Alberta, Canada	Vice President, Corporate Development	Mr. Sousa has been Vice President, Corporate Development of the Company since November 16, 2015. Prior thereto, he was the Managing Director & Head of TD Energy Advisors investment banking sector from July 2010. Prior thereto Mr. Sousa was Managing Director and President of Ross Smith Sousa Energy Advisors between 2008 and 2010 and held positions at Scotia Waterous between 1999 and 2008.	N/A

Notes:

(1) The Company’s directors hold office for a term expiring at the conclusion of the next annual meeting of Shareholders of the Company, or until their successors are elected or appointed pursuant to the ABCA, and are eligible for re-election. The Company’s officers are appointed by and serve at the discretion of the Board.
(2) Member of the Audit Committee. Mr. McRae is the Chairman of the Audit Committee.
(3) Member of the Reserves Committee. Mr. Begley is the Chairman of the Reserves Committee.
(4) Member of the Compensation and Governance Committee. Mr. Rooney is the Chairman of the Compensation and Governance Committee.
(5) The information set forth above is current as at the date of the filing of this Annual Information Form (March 9, 2017).

As at December 31, 2016, the directors and executive officers of the Company, as a group, beneficially owned, controlled or directed, directly or indirectly, an aggregate of 1,254,695 Common Shares, representing 0.3% of the issued and outstanding Common Shares (not including any Common Shares issuable pursuant to the exercise of the issued and outstanding Stock Options, RSUs, Performance Awards or DSUs). As at March 8, 2017, the directors and executive officers of the Company, as a group, beneficially owned, controlled or directed, directly or indirectly, an aggregate of 1,638,433 Common Shares, representing 0.3% of the issued and outstanding Common Shares (not including any Common Shares issuable pursuant to the exercise of the issued and outstanding Stock Options, RSUs, Performance Awards or DSUs).

Corporate Cease Trade Orders, Bankruptcies, Penalties or Sanctions

Other than as disclosed below, to the knowledge of the Company, no current director or executive officer of the Company has, within the last ten years prior to the date of this document, been a director, chief executive officer or chief financial officer of any issuer (including the Company) that: (a) while the person was acting in the capacity as director, chief executive officer or chief financial officer, was the subject of a cease trade or similar order or an order that denied the company access to any exemption under securities legislation, that was in effect for a period of more than thirty (30) consecutive days; or (b) was subject to an order that resulted, after the director or executive officer ceased to be a director, chief executive officer or chief financial officer of an issuer, in the issuer being the subject of a cease trade or similar order or an order that denied the relevant issuer access to any exemption under securities legislation, for a period of more than thirty (30) consecutive days, which resulted from an event that occurred while that person was acting as a director, chief executive officer or chief financial officer of the issuer.

To the knowledge of the Company, other than as disclosed below, no current director or executive officer or security-holder holding a sufficient number of securities of the Company to affect materially the control of the Company has, within the last ten years prior to the date of this document, been a director or executive officer of any company (including the Company) that, while such 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 for compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets.

In addition, no current director or executive officer or security-holder holding a sufficient number of securities of the Company to affect materially the control of the Company has, within the last ten years prior to the date of this document, 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, officer or security-holder.

To the knowledge of the Company, no current director or executive officer or security-holder holding a sufficient number of securities of the Company to affect materially the control of the Company has been subject to: (a) 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 (b) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

Conflicts of Interest

Certain of the directors and officers of the Company are engaged in, and may continue to be engaged in, other activities in the oil and natural gas industry from time to time. As a result of these and other activities, certain directors and officers of the Company may become subject to conflicts of interest from time to time. The ABCA provides that in the event that an officer or director 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 material transaction or proposed material contract or proposed material transaction, such officer or director shall disclose the nature and extent of his or her interest and shall refrain from voting to approve such contract or transaction, unless otherwise provided under the ABCA. To the extent that conflicts of interest arise, such conflicts will be resolved in accordance with the provisions of the ABCA.

As of the date hereof, the Company is not aware of any existing or potential material conflicts of interest between the Company or a subsidiary of the Company and any director or officer of the Company or of any subsidiary of the Company.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

Legal Proceedings

There were no legal proceedings that the Company is or was a party to, or that any of the Company's property is or was the subject of, during the most recently completed financial year, that were or are material to the Company, and there are no such material legal proceedings that the Company knows to be contemplated. For the purposes of the foregoing, a legal proceeding is not considered to be "material" by the Company if it involves a claim for damages and the amount involved, exclusive of interest and costs, does not exceed 10% of the Company's current assets, provided that if any proceeding presents in large degree the same legal and factual issues as other proceedings pending or known to be contemplated, the Company has included the amount involved in the other proceedings in computing the percentage.

Regulatory Actions

During the year ended December 31, 2016, there were: (a) no penalties or sanctions imposed against the Company by a court relating to securities legislation or by a securities regulatory authority; (b) no other penalties or sanctions imposed by a court or regulatory body against the Company that would likely be considered important to a reasonable investor in making an investment decision; and (c) no settlement agreements entered into by the Company with a court relating to securities legislation or with a securities regulatory authority.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There were no material interests, direct or indirect, of any director or executive officer of the Company, any person or company that beneficially owns, or controls or directs, directly or indirectly, more than 10% of the outstanding Common Shares, or any associate or affiliate of any of such persons or companies, in any transaction within the three most recently completed financial years or during the current financial year that has materially affected or is reasonably expected to materially affect the Company or a subsidiary of the Company.

On January 31, 2017 the Company completed the Asset Acquisition. A portion of the consideration for the Acquired Assets was comprised of 100 million Common Shares issued to SCL. After giving effect to the completion of the Asset Acquisition, SCL holds approximately 19.7% of the issued and outstanding Common Shares. Subject to certain exceptions, SCL has agreed for a period of six months from January 31, 2017, not to offer, sell, contract to sell, pledge or otherwise dispose of, directly or indirectly, any of the Common Shares without the prior written consent of Athabasca. See "*General Development of the Business – Recent Developments*".

TRANSFER AGENTS AND REGISTRARS

Computershare Trust Company of Canada at its office in Calgary, is the transfer agent and registrar for the Common Shares.

MATERIAL CONTRACTS

As at December 31, 2016, the following were the only material contracts, other than those contracts entered into in the ordinary course of business, which the Company or any of its subsidiaries has entered into within the most recently completed financial year, or before the most recently completed financial year and which were still in effect as of December 31, 2016:

- the Note Indenture;
- the Rights Plan referred to under the heading "*Description of Capital Structure – Shareholder Rights Plan*";
- the Murphy Purchase and Sale Agreement (entered into January 27, 2016). See "*The Murphy Transaction*" under the heading "*General Development of the Business – Three Year History - 2016*";

- the Placid JDA (entered into May 13 2016). See definition of "*Placid JDA*" and "*General Development of the Business- Three Year History- 2016*";

- the Kaybob JDA (entered into May 13 2016). See definition of "*Kaybob JDA*" and "*General Development of the Business- Three Year History- 2016*";

- the Acquisition Agreement. See "*General Development of the Business – Recent Developments*";

- the Original Royalty Transaction Agreements (entered into on June 20, 2016). See "*General Development of the Business- Three Year History- 2016"* ; and

- the Upsized Royalty Transaction Agreements (entered into on November 10, 2016). See "*General Development of the Business- Three Year History- 2016".*

Subsequent to December 31, 2016 and as at March 1, 201, the Company also entered into the following material contracts which are still in effect as of the date hereof:

- the New Note Indenture. See "*Description of Capital Structure – Senior Secured Notes*";

- the Amended Credit Facility. See "*Description of Capital Structure - Revolving Senior Secured Credit Facility*";

- the LC Facility. See "*Description of Capital Structure - LC Facility*"; and

- the Acquisition Royalty Agreements (entered into on February 24, 2017). See "*General Development of the Business-Recent Developments*.

Copies of these material contracts are available for review on the Company's SEDAR profile at www.sedar.com.

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, including the governments of Canada and Alberta, all of which investors in the oil and gas industry should carefully consider. All current legislation is a matter of public record and the Company is unable to predict what additional legislation or amendments governments may enact in the future. The following comprises some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry in western Canada.

Pricing and Marketing

Oil

In Canada, producers of oil are entitled to negotiate sales contracts directly with oil purchasers, which results in the market determining the price of oil. Worldwide supply and demand factors primarily determine oil prices; however, 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 barrels of oil equivalent per day 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 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.

The Province of 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 March 31, 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 LNG 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's plan to replace its Line 3 pipeline system, while also rejecting Enbridge'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 kilometres in size. The region includes a substantial portion of the Athabasca oil sands area, which contains approximately 82% of the province's oil sands resources and much of the Cold Lake oil sands area.

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 kilometres 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 kilometres 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 liabilities to deemed assets is assessed once each month and failure to post the required security deposit may result in the initiation of enforcement action by the 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 liabilities to deemed assets 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 (the "**Court**"), which is currently under appeal with the Court of Appeal of Alberta. In *Redwater Energy Corporation (Re),* 2016 ABQB 278 ("***Redwater***"), the Court 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, which effectively 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, which interim rules include the following:

(1) 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.

(2) 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.

(3) 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;

(4) The acquisition will improve the licensee's LMR to 2.0 or higher; or

(5) 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. 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 the Company's operations and cash flow.

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.

INTEREST OF EXPERTS

Names of Experts

The only persons or companies who are 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 NI 51-102 by the Company during, or relating to the Company's most recently completed financial year, and whose profession or business gives authority to the report, valuation, statement or opinion made by the person or company, are GLJ and DMCL (collectively, the "**Experts**"), Athabasca's independent engineering evaluators, and Ernst & Young LLP, the Company's auditors.

Interests of Experts

There were no registered or beneficial interests, direct or indirect, in any securities or other property of the Company or of one of its associates or affiliates: (a) held by an Expert or by the "designated professionals" (as defined in Form 51-102F2 to NI 51-102) of such Expert, when such Expert prepared the report, valuation, statement or opinion referred to herein as having been prepared by such Expert; (b) received by an Expert or by the "designated professionals" of such Expert, after the time specified above; or (c) to be received by an Expert or by the "designated professionals" of such Expert; except in each case for the ownership of Common Shares, which in respect of each Expert and such Expert's "designated professionals", as a group, has at all relevant times represented less than one percent of the outstanding Common Shares. In addition, none of the Experts, and no director, officer or employee of any of the Experts, is or is expected to be elected, appointed or employed as a director, officer or employee of the Company or of any associate or affiliate of the Company.

Ernst & Young LLP is independent within the meaning of the Rules of Professional Conduct of the Chartered Professional Accountants of Alberta.

RISK FACTORS

An investment in the Common Shares involves a substantial degree of risk and is highly speculative due to the nature of Athabasca's business and its stage of development. As a result, investors should consider investing in the Common Shares only if they can afford to lose their entire investment. Investors should carefully consider the risks described below and the other information contained in this Annual Information Form before making a decision to buy Common Shares.

If any of the following risks or other risks occur Athabasca's business, prospects, financial condition, results of operations and cash flows could be materially adversely impacted. In that case, the trading price of the Common Shares could decline and investors could lose all or part of their investment in the Common Shares. There is no assurance that risk management steps taken by Athabasca will avoid future loss due to the occurrence of the risk factors described below or other unforeseen risks.

Risks Relating to Athabasca's Business

Weakness in the oil and gas industry may affect our operations and financial results

Recent market events and conditions, including global excess oil and natural gas supply, recent actions taken by the Organization of the Petroleum Exporting Countries ("**OPEC**"), slowing growth in China and other emerging economies, market volatility and disruptions in Asia, and sovereign debt levels in various countries, have caused significant weakness and volatility in commodity prices. These events and conditions have caused a significant decrease in the valuation of oil and gas companies and a decrease in confidence in the oil and gas industry. These difficulties have been exacerbated in Canada by the recent changes in government at a federal level and, in the case of Alberta, the provincial level and the resultant uncertainty surrounding regulatory, tax and royalty changes 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 especially as certain reserves become uneconomic. In addition, lower commodity prices have restricted, and may continue to restrict, our cash flow resulting in a reduced capital expenditure budget. As a result, Athabasca may not be able to replace its production with additional reserves and both its production and reserves could be reduced on a year over year basis. Any decrease in value of our reserves may reduce the amounts available under the Amended Credit Facility and the Amended LC Facility. 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 terms. If these conditions persist, our cash flow may not be sufficient to continue to fund our operations and to satisfy our obligations when due and our ability to continue as a going concern and discharge our obligations will require additional equity or debt financing and/or proceeds from asset sales. There can be no assurance that such equity or debt financing will be available on terms that are satisfactory to the Company or at all. Similarly, there can be no assurance that we will be able to realize any or sufficient proceeds from asset sales to discharge our obligations and continue as a going concern.

Political uncertainty may affect our operations

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 the North American Free Trade Agreement, 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 the Corporation.

In addition to the political disruption in the United States, in 2016 the citizens of the United Kingdom 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 the Corporation's ability to market its products internationally, increase costs for goods and services required for the Corporation's operations, reduce access to skilled labour and negatively impact our business, operations, financial conditions and ultimately the market value of the Common Shares.

Declines in oil and natural gas commodity prices may adversely affect our operating results and the value of our reserves and resources

Numerous factors beyond our control do, and will continue to, affect the marketability and price of oil and natural gas acquired or discovered by us. Our ability to market our oil and natural gas may depend upon our ability to acquire space on pipelines that deliver our production to commercial markets. Deliverability uncertainties related to the distance our reserves are from pipelines, railway lines, processing and storage facilities, operational problems affecting pipelines, railway lines and facilities as well as government regulation relating to prices, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business may also affect us.

Prices for oil and natural gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors beyond our control. These factors include economic conditions in the United States, Canada, Europe, China and emerging markets, the actions of OPEC, governmental regulation, political stability in the Middle East, Northern Africa and elsewhere, the foreign supply and demand of oil and natural gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Prices for oil and natural gas are also subject to the availability of foreign markets and our ability to access such markets. Oil prices are expected to remain volatile and may decline in the near future as a result of global excess supply due to the increased growth of shale oil production in the United States, the decline in global demand for exported crude oil commodities, and OPEC's recent decisions pertaining to the oil production of OPEC member countries, among other factors. A material decline in 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 acquisition, development and exploration activities. Any substantial and extended decline in the price of oil and natural gas would have an adverse effect on our carrying value of our reserves, borrowing capacity including available limits under our Amended Credit Facility, revenues, profitability and cash flows 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, 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.

Any prolonged period of low crude oil and/or natural gas prices could result in a decision by us to suspend or slow development activities, to suspend or slow the construction or expansion of bitumen recovery, crude oil and/or natural gas projects, or (following the commencement of production) to suspend or reduce production levels. Any of such actions could have a material adverse effect on our results of operations and financial condition.

We conduct an assessment of the carrying value of our assets to the extent required by International Financial Reporting Standards. If commodity prices decline, the carrying value of our assets could be subject to downward revision, and our earnings could be adversely affected.

Adverse changes in general economic and market conditions could negatively impact demand for oil and natural gas, revenue, operating costs, results of financing efforts, timing and extent of capital expenditures or credit risk and counterparty risk

Our business is subject to general economic conditions. Adverse changes in general economic and market conditions could negatively impact demand for crude oil, bitumen, bitumen blend and natural gas, as well as revenue, operating costs, results of financing efforts, timing and extent of capital expenditures or credit risk and counterparty risk. Volatility in crude oil, bitumen blend, natural gas, condensate, synthetic crude oil ("SCO") and other diluent prices, fluctuations in interest rates, product supply and demand fundamentals, market competition, labour market supplies, risks associated with technology, risks of a widespread pandemic, our ability to generate sufficient cash flow from operations to meet our current and future obligations, our ability to access external sources of debt and equity capital, general economic and business conditions, our ability to make capital investments and the amounts of capital investments, risks associated with potential future lawsuits and regulations, assessments and audits (including income tax) against us, political and economic conditions in the geographic regions in which we operate, difficulty in obtaining necessary regulatory approvals, a significant decline in our reputation, and such other risks and uncertainties, could individually or in the aggregate have a material adverse impact on our business, prospects, financial condition, results of operation or cash flows. Challenging market conditions and the health of the economy as a whole may have a material adverse effect on our business, financial condition, liquidity and results of operations. There can be no assurance that any risk management steps taken by us with the objective of mitigating the foregoing risks will avoid future loss due to the occurrence of such risks.

We may not 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 our business and operations. The integration of acquired businesses may require substantial management effort, time and resources diverting management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of services provided and assets required to provide such services. In this regard, certain assets may be periodically disposed of so we can focus our efforts and resources more efficiently. Depending on the state of the market for such assets, certain of our assets, if disposed of, may realize less than their carrying value on our financial statements.

In May, 2016, we completed a strategic joint venture with Murphy to develop the Duvernay and Montney Formations in the Greater Kaybob and Greater Placid areas. Pursuant to the Murphy Transaction, we sold an operated 70% interest in the Greater Kaybob area and a non-operated 30% interest in the Greater Placid area to Murphy for cash consideration and an additional $219 million Kaybob Carry Commitment whereby Murphy will fund 75% of our share of Duvernay development capital up to a one billion gross investment over the next four years. Murphy also assumed operatorship of the Greater Kaybob assets and we retained operatorship of the Greater Placid assets. There are risks related to our dependence on Murphy as the Company’s joint venture participant in the Company’s Duvernay and Montney assets and as the operator of the Company’s Duvernay assets, including, but not limited to, Murphy’s willingness and ability to satisfy its obligations in relation to the payment of the Kaybob Carry Commitment and the consequences of a failure to make such payment. Any partial or complete failure to make such payment by Murphy may have an adverse financial impact upon the Company. In addition, there is the potential for adverse consequences in the event that either the Company or Murphy defaults under certain of the agreements in respect of the Murphy Transaction. Therefore, there is a risk that we may not realize the expected benefits, financial or otherwise, from the Murphy Transaction.

In addition, on January 31, 2017, we completed the Asset Acquisition. See "*Risk Factors—Risks Related to the Asset Acquisition*".

Our reserves at the dates described herein may not be the same as the current market value of our estimated reserves

You should not assume that the future net revenues attributable to our estimated reserves as of December 31, 2016, as disclosed in the Independent Reports contained herein, is the current market value of our estimated reserves. Actual future net revenues from our oil and natural gas properties will be affected by factors such as:

- the actual prices we receive for oil, natural gas and NGLs;
- the actual development and production expenditures;
- the amount and timing of actual production; and
- changes in governmental regulations or taxation.

Estimates of reserves and future net revenue should be regarded only as estimates that may change as further production history and additional information become available. Not only are such reserves and revenue estimates based on that information which is currently available, but such estimates are also subject to the uncertainties inherent in the application of judgmental factors in interpreting such information. The timing of both our production (including the timing of ramp-up of production at the Hangingstone Project and achieving design capacity) and timing of and our incurrence of expenses in connection with the development and production of oil and natural gas properties will affect the timing and amount of actual future net revenues from reserves, and thus their actual present value. In addition, the discount factors we are required to use under NI 51-101 when calculating the net present value of future net revenues may not be the most appropriate discount factors based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general. Actual future prices and costs may differ materially from those used in the net present value estimates included herein, which could have a material effect on the value of our reserves. The oil and natural gas prices used in computing our reserves as of December 31, 2016 under NI 51-101 are summarized herein.

Our ability to finance our capital expenditures depends on many factors

Substantial capital expenditures will be required to fund the exploration and development of our Thermal Oil assets and Light Oil assets. Our 2016 capital and operating budgets have been funded with existing cash and short term investments, the obligation of Murphy to fund the Kaybob Carry Commitment, cash flow from operations and the Revolving Credit Facility or other debt financing. Additionally, we used $435 million of cash on hand to finance the Asset Acquisition. Athabasca's 2017 activities are expected to be funded with cash flow from operations, the Kaybob Carry Commitment, existing cash and cash-equivalents. Athabasca's current business plan for developing its properties beyond 2017 anticipates that Athabasca will fund its activities and other requirements through cash flow from operations and the Kaybob Carry Commitment. Any significant acceleration in Light Oil development activities or future expansion of Athabasca's thermal oil projects will potentially require additional funding which could include debt, equity, joint ventures or other external financing or a combination of these to the extent permitted by the Amended Credit Facility and the New Notes. The availability of any additional future funding will depend on, amongst other things, the current commodity price environment, operating performance, the Company's credit rating at the time and the current state of the equity and debt capital markets. However, there can be no assurance that the cash that may be generated from our operations and/or the other sources of financing, including the ability to raise additional capital through debt financing or refinancing, will be available or sufficient to meet our requirements, or if external sources of funding are available, that they will be available on terms that are acceptable to us. Additionally, asset divestments are subject to certain limitations in terms of how we are permitted to allocate the proceeds pursuant to the terms of the Amended Credit Facility and the New Notes.

Our ability to obtain the required capital will depend on, among other factors, the overall state of the capital markets, interest rates, royalty rates and investor demand for investments in the energy industry and our securities in particular

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the American and European sovereign debt levels have caused significant volatility in commodity prices. These events and conditions have caused a decrease in confidence in the broader United States and global credit and financial markets and have created a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. These factors have negatively impacted company valuations and are likely to continue to impact the performance of the global economy going forward. Worldwide crude oil commodity prices are expected to remain volatile for the near future as a result of global excess supply, recent actions taken by OPEC and ongoing global credit and liquidity concerns. This volatility may affect our ability to obtain equity or debt financing on acceptable terms.

