ATHABASCA
OIL CORPORATION

Annual Information Form

FOR THE YEAR ENDED DECEMBER 31, 2013

March 18, 2014

TABLE OF CONTENTS

INTRODUCTORY INFORMATION

Except as otherwise indicated, or unless the context otherwise requires, the term the "**Company**" refers to Athabasca Oil Corporation and the term "**Athabasca**" refers to one or more of the Company's direct or indirect subsidiaries, or to the Company and its direct and 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:

- Athabasca's expectations regarding its ability to raise capital;
- Athabasca's plans to submit additional regulatory applications;
- the timing of receipt of regulatory approvals, including in respect of Dover West Sands Project 1;
- the receipt of the approval of Alberta Environment in respect of the Dover Oil Sands Project and Athabasca's plans to exercise the Dover Put Option once the approval of Alberta Environment is received;
- the receipt of proceeds from the sale of Athabasca's interests in the Dover assets pursuant to the exercise of the Dover Put Option;
- the business strategy, objectives and business strengths of Athabasca;
- the commercial development and resource potential of Athabasca's assets;
- Athabasca's growth strategy and opportunities;
- the potential for future joint venture arrangements;
- Athabasca's 2014 exploration and development budget and Athabasca's capital expenditure programs;
- the estimated quantity of Athabasca's Proved Reserves, Probable Reserves and Contingent Resources;
- 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 Hangingstone Project 1 and the Hangingstone Expansion;
- the use of SAGD technology to produce bitumen from the Hangingstone assets, Dover West Sands, Dover assets and Grosmont assets, and the use of SAGD and, potentially TAGD, to produce bitumen from the Dover West Carbonates;
- the timing of the completion of the pipeline that is expected to be constructed from the HS CPF to the Enbridge Cheecham Terminal and the expected capacity thereof;
- IPP providing diluent transportation services in respect of the Hangingstone Projects;
- 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;
- the planned construction of facilities, including a pipeline to SemCAMS' Kaybob Amalgamated Gas Plant, and the capacity thereof;
- Athabasca's drilling plans and plans regarding the completion of wells that have been drilled;

- Athabasca's plans for, and results of, 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:

- 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;
- 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;
- 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:

- the substantial capital requirements of Athabasca's projects and the ability to obtain financing for Athabasca's capital requirements;
- failure to meet the conditions precedent to the exercise by Athabasca of the Dover Put Option, including failure to receive the approval of Alberta Environment when anticipated or at all;
- the potential impact of the exercise of the Dover Put Option on Athabasca;
- the potential for adverse consequences in the event that Athabasca defaults under certain of the PetroChina Transaction Agreements;
- failure by counterparties (including, without limitation, PetroChina International and Phoenix) to make payments or perform their operational or other obligations to the Athabasca in compliance with the terms of contractual arrangements between Athabasca and such counterparties, including in compliance with the time schedules set out in such contractual arrangements, and the possible consequences thereof;
- aboriginal claims;
- fluctuations in market prices for crude oil, natural gas and bitumen blend;
- general economic, market and business conditions in Canada, the United States and globally;
- failure to obtain regulatory approvals or maintain compliance with regulatory requirements;
- dependence on Phoenix as the joint venture participant in the Dover Oil Sands Project, until such time as Athabasca's interests in the Dover assets have been sold to Phoenix pursuant to the exercise of the Dover Put Option;
- failure to meet development schedules and potential cost overruns;

- variations in foreign exchange and interest rates;
- factors affecting potential profitability;
- risks related to future acquisition and joint venture activities;
- reliance on, competition for, loss of, and failure to attract key personnel;
- global financial uncertainty;
- uncertainties inherent in estimating quantities of reserves and resources;
- changes to Athabasca's status given the current stage of development;
- uncertainties inherent in SAGD, TAGD and other bitumen recovery processes;
- risks related to hydraulic fracturing;
- expiration of leases and permits;
- risks inherent in Athabasca's operations, including those related to exploration, development and production of petroleum, natural gas and oil sands reserves and resources, including the production of oil sands reserves and resources using SAGD, TAGD or other in-situ technologies;
- risks related to gathering and processing facilities and pipeline systems;
- availability of drilling and related equipment and limitations on access to Athabasca's assets;
- increases in operating costs could make Athabasca's projects uneconomic;
- the effect of diluent and natural gas supply constraints and increases in the costs thereof;
- gas over bitumen issues affecting operational results;
- environmental risks and hazards and the cost of compliance with environmental regulations, including GHG regulations and potential Canadian and U.S. climate change legislation;
- extent of, and cost of compliance with, government laws and regulations and the effect of changes in such laws and regulations from time to time;
- risks related to Athabasca's filings with taxation authorities, including the risk of tax related reviews and reassessments;
- changes to royalty regimes;
- political risks;
- failure to accurately estimate abandonment and reclamation costs;
- exploration, development and production risks inherent in crude oil and natural gas operations, including the production of crude oil and natural gas using multi-stage fracture and other stimulation technologies;
- the potential for management estimates and assumptions to be inaccurate;
- long term reliance on third parties;
- reliance on third party infrastructure;
- seasonality;
- hedging risks;
- risks associated with establishing and maintaining systems of internal controls;
- insurance risks;
- claims made in respect of Athabasca's operations, properties or assets;
- the effect of a change of control under the PetroChina Transaction Agreements;
- competition for, among other things, capital, the acquisition of reserves and resources, export pipeline capacity and skilled personnel;
- the failure of Athabasca or the holder of certain licenses, leases or permits to meet specific requirements of such licenses, leases or permits;
- risks related to the Amended Credit Facilities;
- breaches of confidentiality;
- costs of new technologies;
- alternatives to and changing demand for petroleum products;
- risks related to the Common Shares; and
- risks pertaining to the Senior Secured Notes.

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:

"**2-D seismic data**" means two-dimensional seismic data, being interpretive data that allows a view of a vertical cross-section beneath a prospective area.

"**3-D seismic data**" means three-dimensional seismic data, being geophysical data that depicts the subsurface strata in three dimensions, and which typically provides a more detailed and accurate interpretation of the subsurface strata than 2-D seismic data.

"**2008 Notes**" means the $400,000,000 aggregate principal amount of 13% senior, secured notes of the Company issued on July 30, 2008 and redeemed on February 10, 2010.

"**2012 Credit Facilities**" has the meaning given to that term under "General Development of the Business – Three Year History – 2012".

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

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

"**AER Decision**" has the meaning given to that term under "General Development of the Business – Three Year History – 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 – Amended Credit Facilities".

"**Amended Credit Facilities**" has the meaning given to that term under "General Development of the Business – Three Year History – 2013".

"**AOC (Dover)**" means AOC (Dover) Energy Inc., a wholly-owned subsidiary of the Company incorporated under the ABCA, which holds an undivided 40% interest in the Dover assets.

"**AOSC (MacKay)**" means AOSC (MacKay) Energy Inc., a former wholly-owned subsidiary of the Company incorporated under the ABCA, which held an undivided 40% interest in the MacKay assets prior to the completion of the MacKay Put Option Transaction.

"**AOSC MacKay Shares**" means all of the issued and outstanding shares of 1659727 Alberta Ltd. and 1659758 Alberta Ltd.

"**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.

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

"**Best Estimate**" has the meaning given to that term under "Independent Reserve and Resource Evaluations – Contingent Resource Estimates – Aggregated Contingent Resource Estimates".

"**BIA**" means the *Bankruptcy and Insolvency Act* (Canada), R.S.C. 1985, c. B-3.

"**Birch assets**" means the interests of Athabasca in approximately 470,000 acres of land as at December 31, 2013, primarily between townships 97 to 103, ranges 13 to 20, west of the fourth meridian in northeastern Alberta, that are more particularly described under "Description of Athabasca's Business – Thermal Oil Division – Birch assets".

"**bitumen**" means a naturally occurring viscous mixture consisting mainly of pentanes and heavier hydrocarbons. Its viscosity is greater than 10,000 milliPascal seconds (centipoise) measured at original temperature in the reservoir and atmospheric pressure, on a gas-free basis. Crude bitumen may contain sulphur and other non-hydrocarbon compounds.

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

"**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, and contain more than 60% of the world's proved conventional oil reserves. After deposition, the porosity and permeability of carbonate rocks are modified by a variety of processes such as mechanical compaction, dissolution, recrystallization and dolomitization. One of the most important effects on carbonate reservoir rocks is the dolomitization process because it typically increases the porosity and permeability of the rock. Generally, fractures make a relatively minor contribution to the overall porosity of carbonate rocks, but they have a strong influence on fluid flow. Most carbonate rocks tend to have some fractures because of the brittle nature of the rock.

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

"**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 prepared jointly by The Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society), 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.

"**Contingent Resources**" has the meaning given to that term under "Independent Reserve and Resource Evaluations – Contingent Resource Estimates – Aggregated Contingent Resource Estimates".

"**DBRS**" means DBRS Limited.

"**delineation well**" means a well that is so located in relation to another well penetrating an accumulation of petroleum that there is a reasonable expectation that another portion of the accumulation will be penetrated by the first mentioned well and that the drilling of the first-mentioned well is necessary in order to determine the commercial value of the accumulation.

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

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

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

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

"**D&M Report**" means the reports of D&M dated effective as of December 31, 2013 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 interests of the Participants in approximately 150,000 acres of land as at December 31, 2013, primarily between townships 92 to 97, ranges 15 to 18 west of the fourth meridian in northeastern Alberta near the city of Fort McMurray, including for greater certainty the Dover Oil Sands Leases, and such additional assets, benefits and interests as may be acquired, from time to time, by or for the benefit of the Participants of the Dover Joint Venture, or that otherwise derive therefrom, including all tangible depreciable property, facilities, equipment and inventory owned or leased for the benefit of conducting the business of the Dover Joint Venture, as well as contracts, agreements and other interests of a miscellaneous nature that are typically acquired, owned or held

in order to explore, develop, construct and operate facilities in relation to, and produce, bitumen, together with cash and near cash equivalents, such as accounts receivable.

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

"**Dover First Phase**" means the construction of the first phase of the Dover Oil Sands Project which is planned to reach a bitumen production rate of up to 50,000 bbls/d (gross).

"**Dover Joint Venture**" means the joint venture between AOC (Dover) and Phoenix which was formed as part of the closing of the PetroChina Transaction pursuant to the Dover Joint Venture Agreement.

"**Dover Joint Venture Agreement**" means the joint venture agreement dated February 10, 2010 entered into as part of the PetroChina Transaction among AOC (Dover), Phoenix and Dover JV Operator pertaining to the ownership and operation of the Dover assets.

"**Dover JV Operator**" means Brion Energy Corporation (formerly, Dover Operating Corp.), a corporation incorporated under the ABCA as part of the closing of the PetroChina Transaction by AOC (Dover) and Phoenix in accordance with their respective Participating Interests in the Dover Joint Venture, which changed its name from "Dover Operating Corp." to "Brion Energy Corporation" on May 31, 2013 .

"**Dover JV Operator Shareholders Agreement**" means the unanimous shareholder agreement dated February 10, 2010, entered into among AOC (Dover), Phoenix and Dover JV Operator as part of the PetroChina Transaction.

"**Dover Oil Sands Leases**" means the crown leases governed by the Dover Joint Venture Agreement.

"**Dover Oil Sands Project**" means the in-situ oil sands project in respect of the Dover assets, as is described in greater detail under "Description of Athabasca's Business – Thermal Oil Division – Dover assets".

"**Dover Oil Sands Project Approval**" means, as it pertains to the Dover Oil Sands Project, AER approval pursuant to section 10 of the *Oil Sands Conservation Act* (Alberta) and Alberta Environment approval pursuant to Part 2, Division 2, of the *Environmental Protection and Enhancement Act* (Alberta).

"**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/Call Option**" means, collectively, the Dover Call Option and the Dover Put Option.

"**Dover West assets**" means the interests of Athabasca in approximately 240,000 acres of land as at December 31, 2013, primarily between townships 87 to 95, ranges 17 to 21, west of the fourth meridian in northeastern Alberta that are more particularly described under "Description of Athabasca's Business – Thermal Oil Division – Dover West assets".

"**Dover West Carbonates**" means the resource within the Leduc and Cooking Lake Formations of the Devonian Woodbend Group, a carbonate reservoir in the Dover West assets.

"**Dover West Carbonates Projects**" means the in-situ oil sands projects that are contemplated in respect of the Dover West Carbonates. See "Description of Athabasca's Business – Thermal Oil Division – Dover West assets – Dover West Carbonates".

"**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 Expansion**" has the meaning given to that term under "Description of Athabasca's Business – Thermal Oil Division – Dover West assets – Dover West Sands".

"**Dover West Sands Project 1**" has the meaning given to that term under "General Development of the Business – Three Year History – 2011".

"**Dover West Sands Projects**" means Dover West Sands Project 1 and the Dover West Sands Expansion, the proposed in-situ oil sands projects in respect of the Dover West Sands, which are more particularly described under "Description of Athabasca's Business – Thermal Oil Division – Dover West assets – Dover West Sands".

"**EBITDA**" means earnings before interest, taxes, depreciation and amortization, calculated as specified in the Amended and Restated Credit Agreement.

"**Enbridge**" has the meaning given to that term under "General Development of the Business – Three Year History – 2013".

"**EODC**" has the meaning given to that term under "General Development of the Business – Three Year History – 2013".

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

"**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).

"**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, 2013, assessing and evaluating the Proved Reserves, Probable Reserves and Contingent Resources of Athabasca, as applicable, located in the Dover, Dover West Sands, Dover West Carbonates and Grosmont areas of Alberta and the Proved Reserves and Probable Reserves attributable to the Light Oil assets.

"**Grosmont area**" refers to the approximately 788,000 gross acres of land, as at December 31, 2013, located primarily between townships 92 to 100, range 25 west of the fourth meridian to range 5 west of the fifth meridian, in northeastern Alberta, in which Athabasca has a 50% working interest, as more particularly described under "Description of Athabasca's Business – Thermal Oil Division – Grosmont assets".

"**Grosmont assets**" refers to Athabasca's interest in approximately 394,000 net acres of land in the Grosmont area, as at December 31, 2013, as more particularly described under "Description of Athabasca's Business – Thermal Oil Division – Grosmont assets".

"**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.

"**Hangingstone assets**" means the interests of Athabasca in approximately 136,000 acres of land as at December 31, 2013, primarily between townships 85 to 88, ranges 9 to 13, west of the fourth meridian in northeastern Alberta that

are more particularly described under "Description of Athabasca's Business – Thermal Oil Division – Hangingstone assets".

"**Hangingstone Expansion**" has the meaning given to that term under "General Development of the Business – Three Year History – 2013".

"**Hangingstone Projects**" means Hangingstone Project 1, the Hangingstone Expansion and any future proposed in-situ oil sands projects in respect of the Hangingstone assets.

"**Hangingstone Project 1**" has the meaning given to that term under "General Development of the Business – Three Year History – 2011".

"**Hangingstone Project 2**" has the meaning given to that term under "Description of Athabasca's Business – Thermal Oil Division – Hangingstone assets – Project Development".

"**Hangingstone Project 3**" has the meaning given to that term under "Description of Athabasca's Business – Thermal Oil Division – Hangingstone assets – Project Development".

"**HS CPF**" has the meaning given to that term under "Description of Athabasca's Business – Thermal Oil Division – Hangingstone assets – Project Development".

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

"**Independent Evaluators**" means, collectively, D&M and GLJ.

"**Independent Reports**" means, collectively, the D&M 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 or TAGD.

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

"**Kaybob Area**" means the interests of Athabasca in approximately 443,000 acres of land as at December 31, 2013, that are located primarily between townships 62 to 68, ranges 14 to 22, west of the fifth meridian in northwestern Alberta that are more particularly described under "Description of Athabasca's Business – Light Oil Division – Kaybob Area".

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

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

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

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

"**Light Oil assets**" means the interests of Athabasca in over 2.7 million net acres of land as at December 31, 2013, primarily in northwestern Alberta, which includes the Kaybob Area, Saxon/Placid Area and the Light Oil Exploration Areas.

"**Light Oil Division**" means Athabasca's business units that are 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 2,211,000 net acres of land as at December 31, 2013, that are located in the Grand Prairie, North Muskwa, South Muskwa and Caribou areas in northwestern Alberta, which are more particularly described under "Description of Athabasca's Business – Light Oil Division – Light Oil Exploration Areas".

"**MacKay assets**" means the former interests of the Participants, which following the Mackay Put Option Transaction were owned exclusively by Phoenix, in approximately 190,080 acres of land primarily between townships 87 to 91, ranges 12 to 15 west of the fourth meridian in northeastern Alberta, including for greater certainty the MacKay Oil Sands Leases, and the additional assets, benefits and interests that were acquired by or for the benefit of the Participants of the MacKay Joint Venture, including all tangible depreciable property, facilities, equipment and inventory owned or leased for the benefit of conducting the business of the MacKay Joint Venture, as well as contracts, agreements and other interests of a miscellaneous nature that were acquired, owned or held in order to explore, develop, construct and operate facilities in relation to, and produce, bitumen, together with cash and near cash equivalents, such as accounts receivable.

"**MacKay Call Option**" means the option granted by the Company to Phoenix to require the Company to sell to Phoenix or an affiliate of Phoenix all of the shares of AOSC (MacKay) (or a wholly-owned subsidiary of AOSC (MacKay)) pursuant to the Put/Call Option Agreement.

"**MacKay Joint Venture**" means the joint venture between AOSC (MacKay) and Phoenix formed as part of the closing of the PetroChina Transaction pursuant to the MacKay Joint Venture Agreement.

"**MacKay Joint Venture Agreement**" means the joint venture agreement dated February 10, 2010 entered into as part of the PetroChina Transaction among AOSC (MacKay), Phoenix and MacKay JV Operator pertaining to the ownership and operation of the MacKay assets.