The inability to access sufficient capital for our operations and other requirements could result in, among other things, us defaulting under the Amended Credit Facility and/or the New Notes and our inability to conduct exploration and development programs in respect of certain or all of its assets. Any of these results could have a material adverse effect on our financial condition, results of operations and prospects.

There are risks related to the early stage of development of certain of our assets

The Company's projects related to its Hangingstone assets, including its 12,000 bbl/d SAGD project, the expansion of the Company's other projects at Hangingstone and any future proposed in-situ oil sands projects in respect of the Company's Hangingstone assets and the Company's Light Oil assets are all currently in the relatively early stages of their development schedules, and all of our other assets are currently in the early stages of exploration or development. There is a risk that one or all of the Hangingstone Projects or any other proposed commercial development of our assets, including in the Light Oil assets, will not achieve the expected production levels on the timing anticipated or at all and that the capital costs of such projects will not be within the applicable estimates. Additionally, there is a risk that one or all of the Hangingstone Projects or any other proposed commercial development of our assets, including in the Light Oil assets, may have delays, interruption of operations or increased costs due to many factors, including, without limitation: breakdown or failure of equipment or processes; construction performance falling below expected levels of output or efficiency; design errors; contractor or operator errors; non-performance by third-party contractors;

labour disputes, disruptions or declines in productivity; increases in materials or labour costs; inability to attract sufficient numbers of qualified workers; delays in obtaining or conditions imposed by, regulatory approvals; changes in project scope; violation of permit requirements; disruption in the supply of energy and other inputs, including natural gas and diluents; and catastrophic events such as fires, earthquakes, storms or explosions.

Given the stage of development of the Hangingstone Projects, the Light Oil assets and any of our other assets, various changes are likely to be made prior to completion. Other than as described herein, no commercial development applications for regulatory approval of our Thermal Oil assets have been submitted. The information contained herein, including, without limitation, resource and economic evaluations, is conditional upon receipt of all regulatory approvals and no material changes being made to our various projects or to the scope of any of the projects. Changes and revisions to the concepts for the Hangingstone Project, the Hangingstone Expansion and the Dover West Sands Project 1, which may be material both in terms of design, timing and cost, are also virtually certain to occur.

There is no assurance that any of our oil sands properties will commence production or continue to produce, achieve the production levels anticipated, generate earnings, operate profitably or provide a return on investment in the future.

In addition to the foregoing, there is also a risk that some or all of our other assets may not be developed on a timely basis or at all. Numerous factors, many of which are beyond our control, could impact our ability to further explore and develop our other assets and the timing thereof.

Concerns regarding hydraulic fracturing may result in changes in regulations that delay the development of oil and natural gas resources and adversely affect our costs of compliance

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. There has been increasing public scrutiny of the impact of hydraulic fracturing on the environment, including contamination of groundwater by fracturing fluids, emissions of methane, volatile organic compounds and hazardous air pollutants, stress on existing water supplies, wastewater disposal issues and seismic activity. The AER has implemented restrictions and operating procedures regarding hydraulic fracturing through Directive 083: Hydraulic Fracturing – Subsurface Integrity. In order to carry out hydraulic fracturing operations a licensee must observe the prescribed setbacks for water wells and top of bedrock, conduct a risk assessment, and fulfill the reporting requirements set out in Directive 59: Well Drilling and Completion Data Filing Requirements which include reporting water source and fracture fluid data. Any new laws, regulations or permitting requirements or amendments to or stricter interpretation or enforcement of existing 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.

Due to recent seismic activity reported in the Fox Creek area of Alberta, in early 2015, the AER announced seismic monitoring and reporting requirements for hydraulic fracturing operators in the Duvernay Zone in the Fox Creek area. These requirements include, among other things, an assessment of the potential for seismicity prior to operations, the implementation of a response plan to address potential events, and the suspension of operations if a seismic event above a particular threshold occurs. The AER continues to monitor seismic activity around the province and may extend these requirements to other areas of the province if necessary.

Implementation of new regulations or the modification of existing regulations could have an adverse effect on our business, financial condition, results of operations and prospects

The oil and gas industry in Canada, including the oil sands industry, operates under federal and provincial statutes and regulations governing such matters as land tenure, prices, royalties, production rates, environmental protection controls, the export of crude oil, natural gas and other products, as well as other matters. The industry is also subject to regulation by governments in such matters as the awarding or acquisition of exploration and production rights, oil sands, petroleum, natural gas or other interests, the imposition of specific drilling obligations, control over the development and abandonment of oil and natural gas properties (including restrictions on production) and possible expropriation or cancellation of lease and permit rights. The regulatory scheme as it relates to oil sands, and the recovery and marketing of bitumen or bitumen by-products from oil sands, is somewhat different and more burdensome from that related to conventional oil and gas in general.

Government regulations may be changed from time to time in response to economic or political conditions. The exercise of discretion by governmental authorities under existing statutes or regulations, the implementation of new statutes or regulations or the modification of existing statutes or regulations affecting the crude oil and natural gas industry could impact the markets for crude oil and natural gas, delay or stop the development of our projects, delay or 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 gas operations, we will require regulatory permits, licenses, registrations, approvals and authorizations from various governmental authorities. There can be no assurance that we will be able to obtain all of the permits, licenses, registrations, approvals and authorizations that may be required to conduct operations that we may wish to undertake. The requirements imposed by any such authority may be costly and time-consuming and may delay commencement or continuation of exploration or our production operations. In addition to regulatory requirements pertaining to the production, marketing and sale of oil and natural gas mentioned above, our business and financial condition could be influenced by federal legislation affecting, in particular, foreign investment, through legislation such as the *Competition Act* (Canada) and the *Investment Canada Act* (Canada) which could limit our ability to access external sources of capital and could cause a decrease in the valuation of Canadian companies.

Our earnings, future capital investments and operations may be adversely affected by changes to applicable royalty regimes

There can be no assurance that the federal government and the provincial governments of the western provinces will not adopt new royalty regimes 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.

We may require additional financing in order to carry out our oil and natural gas acquisition, exploration and development activities

Our cash flow from 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. There is risk that if the economy and banking industry experiences unexpected and/or prolonged deterioration, our access to additional financing may be affected

We may have restricted access to capital and increased borrowing costs. 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. If our revenues from 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.

We may be adversely affected by variations in foreign exchange rates and interest rates

World oil and gas prices are quoted in United States dollars. The Canadian dollar/United States dollar exchange rate, which fluctuates over time, consequently affects the price received by the Canadian producers of oil and natural gas. Recently, the Canadian dollar has decreased materially in value against the United States dollar. Material decreases in the value of the Canadian dollar positively affect commodity prices valued in United States dollars thereby increasing our production revenues. Future Canadian/U.S. dollar exchange rates could accordingly affect the future value of our resources as determined by independent evaluators.

We may incur additional U.S. dollar denominated debt in the future which will result in exposure for us to the aforementioned fluctuations in currency exchange rates. In addition, we may in the future incur indebtedness at variable rates of interest that expose us to additional interest rate risk. If interest rates increase, our debt service obligations on such variable rate indebtedness would increase even though the amount borrowed remains the same, and our net income and cash flows would decrease. This could result in a reduced amount available to fund our exploration and development activities, and could negatively impact the market price of the Common Shares. To the extent that we engage in risk management activities related to foreign exchange rates or interest rates, there is a credit risk associated with counterparties with whom we may contract.

Our exploration and production facilities and other operations and activities and the market for our products may be adversely impacted by climate change legislation, regulations and policies

Our exploration and production facilities and other operations and activities, and the products we market, result in the emission of greenhouse gases which makes us subject to GHG emissions legislation and regulations in the process of being developed and implemented at the provincial and federal level. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place. As a signatory to the United Nations Framework Convention on Climate Change (the "UNFCCC") and a party to the Paris Agreement adopted by the UNFCCC in December 2015, the Government of Canada committed to a 30% reduction in GHG emissions below 2005 levels by 2030.

In addition, 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 per tonne annually until it reaches $50 per tonne in 2022 at which time the program will be reviewed. At the provincial level, the Government of Alberta enacted the Climate Change and Emissions Management Act, which, among other requirements, requires facilities emitting more than 100,000 tonnes of GHG in any subsequent year to reduce, by 2017, their emissions intensity by up to 20% of their baseline years, depending on the number of years of operation. In addition, Alberta’s Climate Leadership Plan imposes a carbon tax on all emitters starting in January 2017 and sets a 100 megatonne per year limit for GHG emissions for oil sands operations of all emitters in the aggregate. We will be an emitter for the purposes of the proposed carbon tax. The direct or indirect costs of compliance with these proposed regulations and the impact these regulations may have on the market for our products may have a material effect on our business, financial condition, results of operations and prospects.

Environmental legislation regulating carbon fuel standards as well as other GHG regulations at various stages of consideration and implementation in Canada, the United States or other jurisdictions in which our products are sold, could result in increased costs and/or reduced revenue for oil sands companies such as us and impact the market for our products. For example, both California and the United States federal government have passed legislation which, in some circumstances, considers the lifecycle GHG emissions of purchased fuel and which may negatively affect the marketing of bitumen, bitumen blend or SCO, or require the purchase of emissions credits in order to effect sales in such jurisdictions.

In addition, concerns about climate change have resulted in a number of environmental activists and members of the public, including some members of the investment community, opposing the continued use and development of fossil fuels. Given the evolving nature of the debate related to climate change and the control of GHG, it is not possible to predict the magnitude of the impact of current and future GHG regulation or lending or investment policies by the financial industry on our operations and financial condition.

Political events may affect the marketability and price of oil and natural gas and our net production revenue

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 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.

There are uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids reserves and the future cash flows attributed to such reserves

The Independent Evaluators have completed geological evaluations of our properties effective as of December 31, 2016 and an evaluation of the Acquired Assets effective December 31, 2016. There are numerous uncertainties inherent in estimating the quantities of reserves and resources attributable to our assets and the future cash flows attributed to such reserves and resources, including many factors beyond our control, and no assurance can be given that the indicated level of reserves and resources will be realized.

In general, estimates of recoverable reserves and resources are based upon a number of factors and assumptions made as of the date on which the reserves and resource estimates were determined, such as geological and engineering estimates, 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, estimates of future commodity prices and operating costs, all of which may vary considerably from actual results. All such estimates are, to some degree, uncertain and classifications of reserves and resources are only attempts to define the degree of uncertainty involved. For these reasons, estimates of the economically recoverable bitumen, crude oil and natural gas and the classification of such reserves and resources based on risk of recovery prepared by different engineers or by the same engineers at different times may vary substantially.

Estimates with respect to reserves and resources that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves and resources, rather than upon actual production history. Recovery factors and drainage areas were estimated by experience and analogy to similar producing pools. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves and resources based upon production history will result in variations, which may be material, in the estimated reserves and resources. Reserves and resource estimates may require revision based on actual production experience. Such figures have been determined based upon assumed oil and natural gas prices and operating costs. Market fluctuations of oil prices may render uneconomic the recovery of our reserves and resources. Estimates of reserves and future net revenue should be regarded only as estimates that may change as further production history and additional information become available. Not only are such reserves and revenue estimates based on that information which is currently available, but such estimates are also subject to the uncertainties inherent in the application of judgmental factors in interpreting such information. Moreover, short term factors relating to oil sands, petroleum and natural reserves and resources may impair the profitability of our projects in any particular period.

In accordance with applicable securities laws, GLJ and DMCL have used forecast prices and costs in estimating our reserves and future net cash flows as of December 31, 2016 and the reserves and future net cash flows attributable to the Acquired Assets as of December 31, 2016. Actual future net cash flows will also 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 revenues, taxes, development and operating expenditures and cash flows associated with our reserves will vary from the estimates contained in the evaluations, and such variations could be material. The evaluations are based in part on the assumed success of activities we intend to undertake in future years. The reserves and estimated cash flows to be derived therefrom and contained in the evaluations will be reduced to the extent that such activities do not achieve the level of success assumed in the evaluations. The evaluations are effective as of a specific effective date and have not been updated and thus do not reflect changes in our reserves since that date.

There is no certainty that any of our assets or the Acquired Assets will produce any portion of the volumes currently classified by the Independent Evaluators as "Proved Reserves" or "Probable Reserves".

Our operations are dependent in part on assets operated by other companies

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.

We will be dependent upon Murphy as operator of the Kaybob assets and as our joint venture participant in the Kaybob and Placid assets. We are dependent upon Murphy's willingness and ability to satisfy its obligations in relation to the Kaybob Carry Commitment and any partial or complete failure to do so by Murphy may have an adverse financial impact upon us. We may not realize the expected benefit or any benefit at all, financial or otherwise from the Murphy Transaction.

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 recourse from such companies. To the extent that any of such companies go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in such assets being shut-in, the Company potentially becoming subject to additional liabilities relating to such assets and the Company having difficulty collecting revenue due from such operators. Any of these factors could materially adversely affect our financial and operational results.

Future acquisition and joint venture activities may have substantial risks

We may consider the acquisition of additional companies or assets in our industry or enter into joint venture arrangements. There can be no assurance that suitable acquisition candidates or joint venture partners will be identified or that related agreements will be entered into on favourable terms. There may be additional risks associated with entering into joint venture arrangements with foreign state-owned entities ("SOE") which may affect the ability to proceed with or finalize a joint venture transaction, including but not limited to the evolving legal, regulatory and compliance regime in Canada relating to dealings with SOE's, the foreign legal regime to which the SOE and any proposed transaction may be subject and the political climate where the SOE is based.

The acquisition of oil and natural gas companies and assets is subject to substantial risks, including the failure to identify material problems during due diligence, the risk of over-paying for assets, and the inability to arrange financing for an acquisition as may be required or desired. Further, the integration and consolidation of acquisitions and joint venture arrangements requires substantial human, financial and other resources and, ultimately, our acquisitions and joint venture arrangements may not be successfully integrated. There can be no assurances that any future acquisitions or joint venture arrangements will perform as expected or that the returns from such acquisitions or joint venture arrangements will support the indebtedness incurred to acquire them or the capital expenditures needed to develop them.

Crude oil and natural gas exploration, development and production involves a high degree of risk

Crude oil and natural gas exploration involves a high degree of risk and there is no assurance that expenditures made by us on exploration will result in new discoveries of crude oil or natural gas in commercial quantities. It is difficult to project the costs of implementing an exploratory drilling program due to the inherent uncertainties of drilling in unknown formations, the costs associated with encountering various drilling conditions and changes in drilling plans and locations as a result of prior exploratory wells or additional seismic data and interpretations thereof.

Future crude oil and 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, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completing (including hydraulic fracturing) and operating costs. In addition, drilling hazards, environmental damage and various field operating conditions could greatly increase the cost of operations and adversely affect the production from successful wells. Field operating conditions include, but are not limited to, delays in obtaining governmental approvals or consents and shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, it is not possible to eliminate production delays and declines from normal field operating conditions, which can negatively affect revenue and cash flow levels to varying degrees.

We may experience capital cost over-runs and project delays for our oil sands projects

Historically, oil sands projects have experienced capital cost over-runs due to a variety of factors. Prior to the onset of the most recent global financial crisis, the large number of existing and planned bitumen recovery and upgrading projects in the Athabasca oil sands area of northeast Alberta had created a strong demand for, and in some cases shortages of, the labour, goods and services that are required to complete and operate these types of projects. As the North American and world economies continue to improve and the demand for commodities continues to recover, these conditions could again materialize in the Athabasca oil sands area. Similarly, strong crude oil and natural gas prices may result in increased competition for, and shortages of, the labour, goods and services that are required to complete and operate bitumen recovery projects and crude oil and natural gas operations.

Although we are defining our schedule for developing our oil sands, crude oil and natural gas resources (including obtaining regulatory approvals), and commencing and completing the construction of certain projects (including future Hangingstone Projects), there is no assurance that the development and project schedules will proceed as planned. Any delays in the development and project schedules could be material and could adversely affect our results of operations and financial condition.

Project delays may delay expected revenues from operations. Significant project cost over-runs could make a project uneconomic. Additionally, there is a risk that our future projects may have delays, interruption of operations or increased costs. Our ability to execute projects, and the performance of such projects, depends upon numerous factors beyond our control, including:

- an inability to obtain adequate financing, or financing on terms satisfactory to us;
- shortages of, or delays in obtaining qualified labour, equipment, materials or services;
- labour disputes, disruptions or declines in productivity;
- changes in the scope of the project or increases in the amount or cost of materials or labour;
- contractor or operator errors in design or construction and non-performance by, or financial failure of, third party contractors;
- breakdown or failure of equipment or processes including facility performance falling below expected levels of output or efficiency;
- delays in obtaining, or conditions imposed by, regulatory approvals;
- reservoir performance;
- challenges to our proprietary technology and/or that of our suppliers or licensors;
- transportation or construction accidents, disruption or delays in availability of transportation services or adverse weather conditions affecting construction or transportation;
- unforeseen site surface or subsurface conditions;
- the availability of, and the ability to acquire, water supplies needed for drilling, or our ability to dispose of water used or removed from strata at reasonable costs and within applicable environmental regulations;
- disruption in the supply of energy;
- catastrophic events such as fires, earthquakes, storms or explosions;
- the availability of processing capacity;
- the availability of storage capacity;
- the availability of alternative fuel sources;
- the effects of inclement weather including delays or suspension of operations;
- the availability of drilling and related equipment;

- unexpected cost increases;
- transportation or operations accidents or other accidental events, including environmental and health and safety risks and hazards such as fire, explosion, blowouts, cratering, sour gas releases and spills;
- currency fluctuations;
- changes in regulations, including those related to climate change, hydraulic fracturing and other environmental regulations; 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 or the projects may not perform to our expectations or as required by regulatory approvals.

The cost to construct projects for the development of our oil sands resources has not been fixed and remains dependent on many factors, some of which are beyond our control. There is no assurance that the current construction and operation schedules will proceed as planned without any delays or cost over-runs. Any delays may increase the costs of those projects, which could result in the need for additional capital, and there can be no assurance that such capital will be available on acceptable terms or at all.

Lack of availability of capacity of gathering, processing and pipeline systems could affect our ability to realize the full economic potential of our production or result in a reduction of the price offered for our production

We deliver our products through gathering and processing facilities and pipeline systems some of which we do not own and by rail. The amount of oil and natural gas that we can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities, pipeline systems and railway lines. The lack of availability of capacity in any of the gathering and processing facilities, pipeline systems and railway lines, and in particular the processing facilities, could result in our inability to realize the full economic potential of our production or in a reduction of the price offered for our production. The lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to produce and market oil and natural gas production. In addition, the pro-rationing of capacity on inter-provincial pipeline systems 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. Furthermore, producers are increasingly turning to rail as an alternative means of transportation. In recent years, the volume of crude oil shipped by rail in North America has increased dramatically. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities could harm our business and, in turn, our financial condition, results of operations and cash flows. The federal government has signaled that it plans to review the National Energy Board approval process for large 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, imposed a per tonne levy of $1.65 on crude oil shipped by rail to compensate victims and for environmental cleanup in the event of a railway accident. In addition to this legislation, new regulations have implemented the TC-117 standard for all rail tank cars carrying flammable liquids which formalized the commitment to retrofit, and eventually phase out DOT-111 tank cars carrying crude oil. The increased regulation of rail transportation may reduce the ability of railway lines to alleviate pipeline capacity issues and add additional costs to the transportation of crude oil by rail. 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 complicit 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 materially adverse effect on our ability to process our production and deliver the same for sale.

Our operations are affected by federal and provincial statutes and regulations regarding the protection of the environment

Our operations are, and will continue to be, affected in varying degrees by federal and provincial statutes and regulations regarding the protection of the environment. Should there be changes to existing statutes or regulations, such as the Licensee Liability Rating Program, our competitive position within the oil sands and petroleum and natural gas industries may be adversely affected, as many industry players have greater resources than us.

Future environmental approvals, laws or regulations may adversely impact our ability to develop and operate our oil sands or light oil projects or increase or maintain production, may increase unit costs of production, or may prevent us from realizing other business opportunities from our exploration leases and permits. Equipment from suppliers which can meet future emission standards may not be available on an economic or timely basis and other methods of reducing emissions to required levels in the future may significantly increase operating costs or reduce output. There is a risk that the federal and/or provincial governments could pass legislation that would tax such emissions or require, directly or indirectly, reductions in such emissions produced by energy industry participants, which we may be unable to mitigate.

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain oil and gas industry operations and requirements to report, investigate and remediate such spill, release or emission. In addition, such legislation sets out the requirements with respect to oilfield waste handling and storage, habitat protection, occupational health and safety 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, penalties and other liabilities, some of which may be material, or the revocation or denial of permits necessary to our business. 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. Under certain circumstances, we can have liability for contamination at our facilities even if it arises from third parties or from conduct that was legal at the time it occurred. No assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on our business, financial condition, results of operations and prospects.

Claims may be made by aboriginal peoples against us or our assets

Aboriginal peoples have claimed aboriginal title and rights to portions of western Canada. Claims by aboriginal peoples or groups could, among other things, delay or prevent the exploration or development of our properties, which in turn could have a material adverse effect on our business, financial condition, results of operations and prospects.

Reliance on key personnel and operators may adversely impact our business

The design, development and construction of, and commencement of operations at each of our oil sands and light oil projects will require experienced executive, management and technical personnel and operational employees and contractors with expertise in a wide range of areas. There can be no assurance that all of the required employees with the necessary expertise will be available. It is likely that other oil sands and light oil projects or expansions will proceed in the same time frame as our projects and our projects will compete with these other projects for experienced employees and such competition may result in increases to compensation paid to such personnel or a lack of qualified personnel.

Any inability on the part of us to attract and retain qualified personnel, may delay or interrupt the design, development and construction of, and commencement of operations of such projects. Sustained delays or interruptions could have a material adverse effect on our projects, and on our financial condition and performance. In addition, rising personnel costs would adversely impact the costs associated with the design, development and construction of, and commencement of operations at our projects, which could be significant and material.

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

We may not be able to comply with financial assurance covenants contained within our pipeline transportation agreements

We have contracts for pipeline transportation in place with third parties which contain certain financial assurance covenants. Depending upon our capitalization, liquidity position and state of operational performance at certain times, we may not be in a position to comply with the financial assurance covenants contained within these agreements, which may require us to provide security to the third parties we have contracted with including, but not limited to, letters of credit.

Demand for equipment or access restrictions may affect our exploration and development activities

Oil and gas exploration and development activities (including those for bitumen from oil sands) are dependent on the availability of drilling and related equipment in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to us and may delay exploration and development activities. There can be no assurance that sufficient drilling and completion equipment, services and supplies will be available when needed. Shortages could delay our proposed exploration, development and sales activities. If the demand for, and wage rates of, qualified rig crews rise in the drilling industry then the oil industry may experience shortages of qualified personnel to operate drilling rigs. This could delay and increase the costs of our drilling operations. One or more of these events could have a material adverse effect on our results of operations and financial condition.

Operating costs may vary considerably during the operating period which may in turn have a material adverse effect on our results of operations and financial condition

The operating costs of the projects undertaken by us will be significant components of the cost of production of the products produced by such projects. Those operating costs may vary considerably during the operating period. The principal factors which could affect operating costs include, without limitation: the amount and cost of labour to operate the projects; the cost of chemicals; the actual SOR required to operate our oil sands projects; the cost of natural gas, diluent and electricity; the cost of complying with regulatory approvals; the maintenance cost of the facilities; the cost to process product, the cost to transport sales products and the cost to dispose of certain by-products; and the cost of insurance and taxes. Unexpected increases in operating costs may result in decreased earnings, which may in turn have a material adverse effect on our results of operations and financial condition.

Our ability to sell bitumen blend profitably will be dependent on, among other things, availability of supply of natural gas and diluents and the cost of natural gas and the cost of diluent

Extracting bitumen using SAGD technology in order to sell bitumen blend requires considerable quantities of natural gas and diluent. Natural gas is used as an energy input, primarily to produce steam from water at the in-situ extraction site. The amount of steam required to extract one barrel of oil is commonly referred to as the SOR. A higher SOR indicates that more steam is required, and therefore more natural gas. Natural gas is currently plentiful in the Athabasca region. Diluent is used to create bitumen blend, which has a lower viscosity than bitumen and is able to flow in a pipeline to markets. Condensate, a by-product of natural gas processing, is currently the diluent preferred by bitumen producers. However, the current demand for condensate in the Athabasca region for use as diluent exceeds regional supply. An alternative diluent to condensate is SCO. SCO is currently plentiful in the Athabasca region, but under current market conditions the operating netback realized for a SCO bitumen blend is less than for a condensate bitumen blend.

Our ability to sell bitumen blend profitably will be dependent on, among other things, the cost of natural gas and the cost of diluent. As production of non-upgraded bitumen increases in the Athabasca region, so will the demand for natural gas and diluent. As the demand for natural gas and diluent increases, the availability of these products may decrease and cost of these products may increase. If we are unable to source a stable supply of natural gas and/or diluent at economic prices, one or more of our projects may become uneconomic, which could have a material adverse effect on our results of operations and financial condition.

Further, heavy oil and bitumen are characterized by high specific gravity or weight and high viscosity or resistance to flow. Diluent is required to facilitate the transportation of heavy oil and bitumen. A shortfall in the supply of diluents may cause its price to increase thereby increasing the cost to transport heavy oil and bitumen to market and correspondingly increasing our overall operating cost, decreasing our net revenues and negatively impacting the overall profitability of our heavy oil and bitumen projects.

Our inability to utilize the most advanced commercially available technology could adversely affect our business, financial condition and results of operations

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

Changing demand for oil and natural gas products could have an adverse effect on our business, financial condition, results of operations and cash flows

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

Production or potential production of natural gas overlying bitumen resources on our oil sands leases will pose a risk to our ability to recover the bitumen resources on these properties using SAGD technology

Some of our oil sands leases contain producing and shut-in natural gas wells owned by third parties that may penetrate, or otherwise result in the applicable petroleum and natural gas zones coming into communication with, our bitumen resources. In October 2009, the ERCB ordered the interim shut-in of 297 intervals associated with 158 gas wells largely in the Dover West area to mitigate potential future risk to bitumen recovery in the area. On December 15, 2011, pursuant to Order 11-002, the Energy Resources Conservation Board of Alberta (predecessor to the AER) shut-in these, as well as other wells. There are also natural gas zones in several of our asset areas that do not currently contain producing or shut-in natural gas wells. There is a risk that if the production of natural gas from these zones penetrates or otherwise comes into communication with our bitumen resources, there may be a loss of steam or steam chamber pressure during the SAGD bitumen extraction process, which could adversely affect our ability to recover bitumen using SAGD technology. No assurance can be provided that the production or potential production of natural gas overlying bitumen resources on our oil sands leases will not pose a risk to our ability to recover the bitumen resources on these properties using SAGD technology, and such risk could have a material adverse effect on our business, financial condition, liquidity and results of operations.

Changes of the ratio of our deemed assets to deemed liabilities or changes to the requirements of liability management programs may result in significant increases to the security that must be posted

The Province of Alberta has developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder is unable to satisfy its obligation. These programs generally involve an assessment of the ratio of a licensee's deemed assets to deemed liabilities. If a licensee's deemed liabilities exceed its deemed assets, a security deposit is required. Changes 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 requirement. 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. This is of particular concern to junior oil and gas companies that may be disproportionately affected by price instability

Tax reassessments or changes to income tax laws may have an adverse effect on us

Income tax provisions, including current and future income tax assets and liabilities in our financial statements, and income tax filing positions require estimates and interpretations of federal and provincial income tax rules and regulations, and judgments as to their interpretation and application to our specific situation. In addition, there can be no assurance that the Canada Revenue Agency or a provincial or other tax agency will agree with our tax filing positions or will not change its administrative practices to the detriment of us or our shareholders and creditors. Our business and operations are complex and we have executed a number of significant financings, acquisitions, dispositions, reorganizations, joint ventures and business combinations over the course of our history. The computation of income taxes payable as a result of these transactions involves many complex factors as well as our interpretation of and compliance with relevant tax legislation and regulations. While we believe that our tax filing positions are supportable under applicable law, a number of our tax filing positions are or may be the subject of review by taxation authorities. Therefore, it is possible that additional taxes could be payable by us and the ultimate value of our income tax assets and liabilities could change in the future and that such additional taxes and changes to such amounts could be materially adverse to us.

When reserves and resources have been extracted from projects, abandonment and reclamation costs will be incurred

Estimates of our abandonment and reclamation costs will be a function of regulatory requirements existing at the time that the estimates are made, which are subject to change in the future. In addition, the value of the salvaged equipment may be more or less than the abandonment and reclamation costs. Consequently, the estimates may or may not accurately reflect these future costs. In addition, in the future we or the operator of our projects may determine it prudent, or be required by applicable laws or regulations, to establish and fund one or more reclamation funds to provide for payment of future abandonment and reclamation costs, which could result in a material increase in the cost of our projects.

We continually must replace reserves depleted by production. Our exploration activities may not result in additional discoveries

Our ability to replenish our reserves is important to our long-term viability. Depleted reserves must be replaced by further development of existing sites or by locating new sites in order to maintain production levels over the long term. Resource exploration and development are highly speculative in nature. Our exploration projects involve many risks, require substantial expenditures and may not result in the discovery of sufficient additional deposits that can be extracted profitably. Once a site with deposits is discovered, it may take several years from the initial phases of drilling until production is possible, during which time the economic feasibility of production may change. Substantial expenditures are required to establish recoverable proven and probable reserves and to construct extraction and processing facilities. As a result, there is no assurance that current or future exploration programs will be successful and there is a risk that depletion of reserves will not be offset by discoveries or acquisitions.

Our operations are subject to environmental and health and safety risks and hazards, which could delay or impede development, result in significant and increased costs and impose liabilities on us

Our exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, but not limited to, fire, explosion, blowouts, cratering, sour gas releases and spills and other environmental hazards. These typical risks and hazards could result in substantial damage to wells, production facilities, other property and the environment or 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. SAGD and other in-situ exploration and 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 of these risks, nor are all such risks insurable. Although we maintain liability insurance in an amount that we consider consistent with industry practice, the liabilities associated with certain risks could exceed policy limits, in which event we could incur significant costs.

In addition to the foregoing, recovering bitumen from oil sands and upgrading the recovered bitumen into a diluent-bitumen blend product, a synthetic crude-bitumen blend product or other products involves particular risks and uncertainties. Our projects will be susceptible to loss of production, slowdowns, or restrictions on its ability to produce higher value products due to the interdependence of its component systems. Severe climatic conditions can cause reduced production and in some situations result in higher costs.

Estimates may be used in management's assessment of items such as fair values, income taxes, stock based compensation and asset retirement obligations and actual results could differ materially from such estimates and assumptions

In preparing consolidated financial statements in conformity with Canadian Generally Accepted Accounting Principles or International Financial Reporting Standards, estimates and assumptions are used by management in determining the reported amounts of assets and liabilities, revenues and expenses recognized during the periods presented and disclosures of contingent assets and liabilities known to exist as of the date of the financial statements. These estimates and assumptions must be made because certain information that is used in the preparation of such financial statements is dependent on future events, cannot be calculated with a high degree of precision from data available, or is not capable of being readily calculated based on generally accepted methodologies. In some cases, these estimates are particularly difficult to determine and we must exercise significant judgment. Estimates may be used in management's assessment of items such as fair values, income taxes, stock based compensation and asset retirement obligations. Actual results for all estimates could differ materially from the estimates and assumptions used by us, which could have a material adverse effect on the financial condition, results of operations and cash flows of us.

Failure by third parties to meet their contractual obligations to us may adversely affect our business, financial condition, results of operations and prospects

We will be obliged to enter into long term arrangements with third parties in order to construct and operate the Acquired Assets, the Hangingstone Project, Hangingstone Expansion and our activities in the Athabasca-operated Greater Placid area and any other bitumen recovery, crude oil or natural gas development project that we may propose to undertake. Such arrangements may include engineering, equipment procurement and construction contracts, long term maintenance contracts for key equipment, contracts for shipping bitumen, bitumen products, crude oil or natural gas to market, and contracts for services of a constant or recurring nature. We will be dependent on the ability of these third parties to perform their obligations in a timely, cost efficient, reliable and effective manner. There is no assurance that such arrangements can be made on a cost-effective basis or that we will not be obliged to fund the creation of necessary resources, which could increase our operating costs and thereby adversely affect our results of operations and financial condition.

Failure of third parties to provide an adequate supply of services in a timely, cost efficient, reliable and effective manner could negatively impact the operation of the project or projects affected

The projects that we may propose to undertake, will depend on certain infrastructure owned and operated by third parties, including without limitation: pipelines for the transportation of feedstocks to the project, and petroleum products to be sold by the project; pipelines for the transportation of natural gas; the availability of and access to processing capacity, electricity transmission systems for the provision and/or sale of electricity; and roads, bridges and highways for the transportation of heavy loads in the project areas. The failure of any or all of these third parties to provide an adequate supply of such services in a timely, cost efficient, reliable and effective manner could negatively impact the operation of the project or projects affected, and thereby adversely affect our results of operations and financial condition.

Seasonality and weather conditions may adversely affect our operations

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

Natural disasters, weather conditions, disruption of energy, unanticipated geological conditions, equipment failures, and other unexpected events may lead our customers, our suppliers or our facilities to curtail production or shut down operations

Operating levels within the oil and gas extraction industry are subject to unexpected conditions and events that are beyond the industry's control. Those events could cause industry members or their suppliers to curtail production or shut down a portion or all of their operations, which could reduce the demand for our products, and could affect adversely our sales, margins and profitability.

Interruptions in production capabilities inevitably will increase our production costs and reduce our profitability. We do not have meaningful excess capacity for current production needs, and we are not able to quickly increase production at one site to offset an interruption in production at another site.

A portion of our production costs are fixed regardless of current operating levels. As noted, our operating levels are subject to conditions beyond our control that can delay deliveries or increase the cost of operation at particular sites for varying lengths of time. These include weather conditions (for example, extreme winter weather, tornadoes, floods, and the lack of availability of process water due to drought) and natural and man-made disasters, wildfires, unanticipated geological conditions, including variations in the amount and type of rock and soil overlying the oil or natural gas deposits, variations in rock and other natural materials and variations in geologic conditions.

On May 5, 2016, the Hangingstone Project was shut down for 19 days due to the regional Fort McMurray wildfires. The decision to shut down the well sites and central facility was due to elevated safety risks from the fire's proximity to the Hangingstone Project. There was no damage to the facility, field pipelines or well sites; however, during the shut down production and revenue from the Hangingstone Project were reduced and operating costs were increased during the second quarter of 2016 to protect the site and return to operations.

The processes that take place in our facilities and those facilities owned by third parties through which our production is transported and processed, depend on critical pieces of equipment. This equipment may, on occasion, be out of service because of unanticipated failures. In addition, some of these facilities have been in operation for several decades, and the equipment is aged. In the future, we may experience additional material shutdowns or periods of reduced production because of equipment failures. Further, remediation of any interruption in production capability may require us to make large capital expenditures that could have a negative effect on our profitability and cash flows. Our business interruption insurance would not cover all or any of the lost revenues associated with equipment failures.

Longer-term business disruptions could result in a loss of customers, which adversely could affect our future sales levels and, therefore, our profitability.

We may enter into hedging arrangements which are subject to risks

The nature of our operations will result in exposure to fluctuations in commodity prices. We may use financial instruments and physical delivery contracts to hedge our exposure to these risks. In addition, we have previously and may in future enter into hedging arrangements to act as a risk control mechanism with respect to foreign denominated debt incurred by us. Under the terms of the New Notes and the Amended Credit Facility, we are required to enter into certain oil and gas hedging requirements with respect to our production. If we engage in hedging we will be exposed to credit related losses in the event of non-performance by counterparties to the financial instruments. In addition, if product prices increase above those levels specified in any future hedging agreements, we could lose the cost of floors or a fixed price could limit us from receiving the full benefit of commodity price increases. If we enter into hedging arrangements, we may suffer financial loss if we are unable to commence operations on schedule, 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, a sudden unexpected event materially impacts oil and natural gas prices, or if we are unable to produce sufficient quantities of bitumen, crude oil or natural gas to fulfill our obligations. If currency exchange rates result in a stronger-performing Canadian dollar relative to previously incurred foreign denominated debt, this may result in us incurring financial loss as a result of the financial hedging arrangements we have in place.

We may also hedge our exposure to the costs of inputs to a project, such as natural gas, electricity or diluent. If the prices of these inputs fall below the levels specified in any future hedging agreements, we could lose the cost of ceilings or a fixed price could limit us from receiving the full benefit of commodity price decreases.

Ineffective internal controls could harm our results of operations or cause us to fail to meet our reporting obligations

Effective internal controls are necessary for us to provide reliable financial reports and to help prevent fraud. Although we undertake a number of procedures in order to help ensure the reliability of its financial reports, including those imposed on it under Canadian securities laws, we cannot be certain that such measures will ensure that we will maintain adequate control over financial processes and reporting. Failure to implement required new or improved controls, or difficulties encountered in their implementation, could harm our results of operations or cause us to fail to meet our reporting obligations. If we or our independent auditors discover a material weakness, the disclosure of that fact, even if quickly remedied, could reduce the market's confidence in our consolidated financial statements and harm the trading price of the Common Shares.

Our insurance may not be sufficient to cover all liabilities

Our involvement in the exploration for and development of oil, natural gas and bitumen 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. Our property, business interruption and liability insurance is subject to deductibles, limits and exclusions, and may not provide sufficient coverage for these and other insurable risks. 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. Further, there can be no assurance that such insurance will continue to be offered on an economically feasible basis, that all events that could give rise to a loss or liability are insurable, or that the amounts of insurance (net of applicable deductibles) will at all times be sufficient to cover each and every loss or claim that may occur involving our assets or operations.

We may become involved in 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 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 proceeding, the proceedings could be costly and time-consuming and would divert the attention of management and key personnel from our business operations, which could adversely affect our financial condition.

Competition may adversely affect our results of operations, financial condition, cash flows and prospects

The Canadian and international petroleum industry is highly competitive in all aspects, including the exploration for, and the development of, new sources of supply, the acquisition of resource interests, access to third party infrastructure and the distribution and marketing of petroleum products. We will compete with other bitumen producers, and competes with producers of crude oil, natural gas and SCO. Some of the conventional producers that we compete with have lower operating costs than us and many of them have greater resources than us. Certain of our competitors may have greater resources to source, attract, and retain the personnel, materials and services that we will require to conduct our operations. The petroleum industry also competes with other industries in supplying energy, fuel and related products to consumers.

A number of companies other than us have announced plans to enter the oil sands business and begin production of bitumen, or expand existing operations. Expansion of existing operations and the development of new projects could materially increase the supply of bitumen or synthetic crude oil and other competing crude oil products in the marketplace and could materially increase the costs of inputs such as natural gas, diluent, labour, equipment, materials or services. Depending on the levels of future demand, increased supplies could have a negative impact on prices of bitumen and, accordingly, our results of operations and cash flow.

A defect in the chain of title for our properties may adversely affect our business, financial condition, results of operations and prospects

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise. Our actual interest in properties may, 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 legislative changes which affect our title to the oil and natural gas properties we control that could impair our activities on them and result in a reduction of the revenue received by us.

Breaches of confidentiality may cause significant damage to our business

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 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.

Forward looking information may prove inaccurate

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 risks 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. See "*Forward looking Statements*".

In the future we may acquire or move into new industry related activities or new geographical areas, which may in turn result in our future operational and financial conditions being adversely affected

The operations and 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.

Loss of information and computer systems could adversely affect our business

We are heavily dependent on our information systems and computer based programs, including our well operations information, seismic data, electronic data processing and accounting data. If any of such programs or systems were to fail or create erroneous information in our hardware or software network infrastructure, possible consequences include a loss of communication links or reliable information, inability to find, produce, process and sell oil and natural gas and inability to automatically process commercial transactions or engage in similar automated or computerized business activities. Any such consequence which results in a loss of data or which is not resolved within a short period of time could have a material adverse effect on our business.

Cyber-security breaches could adversely affect our business

We have become increasingly dependent upon the availability, capacity, reliability and security of our information technology infrastructure and its 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 contracts with its 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 its reputation. We have various technical controls in place to mitigate the risk of cyber-attack including an information technology acceptable usage policy, password protocols, firewalls and controlled remote access all of which are validated by an annual independent audit and which risk mitigation measures are in line with industry-accepted standards to protect the Company's 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.

Our oil and natural gas properties, wells and facilities could be subject to a terrorist attack or physical sabotage

In addition to the risks outlined herein related to geopolitical developments, our oil and natural gas properties, wells and facilities could be subject to a terrorist attack or physical sabotage. While our oil and gas properties are all located in Canada, a politically stable, developed nation, if any of our properties, wells or facilities are the subject of terrorist attack or sabotage it may have a material adverse effect on our business, financial condition, results of operations and prospects. We may not have adequate insurance to protect against such risks.

Our identified potential drilling locations are scheduled out over many years, making them susceptible to uncertainties that could materially alter the timing of their drilling or make their drilling uneconomic. In addition, we may not be able to generate enough cash flow from operations and/or raise the amount of capital that would be necessary to drill the necessary well locations to hold all of our leasehold.

Our ability to drill and develop our locations as planned depends on a number of uncertainties, including oil, natural gas and NGLs prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, historical drilling results, lease expirations, gathering system and pipeline transportation constraints, the extent our leases cover contiguous acreage, access to and availability of water sourcing and distribution systems, produced water and other waste disposal, regulatory approvals and other factors. Our estimate of the number of potential gross horizontal well locations is also based on a number of assumptions with respect to well spacing. Because of these uncertain factors, we do not know if all of the potential well locations we have identified will be drilled as expected or at all or if we will be able to produce oil, natural gas and NGLs from these or any other potential well locations. In addition, unless production is established within the drilling units covering the undeveloped acres on which some of the potential locations are obtained, the leases for such acreage will expire. As such, our actual drilling activities may materially differ from those presently identified.