"**MacKay JV Operator**" means MacKay Operating Corp., a corporation that was incorporated under the ABCA as part of the closing of the PetroChina Transaction by AOSC (MacKay).

"**MacKay JV Operator Shareholders Agreement**" means the unanimous shareholder agreement dated February 10, 2010 entered into among AOSC (MacKay), Phoenix and MacKay JV Operator as part of the PetroChina Transaction.

"**MacKay Oil Sands Leases**" means the crown leases that were governed by the MacKay Joint Venture Agreement.

"**MacKay Oil Sands Project**" means the in-situ oil sands project in respect of the MacKay assets.

"**MacKay Oil Sands Project Approval**" means, as it pertained to the MacKay Oil Sands Project, ERCB approval pursuant to section 10 of the *Oil Sands Conservation Act* (Alberta) and Alberta Environment approval pursuant to Part 2, Division 2, of the *Environmental Protection and Enhancement Act* (Alberta).

"**MacKay 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 AOSC (MacKay) (or a wholly-owned subsidiary of AOSC (MacKay)) pursuant to the Put/Call Option Agreement.

"**MacKay Put/Call Option**" means, collectively, the MacKay Call Option and the MacKay Put Option.

"**MacKay Put Option Transaction**" means the exercise by the Company of the MacKay Put Option (which is more particularly described under "General Development of the Business – Three Year History – 2011") and the sale by the Company of the AOSC MacKay Shares to Phoenix and the repayment of PetroChina Loan #1 and PetroChina Loan #2 (which are more particularly described under "General Development of the Business – Three Year History – 2012").

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

"**Majority Approval**" means: (a) with reference to any action, determination or decision of the board of directors of Dover JV Operator, the approval of such action, determination or decision of directors holding voting rights greater than 50%; and (b) with reference to any action, determination or decision of the Management Committee, the approval of such action, determination or decision of one or more Participants holding Participating Interests greater than 50%.

"**Management Committee**" means the management committee formed to supervise the business and affairs of the Dover Joint Venture and the activities of Dover JV Operator.

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

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

"**natural gas**" means a mixture of lighter hydrocarbons that exist either in the gaseous phase or in solution in crude oil in reservoirs but are gaseous at atmospheric conditions, 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.

"**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, condensate and small quantities of non-hydrocarbons.

"**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.

"**Operating Services Agreement**" means the operating services agreement dated February 10, 2010, entered into as part of the PetroChina Transaction between MacKay JV Operator and Dover JV Operator.

"**Participant**" means: (a) with reference to the MacKay Joint Venture, a person that had a Participating Interest in the MacKay Joint Venture and was a party to the MacKay Joint Venture Agreement, prior to the completion of the Mackay Put Option Transaction; and (b) with reference to the Dover Joint Venture, a person that has a Participating Interest in the Dover Joint Venture and is a party to the Dover Joint Venture Agreement, in any case, as the context requires or permits.

"**Participating Interest**" means: (a) with reference to the MacKay Joint Venture, an undivided beneficial ownership interest in the MacKay Joint Venture, the MacKay assets and bitumen recovered from the lands underlying the MacKay Oil Sands Leases; and (b) with reference to the Dover Joint Venture, 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.

"**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 Loan #1**" has the meaning given to that term under "General Development of the Business – Recent Significant Transactions – The PetroChina Transaction – The PetroChina Loans".

"**PetroChina Loan #2**" has the meaning given to that term under "General Development of the Business – Recent Significant Transactions – The PetroChina Transaction – The PetroChina Loans".

"**PetroChina Loan #3**" has the meaning given to that term under "General Development of the Business – Recent Significant Transactions – The PetroChina Transaction – The PetroChina Loans".

"**PetroChina Loan Agreements**" means the agreements entered into between Phoenix and the Company in respect of the PetroChina Loans.

"**PetroChina Loans**" means, collectively, PetroChina Loan #1, PetroChina Loan #2 and PetroChina Loan #3.

"**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 as part of the PetroChina Transaction.

"**PetroChina Transaction**" means, collectively, the transactions contemplated by the PetroChina Transaction Agreements; provided that references in this Annual Information Form to the closing or completion of the PetroChina Transaction do not include the exercise of any of the Put/Call Options or the closing of any Put/Call Option Transaction.

"**PetroChina Transaction Agreements**" means, collectively, the following agreements: the PetroChina Share Purchase Agreement; the MacKay Joint Venture Agreement; the Dover Joint Venture Agreement; the MacKay JV Operator Shareholders Agreement; the Dover JV Operator Shareholders Agreement; the Operating Services Agreement; the Put/Call Option Agreement; the Umbrella Agreement; the PetroChina Loan Agreements; and the security agreements associated with PetroChina Loan #1 and PetroChina Loan #2.

"**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 to form "Cretaceous Oilsands Holdings Limited" and the subsequent amalgamation of Cretaceous Oilsands Holdings Limited and Phoenix Energy Holdings Limited on October 1, 2012 to form "Phoenix Energy Holdings Limited". For greater certainty, references to "Phoenix" that are contained herein refer to Cretaceous Oilsands Holdings Limited (as amalgamation predecessor to Phoenix Energy Holdings Limited) prior to October 1, 2012 and to Phoenix Energy Holdings Limited (as amalgamation successor to Cretaceous Oilsands Holdings Limited) subsequent to October 1, 2012.

"**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.

"**Plan of Arrangement**" means the plan of arrangement under the ABCA effective March 22, 2010 pursuant to which, among other things, the Special Dividend was paid.

"**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 Reserve and Resource Evaluations – Reserves and Resources Classifications – Reserves Categories".

"**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 Reserve and Resource Evaluations – Reserves and Resources Classifications – Reserves Categories".

"**Put/Call Option Agreement**" means the agreement dated February 10, 2010 setting forth the MacKay Put/Call Option and the Dover Put/Call Option, among the Company, Phoenix, AOSC (MacKay), AOC (Dover), AOSC MacKay Corp. and AOC Dover Corp.

"**Put/Call Options**" means the options granted by and to the Company and Phoenix pursuant to the Put/Call Option Agreement.

"**Put/Call Option Transactions**" means the transactions contemplated in relation to the Put/Call Options pursuant to the Put/Call Option Agreement.

"**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 and HSE Committee**" means the reserves and health, safety and environmental 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.

"**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".

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

"**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.

"**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.).

"**Saxon/Placid Area**" means the interests of Athabasca in approximately 159,000 net acres of land as at December 31, 2013, that are located primarily between townships 60 to 64, ranges 21 to 26, west of the fifth meridian in northwestern Alberta, and includes Athabasca's interests in the Saxon, Placid and Simonette areas, more particularly described under "Description of Athabasca's Business – Light Oil Division – Saxon/Placid Area".

"**SCO**" or "**synthetic crude oil**" means crude oil produced by upgrading bitumen to a mixture of hydrocarbons similar to light crude oil produced either by the removal of carbon (coking) or the addition of hydrogen through hydrotreating. It is considered synthetic because its original composition mark has been altered in the upgrading process.

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

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

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

"**Special Dividend**" means the dividends paid on March 22, 2010 pursuant to the Plan of Arrangement in the aggregate amount of $4.25 per share (approximately $1.332 billion in total) utilizing a portion of the proceeds of the PetroChina Transaction.

"**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.

"**TAGD Pilot and Demonstration Project**" has the meaning given to that term under "General Development of the Business – Three Year History – 2011".

"**Thermal Oil assets**" means the interests of Athabasca in over 1.5 million net acres of oil sands leases in the Athabasca region of northeastern Alberta, as at December 31, 2013.

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

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

"**Umbrella Agreement**" means the umbrella agreement dated February 10, 2010 entered into among the Company, AOSC MacKay Corp., AOC Dover Corp., AOSC (MacKay), AOC (Dover), Phoenix, PetroChina International, MacKay JV Operator and Dover JV Operator.

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

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

"**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
bbls/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
Mbbls	thousand barrels
MMbbls	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	35.494
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	2.471

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

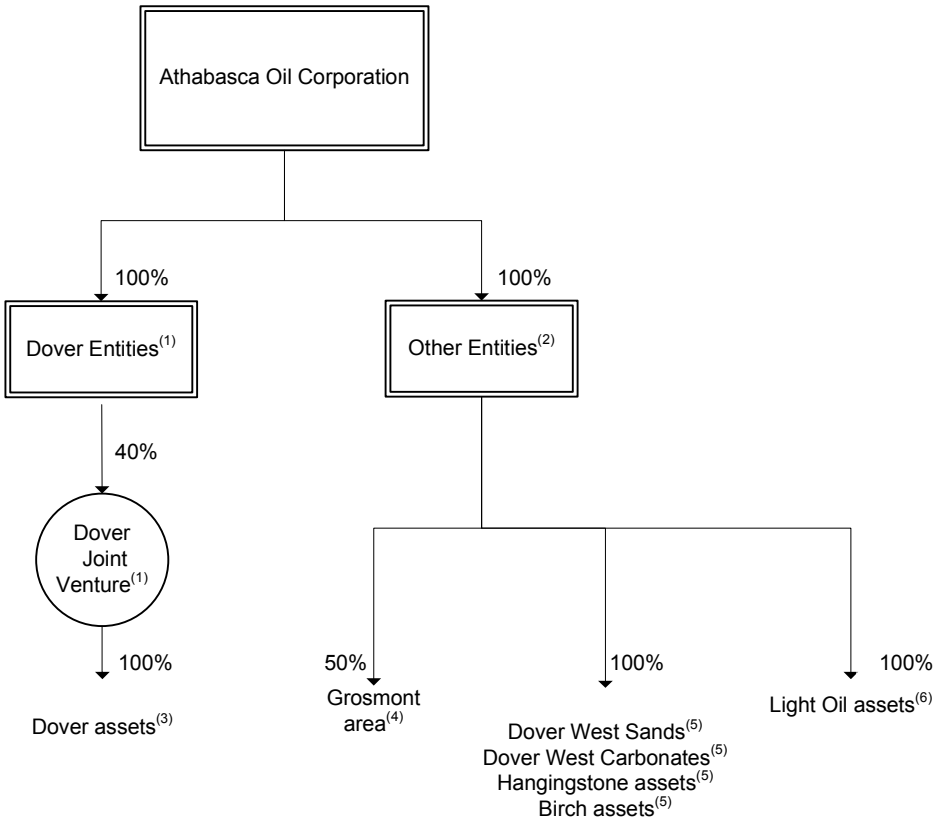
Name, Address and Incorporation

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".

The Company's head office is located at Suite 2000, 250 – 6th Avenue S.W., Calgary, Alberta T2P 3H7, 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 December 31, 2013, 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 Dover entities are corporations which are directly or indirectly wholly-owned by the Company: AOC Dover Corp. and AOC (Dover). AOC (Dover): (a) holds an undivided 40% working interest in the Dover assets; (b) holds 40% of the issued and outstanding shares in the capital of the Dover JV Operator; and (c) is a Participant in the Dover Joint

Venture as to a 40% Participating Interest. See "General Development of the Business – Recent Significant Transactions – The PetroChina Transaction".

(2) The "Other Entities" are corporations and partnerships directly or indirectly wholly-owned by the Company: AOC Dover West Corp., AOC Grosmont Ltd., AOC Carbonates Ltd., AOC Light Oil Corp., AOC (ELE) Corp., AOC Birch Corp., AOC Kaybob Corp., AOC Grande Prairie Corp., AOC Simonette Corp., AOC Muskwa North Corp., AOC Muskwa South Corp., AOC Caribou Corp., AOC Dover West Partnership, AOC Grosmont Partnership, AOC Carbonates Partnership, AOC Hangingstone Partnership, AOC Birch Partnership, AOC Light Oil Partnership, AOC Kaybob Partnership, AOC Grande Prairie Partnership, AOC Simonette Partnership, AOC Muskwa North Partnership, AOC Muskwa South Partnership and AOC Caribou Partnership.

(3) See "Description of Athabasca's Business – Thermal Oil Division – Dover assets" for a description of Athabasca's 40% working interest in the Dover assets.

(4) See "Description of Athabasca's Business – Thermal Oil Division – Grosmont assets" for a description of Athabasca's 50% working interest in the Grosmont area. ZAM Ventures Alberta Inc., a family investment entity advised by Ziff Brothers Investments, L.L.C. (and an affiliate of ZAM Investments Luxembourg, s.á.r.l.), holds the remaining 50% working interest in the Grosmont area.

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

(6) 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, bitumen from oil sands in the Athabasca region of northeastern Alberta, Canada, and light oil and liquids-rich natural gas from regions in northwestern Alberta, Canada. Athabasca is organized into the following two divisions:

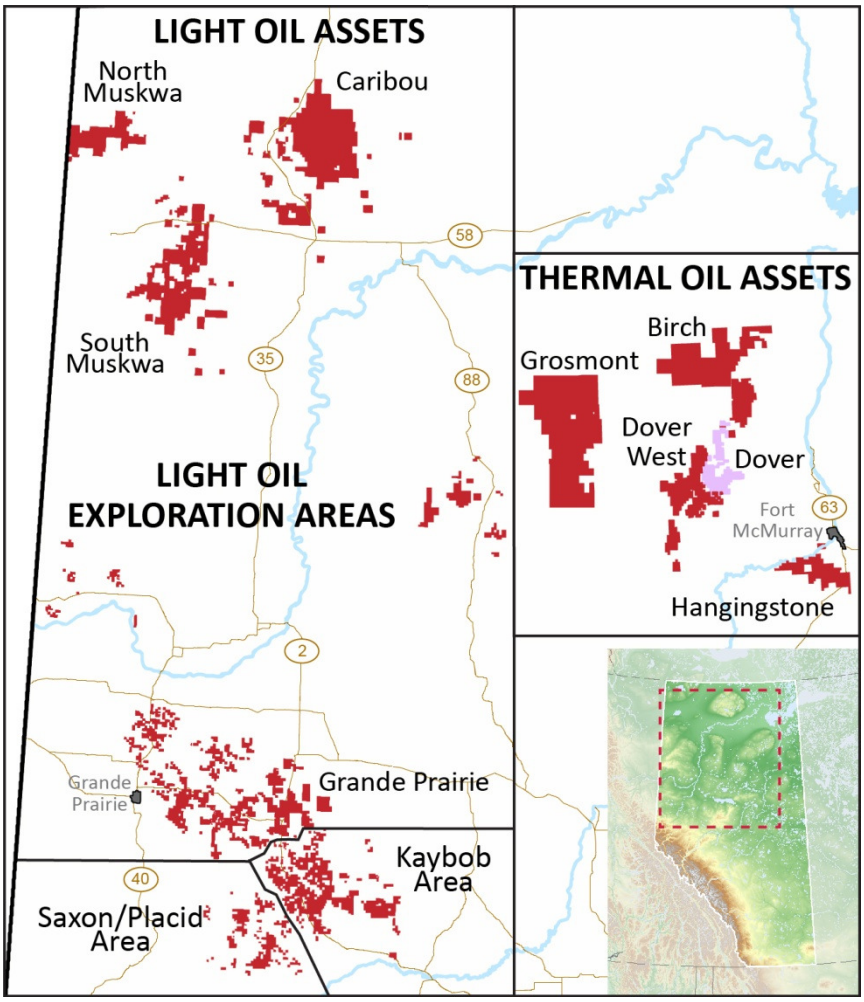
Thermal Oil Division

As at December 31, 2013, Athabasca held over 1.5 million net acres of oil sands leases in the Athabasca region of northeastern Alberta. In respect of its bitumen assets, Athabasca is advancing only in-situ oil sands exploration and development projects using methods such as SAGD and experimental in-situ extraction technologies such as TAGD. As at December 31, 2013, Athabasca's principal thermal oil assets were Hangingstone (100% working interest), Dover West (Sands and Carbonates) (100% interest), Dover (40% interest), Birch (100% interest) and Grosmont (50% interest). See "Description of Athabasca's Business – Thermal Oil Division".

Light Oil Division

As at December 31, 2013, Athabasca held over 2.7 million net acres of petroleum and natural gas leases, predominately in northwestern Alberta. Athabasca's current principal light oil development properties are located in the Kaybob Area and Saxon/Placid Area, and Athabasca has also conducted exploration and limited development activities in its Light Oil Exploration Areas. See "Description of Athabasca's Business – Light Oil Division".

The following map illustrates the locations of Athabasca's Thermal Oil assets and Light Oil assets, as at December 31, 2013:



Athabasca's Independent Evaluators have assigned to Athabasca, in the aggregate, as at December 31, 2013, approximately 65.7 MMboe of Proved Reserves and 416.7 MMboe of Probable Reserves on a Gross Reserves basis (including the Probable Reserves attributable to Athabasca's undivided 40% working interest in the Dover assets), and approximately 10.5 billion barrels of Best Estimate Contingent Resources on a Company Interest basis. See "Independent Reserve and Resource Evaluations".

The Company's Common Shares trade on the TSX under the trading symbol "ATH".

GENERAL DEVELOPMENT OF THE BUSINESS

Recent Significant Transactions - The PetroChina Transaction

Sale of a 60% Interest in the MacKay Assets and Dover Assets

On February 10, 2010, pursuant to the PetroChina Share Purchase Agreement, the Company sold all of the issued and outstanding shares of AOSC Newco, a wholly-owned subsidiary of the Company, to Phoenix for consideration of $1.9 billion. Phoenix also reimbursed the Company for 60% of the expenditures in respect of the oil sands assets

of AOSC Newco incurred by the Company during the period commencing November 1, 2009 and ending on the closing date of the PetroChina Transaction.

AOSC Newco was the owner of an undivided 60% interest in the MacKay assets and the Dover assets. Following the sale of the shares of AOSC Newco to Phoenix pursuant to the PetroChina Share Purchase Agreement: (a) AOSC Newco amalgamated with Phoenix, a wholly-owned subsidiary of PetroChina International; (b) Phoenix became the owner of the undivided 60% interest in the MacKay assets and the Dover assets; (c) Phoenix and AOSC (MacKay) formed the MacKay Joint Venture for the development of the MacKay Oil Sands Project; and (d) Phoenix and AOC (Dover) formed the Dover Joint Venture for the development of the Dover Oil Sands Project.