Well locations that we decide to drill may not yield oil, natural gas or NGLs in commercial quantities

Properties that we decide to drill that do not yield oil, natural gas or NGLs in commercial quantities will adversely affect our results of operations and financial condition. There is no way to conclusively predict in advance of drilling and testing whether any particular well will yield oil, natural gas or NGLs in sufficient quantities to recover drilling or completion costs or to be economically viable. We cannot assure you that the analogies we draw from available data from other wells, more fully explored prospects or producing fields will be applicable to our drilling prospects.

While our costs for drilling rigs, equipment, supplies, personnel and oilfield services are currently low compared to historical prices, the future unavailability or high cost of these goods, services and personnel could adversely affect our ability to execute our exploration and development drilling plans within our budget and on a timely basis.

We currently operate 2 rigs and plan to operate two rigs during the remainder of 2017. We have not entered into contracts for all of the rigs we ultimately will need to execute our drilling program, and the terms of the drilling and daywork contracts for our currently contracted rigs will be renegotiated and renewed or allowed to expire, at our sole discretion, at the expiry of their current term. Although we currently anticipate, based on current pricing and availability, that we will be able to secure sufficient drilling rigs, we cannot be certain that, in the future, we will be able to do so on a timely or cost effective basis, or at all.

Historically, there have been shortages of drilling and workover rigs, pipe, equipment, supplies and certain oilfield services in our area during periods of increased drilling activity. We cannot predict whether shortages will exist in the future and, if so, what their timing and duration will be. Shortages or significant increases in the cost of drilling rigs, pipe, equipment, supplies, or oilfield services could delay or adversely affect our development and exploration operations or cause us to incur significant expenditures that are not provided for in our capital budget. Shortages or increased costs in drilling and workover rigs, pipe, equipment, supplies and certain oilfield services could result in our inability to meet production and other estimates, and therefore, our financial condition and results from operations may be materially and adversely affected.

In addition, the historical demand for qualified and experienced field and operations personnel, geologists, geophysicists, engineers, landmen and other professionals in the oil and natural gas industry has fluctuated significantly, often in correlation with oil, natural gas and NGLs prices, causing periodic shortages. Other companies may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer. The cost to attract and retain qualified personnel has increased significantly over the past five years due to competition and may increase substantially in the future.

Risks Related to the Asset Acquisition

We may fail to realize the anticipated benefits of the Asset Acquisition and achieving the benefits of the Asset Acquisition may divert management focus and resources

We believe that the Asset Acquisition will provide certain benefits to us and our stakeholders. There is, however, a risk that some or all of the expected benefits of the Asset Acquisition may fail to materialize, or may not occur within the time periods anticipated by us. The realization of such benefits may be affected by a number of factors, many of which are beyond our control. If the Asset Acquisition fails to provide the results that we anticipate, the Asset Acquisition could materially and adversely affect us and our financial results.

Additionally, anticipated benefits from the Asset Acquisition may be offset by costs incurred in integrating the Acquired Assets or in required capital expenditures related to the Acquired Assets. We expect to incur significant one-time transaction costs in connection with the Asset Acquisition. The incurrence of these costs may have an unfavorable effect on our liquidity, cash flows and operating results in the periods in which they are incurred.

There may be unexpected costs or potential undisclosed liabilities associated with the Asset Acquisition

We are subject to the risk that there are undisclosed or unknown liabilities of, or issues concerning, the Acquired Assets. In connection with the Asset Acquisition, there may be liabilities that we failed to discover or were unable to quantify in our due diligence. We may discover that we have acquired substantial undisclosed liabilities or that the magnitude of known liabilities was not quantified correctly. The existence of any such liabilities could have a material adverse impact on our financial condition and results of operations. Furthermore, the representations, warranties and indemnities contained in the Acquisition Agreement are limited, and our ability to seek remedies for any breach of such provisions following completion of the Asset Acquisition may be limited. In addition, we may be unable to retain existing suppliers, contractors or employees related to the Acquired Assets following the Asset Acquisition. Our inability to retain such suppliers, contractors or employees could have a material adverse impact on our financial conditions and results of operations.

Additionally, the Acquired Assets are subject to risks associated with oil sands operations, including operational hazards and risks, strict environmental and safety requirements, and close scrutiny by government, the public and the media, as well as risks and uncertainties associated with exploration for crude oil and natural gas. The impact of any of these risks could mean that we would be unable to realize the expected benefits, financial or otherwise, from the Asset Acquisition, which could result in an adverse financial impact upon the Company.

Our engineering, title, environmental and economic assessments of the Acquired Assets may be materially incorrect

Our acquisition of the Acquired Assets is based in large part on engineering, environmental and economic assessments made by us, independent engineers and consultants. These assessments include a series of assumptions regarding such factors as recoverability and marketability of oil and natural gas, environmental restrictions and prohibitions regarding releases and emissions of various substances, future prices of oil and gas and operating costs, future capital expenditures and royalties and other government levies which will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond our control. All such assessments involve a measure of geologic, engineering, environmental and regulatory uncertainty that could result in lower production and reserves or higher operating or capital expenditures than anticipated.

In addition, we cannot guarantee that any unforeseen defects in the chain of title will not arise to defeat our title to certain assets or that environmental defects or deficiencies do not exist.

There are risks related to the integration of the Acquired Assets into Athabasca's existing business

The ability to realize the benefits of the Asset Acquisition will depend in part on successfully consolidating functions and integrating operations, procedures and personnel in a timely and efficient manner, as well as on our ability to realize the anticipated development opportunities and operating synergies from the Asset Acquisition. Certain operational and strategic decisions and certain staffing decisions following completion of the Asset Acquisition have not yet been made. These decisions and the integration will require the dedication of substantial management effort, time and resources which may divert management's focus and resources from other strategic opportunities following completion of the Asset Acquisition, and from operational matters during this process. The integration process may result in the loss of key employees and the disruption of ongoing business, supplier and employee relationships that may adversely affect our ability to achieve the anticipated benefits of the Asset Acquisition and any future acquisitions.

The reserves attributable to the Acquired Assets may not be the same as the current market value of such estimated reserves

You should not assume that the future net revenues attributable to Acquired Asset reserves as of December 31, 2016, as disclosed herein, is the current market value of such estimated reserves. Actual future net revenues will be affected by factors such as:

- the actual prices received for oil, natural gas and NGLs;
- the actual development and production expenditures;
- the amount and timing of actual production; and
- changes in governmental regulations or taxation.

The timing of both production and the incurrence of expenses in connection with the development and production of the Acquired Assets will affect the timing and amount of actual future net revenues from reserves, and thus their actual present value. In addition, the discount factors required to be used under NI 51-101 when calculating the net present value of future net revenues may not be the most appropriate discount factors based on interest rates in effect from time to time and risks associated with the Acquired Assets or the oil and natural gas industry in general. Actual future prices and costs may differ materially from those used in the net present value estimates included herein, which could have a material effect on the value of such reserves.

There are other Operational and Reserves Risks Relating to the Acquired Assets

The risk factors set forth above, including those relating to the oil and natural gas business, environmental matters and our operations and reserves apply equally in respect of the Acquired Assets. In particular, the reserve and recovery information contained herein in respect of the Acquired Assets is only an estimate and the actual production from and ultimate reserves of those properties may be greater or less than the estimates contained herein.

We will have additional capital requirements following the completion of the Asset Acquisition

Following completion of the Asset Acquisition, we will require significant ongoing capital expenditures and, although we anticipate that we will be able to fund these expenditures through a combination of operating cash flow, usage of our available credit facilities and subsequent debt, equity and/or hybrid offerings, there can be no assurance that we will be able to generate substantial operating cash flow and/or obtain such financing on acceptable terms, or at all.

Risks Related to our Indebtedness

We have significant amounts of indebtedness and our indebtedness could adversely affect our financial health and operating flexibility

Our indebtedness could have important consequences to us, including:

- limiting our ability to borrow additional amounts for working capital, capital expenditures, debt service requirements, execution of our growth strategy or other purposes;
- limiting our ability to use operating cash flow in other areas of our business because we must dedicate a substantial portion of these funds to service the indebtedness;
- increasing our vulnerability to general adverse economic and industry conditions, including increases in interest rates;
- limiting our ability to capitalize on business opportunities and to react to competitive pressures and adverse changes in government regulation; and

- limiting our ability, or increasing the costs, to refinance indebtedness.

The covenants under the New Notes and the Amended Credit Facility, among other things, restrict the ability of Athabasca and its subsidiaries to:

- incur indebtedness;
- make restricted payments, including paying dividends and prepaying junior debt;
- make investments;
- create liens;
- sell assets; or
- engage in mergers or acquisitions.

Our failure to comply with these covenants would likely result in an event of default under our debt agreements. Such a default, if not cured or waived, may allow the creditors to accelerate the related indebtedness and could result in acceleration of any of our other indebtedness to which a cross-acceleration or cross-default provision applies. In the event that noteholders accelerate the repayment of our indebtedness, we may not have sufficient assets or be able to borrow sufficient funds to repay or refinance that indebtedness.

Despite our current level of indebtedness, we may still be able to incur substantially more debt. This could further exacerbate the risks associated with our substantial indebtedness

We may be able to incur substantial additional indebtedness in the future, including additional secured indebtedness and indebtedness secured on a first lien basis, subject to certain limitations, including under New Note Indenture. If new debt is added to our current debt levels, the related risks that we now face could increase. Significant additions of undeveloped oil and gas properties financed with debt may result in increased indebtedness, which could curtail drilling and development of such oil and gas properties or existing oil and gas properties or could cause us to not comply with our debt covenants. In addition, the incurrence of additional indebtedness could make it more difficult to satisfy our existing financial obligations.

We are required to maintain compliance with the terms of our debt instruments

We currently have outstanding indebtedness or commitments under the LC Facility, the Amended Credit Facility and the New Notes (collectively the "**Secured Debt**"). We are required to comply with covenants under the Secured Debt 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 a demand being made under the LC Facility or a default under the Amended Credit Facility which could result in us being required to repay amounts owing thereunder. Even if we are able to obtain new financing, it may not be on commercially reasonable terms or terms that are acceptable to us. If we are unable to repay amounts owing under any or all of the New Notes, LC Facility or the Amended Credit Facility, the New Noteholders or lenders under the LC Facility and the Amended Credit Facility, as applicable, could proceed to foreclose or otherwise realize upon the collateral granted to them to secure the indebtedness. 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, the Secured Debt may impose operating and financial restrictions on us that could include restrictions on the payment of dividends, repurchase or making of other distributions with respect to our junior debt, incurring of additional indebtedness, creation of liens, the provision of guarantees, the assumption of loans, making of capital expenditures, entering into amalgamations, mergers, take-over bids or disposition of assets, among others.

The available lending limits of the Amended Credit Facility are reviewed semi-annually and are based on the lenders' assessment of the Company's reserves and future commodity prices as well as the application of applicable discount rates and other factors by the lenders, including their respective normal petroleum and natural gas lending criteria and practices in effect at the time of such review for loans to borrowers in the Canadian petroleum and natural gas industry. A material decline in commodity prices or the value of our reserves could reduce the available lending limits under the Amended Credit Facility, therefore reducing the funds available to the Company which could result in a portion, or all, of the Company's indebtedness under the Amended Credit Facility being required to be repaid. The acceleration of our indebtedness under the Amended Credit Facility may permit acceleration of indebtedness under other agreements relating to our Secured Debt that contain cross default or cross-acceleration provisions.

If Athabasca experiences certain changes in control, Athabasca may be required to make an offer to repurchase all of the outstanding New Notes prior to their maturity at 101% of their principal amount. Additionally, under the Amended Credit Facility, certain changes in control may permit the lenders to accelerate the maturity of borrowings under such facilities, terminate their commitments to lend and require repayment of amounts drawn under the Amended Credit Facility. Athabasca may not have sufficient funds or be able to arrange for additional financing at the time of the change of control to make the required repurchase of the New Notes and repay any of Athabasca's other indebtedness that may also become due. As a result, we may require additional financing from third parties to fund any such purchases, and it may be unable to obtain financing on satisfactory terms or at all. Further, our ability to repurchase the New Notes may also be limited by law.

Risks Related to the Common Shares

Volatile Market Price for Common Shares

The market price for Common Shares may be volatile and subject to wide fluctuations in response to numerous factors, many of which are beyond Athabasca’s control, including the following: (a) actual or anticipated fluctuations in Athabasca’s quarterly results of operations; (b) actual or anticipated changes in crude oil, bitumen blend, natural gas, SCO and other diluent prices; (c) recommendations by securities research analysts; (d) changes in the economic performance or market valuations of other companies that investors deem comparable to Athabasca; (e) addition or departure of Athabasca’s executive officers and other key personnel; (f) release or expiration of lock-up or other transfer restrictions on outstanding Common Shares; (g) sales or perceived sales of additional Common Shares; (h) significant acquisitions or business combinations, strategic partnerships, joint ventures or capital commitments by or involving Athabasca or its competitors; and (i) news reports relating to trends, concerns, technological or competitive developments, regulatory changes and other related issues in Athabasca’s industry or target markets.

Financial markets have experienced significant price and volume fluctuations in the last several years that have particularly affected the market prices of equity securities of companies and that have, in many cases, been unrelated to the operating performance, underlying asset values or prospects of such companies. Accordingly, the market price of the Common Shares may decline even if Athabasca’s operating results, underlying asset values or prospects have not changed. Additionally, these factors, as well as other related factors, may cause decreases in asset values that are deemed to be other than temporary, which may result in impairment losses. As well, certain institutional investors may base their investment decisions on consideration of Athabasca’s environmental, governance and social practices and performance against such institutions’ respective investment guidelines and criteria, and failure to meet such criteria may result in a limited or no investment in the Common Shares by those institutions, which could adversely affect the trading price of the Common Shares. There can be no assurance that continuing fluctuations in the price and volume of publicly traded equity securities will not occur. If such increased levels of volatility and market turmoil continue, Athabasca’s operations could be adversely impacted and the trading price of the Common Shares may be adversely affected.

Issuance of Additional Securities

The Board may issue an unlimited number of Common Shares, without any vote or action by Athabasca’s Shareholders, subject to the rules of the TSX or such other stock exchange on which Athabasca’s securities may be listed from time to time. Athabasca may make future acquisitions or enter into financings or other transactions involving the issuance of securities. In addition, pursuant to the Stock Option Plan, the Performance Plan and the 2015 RSU Plan, Athabasca may issue Stock Options and RSUs exercisable to acquire up to 10% of the number of Common Shares outstanding at any given time. If Athabasca issues any additional Common Shares, the percentage ownership of existing Shareholders will be reduced and diluted.

Dividend Policy

Other than the Special Dividend, Athabasca has never declared or paid any cash dividends on its Common Shares. Athabasca does not currently anticipate paying any cash dividends on its Common Shares in the foreseeable future but will review that policy from time to time as circumstances warrant. Athabasca currently intends to retain future earnings, if any, for future operations, expansion and debt repayment. Any decision to declare and pay dividends in the future will be made at the discretion of the Board and will depend on, among other things, Athabasca's results of operations, current and anticipated cash requirements and surplus, financial condition, contractual restrictions and financing agreement covenants, including those contained in the Amended and Restated Credit Agreement, the LC Facility and New Note Indenture, and other factors that the Board may deem relevant. For a description of the restrictions that are contained in the Amended and Restated Credit Agreement, LC Facility and New Note Indenture that relate to Athabasca's ability to pay dividends, please see "*Dividends*" above.

As a result of the foregoing factors, purchasers of Common Shares may not receive any return on an investment in Common Shares unless they sell such Common Shares for a price greater than that which they paid for it.

AUDIT COMMITTEE INFORMATION

National Instrument 52-110 *Audit Committees* of the Canadian Securities Administrators ("**NI 52-110**") requires the Company to disclose annually in its Annual Information Form certain information concerning the constitution of its Audit Committee and its relationship with its independent auditor.

Audit Committee Mandate and Terms of Reference for Chair

The Board has adopted a written mandate for the Audit Committee, which sets out the Audit Committee's responsibilities. The mandate states that the Audit Committee's primary purpose is to assist the Board in fulfilling its oversight responsibilities with respect to: the integrity of the Company's annual and quarterly financial statements to be provided to Shareholders and regulatory bodies; the Company's compliance with accounting and finance-based legal and regulatory requirements; the external auditor's qualifications, independence and compensation, and communicating with the external auditor; the system of internal accounting and financial reporting controls that management has established; the performance of the external audit process and of the external auditor; financial policies and strategies, including the Company's capital structure; financial risk management practices; and transactions or circumstances which could materially affect the financial profile of the Company. A copy of the mandate of the Audit Committee is attached to this Annual Information Form as Schedule "D".

Composition of the Audit Committee and Relevant Education and Experience

As at the date of filing of this Annual Information Form, the Audit Committee consists of Messrs. Marshall McRae (chair), Carlos Fierro and Robert R. Rooney. Each of the members of the Audit Committee is considered "independent" and "financially literate" within the meaning of NI 52-110.

Mr. McRae has been an independent financial and management consultant since August 2009. Prior thereto, Mr. McRae was Chief Financial Officer of CCS Inc., administrator of CCS Income Trust and its successor corporation, CCS Corporation since August 2002. Mr. McRae has over 30 years of experience in senior operating and financial management positions with a number of publicly traded and private companies, including CCS Inc., Versacold Corporation and Mark's Work Wearhouse Limited. Mr. McRae is a director and the Chair of the audit committee of Gibson Energy Inc. and a director of Black Diamond Group Limited. Mr. McRae served as interim Executive Vice President and CFO of Black Diamond Group Limited from October 16, 2013 to August 8, 2014 and as its Executive Vice President to December 31, 2014. Mr. McRae obtained a Bachelor of Commerce degree, with Distinction, from the University of Calgary in 1979, and a Chartered Accountant designation from the Institute of Chartered Accountants of Alberta in 1981.

Mr. Fierro is an independent investor and serves on public and private corporate boards. From May 2016, Mr. Fierro has served as a senior advisor to Guggenheim Securities, the investment banking arm of Guggenheim Partners. Mr. Fierro serves on the board of directors, audit and conflicts committee of Shell Midstream Partners. From September

2008 to June 2013, Mr. Fierro was the Managing Director and Global Head of the Natural Resources Group for Barclays PLC. Prior thereto, Mr. Fierro spent 11 years at Lehman Brothers, where his last role was the Global Head of the National Resources Group. Before joining Lehman Brothers, Mr. Fierro was a transactional lawyer with Baker Botts LLP., where he practiced corporate, M&A and securities law. Mr. Fierro obtained a Bachelor of Arts degree from the University of Notre Dame in 1983 and a Juris Doctor (J.D.) from Harvard University in 1986.

Mr. Rooney is currently the Chief Legal Officer and Executive Vice President at Enbridge Inc. since February 1, 2017. Prior thereto he was a co-founder and Managing Director of RimRock Oil and Gas Inc., a private Calgary based company. Before joining RimRock, Mr. Rooney was the Vice-Chairman and a director of Repsol Oil & Gas Canada Inc. Mr. Rooney was Executive Vice President, Corporate and General Counsel at Talisman Energy Inc. prior to its acquisition by Repsol S.A. in May, 2015. Prior thereto, Mr. Rooney was a partner at Bennett Jones LLP, where he was a member of the Executive Committee and co-leader of the Energy & Natural Resources Group. Mr. Rooney has been a co-founder and served as a director and officer of several public and private corporations. Mr. Rooney attended the University of Calgary, earned an LLB from Western University and is a member of the Law Society of Alberta.

The Company believes that each of the members of the Audit Committee possesses: (a) an understanding of the accounting principles used by the Company to prepare its financial statements; (b) the ability to assess the general application of such accounting principles in connection with the accounting for estimates, accruals and reserves; (c) experience preparing, auditing, analyzing or evaluating financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of issues that can reasonably be expected to be raised by the Company's financial statements, or experience actively supervising one or more individuals engaged in such activities; and (d) an understanding of internal controls and procedures for financial reporting.

Audit Committee Oversight

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

Pre-Approval Policies and Procedures for the Engagement of Non-Audit Services

The Audit Committee must pre-approve and disclose, as required, the retention of the external auditor for non-audit services to be provided to the Company or any of its subsidiaries that is permitted under applicable law. In the discretion of the Audit Committee, it may annually delegate to one or more of its independent members or to management the authority to grant pre-approvals for the provision of non-audit services; subject to, in the case of any such delegation to management, the subsequent ratification by the Audit Committee.

External Audit Service Fees

The following table summarizes the fees paid by the Company to its auditors, Ernst & Young LLP, for external audit and other services during the periods indicated.

Nature of Services	Fees Paid to Auditor in Year Ended December 31, 2016 ($)	Fees Paid to Auditor in Year Ended December 31, 2015 ($)
Audit Fees[(1)]	436,218	449,510
Audit-Related Fees[(2)]	9,750	19,490
Tax Fees[(3)]	221,124	238,610
All Other Fees[(4)]	71,930	73,160
Total	739,022	780,770

Notes:

(1) "**Audit Fees**" include fees necessary to perform the annual audit and quarterly reviews of the Company's financial statements. Audit Fees also include audit or other attest services required by legislation or regulation, such as comfort letters, consents, reviews of securities filings and statutory audits.

(2) "**Audit-Related Fees**" include services that are traditionally performed by the auditor. These audit-related services include fees for accounting consultations on International Financial Reporting Standards matters, accounting consultations on proposed transactions, internal control reviews and audit or attest services not required by legislation or regulation.

(3) "**Tax Fees**" include fees for all tax services other than those included in "Audit Fees" and "Audit-Related Fees". This category includes fees for tax compliance, tax planning and tax advice. Tax planning and tax advice includes assistance with tax audits and appeals, tax advice related to mergers and acquisitions, and requests for rulings or technical advice from tax authorities.

(4) "**All Other Fees**" include all other non-audit services. The amounts shown in All Other Fees for the years ended December 31, 2015 and 2016 primarily relate to surcharges and other outlays charged by Ernst & Young LLP.

ADDITIONAL INFORMATION

Additional information relating to the Company can be found on SEDAR at www.sedar.com. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of securities and securities authorized for issuance under the Company's equity compensation plans, is contained in the Information Circular for the Company's most recent annual meeting of securityholders that involved the election of directors. Additional financial information about Athabasca is provided in the Company's financial statements and management's discussion and analysis for the year ended December 31, 2016, which may be found on SEDAR at www.sedar.com

SCHEDULE "A1"

SUPPLEMENTAL DISCLOSURE - CONTINGENT RESOURCE ESTIMATES

Athabasca has engaged DMCL and GLJ to prepare Contingent Resource evaluations of its Hangingstone, Dover West Sands and Birch assets, all of which are located in the Province of Alberta. All of Athabasca's Contingent Resources have been evaluated in accordance with NI 51-101. DMCL's Report on Contingent Resources Data by Independent Qualified Reserves Evaluator or Auditor and GLJ's Report on Reserves Data, Contingent Resources Data by Independent Qualified Reserves Evaluator or Auditor are set forth in Schedule "C" to this Annual Information Form.

Quantities of Contingent Resources may be estimated using low estimate (high certainty), Best Estimate (most likely) and high estimate (low certainty) cases. In this Annual Information Form, Athabasca has reported its Contingent Resources using the Best Estimate case, which is considered to be the best estimate of the quantity of Contingent Resources that may actually be recovered. All of the Company's Contingent Resources disclosed herein are classified under the product type of bitumen resources. It should not be assumed that the estimates of recovery, production and net revenue that are reflected in the table that is provided below represent the fair market value of Athabasca's bitumen resources. There is no assurance that the forecast prices and cost assumptions will be realized and variances could be material and there is no guarantee that the estimated resources will be recovered or produced. Actual resources may be greater than or less than the estimates provided herein. There is no certainty that it will be commercially viable for Athabasca to produce any portion of the Contingent Resources on any of its properties.

The Contingent Resources estimates presented in the Independent Reports are based upon the definitions and guidelines contained in the COGE Handbook. A summary of the applicable definitions is set forth below:

"**Best Estimate**" is a classification of estimated resources described in the COGE Handbook as being considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the Best Estimate. If probabilistic methods are used, there should be a 50% probability (P50) that the quantities actually recovered will equal or exceed the Best Estimate.

"**chance of development**" means the estimated probability that, once discovered, a known accumulation will be commercially developed.

"**Contingent Resources**" are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include such factors as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as "Contingent Resources" the estimated discovered recoverable quantities associated with a project in the early evaluation stage.

"**Economic**" means those Contingent Resources that are currently economically recoverable based on the same fiscal conditions used in the assessment of reserves.

"**risked**" means the applicable reported volumes or revenues have been risked (or adjusted) based on the chance of commerciality of such resources in accordance with the COGE Handbook. In accordance with the COGE Handbook for contingent resources, the chance of commerciality is solely based on the chance of development based on all contingencies required for the re-classification of the contingent resources as reserves being resolved. Therefore risked reported volumes and values of contingent resources reflect the risking (or adjustment) of such volumes or values based on the chance of development of such resources.

"**unrisked**" means applicable reported volumes or values of resources have not been risked (or adjusted) based on the chance of commerciality of such resources. In accordance with the COGE Handbook for contingent resources, the chance of commerciality is solely based on the chance of development based on all contingencies required for the re-classification of the contingent resources as reserves being resolved. Therefore unrisked reported volumes and values of contingent resources do not reflect the risking (or adjustment) of such volumes or values based on the chance of development of such resources.

Contingent resources may be divided into the following project maturity sub-classes:

"**Development Pending**" is assigned to Contingent Resources for a particular project where resolution of the final conditions for development is being actively pursued (high chance of development).

"**Development On Hold**" is assigned to Contingent Resources for a particular project where there is a reasonable chance of development, but there are major non-technical contingencies to be resolved that are usually beyond the control of the operator.

"**Development Unclarified**" is assigned to Contingent Resources for a particular project where evaluation is incomplete and there is ongoing activity to resolve any risks or uncertainties or which require significant further appraisal to clarify potential for development and where contingencies have yet to be defined.

"**Development Not Viable**" is assigned to Contingent Resources for a particular project where no further data acquisition or evaluation is currently planned and there is a low chance of development.

Other Terms not defined in this Schedule "A" have the meaning ascribed to such terms under "*Glossary of Defined Terms*" in the main body of this Annual Information Form.

The following tables set forth: (a) the unrisked Best Estimate Contingent Resources; (b) the risked Best Estimate Contingent Resources; and (c) the associated risked future net revenue (before income taxes) estimates for the Contingent Resources calculated by GLJ and DMCL. The evaluation procedures employed by GLJ and DMCL are in accordance with the standards set forth in the COGE Handbook. The price forecasts that formed the basis for the net present value estimates that are contained herein were based on GLJ's January 1, 2017 pricing models set forth below under "*Forecast Prices & Costs Used in Contingent Resource Estimates*". There is no assurance that the forecast price and cost assumptions used will be realized and variances could be material. See "*Forward Looking Statements*" in this Annual Information Form.

An estimate of risked net present value of future net revenue of Contingent Resources is preliminary in nature and is provided to assist the reader in reaching an opinion on the merit and likelihood of Athabasca proceeding with the required investment. It includes Contingent Resources that are considered too uncertain with respect to the chance of development to be classified as reserves. There is uncertainty that the risked net present value of future net revenue will be realized.

Summary of Unrisked and Risked Contingent Resources and Risked Net Present Value of Future Net Revenue (Best Estimate Contingent Resources)(1,2,3,4,5,6,7,8,9,10)

						Risked Net Present Value Of Future Net Revenue Before Income Tax Discounted at (%/year)				
Project Maturity Sub-Class	Working Interest	Gross UnRisked Best Estimate Contingent Resources	Chance of Development	Gross Risked Best Estimate Contingent Resources(1)	Net Risked Best Estimate Contingent Resources	0%	5%	10%	15%	20%
	(%)	(MMboe)	(%)	(MMboe)	(MMboe)	(MM$)	(MM$)	(MM$)	(MM$)	(MM$)
Thermal Oil Assets										
Hangingstone Development Pending	100	272	89	242	192	5,452	1,124	222	-15	-83
Hangingstone Development On Hold	100	478	70	335	265	7,552	1,557	307	-20	-114
Hangingstone Development Unclarified	100	38	25	10	8	217	45	9	-1	-3
Dover West Sands On Hold	100	101	77	78	66	486	162	12	-50	-73

Project Maturity Sub-Class	Working Interest	Gross UnRisked Best Estimate Contingent Resources	Chance of Development	Gross Risked Best Estimate Contingent Resources(1)	Net Risked Best Estimate Contingent Resources	Risked Net Present Value Of Future Net Revenue Before Income Tax Discounted at (%/year) 0%	5%	10%	15%	20%
	(%)	(MMboe)	(%)	(MMboe)	(MMboe)	(MM$)	(MM$)	(MM$)	(MM$)	(MM$)
Dover West Sands Unclarified	100	2894	54	1,563	1,232	16,876	3,510	464	-200	-293
Birch On Hold	100	1441	70	1,009	797	22,462	4,473	935	131	-55
Birch Unlarified	100	675	46	310	245	6,912	1,376	288	40	-17
Total: Thermal Oil Assets		**5,900**		**3,546**	**2,805**	**59,956**	**12,248**	**2,238**	**-114**	**-637**

Notes:

(1) See definitions for "Contingent Resources", "Best Estimate", "risked", "unrisked" "Development Pending", "Development on Hold" and "Development Unclarified" above.

(2) The volumes of Contingent Resources in this table were calculated at the outlet of the proposed extraction plant.

(3) There is no certainty that it will be commercially viable to produce any portion of the Contingent Resources.

(4) The Contingent Resource estimates set out in the table reflect, as at December 31, 2016, Athabasca’s 100% working interest in the Hangingstone, Birch and Dover West Sands assets.

(5) Based on the estimates contained in the GLJ Report or the DMCL Report dated effective as of December 31, 2016, but calculated by each of GLJ and DMCL using GLJ’s pricing forecasts for consistency and in accordance with the COGE Handbook.

(6) Totals may not add due to rounding.

(7) Gross unrisked Contingent Resource volumes have been included here to provide a comparison with the Company's Contingent Resources disclosure from previous years in which risking was not included.

(8) All of the Company’s Contingent Resources are of the bitumen product type.

(9) All evaluations of future revenue are after the deduction of royalties, development costs, production costs and well abandonment and reclamation costs but before consideration of indirect costs such as administrative, overhead and other miscellaneous expenses.

(10) The estimates of Contingent Resources (Best Estimate) and future net revenue for individual properties may not reflect the same confidence levels as estimates of Contingent Resources (Best Estimate) and future net revenues for all properties, due to the effects of aggregation.

Forecast Prices & Costs Used in Contingent Resource Estimates

Year	Inflation	Bank of Canada Average Noon Exchange Rate	WTI Oil at Cushing Oklahoma Current	Light Sweet Crude Oil (40° API, 0.3%S) at Edmonton Current	WCS Stream Quality at Hardisty Current	Midwest price at Chicago Current	AECO/NIT Spot Current	Natural Gas Liquids Edmonton Pentanes Plus	Propane	Butane
	%	($US/$Cdn)	($US/bbl)	($Cdn/bbl)	($Cdn/bbl)	($USD/MMBtu)	($Cdn/MMBtu)	($Cdn/bbl)	($Cdn/bbl)	($Cdn/bbl)
2017	2.00	0.750	55.00	69.33	53.32	3.65	3.46	72.11	28.43	49.92
2018	2.00	0.775	59.00	72.26	56.79	3.25	3.10	74.79	26.74	54.19
2019	2.00	0.800	64.00	75.00	61.27	3.45	3.27	78.75	26.25	56.25
2020	2.00	0.825	67.00	76.36	63.00	3.65	3.49	79.80	26.73	57.27
2021	2.00	0.850	71.00	78.82	65.90	3.85	3.67	82.37	27.59	59.12
2022	2.00	0.850	74.00	82.35	69.42	4.05	3.86	86.06	28.82	61.76
2023	2.00	0.850	77.00	85.88	72.91	4.25	4.05	89.32	30.06	64.41
2024	2.00	0.850	80.00	89.41	76.45	4.36	4.16	92.99	31.29	67.06
2025	2.00	0.850	83.00	92.94	79.93	4.44	4.24	97.59	32.53	69.71
2026	2.00	0.850	86.05	95.61	83.47	4.53	4.32	99.91	33.46	71.71
2027+	Escalated oil, gas and product prices at 2.0% per year thereafter.									

Description of Hangingstone Contingent Resources

The Contingent Resources assigned to Athabasca's Hangingstone assets assume that such resources will be produced using SAGD technology which has been successfully implemented in the ramp up of the Hangingstone Project during 2015 and 2016. The production of the Hangingstone resources is contingent upon the completion of the Hangingstone Expansion Project 2B and Project 3, for which first oil is forecast for 2023 and 2025 respectively (for full description of the Hangingstone Expansion refer to "*Description of Athabasca's Business – Thermal Oil Division – Hangingstone assets –Hangingstone Expansion*"). The environmental impact assessment for this Hangingstone Expansion was deemed to be technically complete by the AER on October 19, 2016. The infrastructure already in place to support the Hangingstone Expansion includes the access road to the Central Production Facility, the diluent import pipeline, the dilbit sales pipeline to Cheecham Terminal and the gas import pipeline. Water source and disposal wells have been identified for the Hangingstone Expansion and are described in the environmental impact assessment. The construction of the associated water wells and pipelines will be part of the Hangingstone Expansion project.

Based on the development plan proposed by the Company, the total Best Estimate capital cost of first commercial production in 2023 at the completion of Hangingstone Expansion Project 2B is estimated at approximately $ 1020 million (uninflated, unrisked, undiscounted).

The contingencies identified for the development of the Hangingstone Contingent Resources are:

- Regulatory Approval – the environmental impact assessment was deemed to be technically complete by the AER on October 19, 2016, but there are still three SOC's outstanding. Athabasca is pursuing resolution of these SOC's and expects to resolve them in 2017.
- Corporate Commitment – the Hangingstone Expansion is not expected to be sanctioned by the Board until the Hangingstone Project has demonstrated a successful production ramp-up to design capacity, market conditions allow for further development and project funding is secured.

In accordance with the COGE Handbook, Hangingstone Contingent Resources have been divided into the sub-classes of Development Pending, Development on Hold and Development Unclarified.

The Hangingstone risked Best Estimate Contingent Resource volumes identified as Development Pending in the above table have been determined to be Economic by the Independent Evaluator. A development plan is in place and FEED has been completed on Hangingstone Project 2B. There is 3D seismic and development level delineation drilling density in these areas. First steam is planned for 2022 subject to project sanctioning. The duration of the Hangingstone Project from regulatory approval to first steam was two and a half years. Athabasca will execute the Hangingstone Expansion with the same proven execution strategy and facility design utilized for the Hangingstone Project, consequently Athabasca does not need to do further work on the Hangingstone Expansion until 2019 to maintain a reasonable expectation of reaching first steam in 2022. The chance of development of these resources is estimated to be approximately 90% given their proximity to the existing HS CPF and the level of existing delineation but subject to market conditions and securing a suitable means of financing.

The Hangingstone risked Best Estimate Contingent Resource volumes identified as Development On Hold in the above table have been determined to be Economic by the Independent Evaluator. These resources have adequate delineation to support resource classification and an investment decision and a development plan is in place. Incremental delineation will be completed in future to support execution in line with standard staged development project execution. These resources are considered to be Development On Hold rather than Development Pending as Athabasca has chosen not to develop them until after development of the Development Pending Contingent Resources. The chance of development of these Contingent Resources is estimated to be 70% given that they are geographically further from the HS CPF than the Development Pending Contingent Resources, they have a lower level of delineation and their development is subject to required regulatory approvals, market conditions, securing a suitable means of financing and corporate commitment to proceed.

The Hangingstone risked Best Estimate Contingent Resource volumes identified as Development Unclarified in the above table have been determined to be Economic by the Independent Evaluator. These Contingent Resources are considered to be Development Unclarified rather than Development Pending or Development on Hold as there is a lower level of delineation in this area and they are located physically furthest from the HS CPF. The delineation conducted to date is sufficient to prepare the development strategy consistent with a project evaluation scenario status of pre-development. Based on the COGE Handbook, a pre-development study is considered an intermediate step in the development of a project evaluation scenario. The level of economic analysis is sufficient to assess development options and overall project viability, but is insufficient for a final investment decision. For these resources, additional delineation to refine pad layouts and successful execution of the project will be required in order to advance these assets to a project evaluation scenario status of Development On Hold. The chance of development of these Contingent Resources is estimated to be 25% due to their physical location and delineation level and their development is subject to required regulatory approvals, market conditions, securing a suitable means of financing and corporate commitment to proceed.

The positive factors relevant to the Contingent Resource estimates for Hangingstone include:

- Using established technology which has been successfully implemented in the Hangingstone Project.
- The environmental impact assessment has been deemed technically complete by the AER.
- A development plan is in place for all phases of the asset for the full lifecycle of the project (however, for the Contingent Resources in the Development Unclarified project maturity sub-class, the development plan is based on a pre-development study).
- The reservoir has been defined across the asset using delineation drilling as well as 2D and 3D seismic. The level of delineation supports the risks assigned to the different project maturity sub-classes. As development progresses in Hangingstone, incremental delineation across the asset may result in changes to the project maturity sub-classes and to the assigned risks.
- Existing infrastructure supporting development of the Contingent Resources including an access road to the HS CPF, the diluent import pipeline, the dilbit sales pipeline from the HS CPF to the Enbridge Cheecham terminal and the gas import pipeline. All pipelines are sized to transport the respective products to support 80,000 bbl/d of bitumen production.
- Pipeline capacity to take up to 80,000 bbl/d of bitumen to Edmonton.
- Water source and disposal wells are identified.
- A salt zone suitable to build caverns used to process water treatment waste have been located and tested adjacent to the HS CPF. The regulatory ownership rights for the salt zones have been secured that support the lifecycle requirements of the Hangingstone asset.

The negative factors relevant to the Contingent Resource estimates for Hangingstone include:

- Economic sensitivity to future oil pricing.
- Uncertainty regarding regulatory regimes in Alberta.
- Ability to access project funding.
- Potential lack of pipeline capacity beyond Edmonton to access bitumen markets.
- Resource scarcity attributable to a number of other oil sands projects being developed in the area in the same timeframe.

See also "*Risk Factors*" in this Annual Information Form.

Description of Dover West Sands Contingent Resources

The estimates of Contingent Resources assigned to Athabasca's Dover West Sands assets assume that such resources will be produced using SAGD technology. There are adequate analogues in the area and reservoir studies to confirm that SAGD is applicable to the Dover West reservoir. Athabasca will leverage the experience gained in successfully delivering and ramping up the Hangingstone Project during 2015 and 2016 to deliver the Dover West Sands Project 1. The commencement of production from the Dover West Sands resources is contingent upon the commissioning and completion of the 12,000 bbl/d Dover West Sands Project 1 for which first oil is forecast in 2023. If commissioned and completed, the second phase of the Dover West Sands Project is expected to have a capacity of 40,000 bbl/d with first oil expected in 2026. If commissioned and completed, six subsequent 40,000 bbl/d phases may follow at two yearly intervals to the expected ultimate approximate capacity of 290,000 bbl/d.

The regulatory application for the Dover West Sands Project 1 was submitted to the ERCB (now the AER) in December 2011. The application process was prolonged as Athabasca was focused on an SOC that had been filed by the FMFN in relation to the Dover Oil Sands Project of which Athabasca was a 40% owner at the time and as such the Dover West Sands Project 1 regulatory application was not progressed by Athabasca during this time period pending closure of the SOC (which took approximately 2 years). During the intervening period, Athabasca has been assessing the development timeline of the Dover West Sands Project 1. Given the change in global commodity prices has affected the ability to finance projects in the near term, the considerable uncertainty in regulatory and royalty regimes and Athabasca's focus on its Hangingstone Project in the immediate future, a decision regarding proceeding with the regulatory application has not yet been taken. Due to this uncertainty, 87 MMboe of Probable Reserves (which had previously been allocated in the GLJ independent report effective December 31, 2014), were re-classified in 2015 as Contingent Resources in the Independent Reports and this did not change for the year ending December 31, 2016.

The only infrastructure already in place to support the Dover West Sands Project 1 is an access road.

Based on the development plan proposed by the Company, the total Best Estimate capital cost of first commercial production in 2023 for Dover West Sands Project 1 is estimated at approximately $595 million (uninflated, unrisked, undiscounted).

The contingencies identified for the development of the Dover West Sands Contingent Resources are:

- Regulatory Approval – an application has been filed but approval has not yet been granted.
- Corporate Commitment – the Dover West Sands project is not expected to be sanctioned by the Board until market conditions allow and project funding is secured.
- Delineation – development level delineation has only been achieved in the Development On Hold area of the reservoir. Further delineation is required in the Development Unclarified area before a final investment decision can be made.

In accordance with the in the COGE Handbook, Dover West Sands Contingent Resources have been divided into the sub-classes of Development On Hold and Development Unclarified.

The Dover West Sands risked Best Estimate Contingent Resource volumes identified as Development On Hold in the above table have been determined to be Economic by the Independent Evaluator. These resources will be produced via the Dover West Sands Project 1 for which a development plan is in place and FEED has been completed. There is 3D seismic and development level delineation drilling density in these areas. These resources are considered to be Development On Hold rather than Development Pending as Athabasca does not yet have regulatory approval and, due to the current economic climate, Athabasca does not expect to produce these resources before 2023. The duration of the Hangingstone Project from regulatory approval to first steam was approximately two and a half years. Athabasca will execute the Dover West Sands Project 1 with the same execution strategy and facility design utilized for the Hangingstone Project, consequently Athabasca does not need to do further work on the Dover West Sands Phase 1 project until 2020 to maintain a reasonable expectation of reaching first steam in 2023. The chance of development of these Contingent Resources is estimated to be 77% due to uncertainties related to the regulatory application status, securing a suitable means of financing, market conditions and corporate commitment to proceed.