Upon the completion of the PetroChina Transaction: (a) AOSC (MacKay) was the owner of an undivided 40% interest in the MacKay assets; (b) AOC (Dover) was the owner of an undivided 40% interest in the Dover assets; (c) Phoenix and AOSC (MacKay) incorporated and organized MacKay JV Operator to act as the operator for the MacKay Joint Venture; and (d) Phoenix and AOC (Dover) incorporated and organized Dover JV Operator to act as the operator for the Dover Joint Venture.

The PetroChina Loans

PetroChina Loan #1

Concurrent with the sale of the shares of AOSC Newco to Phoenix, Phoenix provided the Company with a non-revolving loan in the amount of $430 million, on a full recourse security basis to the assets of the Company and its material subsidiaries ("**PetroChina Loan #1**"). The Company used the proceeds of PetroChina Loan #1 to redeem the 2008 Notes. Interest on PetroChina Loan #1 was payable semi-annually at a rate equal to LIBOR plus 450 basis points. PetroChina Loan #1 matured on the closing date of the MacKay Put Option Transaction and the principal and interest outstanding under PetroChina Loan #1 was repaid from the cash proceeds paid to the Company upon closing of the MacKay Put Option Transaction.

PetroChina Loan #2

Phoenix also agreed to loan the Company up to $100 million under a non-revolving multi-draw credit facility, on a limited recourse security basis to the assets of AOSC (MacKay) and AOC (Dover) ("**PetroChina Loan #2**"). PetroChina Loan #2 matured on the closing date of the MacKay Put Option Transaction and the principal and interest outstanding under PetroChina Loan #2 was repaid from the cash proceeds paid to the Company upon closing of the MacKay Put Option Transaction.

PetroChina Loan #3

Phoenix also agreed to provide a limited recourse, non-revolving, multi-draw credit facility as part of the PetroChina Transaction with a maximum principal amount of $560 million ("**PetroChina Loan #3**"). A condition precedent to the Company's ability to draw on PetroChina Loan #3 was that the MacKay Put/Call Option not be exercised by either the Company or Phoenix. As a result of Athabasca's exercise of the MacKay Put Option on December 23, 2011, the condition precedent to PetroChina Loan #3 was not met and PetroChina Loan #3 terminated.

The Put/Call Options

As part of the PetroChina Transaction, the Company, AOSC MacKay Corp., AOC Dover Corp., AOSC (MacKay), AOC (Dover) and Phoenix entered into the Put/Call Option Agreement in respect of the grant of the Put/Call Options. Pursuant to the Put/Call Options, the Company could require Phoenix to purchase, or Phoenix could exercise the right to acquire, as the case may be, the Company's remaining 40% working interest in one or both of the MacKay assets and the Dover assets by acquiring the assets or shares of AOSC (MacKay) (or a wholly-owned subsidiary thereof) or AOC (Dover) (or a wholly-owned subsidiary thereof), for aggregate cash consideration of up to $2 billion.

As is described under "General Development of the Business – Three Year History" below, the Mackay Put Option was exercised on December 23, 2011 and the MacKay Put Option Transaction was completed on March 15, 2012.

As is described under "General Development of the Business – Recent Developments" below, the Dover JV Operator received the approval of the Lieutenant Governor in Council in respect of the Dover Oil Sands Project on March 13, 2014. The Dover JV Operator and Athabasca are currently awaiting the approval of Alberta Environment in respect of the Dover Oil Sands Project. Athabasca expects to exercise the Dover Put Option upon the receipt of the approval of Alberta Environment.

Three Year History

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

2011

On March 8, 2011, the Company announced that it had acquired a 100% working interest in approximately 1.0 million acres of Alberta crown petroleum and natural gas rights in the Alberta Deep Basin, including rights in the Duvernay, Montney, Charlie Lake and Nordegg Formations.

On March 31, 2011, Athabasca submitted an application to the ERCB and Alberta Environment in respect of a planned 12,000 bbls/d SAGD project for its Hangingstone assets ("**Hangingstone Project 1**").

In the first quarter of 2011, Athabasca completed the construction of a TAGD field test facility to test bitumen recovery from the Dover West Carbonates. Heating operations for the test commenced in April of 2011 using two 250-metre horizontal wells and production from the test commenced in October of 2011.

In October 2011, Athabasca submitted an application to the ERCB and Alberta Environment for a TAGD pilot and demonstration project within the Dover West Carbonates with a production capacity of up to 6,000 bbls/d (the "**TAGD Pilot and Demonstration Project**").

In December 2011, Athabasca submitted an application to the ERCB and Alberta Environment for a SAGD project with a planned production capacity of up to 12,000 bbls/d in the Dover West Sands ("**Dover West Sands Project 1**").

On December 23, 2011, MacKay JV Operator received the MacKay Oil Sands Project Approval, and pursuant to the terms of the Put/Call Option Agreement, the Company exercised the MacKay Put Option to require Phoenix, or an affiliate of Phoenix, to purchase all of the AOSC MacKay Shares for cash consideration of $680 million, subject to closing adjustments and the repayment by Athabasca of PetroChina Loan #1 and PetroChina Loan #2.

2012

On March 15, 2012, the MacKay Put Option Transaction closed, whereby the Company sold the AOSC MacKay Shares to Phoenix for cash consideration of $680 million, less certain closing adjustments and repayment by the Company of the amounts that were outstanding under PetroChina Loan #1 and PetroChina Loan #2. Following the completion of the MacKay Put Option Transaction, Athabasca no longer held an interest in the MacKay assets.

On May 10, 2012, the Company received the requisite shareholder approval and changed its name from "Athabasca Oil Sands Corp." to "Athabasca Oil Corporation".

In October 2012, Athabasca received regulatory approval for the development of Hangingstone Project 1.

On November 19, 2012, the Company issued $550 million aggregate principal amount of Senior Secured Notes, as is more particularly described under "Description of Capital Structure – Senior Secured Notes".

In connection with the issuance of the Senior Secured Notes, on November 30, 2012 the Company entered into a credit agreement with a syndicate of financial institutions providing for senior secured first lien revolving credit facilities in the aggregate amount of $200 million (the "**2012 Credit Facilities**").

2013

On March 21, 2013, Athabasca announced that it had entered into an agreement with Enbridge Pipelines (Athabasca) Inc. ("**Enbridge**") for the transportation and terminaling of dilbit to be produced from Hangingstone Project 1.

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 began on April 23, 2013 and was completed on April 29, 2013. On August 6, 2013, the AER announced that the Dover JV Operator's application in respect of the Dover Oil Sands Project was approved, subject to the conditions set forth in the AER's written decision (the "**AER Decision**"), including the approval of the Lieutenant Governor in Council. The FMFN subsequently sought the approval of the Court of Appeal of Alberta to appeal the AER Decision. On October 18, 2013, the Court of Appeal of Alberta granted the FMFN leave to appeal on a specific question of law that arose from the AER Decision.

On May 6, 2013, the Company formed an Executive Operational and Development Committee ("**EODC**") that was tasked with refining the Company's operational performance plan to target top-tier performance and incorporate the flexibility required to address available corporate financing. The Board appointed Mr. Ronald Eckhardt, a director and the Chairman of the Reserves and HSE Committee, to chair the EODC. The Company announced that the EODC had completed its mandate on October 30, 2013.

On May 17, 2013, Athabasca submitted a regulatory application to the AER and Alberta Environment in respect of an incremental 70,000 bbls/d of production from its Hangingstone assets (the "**Hangingstone Expansion**").

Athabasca's regulatory application in respect of the TAGD Pilot and Demonstration Project was approved by the AER on September 19, 2013 and by Alberta Environment on December 17, 2013.

On November 6, 2013, Athabasca entered into a long term Condensate Transportation Services Agreement with IPP. Pursuant to the agreement, IPP agreed to construct and operate a pipeline for the transportation of diluent to Hangingstone Project 1 and to provide diluent transportation for the Hangingstone Expansion, if the Hangingstone Expansion is sanctioned and an election is made by Athabasca.

Athabasca sold a 50% working interest in the Kaybob Infrastructure Assets to a third party for gross cash consideration of $145.9 million on December 23, 2013. Athabasca continues to be the operator of the Kaybob Infrastructure Assets.

On December 16, 2013, the Company entered into the Amended and Restated Credit Agreement providing for senior secured first lien credit facilities in the aggregate amount of $350 million (the "**Amended Credit Facilities**") to replace the 2012 Credit Facilities, as more particularly described under "Description of Capital Structure – Amended Credit Facilities".

Recent Developments

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 and Athabasca are currently awaiting the approval of Alberta Environment in respect of the Dover Oil Sands Project. Athabasca expects to exercise the Dover Put Option upon the receipt of the approval of Alberta Environment.

On March 14, 2014, Thomas Buchanan was appointed as Chairman of the Board to replace William Gallacher, who resigned from the Board to concentrate on his other endeavors. A new Board member, Peter Sametz, was also appointed to the Board on March 14, 2014.

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, 2013 for which disclosure is required under Part 8 of NI 51-102.

DESCRIPTION OF ATHABASCA'S BUSINESS

Athabasca's Development Strategy for its Principal Properties

As at December 31, 2013, Athabasca's principal properties were the Hangingstone assets, the Dover West assets and its interests in the Dover assets in northeastern Alberta, and its interests in the Kaybob Area and Saxon/Placid Area in northwestern Alberta. Athabasca also has other exploration and development opportunities at its Birch and Grosmont asset areas and within its Light Oil Exploration Areas.

As at December 31, 2013, Athabasca's Thermal Oil assets and Light Oil assets have been assigned in the aggregate, on a Gross Reserves basis, approximately 65.7 MMboe of Proved Reserves and 416.7 MMboe of Probable Reserves (including the Probable Reserves attributable to Athabasca's undivided 40% working interest in the Dover assets). Athabasca's Thermal Oil assets have also been assigned in the aggregate approximately 10.5 billion barrels of Best Estimate Contingent Resources by the Independent Evaluators on a Company Interest basis. See "Independent Reserve and Resource Evaluations".

Athabasca's 2014 activities are expected to be funded with existing cash and short term investments, cash flow from operations, the proceeds from the sale of Athabasca's interests in the Dover assets pursuant to the exercise of the Dover Put Option, and by the Amended Credit Facilities or other available debt financing. Athabasca's current business plan for developing its properties beyond 2014 anticipates that Athabasca will fund its activities and other requirements through some combination of cash flow from operations, a reasonable level of debt and through potential joint venture arrangements. See "Risk Factors – Substantial Capital Requirements and Liquidity Risk" for additional information.

Pace of Development

Management has a continual focus on optimizing Athabasca's development plans and increasing Shareholder value. The final determination and execution of Athabasca's project development plans will depend on a variety of factors, including the results of Athabasca's exploration and development activities, the development of new business opportunities, the receipt of proceeds expected from the sale of Athabasca's interest in the Dover assets following the exercise of the Dover Put Option, the availability of financing, developments in technology, the priorities of Athabasca and of its current and any future joint venture partners and general economic conditions.

Thermal Oil Division

Hangingstone assets

Location and Size

The Hangingstone assets are located within the Athabasca oil sands fairway of northeastern Alberta between townships 85 to 88, ranges 9 to 13, west of the fourth meridian. The leases are approximately 15 to 20 kilometres southwest of the city of Fort McMurray and are near existing infrastructure, including high voltage power, fuel gas and diluent supply and bitumen blend sales pipelines. The main highway leading to the city of Fort McMurray, Highway 63, runs through the assets. The Hangingstone assets comprise a concentrated, contiguous land base of approximately 136,000 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.

D&M has assigned approximately 51.1 MMbbls of Proved Reserves and 174 MMbbls of Probable Reserves on a Gross Reserves basis, and 782 MMbbls of Best Estimate Contingent Resources on a Company Interest basis, to the Hangingstone assets as at December 31, 2013. See "Independent Reserve and Resource Evaluations".

Project Development

Athabasca plans to develop the Hangingstone assets using SAGD with a staged development strategy. In October 2012, Athabasca received regulatory approval for the development of Hangingstone Project 1. On November 27, 2012, the Board sanctioned a $536 million development budget for Hangingstone Project 1 and an additional budget of $27 million for the construction of supporting infrastructure. Hangingstone Project 1 is expected to be comprised of a central processing facility (the "**HS CPF**") and twenty SAGD well pairs on four well pads and has a planned production capacity of 12,000 bbls/d.

On May 17, 2013, Athabasca submitted a regulatory application to the AER and Alberta Environment in respect of the Hangingstone Expansion. Athabasca intends to develop the Hangingstone Expansion through two projects: the first Hangingstone Expansion project ("**Hangingstone Project 2**") is planned to have a production capacity of 40,000 bbls/d; followed by a second Hangingstone Expansion project ("**Hangingstone Project 3**"), which is planned to have a production capacity of 30,000 bbls/d. Combined, Hangingstone Project 1 and the Hangingstone Expansion would bring the overall production potential from the Hangingstone assets to more than 80,000 bbls/d.

On December 16, 2013, the Board approved a 2014 capital budget that included $225 million for Hangingstone Project 1, $58 million for regional infrastructure and production support, and $45 million for regional activities and to advance the regulatory approval in respect of the Hangingstone Expansion.

The HS CPF is designed to process all bitumen from Hangingstone Project 1 and is planned to be expanded to accommodate Hangingstone Project 2 and Hangingstone Project 3. By the end of 2013, earthworks construction and pile driving for the HS CPF were substantially complete and piping and equipment modules had begun to arrive on site for installation on their foundations. Athabasca commenced the drilling of the SAGD well pairs for Hangingstone Project 1 with one rig in August of 2013 and with a second rig in September of 2013. By the end of 2013, fifteen producer wells and ten injector wells had been successfully drilled. First steam from Hangingstone Project 1 is anticipated in the first quarter of 2015 and first production is expected to commence four to six months thereafter. In order to achieve these targets, Athabasca must complete the following key project activities in 2014:

- Delivery/receipt of remaining major modules to the project site;
- Finish horizontal well drilling and completions;
- Completion of all infrastructure development including power, fuel gas and make-up water supply;
- Mechanical construction progress in line with plan to support commissioning in the first quarter of 2015.

In 2013, Athabasca also progressed the front-end engineering and design in respect of the Hangingstone Expansion and completed the drilling of twenty-three delineation appraisal wells. Athabasca continues to work on its

development plans in respect of the Hangingstone Expansion and intends to progress the engineering and design of the projects throughout 2014.

On March 21, 2013, Athabasca announced that it had entered into an agreement with Enbridge for the transportation and terminaling of dilbit to be produced from Hangingstone Project 1. As part of the agreement, Enbridge has agreed to construct a new 50-kilometre-long, 16-inch pipeline from the HS CPF to the existing Enbridge Cheecham Terminal and to modify the Enbridge Cheecham Terminal to support the incremental production. The new pipeline is anticipated to be in service in the latter half of 2015 and is expected to have sufficient capacity to handle the production from both Hangingstone Project 1 and the Hangingstone Expansion.

On November 6, 2013, Athabasca entered into a Condensate Transportation Services Agreement with IPP. Under the long-term ship-or-pay arrangement, IPP has agreed to provide diluent transportation services to Athabasca through its Polaris pipeline to support the production from Hangingstone Project 1. Pursuant to the agreement, IPP has also agreed to provide diluent transportation for the Hangingstone Expansion, if the Hangingstone Expansion is sanctioned and an election is made by Athabasca.

Athabasca's decisions regarding the Hangingstone assets' ultimate production capacity, the size of the developments and the pace of development will be based on various factors, including economics, the availability of financing, capital investment opportunities in other asset areas, reservoir knowledge, operational complexities, optimization of processing facilities, utilization of improving technologies and water management planning.

Dover West assets

Location and Size

Athabasca has a 100% working interest in its Dover West assets, which contain resources in the Dover West Sands and in the Dover West Carbonates. The Dover West assets are located within the Athabasca oil sands fairway of northeastern Alberta between townships 87 to 95, ranges 17 to 21, west of the fourth meridian approximately 90 kilometres northwest of the city of Fort McMurray. As at December 31, 2013, the Dover West assets were comprised of a large contiguous land base of approximately 240,000 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). As a result, management believes that the Dover West assets contain the highest resource density of all of Athabasca's asset areas.

GLJ assigned, as at December 31, 2013, approximately 2.96 billion barrels of Best Estimate Contingent Resources (on a Company Interest basis) and 87.1 MMbbls of Probable Reserves (on a Gross Reserves basis) within the Dover West Sands, and approximately 3.0 billion barrels of Best Estimate Contingent Resources (on a Company Interest basis) within the Dover West Carbonates. The resources attributed to the Dover West Carbonates are contained in carbonate reservoirs and SAGD and TAGD are the recovery processes currently being considered to develop these resources. The commercial viability of SAGD technology has been demonstrated successfully for application to certain non-carbonate reservoirs but the commercial viability of SAGD technology has not been demonstrated for the subject reservoirs or a good analogue to date. TAGD is considered by GLJ to be an experimental technology. For important additional information, see "Independent Reserve and Resource Evaluations – Contingent Resource Estimates" and "Risk Factors – Bitumen Recovery Processes".

In 2011, Athabasca received regulatory approval to build a 64 kilometre road into the Dover West asset area. Design and construction commenced in cooperation with a third party industry participant in 2011 and the road was completed in 2013.

Dover West Sands

Project Development

Athabasca is planning to develop the Dover West Sands using SAGD with a staged development strategy. Athabasca submitted an application to the ERCB and Alberta Environment in December of 2011 in respect of Dover West Sands Project 1, which has a planned production capacity of 12,000 bbls/d. Regulatory approval for Dover West Sands Project 1 was not received in 2013, as was originally anticipated, and it is now expected to be received in the first half of 2014.