The Dover West Sands risked Best Estimate Contingent Resource volumes identified as Development Unclarified in the above table have been determined to be Economic by the Independent Evaluator. These Contingent Resources are considered to be Development Unclarified rather than Development Pending or Development on Hold as there is a lower level of delineation in these areas and they are located physically further from the proposed Dover West Sands Project 1 central processing area. The delineation conducted to date is sufficient to prepare the development strategy consistent with a project evaluation scenario status of pre-development. Based on the COGE Handbook, a pre-development study is considered an intermediate step in the development of a project evaluation scenario. The level of economic analysis is sufficient to assess development options and overall project viability, but is insufficient for a final investment decision. For these resources, additional delineation to refine pad layouts and successful execution of the project will be required in order to advance these assets to a project evaluation scenario status of Development On Hold. The chance of development of these Contingent Resources is estimated to be 54% due to their physical location, delineation level, required regulatory approvals, market conditions, securing a suitable means of financing and corporate commitment to proceed.

The positive factors relevant to the Contingent Resource estimates for Dover West Sands include:

- Using established technology which is being successfully implemented in the Hangingstone Project.
- The regulatory application has been submitted for Dover West Sands Project 1.
- A development plan is in place for all phases of the assets (however, for the Contingent Resources in the Development Unclarified project maturity sub-class, the development plan is based on a pre-development study) for the full lifecycle and FEED has been completed for Dover West Sands Project 1.
- The reservoir has been defined across the asset using delineation drilling as well as 2D and 3D seismic. The level of delineation supports the risks assigned to the different project maturity sub-classes. As development progresses in Dover West Sands, incremental delineation across the asset may result in changes to the project maturity sub-classes and to the assigned risks.
- Water source and disposal wells identified for Dover West Sands Project 1.

The negative factors relevant to the Contingent Resource estimates for Dover West Sands include:

- Economic sensitivity to future oil pricing.
- Minimal existing infrastructure.
- Uncertainty regarding regulatory regimes in Alberta.
- Ability to access project funding.
- Potential lack of pipeline capacity to access bitumen markets.
- Resource scarcity attributable to a number of other oil sands projects being developed in the area in the same timeframe.

See also "*Risk Factors*" in this Annual Information Form.

Description of Birch Contingent Resources

The Contingent Resources assigned to Athabasca's Birch assets assume that the resources will be produced using SAGD technology. There are adequate analogues in the area and reservoir studies to confirm that SAGD is applicable to the Birch reservoir. Athabasca will leverage the experience gained in successfully delivering and ramping up the Hangingstone Project during 2015 and 2016 to deliver the Birch project. The production of the Birch resources is contingent upon the completion of the first phase of the Birch Project which, if commissioned, is planned to be on stream in 2025 with a capacity of 12,000 bbl/d. If commissioned and completed, the second phase of the Birch Project is expected to have a capacity of 40,000 bbl/d with first oil expected in 2028. If commissioned and completed, three subsequent 40,000 bbl/d phases are expected to follow at two yearly intervals to the expected ultimate approximate capacity of 170,000 bbl/d.

A field development plan has been developed for Birch but an environmental impact assessment application has not been submitted.

There is currently no infrastructure in place to support the Birch Project.

Based on the development plan proposed by the Company, the total Best Estimate capital cost of first commercial production in 2025 for the Birch Project is estimated at approximately $660 million (uninflated, unrisked, undiscounted).

The contingencies identified for the development of the Birch Contingent Resources are:

- Regulatory Approval – an application has not been filed for the Birch Project.
- Corporate Commitment – the Birch Project is not expected to be sanctioned by the Board until market conditions allow and project funding is secured.

- Delineation – development level delineation has only been achieved in the Development On Hold area of the Birch Project reservoir. Further delineation is required in the Development Unclarified area before a final investment decision can be made.
- Project Timing – the first phase of the Birch Project is not anticipated to start up until 2025 and significant spending is not anticipated before 2022.

In accordance with the COGE Handbook, Birch Contingent Resources have been divided into the sub-classes of Development on Hold and Development Unclarified.

The Birch risked Best Estimate Contingent Resource volumes identified as Development On Hold in the above table have been determined to be Economic by the Independent Evaluator. There is sufficient 3D seismic and delineation drilling density in these areas to support both application and development requirements and a development plan is in place. These resources are considered to be Development On Hold rather than Development Pending as Athabasca does not yet have regulatory approval and, due to the current economic climate, Athabasca does not expect to produce these resources before 2024. The duration of the Hangingstone Project from commencement of preparation of the regulatory application to first steam was four and a half years. Athabasca will execute the Birch Project with the same execution strategy and facility design utilized for the Hangingstone Project, consequently Athabasca does not need to do further work on the Birch project until 2019 to maintain a reasonable expectation of reaching first steam in 2024. The chance of development of these Contingent Resources is estimated to be 70% due to uncertainties related to the regulatory approvals required, securing a suitable means of financing and corporate commitment to proceed.

The Birch risked Best Estimate Contingent Resource volumes identified as Development Unclarified in the above table have been determined to be Economic by the Independent Evaluator. These Contingent Resources are considered to be Development Unclarified rather than Development Pending or Development on Hold as there is a lower level of delineation in these areas and they are located physically further from the proposed Birch Project central processing area. The delineation is sufficient to prepare the development strategy consistent with a project evaluation scenario status of pre-development. Based on the COGE Handbook, a pre-development study is considered an intermediate step in the development of a project evaluation scenario. The level of economic analysis is sufficient to assess development options and overall project viability, but is insufficient for a final investment decision. For these resources, additional delineation to refine pad layouts and successful execution of the project will be required in order to advance these assets to a project evaluation scenario status of Development On Hold. The chance of development of these Contingent Resources is estimated to be 54% due to their physical location, delineation level, regulatory approvals required, securing a suitable means of financing and corporate commitment to proceed.

The positive factors relevant to the Contingent Resource estimates for the Birch Project include:

- Using established technology which is being successfully implemented in the Hangingstone Project.
- A development plan is in place for all phases of the assets (however, for the Contingent Resources in the Development Unclarified project maturity sub-class, the development plan is based on a pre-development study) for the full lifecycle of the Birch Project.
- The reservoir has been defined across the asset using delineation drilling as well as 2D and 3D seismic. The level of delineation supports the risks assigned to the different project maturity sub-classes. As development progresses in Birch, incremental delineation across the asset may result in changes to the project maturity sub-classes and to the assigned risks.

The negative factors relevant to the Contingent Resource estimates for the Birch Project include:

- Economic sensitivity to future oil pricing.
- No existing infrastructure.
- Uncertainty regarding regulatory regimes in Alberta.
- Ability to access project funding.
- Potential lack of pipeline capacity to access bitumen markets.
- A regulatory application has not yet been submitted for the Birch Project.
- Resource scarcity attributable to a number of other oil sands projects being developed in the area in the same timeframe.

See also "*Risk Factors*" in this Annual Information Form.

Abandonment and Reclamation Costs

In the Independent Reports, DMCL and GLJ have included an estimate of the costs to abandon and reclaim all existing and future wells, pipelines and major dedicated facilities associated with assessed Contingent Resources. No estimate of salvage value is netted against the estimated abandonment and reclamation costs. The estimate for abandonment and reclamation costs are based on the Company's estimation of costs to remediate, reclaim and abandon wells and facilities in which it has a working interest.

The Independent Reports include a Best Estimate for abandonment and reclamation costs (unrisked, undiscounted) of $715 million at Hangingstone, $4,226 million at Dover West Sands and $2166 million at Birch. Abandonment and reclamation costs in the Independent Reports represent all costs associated with the process of restoring the Company's properties (to which Contingent Resources have been allocated) which have been disturbed by oil and gas activities, to a standard imposed by applicable government or regulatory authorities. Abandonment and reclamation costs including all development drilling and all material dedicated gathering and processing facility expansions or builds required to enable production of the Contingent Resources, are included in the Independent Reports.

SCHEDULE "A2"

SUPPLEMENTAL DISCLOSURE - CONTINGENT RESOURCE ESTIMATES PRO FORMA – AS AT DECEMBER 31, 2016

On January 31, 2017, Athabasca completed the Asset Acquisition. Athabasca engaged GLJ to prepare the Acquisition Independent Report, which is an independent assessment and evaluation of Athabasca's consolidated pro forma bitumen, light crude oil and medium crude oil, tight oil, conventional natural gas, shale gas and NGL reserves and Contingent Resources as at December 31, 2016 and the net present values of future net revenue for these reserves and Contingent Resources using forecast prices and costs as at December 31, 2016 after giving effect the Asset Acquisition and assuming that the Asset Acquisition was completed on December 31, 2016. Although Athabasca did not acquire the Acquired Assets until January 31, 2017, and therefore did not beneficially own the Contingent Resources attributable to the Acquired Assets until such date, the information presented in this supplemental Contingent Resource Disclosure is shown for convenience of reference, on a pro-forma basis, effective December 31, 2016.

The resources data set forth below is based upon a consolidation of the reports prepared by (i) GLJ dated January 5, 2017 relating to the Acquired Assets and (ii) GLJ dated February 9, 2017 relating to the Company's other assets excluding the Acquired Assets with an effective date of December 31, 2016 and (iii) the DMCL Report with an effective date of December 31, 2016. All of Athabasca's Contingent Resources have been evaluated in accordance with NI 51-101 and the COGE Handbook. The Acquisition Independent Report and Athabasca's Contingent Resources were prepared and evaluated in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101 and the COGE Handbook.

Quantities of Contingent Resources may be estimated using low estimate (high certainty), Best Estimate (most likely) and high estimate (low certainty) cases. In this Annual Information Form, Athabasca has reported its Contingent Resources using the Best Estimate case, which is considered to be the best estimate of the quantity of Contingent Resources that may actually be recovered. All of the Company's Contingent Resources disclosed herein are classified under the product type of bitumen resources. It should not be assumed that the estimates of recovery, production and net revenue that are reflected in the table that is provided below represent the fair market value of Athabasca's bitumen resources. There is no assurance that the forecast prices and cost assumptions will be realized and variances could be material and there is no guarantee that the estimated resources will be recovered or produced. Actual resources may be greater than or less than the estimates provided herein. There is no certainty that it will be commercially viable for Athabasca to produce any portion of the Contingent Resources on any of its properties.

The Contingent Resources estimates presented in the Acquisition Independent Report and the Independent Reports are based upon the definitions and guidelines contained in the COGE Handbook. A summary of the applicable definitions is set forth below:

"**Best Estimate**" is a classification of estimated resources described in the COGE Handbook as being considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the Best Estimate. If probabilistic methods are used, there should be a 50% probability (P50) that the quantities actually recovered will equal or exceed the Best Estimate.

"**chance of development**" means the estimated probability that, once discovered, a known accumulation will be commercially developed.

"**Contingent Resources**" are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include such factors as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as "Contingent Resources" the estimated discovered recoverable quantities associated with a project in the early evaluation stage.

"**Economic**" means those Contingent Resources that are currently economically recoverable based on the same fiscal conditions used in the assessment of reserves.

"**risked**" means the applicable reported volumes or revenues have been risked (or adjusted) based on the chance of commerciality of such resources in accordance with the COGE Handbook. In accordance with the COGE Handbook for contingent resources, the chance of commerciality is solely based on the chance of development based on all contingencies required for the re-classification of the contingent resources as reserves being resolved. Therefore risked reported volumes and values of contingent resources reflect the risking (or adjustment) of such volumes or values based on the chance of development of such resources.

"**unrisked**" means applicable reported volumes or values of resources have not been risked (or adjusted) based on the chance of commerciality of such resources. In accordance with the COGE Handbook for contingent resources, the chance of commerciality is solely based on the chance of development based on all contingencies required for the re-classification of the contingent resources as reserves being resolved. Therefore unrisked reported volumes and values of contingent resources do not reflect the risking (or adjustment) of such volumes or values based on the chance of development of such resources.

Contingent resources may be divided into the following project maturity sub-classes:

"**Development Pending**" is assigned to Contingent Resources for a particular project where resolution of the final conditions for development is being actively pursued (high chance of development).

"**Development On Hold**" is assigned to Contingent Resources for a particular project where there is a reasonable chance of development, but there are major non-technical contingencies to be resolved that are usually beyond the control of the operator.

"**Development Unclarified**" is assigned to Contingent Resources for a particular project where evaluation is incomplete and there is ongoing activity to resolve any risks or uncertainties or which require significant further appraisal to clarify potential for development and where contingencies have yet to be defined.

"**Development Not Viable**" is assigned to Contingent Resources for a particular project where no further data acquisition or evaluation is currently planned and there is a low chance of development.

Other Terms not defined in this Schedule "A" have the meaning ascribed to such terms under "*Glossary of Defined Terms*" in the main body of this Annual Information Form.

The following tables set forth: (a) the unrisked Best Estimate Contingent Resources; (b) the risked Best Estimate Contingent Resources; and (c) the associated risked future net revenue (before income taxes) estimates for the Contingent Resources calculated by GLJ in the Acquisition Independent Report. The evaluation procedures employed by GLJ and DMCL are in accordance with the standards set forth in the COGE Handbook. The price forecasts that formed the basis for the net present value estimates that are contained herein were based on GLJ's January 1, 2017 pricing models set forth below under "*Forecast Prices & Costs Used in Contingent Resource Estimates*". There is no assurance that the forecast price and cost assumptions used will be realized and variances could be material. See "*Forward Looking Statements*" in this Annual Information Form.

An estimate of risked net present value of future net revenue of Contingent Resources is preliminary in nature and is provided to assist the reader in reaching an opinion on the merit and likelihood of Athabasca proceeding with the required investment. It includes Contingent Resources that are considered too uncertain with respect to the chance of development to be classified as reserves. There is uncertainty that the risked net present value of future net revenue will be realized.

Summary of Unrisked and Risked Contingent Resources and Risked Net Present Value of Future Net Revenue (Best Estimate Contingent Resources)[1,2,3,4,5,6,7,8,9,10]

Project Maturity Sub-Class	Working Interest	Gross UnRisked Best Estimate Contingent Resources	Chance of Development	Gross Risked Best Estimate Contingent Resources(1)	Net Risked Best Estimate Contingent Resources	Risked Net Present Value Of Future Net Revenue Before Income Tax Discounted at (%/year) 0%	5%	10%	15%	20%
	(%)	(MMboe)	(%)	(MMboe)	(MMboe)	(MM$)	(MM$)	(MM$)	(MM$)	(MM$)
Thermal Oil Assets										
Corner Unclarified	100	372	69	257	211	5,504	1,752	592	191	41
Leismer Unclarified	100	257	76	195	163	2,742	1,512	563	109	-97
Hangingstone Development Pending	100	272	89	242	192	5,452	1,124	222	-15	-83
Hangingstone Development On Hold	100	478	70	335	265	7,552	1,557	307	-20	-114
Hangingstone Development Unclarified	100	38	25	10	8	217	45	9	-1	-3
Dover West Sands On Hold	100	101	77	78	66	486	162	12	-50	-73
Dover West Sands Unclarified	100	2894	54	1,563	1,232	16,876	3,510	464	-200	-293
Birch On Hold	100	1441	70	1,009	797	22,462	4,473	935	131	-55
Birch Unlarified	100	675	46	310	245	6,912	1,376	288	40	-17
Total: Thermal Oil Assets		**6,529**		**3,998**	**3,179**	**68,203**	**15,511**	**3,393**	**186**	**-693**

Notes:

(1) See definitions for "Contingent Resources", "Best Estimate", "risked", "unrisked" "Development Pending", "Development on Hold" and "Development Unclarified" above.

(2) The volumes of Contingent Resources in this table were calculated at the outlet of the proposed extraction plant.

(3) There is no certainty that it will be commercially viable to produce any portion of the Contingent Resources.

(4) The pro forma Contingent Resource estimates set out in the table reflect, as at December 31, 2016, Athabasca’s 100% working interest in the Hangingstone, Birch and Dover West Sands assets and its 100% working interest in the Acquired Assets.

(5) Based on the estimates contained in the Acquisition Independent Report and the Independent Reports dated effective as of December 31, 2016, calculated by GLJ and DMCL using GLJ’s pricing forecasts for consistency and in accordance with the COGE Handbook.

(6) Totals may not add due to rounding.

(7) Gross unrisked Contingent Resource volumes have been included here to provide a comparison with the Company's Contingent Resources disclosure from previous years in which risking was not included.

(8) All of the Company’s Contingent Resources are of the bitumen product type.

(9) All evaluations of future revenue are after the deduction of royalties, development costs, production costs and well abandonment and reclamation costs but before consideration of indirect costs such as administrative, overhead and other miscellaneous expenses.

(10) The estimates of Contingent Resources (Best Estimate) and future net revenue for individual properties may not reflect the same confidence levels as estimates of Contingent Resources (Best Estimate) and future net revenues for all properties, due to the effects of aggregation.

Forecast Prices & Costs Used in Contingent Resource Estimates

Year	Inflation	Bank of Canada Average Noon Exchange Rate	WTI Oil at Cushing Oklahoma Current	Light Sweet Crude Oil (40° API, 0.3%S) at Edmonton Current	WCS Stream Quality at Hardisty Current	Midwest price at Chicago Current	AECO/NIT Spot Current	Natural Gas Liquids Edmonton Pentanes Plus	Propane	Butane
	%	($US/$Cdn)	($US/bbl)	($Cdn/bbl)	($Cdn/bbl)	($USD/MMBtu)	($Cdn/MMBtu)	($Cdn/bbl)	($Cdn/bbl)	($Cdn/bbl)
2017	2.00	0.750	55.00	69.33	53.32	3.65	3.46	72.11	28.43	49.92
2018	2.00	0.775	59.00	72.26	56.79	3.25	3.10	74.79	26.74	54.19
2019	2.00	0.800	64.00	75.00	61.27	3.45	3.27	78.75	26.25	56.25
2020	2.00	0.825	67.00	76.36	63.00	3.65	3.49	79.80	26.73	57.27
2021	2.00	0.850	71.00	78.82	65.90	3.85	3.67	82.37	27.59	59.12
2022	2.00	0.850	74.00	82.35	69.42	4.05	3.86	86.06	28.82	61.76
2023	2.00	0.850	77.00	85.88	72.91	4.25	4.05	89.32	30.06	64.41
2024	2.00	0.850	80.00	89.41	76.45	4.36	4.16	92.99	31.29	67.06
2025	2.00	0.850	83.00	92.94	79.93	4.44	4.24	97.59	32.53	69.71
2026	2.00	0.850	86.05	95.61	83.47	4.53	4.32	99.91	33.46	71.71
2027+	Escalated oil, gas and product prices at 2.0% per year thereafter.									

Description of Hangingstone Contingent Resources

The Contingent Resources assigned to Athabasca's Hangingstone assets assume that such resources will be produced using SAGD technology which has been successfully implemented in the ramp up of the Hangingstone Project during 2015 and 2016. The production of the Hangingstone resources is contingent upon the completion of the Hangingstone Expansion Project 2B and Project 3, for which first oil is forecast for 2023 and 2025 respectively (for full description of the Hangingstone Expansion refer to "*Description of Athabasca's Business – Thermal Oil Division – Hangingstone assets –Hangingstone Expansion*"). The environmental impact assessment for this Hangingstone Expansion was deemed to be technically complete by the AER on October 19, 2016. The infrastructure already in place to support the Hangingstone Expansion includes the access road to the Central Production Facility, the diluent import pipeline, the dilbit sales pipeline to Cheecham Terminal and the gas import pipeline. Water source and disposal wells have been identified for the Hangingstone Expansion and are described in the environmental impact assessment. The construction of the associated water wells and pipelines will be part of the Hangingstone Expansion project.

Based on the development plan proposed by the Company, the total Best Estimate capital cost of first commercial production in 2023 at the completion of Hangingstone Expansion Project 2B is estimated at approximately $1020 million (uninflated, unrisked, undiscounted).

The contingencies identified for the development of the Hangingstone Contingent Resources are:

- Regulatory Approval – the environmental impact assessment was deemed to be technically complete by the AER on October 19, 2016, but there are still three SOC's outstanding. Athabasca is pursuing resolution of these SOC's and expects to resolve them in 2017.
- Corporate Commitment – the Hangingstone Expansion is not expected to be sanctioned by the Board until the Hangingstone Project has demonstrated a successful production ramp-up to design production, market conditions allow for further development and project funding is secured.

In accordance with the COGE Handbook, Hangingstone Contingent Resources have been divided into the sub-classes of Development Pending, Development on Hold and Development Unclarified.

The Hangingstone risked Best Estimate Contingent Resource volumes identified as Development Pending in the above table have been determined to be Economic by the Independent Evaluator. A development plan is in place and FEED has been completed on Hangingstone Project 2B. There is 3D seismic and development level delineation drilling density in these areas. First steam is planned for 2022 subject to project sanctioning. The duration of the Hangingstone Project from regulatory approval to first steam was two and a half years. Athabasca will execute the Hangingstone Expansion with the same proven execution strategy and facility design utilized for the Hangingstone Project, consequently Athabasca does not need to do further work on the Hangingstone Expansion until 2019 to maintain a reasonable expectation of reaching first steam in 2022. The chance of development of these resources is estimated to be approximately 90% given their proximity to the existing HS CPF and the level of existing delineation but subject to market conditions and securing a suitable means of financing.