Management believes that the Dover West Sands could ultimately support production of up to 292,000 bbls/d, once fully developed. Athabasca originally planned to submit a regulatory application for a Dover West Sands expansion project comprised seven additional phases, each with a planned production capacity of up to 40,000 bbls/d (the "**Dover West Sands Expansion**") in 2014, but the application is no longer planned to be submitted in 2014 due to budgetary constraints. While management believes that the Dover West Sands are an attractive and viable long-term development opportunity, it is not expected that Athabasca will fully develop the Dover West Sands Projects without first securing a joint venture partner or another suitable means of financing.

Dover West Carbonates

Project Development

In management's opinion, the work performed in the Dover West Carbonates suggests that multiple in-situ extraction methods, such as TAGD and SAGD, may be suitable for use in the Dover West Carbonates. The existing Contingent Resources assigned to the Dover West Carbonates assume that the assets will be developed using SAGD. However, Athabasca believes TAGD could become a superior in-situ recovery process which could take better advantage of the Dover West Carbonates' reservoir characteristics. Athabasca continues to devote resources to determining the optimal development and production methods for the Dover West Carbonates.

In 2011, Athabasca began conducting steam injection and a TAGD field test in the Dover West Carbonates. The steam injection field tests that were conducted in 2011 supported steam injection as a viable recovery process for the Dover West Carbonates. Since 2011, Athabasca has been conducting a TAGD field test which has demonstrated the effectiveness of TAGD to heat the reservoir through thermal conduction and to produce bitumen through gravity drainage. In 2013, the TAGD field test met or exceeded Athabasca's objectives. Athabasca continues to operate the TAGD field test to obtain additional information about TAGD technology and the reservoir characteristics of the Dover West Carbonates.

In October of 2011, Athabasca submitted an application to the ERCB and Alberta Environment in respect of the TAGD Pilot and Demonstration Project with a production capacity of up to 6,000 bbls/d to further evaluate bitumen recovery using TAGD. The regulatory application was approved by the AER on September 19, 2013 and by Alberta Environment on December 17, 2013. The pilot stage of the TAGD Pilot and Demonstration project is intended to evaluate recovery factors and energy balance and the demonstration stage of the project is intended to demonstrate commercial viability of the TAGD process.

During the second quarter of 2013, Athabasca completed the construction of its heater assembly facility outside of Strathmore, Alberta. The heater assembly facility is comprised of two wells (one deviated and one horizontal) which are being utilized for the testing of TAGD heater prototypes. The first TAGD heater prototype that was tested for nearly a year was found to be reliable. A second pilot heater prototype was assembled during the latter part of 2013 and continues to undergo testing.

The timing of the first commercial development in the Dover West Carbonates will be contingent on the performance of the TAGD Pilot and Demonstration Project, the timing of the required commercial regulatory applications, the receipt of the required regulatory approvals and securing funding for the project. Athabasca believes the Dover West Carbonates could support production of at least 250,000 bbls/d, if fully developed.

Decisions regarding the ultimate production capacity, development size and pace of development of the Dover West Sands Projects and the Dover West Carbonates Projects will be based upon various factors, including economics, the availability of financing, capital investment opportunities in other asset areas, reservoir knowledge, operational complexities, optimization of processing facilities, the development and/or utilization of improving technologies, the availability of transportation infrastructure and water management planning.

Dover assets

AOC (Dover), a wholly owned subsidiary of the Company: (a) owns an undivided 40% working interest in the Dover assets; (b) holds 40% of the issued and outstanding shares in the capital of the Dover JV Operator; and (c) is a Participant in the Dover Joint Venture as to a 40% Participating Interest.

Phoenix holds: (a) the remaining 60% working interest in the Dover assets; (b) 60% of the issued and outstanding shares in the capital of the Dover JV Operator; and (c) is the other Participant in the Dover Joint Venture as to a 60% Participating Interest.

Location and Size

The Dover assets are located within the Athabasca oil sands fairway of northeastern Alberta between townships 92 to 97, ranges 15 to 18, west of the fourth meridian approximately 90 kilometres northwest of the city of Fort McMurray. The bitumen reservoir is contained within the McMurray Formation and is suitable for recovery using SAGD.

The Dover assets comprise a large contiguous land base with a gross acreage of approximately 150,000 acres, as at December 31, 2013, with Athabasca having a net working interest of approximately 60,000 acres.

GLJ has assigned Best Estimate Contingent Resources of approximately 1.22 billion barrels on a Company Interest basis and 137.6 MMbbls of Probable Reserves on a Gross Reserves basis to Athabasca's interests in the Dover assets, as at December 31, 2013. See "Independent Reserve and Resource Evaluations".

Project Development

Athabasca expects that the Dover Oil Sands Project will be developed using SAGD with a phased development strategy comprising five phases. Based on current resource and reserve estimates (see "Independent Reserve and Resource Evaluations"), the Dover First Phase is planned to reach a bitumen production rate of up to 50,000 bbls/d (gross), with expansion capabilities for developing a second stage, and the Dover Oil Sands Project is expected to reach an ultimate planned production capacity of 250,000 bbls/d (gross).

On December 21, 2010, the Dover Joint Venture submitted a regulatory application to the ERCB and Alberta Environment for the Dover Oil Sands Project. In 2011 and 2012, the Dover Joint Venture received and responded to supplemental information requests from the regulators and in July of 2012, the Dover Joint Venture received notification from Alberta Environment that the application was technically complete. During the remainder of 2012, the Dover Joint Venture continued to manage the technical details associated with the regulatory approval process and continued consultation with stakeholders.

The Dover Joint Venture is reviewing the timing of the Dover First Phase to allow for the incorporation of design, construction and other operational knowledge that was acquired as part of the first phase of the MacKay Oil Sands Project. The Dover First Phase could begin production as early as mid-2018. The Dover Joint Venture has completed the field development plan detailing the execution strategy for the initial development area in respect of the Dover First Phase. The Dover JV Operator is preparing to complete the engineering required for a full front-end engineering design package in 2014 to clearly define detailed engineering and project execution requirements.

The timing for commencing and completing the Dover First Phase, as well as the subsequent phases of the Dover Oil Sands Project that would be necessary for the project to reach an ultimate capacity of 250,000 bbls/d (gross),

will be based on a number of factors, including economics, geological definition, reservoir knowledge, operational complexities, optimization of processing facilities, utilization of improving technologies, water management planning, the availability of transportation infrastructure and other factors.

A hearing 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. The hearing began on April 23, 2013 and was completed on April 29, 2013. On August 6, 2013, the AER announced that the Dover JV Operator's application in respect of the Dover Oil Sands Project was approved, subject to the conditions set forth in the AER Decision, including the approval of the Lieutenant Governor in Council. The FMFN subsequently sought the approval of the Court of Appeal of Alberta to appeal the AER Decision. On October 18, 2013, the Court of Appeal of Alberta granted the FMFN leave to appeal on a question of constitutional law that arose from the AER Decision. 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 and Athabasca are currently awaiting the approval of Alberta Environment in respect of the Dover Oil Sands Project. Athabasca expects to exercise the Dover Put Option upon the receipt of the approval of Alberta Environment. Pursuant to the terms of the Dover Put/Call Option Agreement, the exercise of the Dover Put Option by Athabasca will 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)). Until such time as the shares or assets of AOC (Dover) (or a wholly owned subsidiary of AOC (Dover) are sold to Phoenix (or an affiliate of Phoenix), the development of the Dover Oil Sands Project will proceed according to the business plans developed by, and under the operatorship of Dover JV Operator. See "General Development of the Business – Recent Significant Transactions – The PetroChina Transaction".

Birch assets

Athabasca holds a 100% working interest in the Birch assets to which D&M has assigned approximately 2.11 billion barrels of Best Estimate Contingent Resources on a Company Interest basis, as at December 31, 2013. See "Independent Reserve and Resource Evaluations".

The Birch assets are located within the Athabasca oil sands fairway of northeastern Alberta between townships 97 to 103, ranges 13 to 20, west of the fourth meridian, approximately 95 kilometres northwest of the city of Fort McMurray. The Birch assets comprise an extensive contiguous land base of approximately 470,000 acres.

During its 2011/2012 winter drilling season, Athabasca drilled 22 delineation wells and acquired 54 square kilometres of 3-D seismic data to support an initial development project in respect of the Birch assets. In 2013, Athabasca conducted preliminary engineering regarding future site access and evaluated the optimal size of the first development project.

Management believes that the Birch assets have significant commercial potential and that they could potentially support a project or projects of up to 155,000 bbls/d. Athabasca had originally planned to submit a regulatory application for a 12,000 bbls/d project in late 2012 or early 2013, but it has decided not to proceed with a development project in the Birch assets without a joint venture partner or another suitable means of financing.

Grosmont assets

The Grosmont assets represent a long-term opportunity which management believes have the potential for the development of significant amounts of resources. The Grosmont Formation has not been commercially developed by the industry to date, although several companies are devoting resources to unlocking its perceived potential. Athabasca has not prepared a development plan or timeline for the Grosmont assets, and is monitoring industry activity toward demonstrating successful development and production methods for the Grosmont Formation.

The Grosmont area is located within the Athabasca oil sands fairway of northeastern Alberta between townships 92 to 100, range 25 west of the fourth meridian to range 5 west of the fifth meridian. The Grosmont area represents one of the largest contiguous blocks of oil sands leases in the Province of Alberta with a total gross acreage of approximately 788,000 acres in which Athabasca has a 50% working interest and a net acreage leaseholding of approximately 394,000 acres. On November 7, 2008, Athabasca entered into a joint venture with ZAM Ventures Alberta Inc. with respect to the Grosmont area. Athabasca, which is the operator of the joint venture, and ZAM Ventures Alberta Inc., each hold 50% interests in the joint venture. ZAM Ventures Alberta Inc. is a family investment entity advised by Ziff Brothers Investments, L.L.C., and is an affiliate of ZAM Investments Luxembourg, s.á.r.l. Athabasca's plans to develop the Grosmont assets are very preliminary and are only of a scoping nature. Except for one successful third party pilot test in the Grosmont Formation, the direct assessment of productivity from the carbonates in the Grosmont Formation is based solely on laboratory tests, the analysis of cores and logs, and simulation studies. GLJ has assigned approximately 418 MMbbls of Best Estimate Contingent Resources to the Grosmont assets on a Company Interest basis, as at December 31, 2013. The resources at Grosmont are contained in carbonate reservoirs. The commercial viability of SAGD technology, the recovery process currently being considered to develop these resources, has been demonstrated successfully for application to certain non-carbonate reservoirs but not for the subject reservoirs or a good analogue to date. For important additional information, see "Independent Reserve and Resource Evaluations" and "Risk Factors – Bitumen Recovery Processes".

Light Oil Division

As at December 31, 2013, Athabasca held over 2.7 million net acres of petroleum and natural gas rights in its Light Oil asset areas, which include rights in the Duvernay, Montney, Charlie Lake, Nordegg, Slave Point, Rainbow Lake and Muskwa Formations.

Athabasca's current principal light oil development properties are located in the Kaybob Area and Saxon/Placid Area, and Athabasca has also conducted exploration and limited development activities in the Light Oil Exploration Areas, each of which are described below. To date, Athabasca has focused its oil and natural gas drilling efforts in the Duvernay, Montney, Charlie Lake and Nordegg Formations using the combined application of horizontal drilling and multi-stage fracture technology.

Athabasca's Light Oil Division sells its oil 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. Athabasca's natural gas typically receives AECO pricing, adjusted for energy content. The Company's NGLs that are separated at the Simonette Gas Plant are transported through the Pembina Pipeline system and also receive Edmonton prices.

Throughout 2013, the Keyera Simonette Gas Plant experienced a number of restrictions related to sour gas processing and liquids handling, which impacted Athabasca's production. In September of 2013, production was impacted due to a scheduled shut-down of the Keyera Simonette Gas Plant for planned maintenance and plant modifications. The shut-down lasted twenty-five days, which was five days longer than scheduled. The plant was back online on October 1, 2013, and all tied-in wells were back on production by mid-October of 2013. In 2014, Athabasca began construction of a pipeline to SemCAMS' Kaybob Amalgamated Gas Plant. The pipeline will allow production from the Kaybob Area and Saxon/Placid Area to be dually connected to two large midstream plants, which should reduce future downtime risk associated with the production. The cost of the pipeline will be borne by third parties and Athabasca will be entitled to a 10% working interest.

Kaybob Area

The Kaybob Area is located primarily between townships 62 to 68, ranges 14 to 22, west of the fifth meridian in northwestern Alberta, near the town of Fox Creek. As at December 31, 2013, the Kaybob Area was comprised of approximately 443,000 acres of land, of which approximately 15,000 acres had been developed and 428,000 acres remained undeveloped. Athabasca drilled 16 horizontal Montney wells in 2013, 13 of which were completed during 2013 and two more are scheduled to be completed in 2014. Two horizontal Duvernay wells were also drilled in

2013, both of which are scheduled to be completed in 2014. In addition, a vertical disposal well was drilled and completed during 2013.

GLJ has assigned approximately 9.7 MMboe of Proved Reserves and 7.3 MMboe of Probable Reserves on a Gross Reserves basis to Athabasca's interests in the Kaybob Area, as at December 31, 2013. See "Independent Reserve and Resource Evaluations".

During the second quarter of 2012, Athabasca completed the construction of a 63 kilometre, 12-inch pipeline, from its Kaybob and Saxon/Placid Areas to the Keyera Simonette Gas Plant (the "**Main Light Oil Pipeline**"). In 2012, Athabasca also completed the construction of two oil batteries and the related gathering systems and compression facilities in the Kaybob Area. The first of these (the "**Kaybob West Battery**"), which was commissioned in October of 2012, is located at 7-14-063-20-W5M and has a designed capacity of 13,000 bbls/d of oil and 48 MMcf/d of natural gas. The second Kaybob battery and related facilities (the "**Kaybob East Battery**") is located at 16-03-065-18-W5M, has a designed capacity of 13,000 bbls/d of oil and 24 MMcf/d of natural gas, and was brought on stream late in the fourth quarter of 2012. The construction of the pipeline connecting the Kaybob East Battery to the Main Light Oil Pipeline was completed in February of 2013 and the pipeline was commissioned in April of 2013.

In September of 2013, Athabasca entered into an option agreement with a third party giving Athabasca the right to sell up to a 50% working interest in its light oil infrastructure assets in the Kaybob Area, including the Kaybob East Battery, the Kaybob West Battery and the Main Light Oil Pipeline (collectively, the "**Kaybob Infrastructure Assets**") for cash consideration of up to $145 million. Athabasca exercised its option and on December 23, 2013 Athabasca sold a 50% working interest in the Kaybob Infrastructure Assets to the third party for gross cash proceeds of $145.9 million, including closing adjustments. Athabasca continues to be the operator of the Kaybob Infrastructure Assets and has retained the remaining 50% working interest.

Saxon/Placid Area

The Saxon/Placid Area is located primarily between townships 60 to 64, ranges 21 to 26, west of the fifth meridian in northwestern Alberta, approximately 40 kilometres west of the town of Fox Creek. As at December 31, 2013, the Saxon/Placid Area was comprised of approximately 159,000 net acres of land, of which approximately 9,700 acres were developed and 149,300 acres were undeveloped**.** Athabasca drilled 4 horizontal Montney wells in 2013, and completed three of the wells during the year. The fourth Montney well that was drilled in 2013 is expected to be completed late in 2014. One vertical Duvernay well and one horizontal Duvernay well were drilled in 2013 and the horizontal Duvernay well is scheduled to be completed in 2014.

GLJ has assigned approximately 4.7 MMboe of Proved Reserves and 10.7 MMboe of Probable Reserves on a Gross Reserves basis to Athabasca's interests in the Saxon/Placid Area, as at December 31, 2013. See "Independent Reserve and Resource Evaluations".

In the fourth quarter of 2012, Athabasca completed the construction of an oil battery and the related gathering systems and facilities in the Saxon/Placid Area (the "**Saxon Battery**"). The Saxon Battery was tied in to the Main Light Oil Pipeline in late December of 2012. The Saxon Battery is located at 10-19-062-22-W5M and has a designed capacity of 10,000 bbls/d of oil and 12 MMcf/d of natural gas. Athabasca continues to hold a 100% working interest in the Saxon Battery and the pipeline interconnect between the Saxon Battery and the Main Light Oil Pipeline.

Light Oil Exploration Areas

The Light Oil Exploration Areas include Athabasca's oil and gas interests in approximately 2,110,000 net acres of land in the following areas in northwestern Alberta, as at December 31, 2013: (a) the Grand Prairie area, primarily between townships 66 to 83, ranges 19 to 12, west of the sixth meridian; (b) the North Muskwa area, primarily between townships 114 to 118, ranges 7 to 12, west of the sixth meridian; (c) the South Muskwa area, primarily between townships 105 to 112, ranges 1 to 7, west of the fifth meridian; and (d) the Caribou area, primarily between townships 111 to 120, ranges 16 to 23, west of the fifth meridian.

The Grande Prairie area has two prospective formations for oil and gas developments: the Charlie Lake Formation and the Montney Formation. In 2012, Athabasca completed three wells in the Charlie Lake Formation. The modest exploration activity that has been conducted in the North Muskwa and South Muskwa areas to date has been focused on exploring the oil shale of the Muskwa Formation. In the Caribou area, Athabasca's exploration activity has been targeted towards exploring for light oil in the carbonates of the Slave Point Formation. In 2013, Athabasca drilled two vertical core wells in the Muskwa area and three vertical core wells in the Caribou area and acquired 320 kilometres of 2-D seismic data in the Caribou area.

No capital expenditures were approved for the development of the Charlie Lake Formation in the Grande Prairie area or in respect of the development of the North Muskwa or South Muskwa areas as part of Athabasca's 2014 capital budget. As a result, it is expected that approximately 480,000 acres in the Grand Prairie area and 540,000 acres in the North Muskwa and South Muskwa areas will expire during 2014.

GLJ has assigned approximately 0.2 MMboe of Proved Reserves and 0.05 MMboe of Probable Reserves on a Gross Reserves basis to Athabasca's interests in the Light Oil Exploration Areas, as at December 31, 2013. See "Independent Reserve and Resource Evaluations".

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, 2013, Athabasca had 356 employees. Through a combination of normal attrition and workforce reductions that have been undertaken by Athabasca, the size of Athabasca's workforce has been reduced since December 31, 2013. As at March 18, 2014, Athabasca has 281 employees.

INDEPENDENT RESERVE AND RESOURCE EVALUATIONS

Reserves and Resources Classifications

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.

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.

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 Section 5 of the COGE Handbook.

Light Oil Asset Classifications

GLJ evaluated the reserves attributable to the Light Oil assets in accordance with the reserves categories that are set forth above. Additional information regarding the reserves that have been attributed to Athabasca's Light Oil assets can be found under the heading "– Summary of Reserves Data – Forecast Prices and Costs as of December 31, 2013" below.

Thermal Oil Asset Classifications

As an in-situ bitumen project is developed, the estimated recoverable volumes are classified according to their stage of development. Before filing a regulatory application seeking approval to proceed with a development project, the associated estimated recoverable volumes are categorized as Contingent Resources. Upon filing for regulatory approval, and assuming no other significant contingencies exist, the estimated volumes associated with a development project are categorized as reserves. Upon the receipt of regulatory and internal corporate approvals, and assuming no other significant contingencies exist, the estimated volumes associated with an in-situ bitumen development project may be categorized as Proved Reserves.

As a result of the submission of regulatory applications for SAGD projects in respect of the Hangingstone assets, Dover West Sands assets and the Dover assets, GLJ, the independent evaluator of the Dover West Sands and Dover assets, and D&M, the independent evaluator of the Hangingstone assets, have categorized as reserves the estimated recoverable bitumen volumes associated with Hangingstone Project 1, the Hangingstone Expansion, Dover West Sands Project 1 and Athabasca's interests in the Dover First Phase. All other estimates of Athabasca's recoverable bitumen volumes are categorized as Contingent Resources. Currently, all of Athabasca's bitumen reserves are classified as undeveloped reserves, since significant costs will be required to render the reserves capable of production.

Independent Reports

Athabasca engaged the Independent Evaluators to prepare the Independent Reports, which are independent assessments and evaluations of Athabasca's bitumen, conventional crude oil, shale oil, conventional natural gas, shale gas and NGL reserves and resources, effective as at December 31, 2013.

The reserve and Contingent Resource estimates set out below reflect Athabasca's 100% working interests (as at December 31, 2013) in the Hangingstone assets, Dover West Sands, Dover West Carbonates and Birch assets, its interests in the Light Oil assets, its 40% working interests in the Dover assets, and its 50% working interest in the Grosmont area.

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

The effective date of the information provided below is December 31, 2013. The preparation date of the GLJ Report was January 31, 2014. The preparation date of the D&M Report with respect to reserves data was January 31, 2014 and with respect to Contingent Resources data was February 3, 2014. The preparation and disclosure of the reported reserve and resource estimates are the responsibility of Athabasca's management. The Independent Evaluators' responsibilities are to express opinions on the bitumen-in-place, conventional crude oil, shale oil, conventional natural gas, shale gas and NGL reserves and the Contingent Resources data, 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-in-place, crude oil, shale oil, natural gas, shale gas and NGL reserves and Contingent Resources data be prepared in accordance with the COGE Handbook. All of Athabasca's properties are located in the Province of Alberta and are described elsewhere in this Annual Information Form.

GLJ's Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor and Report on Resources Data by Independent Qualified Reserves Evaluator or Auditor, and D&M's Report on Reserves Data by Independent

Qualified Reserves Evaluator or Auditor and Report on Resources Data by Independent Qualified Reserves Evaluator or Auditor, are set forth in Schedule "B" 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 "A" to this Annual Information Form.

The evaluation procedures employed by GLJ and D&M are in compliance with standards contained in the COGE Handbook and the aggregate resource estimates and valuations presented below are arithmetic sums of the resource estimates and valuations contained in the Independent Reports.

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 may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

Management Commentary on Assumptions

Reserve Estimates

Athabasca's bitumen reserves are contained in the Hangingstone assets, Dover West Sands and its interests in the Dover assets. Its conventional crude oil, shale oil, conventional natural gas, shale gas and NGL reserves are located in the Light Oil assets. Proved Reserves have been assigned by GLJ to Athabasca's Light Oil assets and by D&M to Athabasca's Hangingstone assets, as a result of the receipt of regulatory approval for Hangingstone Project 1. Probable Reserves have been assigned by GLJ to Athabasca's interests in the Dover First Phase, Dover West Sands Project 1 and Light Oil assets, and by D&M to Hangingstone Project 1 and the Hangingstone Expansion.

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, 2013, as evaluated by GLJ in the GLJ Report, reflecting Athabasca's 40% working interests in the Dover assets, and as evaluated by D&M in the D&M Report. The pricing used in the forecast price evaluations 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 downhole well abandonment 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 and cost assumptions that have been estimated by GLJ will be realized and variances could be material. Other assumptions have been made by GLJ and D&M and qualifications relating to costs and other matters are included in the GLJ Report and D&M 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, 2013[(1)(2)]

Reserves Category	Light & Medium Oil		Shale Oil		Natural Gas (non-associated and associated)	
	Gross (Mbbls)	Net (Mbbls)	Gross (Mbbls)	Net (Mbbls)	Gross (MMcf)	Net (MMcf)
PROVED RESERVES						
Developed Producing	1,867.90	1,536.20	292.01	225.47	16,540.50	15,139.70
Developed Non-Producing	129.33	114.87	-	-	2,437.80	2,250.60
Undeveloped	1,313.89	1,165.72	657.00	520.08	22,014.50	20,708.10
TOTAL PROVED RESERVES	3,311.13	2,816.80	949.01	745.55	40,992.80	38,098.40
TOTAL PROBABLE RESERVES	2,257.20	1,886.68	1,781.84	1,352.21	50,006.90	46,148.30
TOTAL PROVED PLUS PROBABLE RESERVES	5,568.32	4,703.48	2,730.85	2,097.77	90,999.70	84,246.60

Reserves Category	Shale Gas		Natural Gas Liquids	
	Gross (MMcf)	Net (MMcf)	Gross (Mbbls)	Net (Mbbls)
PROVED RESERVES				
Developed Producing	1,737.10	1,614.20	891.89	707.88
Developed Non-Producing	-	-	118.97	92.09
Undeveloped	3,591.60	3,336.50	1,536.64	1,238.15
TOTAL PROVED RESERVES	5,328.70	4,950.70	2,547.49	2,038.12
TOTAL PROBABLE RESERVES	9,970.10	9,213.30	3,993.40	2,982.65
TOTAL PROVED PLUS PROBABLE RESERVES	15,298.90	14,163.90	6,540.90	5,020.77

Reserves Category	Bitumen		Oil Equivalent	
	Gross (Mbbls)	Net (Mbbls)	Gross (Mboe)	Net (Mboe)
PROVED RESERVES				
Developed Producing	-	-	6,098.07	5,261.88
Developed Non-Producing	-	-	654.61	582.06
Undeveloped	51,128.57	37,835.85	58,903.78	44,767.24
TOTAL PROVED RESERVES (excluding Dover)[(4)]	51,128.57	37,835.85	65,656.46	50,611.17
TOTAL PROVED RESERVES (including Dover)[(5)]	51,128.57	37,835.85	65,656.46	50,611.17
TOTAL PROBABLE RESERVES (excluding Dover)[(4)]	261,086.80	207,084.59	279,115.42	222,533.07
TOTAL PROBABLE RESERVES (including Dover)[(5)]	398,650.70	317,859.17	416,679.33	333,307.64
TOTAL PROVED PLUS PROBABLE RESERVES (excluding Dover)[(4)]	312,215.37	244,920.45	344,771.88	273,144.24
TOTAL PROVED PLUS PROBABLE RESERVES (including Dover)[(5)]	449,779.28	355,695.02	482,335.79	383,918.81

Summary of Net Present Values of Future Net Revenue – Forecast Prices and Costs as of December 31, 2013[(1)(2)]

	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	151,466	136,643	124,874	115,306	107,372	151,466	136,643	124,874	115,306	107,372	23.73	3.96
Developed Non-Producing	13,485	11,160	9,411	8,062	7,000	13,485	11,160	9,411	8,062	7,000	16.17	2.69
Undeveloped	1,896,893	970,677	564,238	359,498	243,813	1,896,893	970,677	564,238	359,498	243,813	12.60	2.10
TOTAL PROVED RESERVES (excluding Dover)[(4)]	2,061,845	1,118,481	698,523	482,866	358,185	1,541,489	820,922	502,507	339,789	246,078	13.80	2.30
TOTAL PROVED RESERVES (including Dover)[(5)]	2,061,845	1,118,481	698,523	482,866	358,185	2,061,845	1,118,481	698,523	482,866	358,185	13.80	2.30
TOTAL PROBABLE RESERVES (excluding Dover) [(4)]	7,412,687	2,539,992	950,882	325,592	42,100	5,534,827	1,808,608	606,257	138,272	(70,677)	4.27	0.71
TOTAL PROBABLE RESERVES (including Dover)[(5)]	10,323,811	3,783,536	1,439,641	444,406	(31,952)	7,796,698	2,808,243	1,004,799	227,425	(150,157)	4.32	0.72
TOTAL PROVED PLUS PROBABLE RESERVES (excluding Dover)[(4)]	9,474,532	3,658,473	1,649,405	808,458	400,284	7,076,315	2,629,530	1,108,764	478,062	175,402	6.04	1.01
TOTAL PROVED PLUS PROBABLE RESERVES (including Dover)[(5)]	12,385,656	4,902,017	2,138,164	927,272	326,233	9,858,542	3,926,724	1,703,322	710,291	208,027	5.57	0.93

Future Net Revenue (Undiscounted) – Forecast Prices and Cost as of December 31, 2013[1]

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 (excluding Dover)[4]	4,567,959	1,109,625	864,732	516,436	15,321	2,061,845	-	2,061,845
PROVED RESERVES (including Dover)[5]	4,567,959	1,109,625	864,732	516,436	15,321	2,061,845	-	2,061,845
PROBABLE RESERVES (excluding Dover)[4]	22,270,463	4,756,799	5,769,670	4,240,312	90,995	7,412,687	1,798,972	5,613,716
PROBABLE RESERVES (including Dover)[5]	32,030,948	6,720,889	8,716,176	6,148,069	122,003	10,323,811	2,527,114	7,796,698
PROVED PLUS PROBABLE RESERVES (excluding Dover)[4]	26,838,423	5,866,424	6,634,403	4,756,748	106,316	9,474,532	1,798,972	7,675,560
PROVED PLUS PROBABLE RESERVES (including Dover)[5]	36,598,908	7,830,515	9,580,908	6,664,505	137,324	12,385,656	2,527,114	9,858,542

Future Net Revenue by Production Group – Forecast Prices and Costs as of December 31, 2013[1][3]

RESERVES CATEGORY	Production Group	Future Net Revenue Before Income Taxes (Discounted at 10%/Year) M$	$/BOE	$/Mcfe
PROVED RESERVES	Light and Medium Crude Oil[6]	81,644	24.37	4.06
	Natural Gas	86,181	11.26	1.88
	Shale Oil	30,463	18.39	3.06
	Bitumen (excluding Dover)[4]	497,804	13.16	2.19
	Bitumen (including Dover)[5]	497,804	13.16	2.19
	Shale Gas	2,430	20.97	3.49
	TOTAL[5]	698,532	13.80	2.30
PROVED PLUS PROBABLE RESERVES	Light and Medium Crude Oil[6]	123,193	21.47	3.58
	Natural Gas	200,325	11.45	1.91
	Shale Oil	70,162	24.31	4.05
	Bitumen (excluding Dover)[4]	1,228,098	5.01	0.84
	Bitumen (including Dover)[5]	1,716,857	4.83	0.80
	Shale Gas	27,627	13.12	2.19
	TOTAL[5]	2,138,164	5.57	0.93

Reconciliation of Reserves by Principal Product Type – Forecast Prices and Costs as of December 31, 2013 [(1)(2)(5)]

The following table sets forth a reconciliation of the changes of Athabasca's working interest, before royalties, of bitumen, conventional crude oil, shale oil, conventional natural gas, shale gas and NGL reserves as at December 31, 2013, compared to such reserves as at December 31, 2012, based on the forecast price and cost assumptions that are described in Note 1 below.

	Bitumen			**Light and Medium Oil**		
FACTORS	**Gross Proved Reserves (MMbbls)**	**Gross Probable Reserves (MMbbls)**	**Gross Proved Plus Probable Reserves (MMbbls)**	**Gross Proved Reserves (MMbbls)**	**Gross Probable Reserves (MMbbls)**	**Gross Proved Plus Probable Reserves (MMbbls)**
December 31, 2012	51.4	290.8	342.3	1.6	1.7	3.3
Discoveries	-	-	-	-	-	-
Extensions and Improved Recovery	-	107.5	107.5	1.7	0.3	2.0
Technical Revisions	(0.3)	0.3	0.0	0.7	0.3	1.1
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	0.1	(0.1)	-
Production	-	-	-	(0.8)	-	(0.8)
December 31, 2013	51.1	398.7	449.8	3.3	2.3	5.6

	Conventional Natural Gas (non-associated & associated)			**Natural Gas Liquids**		
FACTORS	**Gross Proved Reserves (Bcf)**	**Gross Probable Reserves (Bcf)**	**Gross Proved Plus Probable Reserves (Bcf)**	**Gross Proved Reserves (MMbbls)**	**Gross Probable Reserves (MMbbls)**	**Gross Proved Plus Probable Reserves (MMbbls)**
December 31, 2012	39.4	29.5	68.9	1.9	1.8	3.7
Discoveries	-	-	-	-	-	-
Extensions and Improved Recovery	8.8	13.3	22.0	0.6	1.4	2.0
Technical Revisions	(1.1)	6.4	5.3	0.2	0.6	0.9
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	0.2	1.1	1.2	-	0.1	0.1
Production	(6.3)	-	(6.3)	(0.2)	-	(0.2)
December 31, 2013	41.0	50.0	91.0	2.5	4.0	6.5

	Shale Oil			**Shale Gas**		
FACTORS	**Gross Proved Reserves (MMbbls)**	**Gross Probable Reserves (MMbbls)**	**Gross Proved Plus Probable Reserves (MMbbls)**	**Gross Proved Reserves (Bcf)**	**Gross Probable Reserves (Bcf)**	**Gross Proved Plus Probable Reserves (Bcf)**
December 31, 2012	0.5	1.1	1.6	3.6	7.9	11.5
Discoveries	-	-	-	-	-	-
Extensions and Improved Recovery	0.3	0.6	0.9	1.8	2.0	3.8
Technical Revisions	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-
Production	(0.2)	-	(0.2)	(0.7)	-	(0.7)
December 31, 2013	0.9	1.8	2.7	5.3	10.0	15.3

FACTORS	Oil Equivalent Gross Proved Reserves (MMboe)	Oil Equivalent Gross Probable Reserves (MMboe)	Oil Equivalent Gross Proved Plus Probable Reserves (MMboe)
December 31, 2012	62.6	301.6	364.2
Discoveries	-	-	-
Extensions and Improved Recovery	4.4	112.6	116.7
Technical Revisions	0.8	2.5	3.2
Acquisitions	-	-	-
Dispositions	-	-	-
Economic Factors	0.1	0.2	0.3
Production	(2.3)	-	(2.3)
December 31, 2013	65.5	416.7	482.2

Notes:

(1) Based on the GLJ Report and D&M 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 using mid-year discounting in accordance with the COGE Handbook. GLJ is an independent qualified reserves evaluator appointed pursuant to NI 51-101.

(2) Totals may not add due to rounding.

(3) Other revenue and costs not related to a specific production group have been allocated proportionately to production groups. Unit values are based on Athabasca's Net Reserves.

(4) Excludes the reserves and future net revenue estimates that are attributable to Athabasca's 40% working interests in the Dover assets, which as at December 31, 2013, were held directly by the Company's wholly owned subsidiary, AOC (Dover).

(5) Athabasca's investments in the Dover assets are accounted for by the equity method and the reserve and future net revenue estimates set out above include Athabasca's 40% working interests in the Dover assets which, as at December 31, 2013, were held directly by the Company's wholly owned subsidiary, AOC (Dover).

(6) Includes solution gas and other by-products.

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, 2014 pricing models. A summary of applicable selected price forecasts is set forth below.

Year	Oil Sands Inflation %	Bank of Canada Average Noon Exchange Rate ($US/ $Cdn)	WTI Oil at Cushing Oklahoma Current ($US/ bbl)	Light Sweet Crude Oil (40° API, 0.3%S) at Edmonton Current ($Cdn/ bbl)	WCS Stream Quality at Hardisty Current ($Cdn/ bbl)	Dilbit Quality Diff'l Current ($Cdn/ bbl)	Dillbit Stream Quality at Hardisty Current ($Cdn/ bbl)	Heavy Crude Oil (12° API) at Hardisty Current ($Cdn/ bbl)
2014	2.0	0.95	97.50	92.76	75.60	(6.00)	69.60	65.72
2015	2.0	0.95	97.50	93.37	79.36	(5.00)	74.36	70.03
2016	2.0	0.95	97.50	100.00	81.50	(4.00)	77.50	72.85
2017	2.0	0.95	97.50	100.00	81.50	(3.00)	78.50	72.85
2018	2.0	0.95	97.50	100.00	81.50	(3.06)	78.44	72.85
2019	2.0	0.95	97.50	100.00	81.50	(3.12)	78.38	72.85
2020	2.0	0.95	98.54	100.77	82.13	(3.18)	78.95	73.42
2021	2.0	0.95	100.51	102.78	83.76	(3.25)	80.51	74.90
2022	2.0	0.95	102.52	104.83	85.44	(3.31)	82.13	76.42
2023	2.0	0.95	104.57	106.93	87.14	(3.38)	83.76	77.97
2024+	Escalated oil, gas and product prices at 2.0% per year thereafter.							