The Hangingstone risked Best Estimate Contingent Resource volumes identified as Development On Hold in the above table have been determined to be Economic by the Independent Evaluator. These resources have adequate delineation to support resource classification and an investment decision and a development plan is in place. Incremental delineation will be completed in future to support execution in line with standard staged development project execution. These resources are considered to be Development On Hold rather than Development Pending as Athabasca has chosen not to develop them until after development of the Development Pending Contingent Resources. The chance of development of these Contingent Resources is estimated to be 70% given that they are geographically further from the HS CPF than the Development Pending Contingent Resources, they have a lower level of delineation and their development is subject to required regulatory approvals, market conditions, securing a suitable means of financing and corporate commitment to proceed.

The Hangingstone risked Best Estimate Contingent Resource volumes identified as Development Unclarified in the above table have been determined to be Economic by the Independent Evaluator. These Contingent Resources are considered to be Development Unclarified rather than Development Pending or Development on Hold as there is a lower level of delineation in this area and they are located physically furthest from the HS CPF. The delineation conducted to date is sufficient to prepare the development strategy consistent with a project evaluation scenario status of pre-development. Based on the COGE Handbook, a pre-development study is considered an intermediate step in the development of a project evaluation scenario. The level of economic analysis is sufficient to assess development options and overall project viability, but is insufficient for a final investment decision. For these resources, additional delineation to refine pad layouts and successful execution of the project will be required in order to advance these assets to a project evaluation scenario status of Development On Hold. The chance of development of these Contingent Resources is estimated to be 25% due to their physical location and delineation level and their development is subject to required regulatory approvals, market conditions, securing a suitable means of financing and corporate commitment to proceed.

The positive factors relevant to the Contingent Resource estimates for Hangingstone include:

- Using established technology which has been successfully implemented in the Hangingstone Project.
- The environmental impact assessment has been deemed technically complete by the AER.
- A development plan is in place for all phases of the asset for the full lifecycle of the project (however, for the Contingent Resources in the Development Unclarified project maturity sub-class, the development plan is based on a pre-development study).
- The reservoir has been defined across the asset using delineation drilling as well as 2D and 3D seismic. The level of delineation supports the risks assigned to the different project maturity sub-classes. As development progresses in Hangingstone, incremental delineation across the asset may result in changes to the project maturity sub-classes and to the assigned risks.
- Existing infrastructure supporting development of the Contingent Resources including an access road to the HS CPF, the diluent import pipeline, the dilbit sales pipeline from the HS CPF to the Enbridge Cheecham terminal and the gas import pipeline. All pipelines are sized to transport the respective products to support 80,000 bbl/d of bitumen production.
- Pipeline capacity to take up to 80,000 bbl/d of bitumen to Edmonton.
- Water source and disposal wells are identified.
- A salt zone suitable to build caverns used to process water treatment waste have been located and tested adjacent to the HS CPF. The regulatory ownership rights for the salt zones have been secured that support the lifecycle requirements of the Hangingstone asset.

The negative factors relevant to the Contingent Resource estimates for Hangingstone include:

- Economic sensitivity to future oil pricing.
- Uncertainty regarding regulatory regimes in Alberta.
- Ability to access project funding.
- Potential lack of pipeline capacity beyond Edmonton to access bitumen markets.

- Resource scarcity attributable to a number of other oil sands projects being developed in the area in the same timeframe.

See also "*Risk Factors*" in this Annual Information Form.

Description of Dover West Sands Contingent Resources

The estimates of Contingent Resources assigned to Athabasca's Dover West Sands assets assume that such resources will be produced using SAGD technology. There are adequate analogues in the area and reservoir studies to confirm that SAGD is applicable to the Dover West reservoir. Athabasca will leverage the experience gained in successfully delivering and ramping up the Hangingstone Project during 2015 and 2016 to deliver the Dover West Sands Project 1. The commencement of production from the Dover West Sands resources is contingent upon the commissioning and completion of the 12,000 bbl/d Dover West Sands Project 1 for which first oil is forecast in 2023. If commissioned and completed, the second phase of the Dover West Sands Project is expected to have a capacity of 40,000 bbl/d with first oil expected in 2026. If commissioned and completed, six subsequent 40,000 bbl/d phases may follow at two yearly intervals to the expected ultimate approximate capacity of 290,000 bbl/d.

The regulatory application for the Dover West Sands Project 1 was submitted to the ERCB (now the AER) in December 2011. The application process was prolonged as Athabasca was focused on an SOC that had been filed by the FMFN in relation to the Dover Oil Sands Project of which Athabasca was a 40% owner at the time and as such the Dover West Sands Project 1 regulatory application was not progressed by Athabasca during this time period pending closure of the SOC (which took approximately 2 years). During the intervening period, Athabasca has been assessing the development timeline of the Dover West Sands Project 1. Given the change in global commodity prices has affected the ability to finance projects in the near term, the considerable uncertainty in regulatory and royalty regimes and Athabasca's focus on its the Hangingstone Project in the immediate future, a decision regarding proceeding with the regulatory application has not yet been taken. Due to this uncertainty, 87 MMboe of Probable Reserves (which had previously been allocated in the GLJ independent report effective December 31, 2014), were re-classified in 2015 as Contingent Resources in the Independent Reports and this did not change for the year ending December 31, 2016.

The only infrastructure already in place to support the Dover West Sands Project 1 is an access road.

Based on the development plan proposed by the Company, the total Best Estimate capital cost of first commercial production in 2023 for Dover West Sands Project 1 is estimated at approximately $595 million (uninflated, unrisked, undiscounted).

The contingencies identified for the development of the Dover West Sands Contingent Resources are:

- Regulatory Approval – an application has been filed but approval has not yet been granted.
- Corporate Commitment – the Dover West Sands project is not expected to be sanctioned by the Board until market conditions allow and project funding is secured.
- Delineation – development level delineation has only been achieved in the Development On Hold area of the reservoir. Further delineation is required in the Development Unclarified area before a final investment decision can be made.

In accordance with the in the COGE Handbook, Dover West Sands Contingent Resources have been divided into the sub-classes of Development On Hold and Development Unclarified.

The Dover West Sands risked Best Estimate Contingent Resource volumes identified as Development On Hold in the above table have been determined to be Economic by the Independent Evaluator. These resources will be produced via the Dover West Sands Project 1 for which a development plan is in place and FEED has been completed. There is 3D seismic and development level delineation drilling density in these areas. These resources are considered to be Development On Hold rather than Development Pending as Athabasca does not yet have regulatory approval and, due to the current economic climate, Athabasca does not expect to produce these resources before 2023. The duration of the Hangingstone Project from regulatory approval to first steam was approximately two and a half years. Athabasca will execute the Dover West Sands Project 1 with the same execution strategy and facility design utilized for the Hangingstone Project, consequently Athabasca does not need to do further work on the Dover West Sands Phase 1 project until 2020 to maintain a reasonable expectation of reaching first steam in 2023. The chance of development of these Contingent Resources is estimated to be 77% due to uncertainties related to the regulatory application status, securing a suitable means of financing, market conditions and corporate commitment to proceed.

The Dover West Sands risked Best Estimate Contingent Resource volumes identified as Development Unclarified in the above table have been determined to be Economic by the Independent Evaluator. These Contingent Resources are considered to be Development Unclarified rather than Development Pending or Development on Hold as there is a lower level of delineation in these areas and they are located physically further from the proposed Dover West Sands Project 1 central processing area. The delineation conducted to date is sufficient to prepare the development strategy consistent with a project evaluation scenario status of pre-development. Based on the COGE Handbook, a pre-development study is considered an intermediate step in the development of a project evaluation scenario. The level of economic analysis is sufficient to assess development options and overall project viability, but is insufficient for a final investment decision. For these resources, additional delineation to refine pad layouts and successful execution of the project will be required in order to advance these assets to a project evaluation scenario status of Development On Hold. The chance of development of these Contingent Resources is estimated to be 54% due to their physical location, delineation level, required regulatory approvals, market conditions, securing a suitable means of financing and corporate commitment to proceed.

The positive factors relevant to the Contingent Resource estimates for Dover West Sands include:

- Using established technology which is being successfully implemented in the Hangingstone Project.
- The regulatory application has been submitted for Dover West Sands Project 1.
- A development plan is in place for all phases of the assets (however, for the Contingent Resources in the Development Unclarified project maturity sub-class, the development plan is based on a pre-development study) for the full lifecycle and FEED has been completed for Dover West Sands Project 1.
- The reservoir has been defined across the asset using delineation drilling as well as 2D and 3D seismic. The level of delineation supports the risks assigned to the different project maturity sub-classes. As development progresses in Dover West Sands, incremental delineation across the asset may result in changes to the project maturity sub-classes and to the assigned risks.
- Water source and disposal wells identified for Dover West Sands Project 1.

The negative factors relevant to the Contingent Resource estimates for Dover West Sands include:

- Economic sensitivity to future oil pricing.
- Minimal existing infrastructure.
- Uncertainty regarding regulatory regimes in Alberta.
- Ability to access project funding.
- Potential lack of pipeline capacity to access bitumen markets.
- Resource scarcity attributable to a number of other oil sands projects being developed in the area in the same timeframe.

See also "*Risk Factors*" in this Annual Information Form.

Description of Birch Contingent Resources

The Contingent Resources assigned to Athabasca's Birch assets assume that the resources will be produced using SAGD technology. There are adequate analogues in the area and reservoir studies to confirm that SAGD is applicable to the Birch reservoir. Athabasca will leverage the experience gained in successfully delivering and ramping up the Hangingstone Project during 2015 and 2016 to deliver the Birch project. The production of the Birch resources is contingent upon the completion of the first phase of the Birch Project which, if commissioned, is planned to be on stream in 2025 with a capacity of 12,000 bbl/d. If commissioned and completed, the second phase of the Birch Project is expected to have a capacity of 40,000 bbl/d with first oil expected in 2028. If commissioned and completed, three subsequent 40,000 bbl/d phases are expected to follow at two yearly intervals to the expected ultimate approximate capacity of 170,000 bbl/d.

A field development plan has been developed for Birch but an environmental impact assessment application has not been submitted.

There is currently no infrastructure in place to support the Birch Project.

Based on the development plan proposed by the Company, the total Best Estimate capital cost of first commercial production in 2025 for the Birch Project is estimated at approximately $660 million (uninflated, unrisked, undiscounted).

The contingencies identified for the development of the Birch Contingent Resources are:

- Regulatory Approval – an application has not been filed for the Birch Project.
- Corporate Commitment – the Birch Project is not expected to be sanctioned by the Board until market conditions allow and project funding is secured.
- Delineation – development level delineation has only been achieved in the Development On Hold area of the Birch Project reservoir. Further delineation is required in the Development Unclarified area before a final investment decision can be made.
- Project Timing – the first phase of the Birch Project is not anticipated to start up until 2025 and significant spending is not anticipated before 2022.

In accordance with the COGE Handbook, Birch Contingent Resources have been divided into the sub-classes of Development on Hold and Development Unclarified.

The Birch risked Best Estimate Contingent Resource volumes identified as Development On Hold in the above table have been determined to be Economic by the Independent Evaluator. There is sufficient 3D seismic and delineation drilling density in these areas to support both application and development requirements and a development plan is in place. These resources are considered to be Development On Hold rather than Development Pending as Athabasca does not yet have regulatory approval and, due to the current economic climate, Athabasca does not expect to produce these resources before 2024. The duration of the Hangingstone Project from commencement of preparation of the regulatory application to first steam was four and a half years. Athabasca will execute the Birch Project with the same execution strategy and facility design utilized for the Hangingstone Project, consequently Athabasca does not need to do further work on the Birch project until 2019 to maintain a reasonable expectation of reaching first steam in 2024. The chance of development of these Contingent Resources is estimated to be 70% due to uncertainties related to the regulatory approvals required, securing a suitable means of financing and corporate commitment to proceed.

The Birch risked Best Estimate Contingent Resource volumes identified as Development Unclarified in the above table have been determined to be Economic by the Independent Evaluator. These Contingent Resources are considered to be Development Unclarified rather than Development Pending or Development on Hold as there is a lower level of delineation in these areas and they are located physically further from the proposed Birch Project central processing area. The delineation is sufficient to prepare the development strategy consistent with a project evaluation scenario status of pre-development. Based on the COGE Handbook, a pre-development study is considered an intermediate step in the development of a project evaluation scenario. The level of economic analysis is sufficient to assess development options and overall project viability, but is insufficient for a final investment decision. For these resources, additional delineation to refine pad layouts and successful execution of the project will be required in order to advance these assets to a project evaluation scenario status of Development On Hold. The chance of development of these Contingent Resources is estimated to be 54% due to their physical location, delineation level, regulatory approvals required, securing a suitable means of financing and corporate commitment to proceed.

The positive factors relevant to the Contingent Resource estimates for the Birch Project include:

- Using established technology which is being successfully implemented in the Hangingstone Project.

- A development plan is in place for all phases of the assets (however, for the Contingent Resources in the Development Unclarified project maturity sub-class, the development plan is based on a pre-development study) for the full lifecycle of the Birch Project.
- The reservoir has been defined across the asset using delineation drilling as well as 2D and 3D seismic. The level of delineation supports the risks assigned to the different project maturity sub-classes. As development progresses in Birch, incremental delineation across the asset may result in changes to the project maturity sub-classes and to the assigned risks.

The negative factors relevant to the Contingent Resource estimates for the Birch Project include:

- Economic sensitivity to future oil pricing.
- No existing infrastructure.
- Uncertainty regarding regulatory regimes in Alberta.
- Ability to access project funding.
- Potential lack of pipeline capacity to access bitumen markets.
- A regulatory application has not yet been submitted for the Birch Project.
- Resource scarcity attributable to a number of other oil sands projects being developed in the area in the same timeframe.

See also "*Risk Factors*" in this Annual Information Form.

Description of Leismer Contingent Resources

The Contingent Resources assigned to Athabasca's Leismer assets assume that such resources will be produced using SAGD technology which has been successfully implemented in the Leismer Project 1 since 2010. The production of Contingent Resources assigned to the Leismer assets is contingent upon the completion of Leismer Project 3 which, if commissioned, is planned to be on stream in 2022 with a capacity of 40,000 bbl/d which would take the total Leismer plant capacity to 80,000 bbl/d

A field development plan has been developed for the Leismer assets but the existing environmental impact assessment is for a capacity of 40,000 bbl/d and an amendment to take it to 80,000 bbl/d has not been submitted.

The infrastructure already in place to support Leismer Project 3 includes the access road to the Central Production Facility, the diluent import pipeline, the dilbit sales pipeline to Cheecham Terminal, tankage at Cheecham terminal and the gas import pipeline. The existing pipelines and tankage will require debottlenecking to be able to accept the volumes from Leismer Project 3.

Based on the development plan proposed by the Company, the total Best Estimate capital cost of first commercial production in 2022 for the Leismer Project 3 is estimated at approximately $1630 million (uninflated, unrisked, undiscounted).

The contingencies identified for the development of the Leismer Contingent Resources are:

- Regulatory Approval – an amendment to the existing Leismer application has not been filed for the Leismer Project 3.
- Corporate Commitment – the Leismer Project 3 is not expected to be sanctioned by the Board until market conditions allow and project funding is secured.
- Delineation –further delineation is required before a final investment decision can be made.
- Firm development plans and detailed cost estimates have not yet been developed.
- Project Timing –Leismer Project 3 is not anticipated to start up until 2022 and significant spending is not anticipated before 2019.

In accordance with the COGE Handbook, Leismer Contingent Resources have been classified as Development Unclarified by the Independent Evaluator. These Contingent Resources are considered to be Development Unclarified rather than Development Pending or Development on Hold as there is a low level of delineation in these areas and they are located physically far from the proposed Leismer Project central processing area. The delineation is sufficient to prepare the development strategy consistent with a project evaluation scenario status of pre-development. Based on the COGE Handbook, a pre-development study is considered an intermediate step in the development of a project evaluation scenario. The level of economic analysis is sufficient to assess development options and overall project viability, but is insufficient for a final investment decision. For these resources, additional delineation to refine pad layouts and successful execution of the project will be required in order to advance these assets to a project evaluation scenario status of Development On Hold. The chance of development of these Contingent Resources is estimated to be 76% due to their physical location, delineation level, regulatory approvals required, securing a suitable means of financing and corporate commitment to proceed.

The positive factors relevant to the Contingent Resource estimates for the Leismer Project include:

- Using established technology which is being successfully implemented in Leismer Project 1.
- A pre-development plan is in place.
- The reservoir has been defined across the asset using delineation drilling as well as 2D and 3D seismic. The level of delineation supports the risks assigned to the project maturity sub-class of Development Unclarified. As development progresses in Leismer, incremental delineation across the asset may result in changes to the project maturity sub-class and to the assigned risks.

The negative factors relevant to the Contingent Resource estimates for the Leismer Project include:

- Economic sensitivity to future oil pricing.
- Existing infrastructure requires debottlenecking.
- Uncertainty regarding regulatory regimes in Alberta.
- Ability to access project funding.
- Potential lack of pipeline capacity to access bitumen markets.
- The Leismer regulatory application has not yet been amended for Leismer Project 3.
- Resource scarcity attributable to a number of other oil sands projects being developed in the area in the same timeframe.

See also "*Risk Factors*" in this Annual Information Form.

Description of Corner Contingent Resources

The Contingent Resources assigned to Athabasca's Corner assets assume that such resources will be produced using SAGD technology which has been successfully implemented in the nearby Leismer Project since 2010. The production of the Contingent Resources assigned to the Corner assets is contingent upon the completion of Corner Project 2 which, if commissioned, is planned to be on stream in 2025 with a capacity of 30,000 bbl/d which would take the total Corner plant capacity to 70,000 bbl/d.

A field development plan has been developed for the Corner assets but the existing environmental impact assessment is for a capacity of 40,000 bbl/d and an amendment to take it to 70,000 bbl/d has not been submitted.

There is no infrastructure already in place to support the Corner Project although some of the nearby Leismer plant infrastructure could be made use of, this infrastructure includes the access road to the Central Production Facility, the diluent import pipeline, the dilbit sales pipeline to Cheecham Terminal, tankage at Cheecham terminal.

Based on the development plan proposed by the Company, the total Best Estimate capital cost of first commercial production in 2025 for the Corner Project 2 is estimated at approximately $1235 million (uninflated, unrisked, undiscounted).

The contingencies identified for the development of the Corner Contingent Resources are:

- Regulatory Approval – an amendment to the existing Corner application has not been filed for the Corner Project 2.
- Corporate Commitment – the Corner Project 2 is not expected to be sanctioned by the Board until market conditions allow and project funding is secured.
- Delineation –further delineation is required before a final investment decision can be made.
- Firm development plans and detailed cost estimates have not yet been developed.
- Project Timing –Corner Project 2 is not anticipated to start up until 2025 and significant spending is not anticipated before 2022.

In accordance with the COGE Handbook, Corner Contingent Resources have been classified as Development Unclarified by the Independent Evaluator. These Contingent Resources are considered to be Development Unclarified rather than Development Pending or Development on Hold as there is a low level of delineation in these areas and there is not any existing infrastructure in the immediate area. The delineation is sufficient to prepare the development strategy consistent with a project evaluation scenario status of pre-development. Based on the COGE Handbook, a pre-development study is considered an intermediate step in the development of a project evaluation scenario. The level of economic analysis is sufficient to assess development options and overall project viability, but is insufficient for a final investment decision. For these resources, additional delineation to refine pad layouts and successful execution of the project will be required in order to advance these assets to a project evaluation scenario status of Development On Hold. The chance of development of these Contingent Resources is estimated to be 69% due to their physical location, delineation level, regulatory approvals required, securing a suitable means of financing and corporate commitment to proceed.

The positive factors relevant to the Contingent Resource estimates for the Corner Project include:

- Using established technology which is being successfully implemented in nearby Leismer.
- A pre-development plan is in place.
- The reservoir has been defined across the asset using delineation drilling as well as 2D and 3D seismic. The level of delineation supports the risks assigned to the project maturity sub-class of Development Unclarified. As development progresses in Corner, incremental delineation across the asset may result in changes to the project maturity sub-class and to the assigned risks.

The negative factors relevant to the Contingent Resource estimates for the Corner Project include:

- Economic sensitivity to future oil pricing.
- Existing infrastructure requires debottlenecking.
- Uncertainty regarding regulatory regimes in Alberta.
- Ability to access project funding.
- Potential lack of pipeline capacity to access bitumen markets.
- The Corner regulatory application has not yet been amended for Corner Project 2.
- Resource scarcity attributable to a number of other oil sands projects being developed in the area in the same timeframe.

See also "*Risk Factors*" in this Annual Information Form.

Abandonment and Reclamation Costs

In the Acquisition Independent Report and the Independent Reports, DMCL and GLJ have included an estimate of the costs to abandon and reclaim all existing and future wells, pipelines and major dedicated facilities associated with assessed Contingent Resources. No estimate of salvage value is netted against the estimated abandonment and reclamation costs. The estimate for abandonment and reclamation costs are based on the Company's estimation of costs to remediate, reclaim and abandon wells and facilities in which it has a working interest.