Year	Natural Gas Liquids Edmonton Pentanes Plus ($Cdn/ bbl)	Natural Gas Liquids Edmonton Propane ($Cdn/ bbl)	Natural Gas Liquids Edmonton Butane ($Cdn/ bbl)	Diluent Transp. & Postings+ ($Cdn/ bbl)	Diluent at Field Current ($Cdn/ bbl)	Transportation Current ($Cdn/ bbl)	Clastics Bitumen Wellhead Current[1] ($Cdn/ bbl)	Carbonates Bitumen Wellhead Current[2] ($Cdn/ bbl)
2014	105.20	57.83	73.22	6.00	111.20	6.00	43.20	41.70
2015	107.11	58.42	75.95	6.00	113.11	6.00	49.18	47.78
2016	107.00	60.00	78.00	6.00	113.00	6.00	53.71	52.41
2017	107.00	60.00	78.00	4.89	111.89	4.38	57.94	56.75
2018	107.00	60.00	78.00	3.78	110.78	2.75	60.65	59.55
2019	107.00	60.00	78.00	3.78	110.78	2.75	60.56	59.46
2020	107.82	60.46	78.60	3.78	111.60	2.75	61.02	59.91
2021	109.97	61.67	80.17	3.78	113.75	2.75	62.34	61.21
2022	112.17	62.90	81.77	3.78	115.95	2.75	63.70	62.55
2023	114.41	64.16	83.40	3.78	118.19	2.75	65.08	63.91
2024+		Escalated oil, gas and product prices at 2.0% per year thereafter						

Notes:

(1) Blending Ratio = 1 bbl bitumen: 0.429 bbl diluent for bitumen netback pricing. This blending ratio equates to a bitumen blend (dilbit) comprised of 30% condensate and 70% bitumen.

(2) Blending Ratio = 1 bbl bitumen: 0.46 bbl diluent for Carbonates bitumen netback pricing. This blending ratio equates to a bitumen blend (dilbit) comprised of 31.5% condensate and 68.5% bitumen.

The weighted average realized sales prices for Athabasca for the year ended December 31, 2013 were $87.39/bbl for conventional light and medium oil, $3.49/Mcf for conventional natural gas, $66.70/bbl for natural gas liquids, $85.54/bbl for shale oil and $3.91/Mcf for shale gas.

Undeveloped Reserves

Athabasca's proved undeveloped reserves of bitumen are expected to become developed with the construction, start-up and commissioning of Hangingstone Project 1. Athabasca's probable undeveloped reserves of bitumen are expected to become developed with the approval, construction, start-up and commissioning of the Dover First Phase, Dover West Sands Project 1 and the Hangingstone Expansion, subject to the receipt of regulatory approval.

The proved undeveloped reserves attributed to Athabasca's Light Oil assets are generally those reserves that are related to planned infill drilling locations. The probable undeveloped reserves attributed to Athabasca's Light Oil assets are generally those reserves tested or indicated by analogy to be productive or contained within lands that are contiguous to existing production.

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 and in the aggregate before that time using forecast prices and costs:

Proved Undeveloped Reserves

	Bitumen (MMbbls)		Light & Medium Oil (MMbbls)		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	First Attributed	Total at Year-end
Aggregate prior to Dec. 31, 2011	-	-	-	-	-	-	-	-
2011	38.0	38.0	0.7	0.7	8.0	8.0	-	-
2012	51.4	51.4	-	-	8.6	12.2	0.6	0.6
2013	-	51.1	0.9	1.3	3.8	22.0	0.3	1.5

Year	Shale Oil (MMbbls)		Shale Gas (Bcf)		Oil Equivalent (MMboe)	
	First Attributed	Total at Year-end	First Attributed	Total at Year-end	First Attributed	Total at Year-end
Aggregate prior to Dec. 31, 2011	-	-	-	-	-	-
2011	-	-	-	-	40.0	40.0
2012	-	-	1.1	1.1	53.6	54.2
2013	0.3	0.7	1.8	3.6	2.5	58.9

Probable Undeveloped Reserves

Year	Bitumen (MMbbls)		Light & Medium Oil (MMbbls)		Natural Gas (Bcf)		Natural Gas Liquids (MMbbls)	
	First Attributed	Total at Year-end	First Attributed	Total at Year-end	First Attributed	Total at Year-end	First Attributed	Total at Year-end
Aggregate prior to Dec. 31, 2011	251.0	251.0	-	-	-	-	-	-
2011	201.5	415.5	2.0	2.0	16.0	16.0	1.0	0.5
2012	-	290.8	-	1.1	7.1	19.5	0.7	1.2
2013	107.5	398.7	1.0	1.4	14.3	42.3	1.3	3.6

Year	Shale Oil (MMbbls)		Shale Gas (Bcf)		Oil Equivalent (MMboe)	
	First Attributed	Total at Year-end	First Attributed	Total at Year-end	First Attributed	Total at Year-end
Aggregate prior to Dec. 31, 2011	-	-	-	-	41.8	41.8
2011	-	-	-	-	207.2	420.7
2012	0.9	0.9	6.9	6.9	4.0	298.4
2013	0.6	1.7	2.0	9.4	113.0	413.9

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 two years. 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; and
- surface access issues (e.g. landowner issues, weather conditions and receipt of required regulatory approvals).

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 Hangingstone Project 1, the Hangingstone Expansion, Dover West Sands Project 1 and the Dover First Phase, which are the projects that have associated undeveloped bitumen reserves, see "Description of Athabasca's Business – Thermal Oil Division".

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 – Uncertainties Associated with Estimating Reserve and Resource Volumes".

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, 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.

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 Future Development Costs Using Forecast Dollar Costs (M$)	Total Proved Plus Probable Future Development Costs Using Forecast Dollar Costs (M$)
2014	43,620	168,962
2015	97,342	661,999
2016	49,037	972,608
2017	12,027	253,264
2018	12,267	145,455
Total for all remaining years	302,141	4,462,217
Total Undiscounted(1)	516,436	6,664,505

Note:

(1) Totals may not add due to rounding.

Athabasca expects that existing working capital, cash flow from operations, the amounts available under the Amended Credit Facilities or other available debt financing, the proceeds from the sale of Athabasca's interests in the Dover assets pursuant to the exercise of the Dover Put Option, and access to additional external financing, will be sufficient to fund the above future development costs. Athabasca intends to develop its projects in phases or stages and expects that cash flows from the successfully developed early projects will help to finance later projects. Management believes that it is reasonable to assume the availability of external financing in the future, which financing could include additional debt financing, joint ventures, project financing, asset dispositions or equity financing, subject to the terms and conditions of the Note Indenture and the Amended and Restated Credit Agreement. There can be no guarantee, however, that sufficient funds will be available, will be available on terms

acceptable to Athabasca, will be available on a timely basis, or that Athabasca will allocate funding to develop all of its reserves. Failure to develop its reserves would have a negative impact on Athabasca's future net revenue. The costs of future external financing are not included in the reserves and future net revenue estimates and would also reduce future net revenue, the extent to which would depend upon the sources of external financing that are utilized.

Contingent Resource Estimates

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. The tables below reflect Athabasca's Best Estimate Contingent Resources and the associated discounted future net revenues as of December 31, 2013, as evaluated by GLJ and D&M, reflecting Athabasca's 40% working interests in the Dover assets, its 100% working interests in the Hangingstone assets, Dover West Sands, Dover West Carbonates and Birch assets, and its 50% working interest in the Grosmont area.

It should not be assumed that the estimates of recovery, production and net revenue presented in the tables 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. The recovery and production estimates of Athabasca's bitumen resources provided herein are only estimates 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. The contingencies which currently prevent the classification of the Contingent Resources disclosed in the tables below as reserves consist of: economic matters, further facility design and preparation of firm development plans, regulatory matters, including regulatory applications (including, associated reservoir studies and delineation drilling), company approvals and other factors such as legal, environmental and political matters and a lack of markets. 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.

Of Athabasca's approximately 10.5 billion barrels of Best Estimate Contingent Resources (on a Company Interest basis) estimated by GLJ and D&M as at December 31, 2013, approximately 3.4 billion barrels are contained in carbonate reservoirs in Athabasca's Dover West Carbonates and Grosmont assets. SAGD, the in-situ bitumen recovery process considered by GLJ in respect of Athabasca's Dover West Carbonates and Grosmont assets, has not to date been applied successfully in an analogue to the subject reservoirs. TAGD, an alternative process being considered by Athabasca, is an experimental technology. The commercial viability of SAGD technology has been demonstrated successfully for application to certain non-carbonate reservoirs. There are, however, no successful commercial projects that use SAGD or TAGD to recover bitumen from carbonates. The successful development of Athabasca's carbonate reservoirs depends on, among other things, the successful development and application of SAGD, TAGD or other recovery processes to the subject reservoirs. Presently, there exists a large range in the expected recoverable volumes, the lower end of which may not be economically viable. The principal risks associated with SAGD and/or TAGD recovery in carbonate reservoirs are: (a) the possibility of unexpected steam channeling which would increase steam requirements resulting in increased costs and potentially reduced economically recoverable bitumen volumes; (b) the ability to efficiently drain the matrix porosity; (c) potential mechanical operating problems due to production of fines which could cause wellbore plugging and reduced bitumen production rates and potential interruption of surface production operations; and (d) uncertainty as to whether the technologies may be economically applied on a commercial scale. Although the technical risks associated with SAGD have been accounted for in the GLJ Report, the timeline for verification of the viability of these technologies has inherent uncertainty. Development will involve significant capital expenditures and a lengthy time to project payout, and project payout is not assured. If a pilot and/or demonstration project do not demonstrate potential commerciality in the subject reservoirs or a good analogue, then Athabasca's projects on these assets may not proceed and this may occur only after significant expenditures have been incurred by Athabasca. With respect to Athabasca's Grosmont assets, Athabasca has not prepared a development plan or timeline for the area, and is monitoring industry activity toward demonstrating successful development and production methods for the Grosmont Formation. See "Description of Athabasca's Business – Thermal Oil Division – Grosmont assets".

Aggregated Contingent Resource Estimates

The following table sets forth: (a) the Best Estimate Contingent Resources and associated future net revenue estimates contained in the GLJ Report with respect to the Dover assets, the Dover West Sands, the Dover West Carbonates and the Grosmont assets on a Company Interest basis; and (b) the Best Estimate Contingent Resources and associated future net revenue estimates contained in the D&M Report with respect to the Birch assets and Hangingstone assets on a Company Interest basis. The evaluation procedures employed by GLJ and D&M are generally consistent with each other and comply 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 are based on GLJ's January 1, 2014 pricing models (See " – GLJ Price Forecast" above).

		Net Present Value of Future Net Revenue as of December 31, 2013 Contingent Resources – Best Estimate[(1)(2)(3)(4)]				
	Company Interest (MMbbls)	**0% (MM$)**	**5% (MM$)**	**10% (MM$)**	**15% (MM$)**	**20% (MM$)**
Before Income Taxes						
Dover Assets[(5)(11)]	1,222	30,256	8,300	2,515	702	68
Dover West Sands[(5)]	2,957	75,436	17,493	4,518	1,037	7
Dover West Carbonates[(5)(7)]	3,001	85,508	24,435	8,069	2,817	895
Grosmont Assets[(5)(7)(9)]	418	5,325	411	(353)	(391)	(311)
Birch Assets[(6)]	2,111	72,946	18,151	5,073	1,209	(118)
Hangingstone Assets[(6)]	782	22,440	5,159	907	(358)	(762)
Total Contingent Resources (Best Estimate)[(8)]	10,492	291,911	73,949	20,728	5,017	(219)
After Income Taxes						
Total Contingent Resources (Best Estimate)[(8)(10)]		284,227	71,573	19,850	4,645	(392)

Notes:

(1) "**Contingent Resources**" are defined in the COGE Handbook as 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 economic matters, further facility design and preparation of firm development plans, regulatory matters, including regulatory applications, associated reservoir studies, delineation drilling, company approvals and other factors such as legal, environmental and political 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. Contingent Resources may be further classified in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by economic status. The volumes of contingent bitumen resources in this table were calculated at the outlet of the proposed extraction plant.

(2) There is no certainty that it will be commercially viable to produce any portion of the resources.

(3) "**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.

(4) The resource estimates set out in the table reflect, as at December 31, 2013, Athabasca's 100% working interest in the Hangingstone assets, Dover West Sands, Dover West Carbonates and Birch assets, 40% working interest in the Dover assets and 50% working interest in the Grosmont area.

(5) Based on the GLJ Report dated effective as of December 31, 2013.

(6) Based on the estimates contained in the D&M Report dated effective as of December 31, 2013, but calculated by GLJ using GLJ's pricing forecasts for consistency and using mid-year discounting in accordance with the COGE Handbook.

(7) Athabasca's resources at its Dover West Carbonates and Grosmont assets are contained in carbonate reservoirs. SAGD, the in-situ bitumen recovery process considered by GLJ in respect of Athabasca's Dover West Carbonates and Grosmont assets, has not to date been applied successfully in an analogue to the subject reservoirs. TAGD, an alternative process being considered by Athabasca, is an experimental technology. The commercial viability of SAGD technology has been demonstrated successfully for application to certain non-carbonate reservoirs. There are, however, no successful commercial projects that use SAGD or TAGD to recover bitumen from carbonates. The successful development of Athabasca's carbonate reservoirs depends on, among other things, the successful development and application of SAGD, TAGD or other recovery processes to the subject reservoirs. Presently, there exists a large range in the expected recoverable volumes, the lower end of which may not be economically viable. The principal risks associated with SAGD and/or TAGD recovery in carbonate reservoirs are: (a) the possibility of unexpected steam channeling which would increase steam requirements resulting in increased costs and potentially reduced economically recoverable bitumen volumes; (b) the ability to efficiently drain the matrix porosity; (c) potential mechanical operating problems due to production of fines which could cause wellbore plugging and reduced bitumen production rates and potential interruption of surface production operations; and (d) uncertainty as to whether the technologies may be economically applied on a commercial scale. Although the technical risks associated with SAGD have been accounted for in the GLJ Report, the timeline for verification of the viability of these technologies

has inherent uncertainty. Development will involve significant capital expenditures and a lengthy time to project payout, and project payout is not assured. If a pilot and/or demonstration project do not demonstrate potential commerciality in the subject reservoirs or a good analogue, then Athabasca's projects on these assets may not proceed and this may occur only after significant expenditures have been incurred by Athabasca.

(8) Totals may not add due to rounding.

(9) GLJ has determined that the 10% discounted future net revenue associated with the Grosmont assets in the Best Estimate case is negative and considers the Contingent Resources associated with the Grosmont assets to be sub-economic in the Best Estimate case. Athabasca has not prepared a development plan or timeline for the Grosmont assets, and is monitoring industry activity toward demonstrating successful development and production methods for the Grosmont Formation. Athabasca has no current plans to pursue the development of the Grosmont assets and the net present value shown here should therefore not be considered to be a reasonable assessment of the current value of the Grosmont assets to Athabasca.

(10) The after-tax net present value of the properties reflects the tax burden considering Athabasca's consolidated tax position. It does not consider the taxable-entity-level tax situation, or tax planning. It does not provide an estimate of the total taxes which may be paid by each taxable entity in the Company's structure, which may be significantly different.

(11) Athabasca's investment in the Dover assets is accounted for by the equity method and the resource and future net revenue estimates set out in the above table reflect only Athabasca's 40% working interest in the Dover assets which are held directly by the Company's wholly owned subsidiary, AOC (Dover). If Athabasca's interests in the Dover assets were excluded from the totals shown in the above table, Athabasca's Contingent Resources would total, 9,270 MMbbls (Best Estimate) and the associated future net revenue would be as follows:

	Net Present Value of Future Net Revenue as of December 31, 2013 (Excluding Dover) Contingent Resources – Best Estimate				
	0% (MM$)	**5% (MM$)**	**10% (MM$)**	**15% (MM$)**	**20% (MM$)**
Before Income Taxes					
Total Contingent Resources (Best Estimate)	261,655	65,649	18,213	4,315	(151)
After Income Taxes					
Total Contingent Resources (Best Estimate)	261,656	65,649	18,213	4,315	(287)

OTHER OIL AND GAS INFORMATION

Oil & Gas Properties

As at December 31, 2013, Athabasca held approximately 4.2 million net acres of mineral resource leases and permits, including over 1.5 million net acres of oil sands leases and permits in the Athabasca region of northeastern Alberta and over 2.7 million net acres of petroleum and natural gas leases in northwestern Alberta. 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. Management believes that the large scale of Athabasca's assets may also attract interest from potential joint venture partners, should Athabasca choose to pursue that strategy.

As at December 31, 2013, Athabasca had an interest in approximately 101 Gross Wells (98.03 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]**
Crude Oil Wells	48	48	19	18.5	67	66.5
Natural Gas Wells	18	16.03	16	15.5	34	31.53
TOTAL	66	64.03	35	34	101	98.03

Notes:

(1) "**Gross Wells**" means the total number of producing or Non-Producing oil or gas wells in which Athabasca had an interest as of December 31, 2013.

(2) "**Net Wells**" means the aggregate number of producing or Non-Producing 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, 2013, and wells that are capable of production but were not producing as at December 31, 2013, due to facility limitations related to water handling or that were awaiting artificial lift or were waiting to be tied-in. All non-producing wells considered to be capable of producing are located near existing transportation infrastructure.

The following table sets forth certain summary information in respect of Athabasca's Thermal Oil assets and Light Oil assets, as at December 31, 2013.

Asset Area	Working Interest (%)	Approximate Net Acreage (acres)	Gross Proved Reserves (Bitumen)[(1)(2)] (MMbbls)	Gross Probable Reserves (Bitumen)[(1)(2)] (MMbbls)	Company Interest Best Estimate Contingent Resources (Bitumen)[(1)] (MMbbls)	Light Oil Assets Gross Proved Reserves[(1)(2)] (MMboe)	Light Oil Assets Gross Probable Reserves[(1)(2)] (MMboe)
Thermal Oil Assets							
Dover Assets[(3)(4)]	40	60,000	-	137.6	1,222.0	-	-
Dover West Assets		240,000					
Dover West Sands	100		-	87.1	2,957.0	-	-
Dover West Carbonates[(5)]	100		-	-	3,001.0	-	-
Birch Assets	100	470,000	-	-	2,111.0	-	-
Hangingstone Assets	100	136,000	51.1	174.0	782.0	-	-
Grosmont Assets[(5)]	50	394,000	-	-	418.0	-	-
Light Oil Assets							
Kaybob Area	100	443,000	-	-	-	9.7	7.3
Saxon/Placid Area	96	159,000	-	-	-	4.7	10.7
Light Oil Exploration Areas	100	2,110,000	-	-	-	0.2	0.1
Other	100	280,000	-	-	-	-	-
Total[(6)]	N/A	4,292,000	51.1	398.7	10,492.0	14.5	18.1
Total excluding Dover[(6)]	N/A	4,232,000	51.1	261.1	9,270.0	14.5	18.1

Notes:

(1) Based on the Independent Reports.

(2) The estimates of reserves for individual properties may not reflect the same confidence level as estimates of reserves for all properties, due to the effects of aggregation.

(3) 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.

(4) Athabasca's investment in the Dover assets is accounted for by the equity method and the resource estimates set out in this table reflect only Athabasca's 40% working interests in the Dover assets which are held directly by the Company's wholly owned subsidiary, AOC (Dover).

(5) Athabasca's resources at its Dover West Carbonates and Grosmont assets are contained in carbonate reservoirs. SAGD, the in-situ bitumen recovery process considered by GLJ in respect of Athabasca's Dover West Carbonates and Grosmont assets, has not to date been applied successfully in an analogue to the subject reservoirs. TAGD, an alternative process being considered by Athabasca, is an experimental technology. The commercial viability of SAGD technology has been demonstrated successfully for application to certain non-carbonate reservoirs. There are, however, no successful commercial projects that use SAGD or TAGD to recover bitumen from carbonates. The successful development of Athabasca's carbonate reservoirs depends on, among other things, the successful development and application of SAGD, TAGD or other recovery processes to the subject reservoirs. Presently, there exists a large range in the expected recoverable volumes, the lower end of which may not be economically viable. The principal risks associated with SAGD and/or TAGD recovery in carbonate reservoirs are: (a) the possibility of unexpected steam channeling which would increase steam requirements resulting in increased costs and potentially reduced economically recoverable bitumen volumes; (b) the ability to efficiently drain the matrix porosity; (c) potential mechanical operating problems due to production of fines which could cause wellbore plugging and reduced bitumen production rates and potential interruption of surface production operations; and (d) uncertainty as to whether the technologies may be economically applied on a commercial scale. Although the technical risks associated with SAGD have been accounted for in the GLJ Report, the timeline for verification of the viability of these technologies has inherent uncertainty. Development will involve significant capital expenditures and a lengthy time to project payout, and project payout is not assured. If a pilot and/or demonstration project do not demonstrate potential commerciality in the subject reservoirs or a good analogue, then Athabasca's projects on these assets may not proceed and this may occur only after significant expenditures have been incurred by Athabasca. With respect to Athabasca's Grosmont assets, Athabasca has not prepared a development plan or timeline for the area, and is monitoring industry activity toward demonstrating successful development and production methods for the Grosmont Formation. See "Description of Athabasca's Business – Thermal Oil Division – Grosmont assets".

(6) Totals may not add due to rounding.

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 five years and petroleum and natural gas licenses have a primary term of four 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.

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, 2013:

	Gross Acres[(1)(2)]	Net Acres[(1)(2)]	Net Acres Expiring Within One Year[(1)(2)]
Alberta…….	4,726,757	4,242,862	1,020,000
Total…….	4,726,757	4,242,862	1,020,000

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 Charlie Lake Formation in the Grande Prairie area or in respect of the development of the North Muskwa or South Muskwa areas in the 2014 capital budget. As a result, it is expected that approximately 480,000 acres in the Grand Prairie area and 540,000 acres in the North Muskwa and South Muskwa areas will expire during 2014.

Abandonment and Reclamation Costs

Athabasca follows the the Chartered Professional Accountants of Canada's standard for recording asset retirement obligations on its financial statements. This standard requires liability recognition for retirement obligations associated with long-lived assets, which would include abandonment of SAGD, oil and natural gas wells, related facilities, removal of equipment from leased acreage and returning such land to its original condition. At the time that the liability is created, an offsetting asset is also recorded on Athabasca's balance sheet. Under the standard, the estimated fair value of each asset retirement obligation is recorded in the period a well or related asset is drilled, constructed or acquired. Fair value is estimated using the present value of the estimated future cash outflows (adjusted for inflation) to abandon the asset at Athabasca's credit-adjusted risk-free interest rate. The obligation is reviewed regularly by management based upon current regulations, costs, technologies and industry standards. The discounted obligation is recognized as a liability and is accreted, for the time value of money, against income until it is settled or the property is sold. The asset retirement obligation asset is depleted on the same basis as the asset it is associated with and is included as a component of depletion and depreciation expense. Actual restoration expenditures are charged against the accumulated liability as incurred.

The delineation wells that Athabasca drills each winter are generally abandoned during that winter, and therefore no asset retirement obligation is required to be recorded for such wells.

As at December 31, 2013, Athabasca's estimated total undiscounted amount required to settle the asset retirement obligations in respect of Athabasca's 569.1 net wells (652.0 gross wells), pipelines and other infrastructure, net of

estimated salvage recoveries, was $251.7 million. This includes $0.9 million for the Dover asset area wells, which are accounted for by the equity method. These obligations will be settled over the useful lives of the assets, which currently extend up to five years. Athabasca's estimated asset retirement obligation costs are not included in the well abandonment costs that were estimated by GLJ, as are set forth below. The 10% discounted present value of this amount is $53.2 million. Over the next three years, Athabasca expects to incur approximately $12.5 million in expenditures related to these liabilities.

GLJ has estimated that abandonment costs for total Proved plus Probable Reserves, on a Gross Reserves basis, are $137.0 million, undiscounted, and $17.0 million, discounted at 10%.

Tax Horizon

For the fiscal year ended December 31, 2013, 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, changes in or to the scope or costs of the Hangingstone Projects, the Dover West Sands Projects, the Dover West Carbonates Projects or the Company's other exploration and development activities, including in respect of the Light Oil assets, operating costs, interest rates and the Company's other business activities such as any joint venture arrangements 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

The following table sets forth costs incurred by Athabasca for the year ended December 31, 2013:

Division	Proved Property Acquisition Costs ($)	Unproved Property Acquisition Costs ($)	Exploration Costs ($)	Development Costs ($)
Light Oil	-	3,423,092	61,968,806	216,658,594
Thermal Oil	-	-	68,267,023	379,551,850
Total	-	3,423,092	130,235,829	596,210,444

Additionally, during the year ended December 31, 2013, the Company contributed $17,614,000 to its equity investee AOC (Dover), which is developing the Dover Oil Sands Projects as part of the Dover Joint Venture.

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, 2013:

	Exploratory		Development		Total	
	Gross	Net	Gross	Net	Gross	Net
Oil wells	8	8	11	11	19	19
Bitumen wells	-	-	15	15	15	15
Gas wells	5	5	1	0.7	6	5.7
Service wells	18	18	10	10	28	28
Stratigraphic test wells	14	14	-	-	14	14
Dry holes	-	-	-	-	-	-
Total	45	45	37	36.7	82	81.7

On December 17, 2013, Athabasca announced its initial 2014 capital budget and indicated that it will be focussing on the following exploration and development activities in 2014:

- the completion of the construction of Hangingstone Project 1;
- the drilling of two Duvernay wells: one in the Kaybob Area and one in the Saxon/Placid Area;
- the completion and tie-in of four Duvernay wells in the Kaybob Area and Saxon/Placid Area; and
- the drilling and completion of two Montney wells in the Kaybob Area.

Upon receipt of the approval of Alberta Environment in respect of the Dover Oil Sands Project, Athabasca plans to exercise the Dover Put Option. It is expected that Athabasca's 2014 exploration and development program will be expanded once: (a) proceeds from the sale of Athabasca's interests in the Dover assets pursuant to the exercise of the Dover Put Option are received; (b) the productivity of Athabasca's new Duvernay wells has been determined; and (c) there is greater certainty regarding the potential for joint venture arrangements in respect of Athabasca's Duvernay land holdings in the Kaybob Area and Saxon/Placid Area.

Production Estimates

The following table sets out the volumes of Athabasca's working interest production estimated by GLJ and D&M for the year ended December 31, 2014, 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, 2013", "– Future Net Revenue (Undiscounted) – Forecast Prices and Costs as of December 31, 2013" and "– Future Net Revenue by Production Group – Forecast Prices and Costs as of December 31, 2013".

Reserve Category	Light and Medium (bbls/d)	Natural Gas (Mcf/d)	NGLs (bbls/d)	Shale Oil (bbls/d)	Shale Gas (Mcf/d)	Oil Equivalent (Boe/d)
Gross Proved Reserves						
Kaybob Area	1,840	9,914	374	243	1,094	4,291
Saxon/Placid Area	76	3,872	392	-	379	1,176
Light Oil Exploration Areas	-	804	10	-	-	144
Total Gross Proved Reserves(1)	**1,916**	**14,590**	**776**	**243**	**1,472**	**5,612**

Reserve Category	Light and Medium (bbls/d)	Natural Gas (Mcf/d)	NGLs (bbls/d)	Shale Oil (bbls/d)	Shale Gas (Mcf/d)	Oil Equivalent (Boe/d)
Gross Probable Reserves						
Kaybob Area	397	2,228	117	223	799	1,242
Saxon/Placid Area	6	441	83	122	961	443
Light Oil Exploration Areas	-	100	1	-	-	18
Total Gross Probable Reserves(1)	**403**	**2,769**	**201**	**345**	**1,760**	**1,704**

Reserve Category	Light and Medium (bbls/d)	Natural Gas (Mcf/d)	NGLs (bbls/d)	Shale Oil (bbls/d)	Shale Gas (Mcf/d)	Oil Equivalent (Boe/d)
Gross Proved + Probable Reserves						
Kaybob Areas	2,237	12,142	491	467	1,892	5,533
Saxon/Placid Areas	81	4,313	474	122	1,339	1,620
Light Oil Exploration Areas	-	904	11	-	-	162
Total Gross Proved + Probable Reserves(1)	**2,319**	**17,359**	**977**	**588**	**3,232**	**7,316**

Note:

(1) Totals may not add due to rounding.

Both the Kaybob Area and Saxon/Placid Area are estimated to account for greater than 20% of Athabasca's 2014 production volumes. As is shown above, estimated 2014 production volumes for the Kaybob Area are 4,291 boe/d on a Gross Proved Reserves basis and 5,533 boe/d on a Gross Proved plus Probable Reserves basis, and estimated 2014 production volumes for the Saxon/Placid Area are 1,176 boe/d on a Gross Proved Reserves basis and 1,620 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, 2013, certain information in respect of production, product prices received, royalties paid, operating expenses and the resulting netbacks.

	Quarter Ended 2013				Year Ended
	Mar. 31	**June 30**	**Sept. 30**	**Dec. 31**	**Dec. 31, 2013**
Average Daily Production[1]					
Light and Medium Oil (bbls/d)	2,136	2,225	1,885	1,934	2,044
Natural Gas (Mcf/d)	13,235	20,655	16,386	19,793	17,532
NGLs (bbls/d)	492	823	627	796	685
Shale Oil (bbls/d)	766	472	271	332	458
Shale Gas (Mcf/d)	2,405	2,122	1,558	2,281	2,090
Total (Boe/d)	6,000	7,316	5,773	6,740	6,458
Average Prices Received					
Light and Medium Oil ($/bbl)	80.88	89.24	101.84	78.22	87.39
Natural Gas ($/Mcf)	3.39	3.88	2.74	3.77	3.49
NGLs ($/bbl)	51.80	68.46	75.07	67.31	66.70
Shale Oil ($/bbl)	80.01	89.92	101.51	78.85	85.54
Shale Gas ($/Mcf)	3.69	4.42	3.16	4.19	3.91
Total ($/boe)	52.20	52.86	54.79	46.76	51.54
Royalties Paid					
Light and Medium Oil ($/bbl)	(4.96)	(9.32)	(16.71)	(16.44)	(11.61)
Natural Gas ($/Mcf)	(0.17)	(0.09)	(0.12)	(0.21)	(0.15)
NGLs ($/bbl)	(3.37)	(4.52)	(5.89)	(6.51)	(5.21)
Shale Oil ($/bbl)	(4.74)	(4.60)	(5.07)	(4.19)	(4.65)
Shale Gas ($/Mcf)	(0.18)	(0.22)	(0.17)	(0.18)	(0.19)
Total ($/boe)	(3.08)	(3.97)	(6.73)	(6.38)	(5.02)
Operating Expenses[2]					
Light and Medium Oil ($/bbl)	(17.68)	(13.43)	(15.57)	(14.55)	(15.17)
Natural Gas ($/Mcf)	(2.95)	(2.24)	(2.60)	(2.43)	(2.53)
NGLs ($/bbl)	(17.68)	(13.43)	(15.57)	(14.55)	(15.17)
Shale Oil ($/bbl)	(10.76)	(9.37)	(12.25)	(10.78)	(10.38)
Shale Gas ($/Mcf)	(1.79)	(1.56)	(2.04)	(1.80)	(1.73)
Total ($/boe)	(16.33)	(12.97)	(15.27)	(14.15)	(14.57)
Netback Received[3]					
Light and Medium Oil ($/bbl)	58.24	66.49	69.56	47.23	60.61
Natural Gas ($/Mcf)	0.27	1.55	0.02	1.13	0.81
NGLs ($/bbl)	30.75	50.51	53.61	46.25	46.32
Shale Oil ($/bbl)	64.51	75.95	84.19	63.88	70.51
Shale Gas ($/Mcf)	1.72	2.64	0.95	2.21	1.99
Total ($/boe)	32.79	35.92	32.79	26.23	31.95

Notes:

(1) Production is before deduction of royalties and capitalized sales volumes, but excludes inventory.
(2) For wells producing multiple products, operating expenses have been allocated based on barrels of oil equivalent.
(3) 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, 2013:

	Light and Medium Oil (bbls/d)	Natural Gas (Mcf/d)	NGLs (bbls/d)	Shale Oil (bbls/d)	Shale Gas (Mcf/d)	Oil Equivalent (boe/d)
Kaybob Area	1,857	13,718	407	431	1,501	5,231
Saxon/Placid Area	186	3,747	277	28	588	1,213
Light Oil Exploration Areas	1	67	1	-	-	14
Total	2,044	17,532	685	459	2,089	6,458

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, 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.

DIVIDENDS

Other than the Special Dividend, the Company has never declared or paid any cash dividends on its Common Shares. 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 Note Indenture and the Amended and Restated Credit Agreement, and other factors that the Board may deem relevant.

Pursuant to the Amended and Restated Credit Agreement, the Company is prohibited from paying dividends to Shareholders while any borrowings or other obligations are outstanding under the Amended Credit Facilities. Additionally, pursuant to the Note Indenture, 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 are set forth in the Note Indenture) are met, and no default or event of default under the Note Indenture 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 Senior Secured Notes and has the ability to utilize the Amended Credit Facilities that are described below.

As at December 31, 2013, 400,844,142 Common Shares were issued and outstanding and no first preferred shares or second preferred shares were issued and outstanding. In addition, 14,576,555 Stock Options and 10,617,753 RSUs, were issued and outstanding on December 31, 2013.

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.

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 March 19, 2010 and was re-approved by the Shareholders at the annual general and special meeting that was held on May 10, 2012 (the "**Rights Plan Confirmation**"). Pursuant to the Rights Plan Confirmation, the Shareholders also approved an extension to the term of the Rights Plan until the close of business on the first business day following the annual general meeting of the Shareholders to be held in 2015, unless at such meeting the Shareholders reconfirm the Rights Plan for an additional period of time or the Rights Plan is otherwise terminated in accordance with its terms prior thereto.

The objectives of the 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 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 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 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 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 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 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 Rights Plan is available on the Company's SEDAR profile at www.sedar.com.

Amended Credit Facilities

On December 16, 2013, the Company entered into an amended and restated credit agreement (the "**Amended and Restated Credit Agreement**") with a syndicate of financial institutions to replace the 2012 Credit Facilities with the Amended Credit Facilities.

The Amended Credit Facilities are available for general corporate purposes and consist of: (a) a $20 million operating facility (the "**Operating Facility**"); (b) an $80 million credit facility (the "**Tranche A Facility**" and, together with the Operating Facility, the "**Borrowing Base Credit Facilities**"); (c) a $100 million credit facility (the "**Tranche B Facility**"); and (d) a $150 million credit facility (the "**Tranche C Facility**"). The aggregate utilization of the Borrowing Base Credit Facilities is not permitted to exceed the prevailing limit which is determined by the lenders from time to time and was initially set at $100 million (the "**Borrowing Base**"). Any increase in the Borrowing Base and the Borrowing Base Credit Facilities will result in a corresponding permanent decrease in the Tranche B Facility, so long as the Tranche B Facility remains outstanding.