The Acquisition Independent Report and the Independent Reports include an aggregate Best Estimate for abandonment and reclamation costs (unrisked, undiscounted) of $715 million at Hangingstone, $4,226 million at Dover West Sands and $2,166 million at Birch, $294 million at Leismer and $481 million at Corner. Abandonment and reclamation costs in the Acquisition Independent Report and the Independent Reports represent all costs associated with the process of restoring the Company's properties (to which Contingent Resources have been allocated) which have been disturbed by oil and gas activities, to a standard imposed by applicable government or regulatory authorities. Abandonment and reclamation costs including all development drilling and all material dedicated gathering and processing facility expansions or builds required to enable production of the Contingent Resources, are included in the Acquisition Independent Report and the Independent Reports.

SCHEDULE "B"
FORM 51-101F3

REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

Report of Management and Directors on Reserves Data and Other Information

Management of Athabasca Oil Corporation (the "**Company**") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data and includes, if disclosed in the statement required by item 1 of section 2.1 of NI 51-101, other information such as contingent resources data. Independent qualified reserves evaluators have evaluated the Company's reserves data and contingent resources data. The reports of the independent qualified reserves evaluators are presented will be filed with securities regulatory authorities concurrently with this report.

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

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

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

(c) reviewed the reserves data and contingent resources data with management and the independent qualified reserves evaluators.

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

(a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data, contingent resources data and other oil and gas information;

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

(c) the content and filing of this report.

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

(signed) "*Robert Broen"*	(signed) "*Kevin Smith*"
Robert Broen	Kevin G. Smith
President & Chief Executive Officer	Vice President, Light Oil
(signed)"*Ronald J. Eckhardt*"	(signed) *"Bryan Begley*"
Ronald J. Eckhardt	Bryan Begley
Director	Director

Dated March 8, 2017

SCHEDULE "C"
FORM 51-101F2

REPORTS ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATORS OR AUDITORS

AND

REPORTS ON RESOURCES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATORS OR AUDITORS

FORM 51-101F2
REPORT ON RESERVES DATA, CONTINGENT RESOURCES DATA
BY
INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

To the board of directors of Athabasca Oil Corporation (the "Corporation"):

1. We have evaluated the Corporation's reserves data and contingent resources 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. The contingent resources data are risked estimates of volume of contingent resources and related risked net present value of future net revenue as at December 31, 2016, estimated using forecast prices and costs.

2. The reserves data and contingent resources data are the responsibility of the Corporation's management. Our responsibility is to express an opinion on the reserves data and contingent resources 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 and contingent resources data are free of material misstatement. An evaluation also includes assessing whether the reserves data and contingent resources data are in accordance with principles and definitions presented in the COGE Handbook.

5. The following table shows the net present value of 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 Corporation evaluated for the year ended December 31, 2016, and identifies the respective portions thereof that we have evaluated and reported on to the Corporation's board of directors:

Independent Qualified Reserves Evaluator or Auditor	Effective Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate – M$)			
			Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants	12/31/2016	Canada	-	466,581	-	**466,581**

6. The following tables set forth the risked volume and risked net present value of future net revenue of contingent resources (before deduction of income taxes) attributed to contingent resources, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the Corporation's statement prepared in accordance with Form 51-101F1 and identifies the respective portions of the contingent resources data that we have evaluated and reported on to the Corporation's board of directors:

Classification	Independent Qualified Reserves Evaluator or Audit	Effective Date of Evaluation Report	Location of Resources Other than Reserves (Country or Foreign Geographic Area)	Risked Volume (MMboe)
Dover West				
Contingent Resources				
Development On Hold	GLJ Petroleum Consultants	12/31/2016	Canada	78
Development Unclarified	GLJ Petroleum Consultants	12/31/2016	Canada	1,563

7. In our opinion, the reserves data and contingent resources 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 and contingent resources data that we reviewed but did not audit or evaluate.

8. We have no responsibility to update our reports referred to in paragraphs 5 and 6 for events and circumstances occurring after the effective date of our reports.

9. Because the reserves data and contingent resources 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 9, 2017

[(signed) "*Todd J. Ikeda*"
Todd J. Ikeda, P. Eng.
Vice President]

FORM 51-101F2

REPORT on RESERVES DATA
BY
INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

To the board of directors of Athabasca Oil Corporation (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 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 shows the net present value of future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using GLJ prices and DMCL estimated costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated for the year ended December 31, 2016, and identifies the respective portions thereof that we have evaluated and reported on to the Company's management:

Independent Qualified Reserves Evaluator	Effective Date of Evaluation Report	Location of Reserves	Net Present Value of Future Net Revenue (before income tax, 10% discount rate)			
			Audited (MM$)	Evaluated (MM$)	Reviewed (MM$)	Total (MM$)
DeGolyer and MacNaughton Canada Limited	December 31, 2016	Canada	-	801	-	801

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

EXECUTED as to our report referred to above:

DeGolyer and MacNaughton Canada Limited, Calgary, Alberta, dated January 12, 2017.

DEGOLYER and MACNAUGHTON CANADA LIMITED

[(signed) *"Nahla R. Boury"*
Nahla R. Boury, P. Eng.]

FORM 51-101F2
REPORT ON CONTINGENT RESOURCES DATA
BY
INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

To the board of directors of Athabasca Oil Corporation (the "Company"):

1. We have evaluated the Company's contingent resources data for the Hangingstone area as at December 31, 2016. The contingent resources data are risked estimates of volume of contingent resources and related risked net present value of future net revenue as at December 31, 2016, estimated using forecast prices and costs.

2. The contingent resources data are the responsibility of the Company's management. Our responsibility is to express an opinion on the contingent resources 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 contingent resources data are free of material misstatement. An evaluation also includes assessing whether the contingent resources data are in accordance with principles and definitions in the COGE Handbook.

5. The following table sets forth the risked volume and risked net present value of contingent resources (before deduction of income taxes) attributed to contingent resources, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the Company's statement prepared in accordance with Form 51-101F1 and identifies the respective portions of the contingent resources data that we have evaluated and reported on to the Company's management:

Classification	Independent Qualified Reserves Evaluator or Auditor	Effective Date of Evaluation Report	Location of Resources Other than Reserves	Risked Volume (Mbbl)	Risked Net Present Value of Future Net Revenue [(1)] (before income taxes, 10% discount rate)		
					Audited (MM$)	Evaluated (MM$)	Total (MM$)
Development Pending Economic Contingent Resources (Best)	DeGolyer and MacNaughton Canada Limited	December 31, 2016	Canada	241,705	-	222	222
Development on Hold Economic Contingent Resources (Best)	DeGolyer and MacNaughton Canada Limited	December 31, 2016	Canada	334,808	-	308	308
Development Unclarified Economic Contingent Resources (Best)	DeGolyer and MacNaughton Canada Limited	December 31, 2016	Canada	9,626	-	9	9

Note:

(1) Estimated company share risked net present value of future net revenue are defined as Athabasca's participating interest in the Hangingstone area after deductions of royalties payable to others.

6. In our opinion, the contingent resources data 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 contingent resources 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 contingent resources data are based on judgments regarding future events, actual results will vary and the variations may be material.

EXECUTED as to our report referred to above:

DeGolyer and MacNaughton Canada Limited, Calgary, Alberta, dated January 12, 2017.

DEGOLYER and MACNAUGHTON CANADA LIMITED

[(signed) *"Nahla R. Boury"*
Nahla R. Boury, P. Eng.]

FORM 51-101F2
REPORT ON CONTINGENT RESOURCES DATA
BY
INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

To the board of directors of Athabasca Oil Corporation (the "Company"):

1. We have evaluated the Company's contingent resources data for the Birch area as at December 31, 2016. The contingent resources data are risked estimates of volume of contingent resources and related risked net present value of future net revenue as at December 31, 2016, estimated using forecast prices and costs.

2. The contingent resources data are the responsibility of the Company's management. Our responsibility is to express an opinion on the contingent resources 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 contingent resources data are free of material misstatement. An evaluation also includes assessing whether the contingent resources data are in accordance with principles and definitions in the COGE Handbook.

5. The following table sets forth the risked volume and risked net present value of contingent resources (before deduction of income taxes) attributed to contingent resources, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the Company's statement prepared in accordance with Form 51-101F1 and identifies the respective portions of the contingent resources data that we have evaluated and reported on to the Company's management:

					Risked Net Present Value of Future Net Revenue [1] (before income taxes, 10% discount rate)		
Classification	**Independent Qualified Reserves Evaluator or Auditor**	**Effective Date of Evaluation Report**	**Location of Resources Other than Reserves**	**Risked Volume (Mbbl)**	**Audited (MM$)**	**Evaluated (MM$)**	**Total (MM$)**
Development on Hold Economic Contingent Resources (Best)	DeGolyer and MacNaughton Canada Limited	December 31, 2016	Canada	1,008,734	-	936	936
Development Unclarified Economic Contingent Resources (Best)	DeGolyer and MacNaughton Canada Limited	December 31, 2016	Canada	310,414	-	288	288

Note:

(1) Estimated company share risked net present value of future net revenue are defined as Athabasca's participating interest in the Birch area after deductions of royalties payable to others.

6. In our opinion, the contingent resources data 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 contingent resources 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 contingent resources data are based on judgments regarding future events, actual results will vary and the variations may be material.

EXECUTED as to our report referred to above:

DeGolyer and MacNaughton Canada Limited, Calgary, Alberta, dated January 12, 2017.

DEGOLYER and MACNAUGHTON CANADA LIMITED

[(signed) *"Nahla R. Boury"*
Nahla R. Boury, P. Eng.]

SCHEDULE "D"

AUDIT COMMITTEE MANDATE

The Audit Committee **(Committee)** of the board of directors **(Board)** of Athabasca Oil Corporation **(Company)** has the oversight responsibility and specific duties described below and shall comply with the requirements of applicable laws.

COMPOSITION

The Committee will be comprised of at least three directors or such greater number as the Board may determine from time to time. Except to the extent that the Board determines that an exemption contained in National Instrument 52-110 issued by the Canadian Securities Administrators or its successor instrument **(NI 52-110)** is available and determines to rely thereon, all Committee members will be independent within the meaning of NI 52-110.

All Committee members will be "financially literate" (as defined in NI 52-110) unless the Board determines that an exemption under NI 52-110 from such requirement in respect of any particular member is available and determines to rely thereon.

Committee members will be appointed and removed by the Board. The Committee Chair will be appointed by the Board.

RESPONSIBILITIES

The Committee's primary purpose is to assist the Board in fulfilling its oversight responsibilities with respect to: (i) the integrity of annual and quarterly financial statements to be provided to the Company's shareholders and regulatory bodies; (ii) compliance with accounting and finance based legal and regulatory requirements; (iii) the external auditor's qualifications, independence and compensation, and communicating with the external auditor; (iv) the system of internal accounting and financial reporting controls that management has established; (v) performance of the external audit process and of the external auditor; (vi) financial policies; (vii) financial risk management practices; and (viii) transactions or circumstances which could materially affect the financial profile of the Company.

Management of the Company is responsible for preparing the quarterly and annual financial statements of the Company and for maintaining a system of risk assessment and internal controls to provide reasonable assurance that assets are safeguarded and that transactions are authorized, recorded and reported properly. The Committee is responsible for reviewing management’s actions and has the authority to investigate any activity of the Company.

SPECIFIC DUTIES

The Committee will:

Audit Leadership

1. Have a clear understanding with the external auditor that it must maintain an open and transparent relationship with the Committee, and that the ultimate accountability of the external auditor is to the Committee, as representatives of the shareholders of the Company.

2. Provide an avenue for communication between each of the external auditor, financial and senior management and the Board. The Committee has the authority to communicate directly with the external auditors and financial and senior management.

Auditor Qualifications and Selection

3. Subject to required shareholder approval of the appointment of auditors of the Company, be solely responsible for recommending to the Board: (i) the external auditor for the purpose of preparing or issuing an auditor's report or performing other audit review or attest services for the Company; and (ii) the compensation of the external auditor. The Committee is directly responsible for overseeing the work of the external auditor, including the resolution of disagreements between management and the external auditor regarding financial reporting and reviewing, considering and making a recommendation to the Board regarding a proposed discharge of the external auditor when circumstances warrant. In all circumstances the external auditor reports directly to the Committee. The Committee is entitled to adequate funding to compensate the external auditor for completing an audit and audit report or performing other audit, review or attest services.

4. Evaluate the external auditor's qualifications, performance and independence. Take all reasonable steps to ensure that the external auditor does not provide non-audit services that would disqualify it as independent under applicable law.

5. Review the experience and qualifications of the senior members of the external audit team and the quality control procedures of the external auditor. Ensure that the lead audit partner of the external auditor is replaced periodically, according to applicable law. Take all reasonable steps to ensure continuing independence of the external audit firm. Present the Committee's conclusions on auditor independence to the Board.

6. Review and approve policies for the Company's hiring of senior employees and former employees of the external auditor who were engaged on the Company's account and make recommendations to the Board for consideration.

Process

7. Pre-approve all audit services (which may include consent and comfort letters in connection with securities offerings). Pre-approve and disclose, as required, the retention of the external auditor for non-audit services to be provided to the Company or any of its subsidiaries permitted under applicable law. In the discretion of the Committee, annually delegate to one or more of its independent members the authority to grant pre-approvals. Approve all audit fees and terms and all non-audit fees.

8. Meet with the external auditor prior to the audit to review the scope and general extent of the external auditor's annual audit including: (i) the planning and staffing of the audit; and (ii) an explanation from the external auditor of the factors considered in determining the audit scope, including the major risk factors.

9. Require the external auditor to provide a timely report setting out: (i) all critical accounting policies, significant accounting judgments and practices to be used; (ii) all alternative treatments of financial information within International Financial Reporting Standards **(IFRS)** that have been discussed with management, ramifications of the use of such alternative disclosures and treatments and the treatment preferred by the external auditor; and (iii) other material written communications between the external auditor and management.

10. Take all reasonable steps to ensure that officers and directors or persons acting under their direction are aware that they are prohibited from coercing, manipulating, misleading or fraudulently influencing the external auditor when the person knew or should have known that the action could result in rendering the financial statements materially misleading.

11. Upon completion of the annual audit, review the following with management and the external auditor:

    (a) The annual financial statements, including related notes and the Management's Discussion and Analysis of Financial Condition and Results of Operations **(MD&A)** of the Company for filing with applicable securities regulators and provision to shareholders, as required, as well as all annual earnings press releases before their public disclosure.

(b) The significant estimates and judgements and reporting principles, practices and procedures applied by the Company in preparing its financial statements, including any newly adopted accounting policies and the reasons for their adoption.

(c) The results of the audit of the financial statements and whether any limitations were placed on the scope or nature of the audit procedures.

(d) Significant changes to the audit plan, if any, and any serious disputes or difficulties with management encountered during the audit, including any problems or disagreements with management which, if not satisfactorily resolved, would have caused the external auditor to issue a non-standard report on the financial statements of the Company.

(e) The cooperation received by the external auditor during its audit, including access to all requested records, data and information.

(f) Any other matters not described above that are required to be communicated by the independent auditor to the Committee.

Financial Statements and Disclosure

12. At least quarterly, as part of the review of the annual and quarterly financial statements, receive an oral report from the Company's counsel concerning legal and regulatory matters that may have a material impact on the financial statements.

13. Based on discussions with management and the external auditor, in the Committee's discretion, recommend to the Board whether the annual financial statements and MD&A of the Company, together with any annual earnings press releases should be approved for filing with applicable securities regulators and provision to the Company's shareholders, as required, prior to their disclosure.

14. Review the general types and presentation format of information that it is appropriate for the Company to disclose in earnings news releases or other earnings guidance provided to analysts and rating agencies.

15. Review with management and the external auditor the quarterly financial statements and MD&A and quarterly earnings releases prior to their release and recommend to the Board for consideration the quarterly results, financial statements, MD&A and news releases prior to filing them with or furnishing them to the applicable securities regulators and prior to any public announcement of financial results for the periods covered, including a written report of the results of the external auditor's reviews of the quarterly financial statements, significant adjustments, new accounting policies, any disagreements between the external auditor and management and the impact on the financial statements of significant events, transactions or changes in accounting principles or estimates that potentially affect the quality of financial reporting.

Internal Control Supervision

16. As required by applicable law, review with management and the external auditor the Company's internal controls over financial reporting, any significant deficiencies or material weaknesses in their design or operation, any proposed major changes to them and any fraud involving management or other employees who have a significant role in the Company's internal controls over financial reporting.

17. Review with management, the Chief Financial Officer and the external auditor the methods used to establish and monitor the Company's policies with respect to unethical or illegal activities by employees that may have a material impact on the financial statements.

18. Meet with management and the external auditor to discuss any relevant significant recommendations that the external auditor may have, particularly those characterized as "material" or "serious". Review responses of management to any significant recommendations from the external auditor and receive follow-up reports on action taken concerning the recommendations.

19. Review with management and the external auditor any correspondence with regulators or government agencies and any employee complaints or published reports which raise material issues regarding the Company's financial statements or accounting policies of the Company (as required).

20. Review with management and the external auditor any off-balance sheet financing mechanisms, transactions or obligations of the Company.

21. Review with management and the external auditor any material related party transactions.

22. Review with the external auditor the quality of the Company's accounting personnel. This review may occur without the presence of management. Review with management the responsiveness of the external auditor to the needs of the Company.

Disclosure Controls and Procedures

23. Periodically assess and be satisfied with the adequacy of procedures in place for the review of public disclosure of financial information extracted or derived from the applicable financial statements (other than the annual and quarterly required filings) for the Company.

Financial Management

24. Regularly review current and expected future compliance with covenants under all financing agreements.

25. Annually review the instruments the Company and its subsidiaries are permitted to use for short-term investments of excess cash and, in the Committee's discretion, make recommendations to the Board for consideration.

26. Review the Company’s compliance with required tax remittances and other deductions required by applicable law.

Financial Risk Management

27. Receive reports from management with respect to risk assessment, risk management and major financial risk exposures.

28. Discuss with management major financial risk exposures, including those arising from the Company’s exposure to changes in interest rates, foreign currency exchange rates and credit. Review the management of these risks including any proposed hedging of the exposures. Review a summary report of the hedging activities including a summary of the hedge-related instruments

29. Discuss with management guidelines and policies with respect to financial risk assessment and financial risk management, including the processes management uses to assess and manage the Company's financial risk.

30. Annually review the insurance program including coverage for property damage, business interruption, liabilities, and directors and officers.

31. Review any other significant financial exposures of the Company to the risk of a material financial loss including tax audits or other activities.

32. Report to the Board on the financial risks of the Company and make recommendations to the Board for consideration.

33. Establish procedures (through approval of the relevant sections of the Code of Business Conduct) for: (i) the receipt, retention, and treatment of complaints received by the Company regarding accounting, internal accounting and financial reporting controls, or auditing matters; and (ii) the confidential, anonymous submission by employees of concerns regarding questionable accounting or auditing matters.

34. Once or more annually, as the Committee decides, review and assess the Company's Code of Business Conduct and, in the Committee's discretion, recommend any changes to the Board for consideration.

Committee Reporting

35. Following each meeting of the Committee, report to the Board on the activities, findings and any recommendations of the Committee.

36. Report regularly to the Board and review with the Board any issues that arise with respect to the quality or integrity of the financial statements of the Company, compliance with applicable law and the performance and independence of the external auditor of the Company.

37. Annually review and approve the information regarding the Committee required to be disclosed in the Company's Annual Information Form and Committee's report for inclusion in the annual Proxy Circular.

38. Prepare any reports required to be prepared by the Committee under applicable law.

Committee Meetings

39. Meet at least four times annually and as many additional times as needed to carry out its duties effectively. The Committee may, on occasion and in appropriate circumstances, hold meetings by telephone conference call.

40. Meet in separate, non-management, closed sessions with the external auditor at each regularly scheduled meeting.

41. Meet in separate, non-management, in camera sessions at each regularly scheduled meeting.

42. Meet in separate, non-management, closed sessions with any other internal personnel or outside advisors, as needed or appropriate.

43. A quorum for meetings of the Committee will be a majority of its members and the rules for calling, holding, conducting and adjourning meetings of the Committee will be the same as those governing the Board.

Committee Governance

44. Once or more annually, as the Compensation and Governance Committee (CG Committee) decides, receive for consideration that Committee's evaluation of this Mandate and any recommended changes. Review and assess the CG Committee's recommended changes and make recommendations to the Board for consideration.

Advisors/Resources

45. Have the sole authority to retain, oversee, compensate and terminate independent advisors to assist the Committee in its activities.

46. Receive adequate funding from the Company for independent advisors and ordinary administrative expenses that are needed or appropriate for the Committee to carry out its duties.

Other

47. With the CG Committee, the Board and the Board Chair, respond to potential conflict of interest situations, as required.

48. Carry out any other appropriate duties and responsibilities assigned by the Board.

49. To honour the spirit and intent of applicable law as it evolves, authority to make minor technical amendments to this Mandate is delegated to the Secretary, who will report any amendments to the CG Committee at its next meeting.

STANDARDS OF LIABILITY

Nothing contained in this Mandate is intended to expand applicable standards of liability under statutory, regulatory or other legal requirements for the Board or members of the Committee. The purposes and responsibilities outlined in this Mandate are meant to serve as guidelines rather than inflexible rules and, subject to applicable law and the articles and bylaws of the Company, the Committee may adopt such additional procedures and standards, as it deems necessary from time to time to fulfill its responsibilities.

Approved: December 11, 2009

Revised: March 14, 2012
May 11, 2015