The Company has the option of utilizing the Amended Credit Facilities by way of: (a) Canadian prime rate based Canadian dollar advances; (b) U.S. base rate based United States dollar advances; (c) Canadian dollar bankers' acceptances; (d) LIBOR based United States dollar advances; and (e) under the Operating Facility and Tranche A Facility, letters of credit, in Canadian or U.S. dollars; with interest calculated by reference to the applicable

reference rate plus the applicable margin for each, with the applicable margin determined by the Company's debt to EBITDA ratio (calculated as specified in the Amended and Restated Credit Agreement) and varying between the Borrowing Base Credit Facilities, the Tranche B Facility and Tranche C Facility. The Company is required to pay a standby fee, which is also determined by the debt to EBITDA ratio, on undrawn amounts under the Amended Credit Facilities.

The Borrowing Base Facilities and the Tranche B Facility have a 364-day revolving period, which is extendible at the request of the Company for a further 364-day period, provided that no default or event of default has occurred and the consent of two-thirds of the lenders by commitment amount is obtained. The Tranche C Facility has a maturity date of December 31, 2014 and will be reduced to $100 million on August 1, 2014 and to $50 million on November 1, 2014, if it has not been repaid prior to that time. The Borrower is permitted to permanently prepay all or any part of the Amended Credit Facilities at any time without penalty upon required notice and subject to customary provisions regarding breakage costs and cash collateralization of outstanding letters of credit and bankers' acceptances, but all prepayments shall be applied solely to the Tranche C Facility until the Tranche C Facility has been repaid in full and cancelled.

The Amended Credit Facilities include various restrictive covenants, including a debt to EBITDA ratio covenant which is set to commence on December 31, 2014 (the debt to EBITDA ratio covenant related to the 2012 Credit Facilities was set to commence on June 30 2014) and a tangible net worth covenant. The Amended Credit Facilities also include a mandatory repayment covenant that requires the Company to permanently reduce and cancel the Tranche C Facility with: (a) the proceeds from the completion of the sale of Athabasca's interest in the Dover assets following the exercise of the Dover Put Option; or (b) the proceeds of equity offerings or certain permitted disposition transactions, including certain permitted joint venture arrangements (as are specified in the Amended and Restated Credit Agreement). Additionally, while the Tranche C Facility is outstanding, Athabasca's cumulative capital expenditures from October 1, 2013 up to and including December 31, 2014 may not exceed 110% of the permitted capital expenditures budget that is described in the Amended and Restated Credit Agreement. The restrictive covenants, subject to certain exceptions, also limit the ability of the Company and its subsidiaries, to, among other things: incur indebtedness; grant security; pay dividends or other distributions, or make loans or other payments to shareholders; voluntarily redeem or purchase for cancellation the Senior Secured Notes at certain times; undertake asset sales and other dispositions; make certain loans, investments or engage in certain asset acquisitions; provide financial assistance; amend material contracts; enter into certain production sales agreements or currency or interest rate hedging agreements; undertake material changes; and enter into mergers, amalgamations, consolidations and reorganizations.

The Amended Credit Facilities also include customary events of default, including, but not limited to: non-payment of principal, interest or other amounts when due; breach of covenants; incorrect representations or warranties; cross default to certain indebtedness; Borrowing Base shortfalls; default under certain material contracts; change of control; cessation of business; insolvency and bankruptcy events; abandonment of all or substantially all of the oil and gas rights in certain areas with attributed proved reserves; and material judgments, liens or orders. Some of the events of default allow for notice and cure periods and are subject to materiality thresholds.

The Amended Credit Facilities are guaranteed by the Company's material subsidiaries (with the exception of AOC Dover Corp. and AOC (Dover)), and are secured by security interests in substantially all of the existing and future assets of the Company and the guarantor subsidiaries, which security interests have, subject to certain permitted encumbrances, first priority over all other creditors.

As at March 18, 2014, Athabasca does not have any letters of credit outstanding and has not borrowed or drawn any amounts under the Amended Credit Facilities.

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 is 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. The Senior Secured Notes mature on November 19, 2017. At any time prior to November 19, 2014, the Company may redeem the Senior Secured Notes, in whole or in part, at a price equal to 100% of the principal amount of the Senior Secured Notes being redeemed plus accrued but unpaid interest, if any, to but not including the redemption date, plus a "make-whole" premium. The Company may also redeem up to 35% of the original principal amount of the Senior Secured Notes before November 19, 2014 with the net cash proceeds from equity offerings at a redemption price of 107.50% plus accrued and unpaid interest to the applicable redemption date. At any time on or after November 19, 2014, the Company may redeem the Senior Secured Notes at the following redemption prices plus accrued and unpaid interest on the Senior Secured Notes that are redeemed, to the applicable redemption date, if redeemed during the 12-month period beginning on November 19th of each of the following years: 2014 – 107.50%; 2015 – 103.75%; and 2016 and thereafter – 100.00%.

If the Company undergoes certain kinds of changes of control, it is required to offer to repurchase the Senior Secured Notes from holders at a purchase price equal to 101% of the principal amount of the Senior Secured Notes plus accrued and unpaid interest, if any, to, but not including, the date of repurchase.

The Senior Secured Notes are guaranteed on senior secured basis by the Company's material subsidiaries, with the exception of AOC Dover Corp. and AOC (Dover). The Senior Secured Notes and the guarantees are secured by second-priority security interests (subject to certain liens that are permitted pursuant to the terms of the 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 Note Indenture including the Company's rights under the Dover Put/Call Option Agreement. If the Dover Put Option or Dover Call Option are exercised and the sale of the shares or assets of AOC (Dover) (or a wholly-owned subsidiary of AOC (Dover), as the case may be) is completed, the net proceeds from the sale would subsequently be held as collateral. The Senior Secured 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 November 19, 2012 (the "**Collateral Agent Agreement**").

Subject to certain exceptions and qualifications which are set forth in the Note Indenture, the Senior Secured Notes limit the ability of the Company and certain of its subsidiaries that are considered to be "restricted subsidiaries" pursuant to the 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.

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

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 been assigned provisional corporate credit ratings of B by DBRS and B by S&P. The corporate credit rating focuses on a borrower's capacity and willingness to meet its financial commitments as they come due.

The Senior Secured Notes have been assigned provisional credit ratings of B with a "Stable" trend by DBRS and CCC+ with a "Negative" trend by S&P.

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. DBRS has assigned the Company a provisional credit rating of B with a "Stable" trend. 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 "Stable" 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. S&P has assigned the Company a provisional credit rating of CCC+ with a "Negative" trend on the Senior Secured Notes. 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 both DBRS and S&P to provide ratings in respect of the offering of the Senior Secured Notes. No service fees other than 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**
2014			
March (1 to 17)	8.55	8.23	10,245,691
February	8.74	7.65	43,105,172
January	7.99	6.72	49,061,475
2013			
December	6.87	6.19	37,935,058
November	6.61	6.19	25,902,442
October	7.73	6.09	72,186,700
September	7.97	7.29	23,621,457
August	8.43	7.37	36,225,711
July	7.21	6.52	28,849,930
June	7.82	6.42	28,402,328
May	7.34	5.74	40,432,562
April	8.94	6.94	38,592,760
March	9.88	8.51	33,866,581
February	11.21	10.03	23,505,025

	Price Range		
	High ($/share)	**Low ($/share)**	**Volume**
January	10.98	10.33	16,034,396

Prior Sales

The following is a description of securities of the Company that were issued in the financial year ended December 31, 2013 that are not listed or quoted on a marketplace:

(a) the Company granted an aggregate of 5,813,640 RSUs to acquire an aggregate of 5,813,640 Common Shares, each with an exercise price of $0.10; and

(b) the Company granted an aggregate of 3,158,240 Stock Options to acquire an aggregate of 3,158,240 Common Shares with a weighted average exercise price of $7.04.

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

On December 31, 2013, 1,454,767 Common Shares that were previously held in trust by Avenir Consolidated Corporation, pending the satisfaction of certain length of service requirements, were released from escrow to the respective current and former employees, officers and other services providers of the Company that were the beneficiaries of the trust. As at December 31, 2013, 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.

DIRECTORS AND OFFICERS

The names, provinces 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
Tom Buchanan[(2)(4)] Alberta, Canada	Chairman of the Board and Director	Chief Executive Officer of Spyglass Resources Corp. since March 28, 2013. Prior thereto, Chairman and Chief Executive Officer of Charger Energy Corp. from September 2010 until March 28, 2013. Prior thereto, a director and President and Chief Executive Officer of Provident Energy Ltd., the administrator of Provident Energy Trust, from March 2001 to April 2010.	November 14, 2006
Gary Dundas[(2)(3)(4)] Alberta, Canada	Director	Independent businessman. Prior to March 28, 2013, Vice President, Finance and Chief Financial Officer of AvenEx Energy Corp., the entity resulting from the reorganization of Avenir Diversified Income Trust into a corporate structure, which was completed on January 1, 2011. Prior thereto, Vice President, Finance and Chief Financial Officer of Avenir Operating Corp., the administrator of Avenir Diversified Income Trust, from January 2003 until January 1, 2011.	August 28, 2006

Name and Place of Residence	Office	Principal Occupation	Director Since
Ronald J. Eckhardt[(3)(5)] Alberta, Canada	Director	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)(4)] Alberta, Canada	Director	Interim Executive Vice President and Chief Financial Officer of Black Diamond Group Limited since October 16, 2013. Prior thereto, independent financial and management consultant since August 2009. Prior thereto, Chief Financial Officer of CCS Inc., administrator of CCS Income Trust and its successor corporation, CCS Corporation, from August 2002 until August 2009.	October 30, 2009
Peter Sametz[(3)] Alberta, Canada	Director	Chief Executive Officer of Alberta Steam and Power Corp. since February 2013, a private company focused on provision of steam and power to the oil and gas industry. Prior thereto, Interim Chief Executive Officer from February 2012 to December 2012, President, Chief Operating Officer and a director from May 2010 to January 2012 and Executive Vice President and Chief Operating Officer from 2005 to 2010 of Connacher Oil and Gas Limited.	March 14, 2014
Sveinung Svarte[(3)] Alberta, Canada	President and Chief Executive Officer and a Director	President and Chief Executive Officer of the Company since May 6, 2013. Prior thereto, Chief Executive Officer of the Company from November 28, 2012 until May 6, 2013. Prior thereto, President and Chief Executive Officer of the Company from January 8, 2007 until November 28, 2012. Prior thereto, Vice President, Oilsands of Total E&P Canada Ltd. from 2004 until July 2005 and Vice President, Corporate Development of Total E&P Canada Ltd. from July 2005 until January 2007.	October 19, 2006
Kim Anderson Alberta, Canada	Chief Financial Officer	Chief Financial Officer of the Company since February 18, 2014. Prior thereto, Chief Financial Officer of KANATA Energy Group Ltd. from January 9, 2013 until February 14, 2014. Prior thereto, 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
Terry Bachynski Alberta, Canada	Vice President, Regulatory, Stakeholder and Government Affairs	Vice President, Regulatory, Stakeholder and Government Affairs since April 2013. Prior thereto was Vice President Regulatory and Stakeholder Affairs of the Company since October 2009. Also serves as Vice President, Regulatory Affairs for Brion Energy Corporation since January 2013. Prior thereto, Vice President, Regulatory and Stakeholder Affairs for Suncor Energy Inc. from January 2002 to December 2012.	N/A

Name and Place of Residence	Office	Principal Occupation	Director Since
Robert Bowie Alberta, Canada	Vice President, Corporate Development	Vice President, Corporate Development of the Company since November 28, 2012. Prior thereto was Director, Portfolio Management of the Company from February 1, 2012 until November 28, 2012 and was Manager, New Ventures of the Company from October 1, 2010 to February 1, 2012. Prior thereto, was the Acquisitions and Divestitures Manager at Shell Canada Limited during 2010 and held a variety of other commercial and business development positions with Shell Canada Limited beginning in September 1997.	N/A
Rob Broen Alberta, Canada	Chief Operating Officer	Chief Operating Officer of the Company since October 12, 2013. Prior thereto, Senior Vice President, Light Oil of the Company from November 26, 2012 to October 12, 2013. Prior thereto, Senior Vice-President, North American Shale at Talisman Energy Inc. from April 2012 to November 2012. Prior thereto, President and a director of Talisman Energy USA Inc. from 2009 to April 2012.	N/A
Andre De Leebeeck Alberta, Canada	Vice President, Investor Relations and External Communications	Vice President, Investor Relations and External Communications of the Company since November 28, 2012. Prior thereto was the Director, Partner and Investor Relations of the Company from January 30, 2012 until November 28, 2012. Prior thereto was the Senior Operating Officer at Value Creation Inc. from September 2008 to December 31, 2011 and was VP, Thermal at Total E&P Canada Ltd. from September 2006 to September 2008.	N/A
Dan Hausermann Alberta, Canada	Vice President, Geosciences, Reservoir and Development	Vice President, Geosciences, Reservoir and Development of the Company since January 1, 2014. Prior thereto, seconded to Brion Energy Corporation as Vice President, Geosciences, Reservoir and Development from October 2011 until December 2013, and as Manager, Corporate Planning from June 2010 until September 2011. Prior thereto, Manager, Corporate Planning at the Company from February 2008 until February 2009.	N/A
Richard Koshman Alberta, Canada	Vice President, Projects and Thermal Operations	Vice President, Projects and Thermal Operations of the Company since February 16, 2012. Prior thereto, Vice President, Projects from June 1, 2011 until February 16, 2012. Prior thereto, Manager, Thermal Oilsands Projects with Canadian Natural Resources Ltd. from February 2008 until May 2011.	N/A
Anne Schenkenberger Alberta, Canada	Vice President, Legal and Corporate Secretary	Vice President, Legal and Corporate Secretary of the Company since August 18, 2010. Prior thereto, General Counsel and Corporate Secretary of the Company from May 2008 to August 18, 2010. Prior thereto, 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
Kevin Smith Alberta, Canada	Vice President, Light Oil	Vice President, Light Oil since January 6, 2014. Prior thereto, Business Unit, Vice President at Encana Corporation from October 2008 until November 2013.	N/A
Don Verdonck Alberta, Canada	Vice President	Seconded to Brion Energy Corporation as Chief Operating Officer (and now as Executive Senior Vice President) since June 2010. Prior thereto, Vice President, Development and Operations of the Company from February 2007 until June 2010.	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 and HSE Committee. Mr. Eckhardt is the Chairman of the Reserves and HSE Committee.
(4) Member of the Compensation and Governance Committee. Mr. Dundas is the Chairman of the Compensation and Governance Committee.
(5) Mr. Eckhardt was Chair of the EODC from May 6, 2013 until October 30, 2013.

As at December 31, 2013, the directors and executive officers of the Company, as a group, beneficially owned, controlled or directed, directly or indirectly, an aggregate of 30,248,343 Common Shares, representing 7.5% of the issued and outstanding Common Shares (not including any Common Shares issuable pursuant to the exercise of the issued and outstanding Stock Options or RSUs). As at March 18, 2014, the directors and executive officers of the Company, as a group, beneficially owned, controlled or directed, directly or indirectly, an aggregate of 16,922,157 Common Shares, representing 4.2% of the issued and outstanding Common Shares (not including any Common Shares issuable pursuant to the exercise of the issued and outstanding Stock Options or RSUs).

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 officer or securityholder 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 officer or securityholder 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 securityholder.

Mr. Dundas is a director of Mahalo Energy Ltd. ("**Mahalo**"). On May 22, 2009, Mahalo was granted protection from its creditors under the CCAA pursuant to an initial order granted by the Court of Queen's Bench of Alberta. Mahalo concluded a Court approved plan of arrangement to exit CCAA protection on November 12, 2010 that resulted in the cancellation of the existing share capital of the company and the settlement of existing creditor obligations. Mr. Dundas was also a director of Mahalo's wholly owned subsidiary, Mahalo Energy (USA) Inc. ("**Mahalo USA**"). On May 21, 2009, Mahalo USA filed for and received chapter 11 creditor protection in the United States. On April 20, 2010, the US chapter 11 proceedings concluded with the transfer of Mahalo USA to Mahalo's creditors. Also, on June 22, 2010, the Alberta Securities Commission issued a cease trade order against Mahalo for failure to file annual financial statements for the year ended December 31, 2009 and for failure to file interim unaudited financial statements for the period ended March 31, 2010. The securities commissions of each of British Columbia, Manitoba, Ontario and Quebec (and together with Alberta, the "**Commissions**") issued similar orders in respect of the failure to file financial statements. On November 12, 2010, each of the Commissions issued a full revocation order of the cease trade order and a cease to be reporting issuer order in connection with the conclusion of Mahalo's CCAA proceedings.

To the knowledge of the Company, no current director or officer or securityholder 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

On August 6, 2013, the AER announced that the Dover JV Operator's application in respect of the Dover Oil Sands Project was approved, subject to the conditions set forth in the AER Decision (including the approval of the Lieutenant Governor in Council). The FMFN subsequently sought the approval of the Court of Appeal of Alberta to appeal the AER Decision. On October 18, 2013, the Court of Appeal of Alberta granted the FMFN leave to appeal on a specific question of law that arose from the AER Decision relating to the type of constitutional questions that the AER may consider pursuant to its general jurisdiction over issues of law or under the *Administrative Procedures and Jurisdiction Act,* RSA 200, c. A-3. 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.

Other than the appeal by the FMFN which has been discontinued, 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, 2013, 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.

TRANSFER AGENTS AND REGISTRARS

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

MATERIAL CONTRACTS

As at December 31, 2013, 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, 2013:

(a) the Note Indenture;

(b) the Rights Plan referred to under the heading "Description of Capital Structure – Shareholder Rights Plan"; and

(c) the following agreements relating to the PetroChina Transaction:

  (i) the Dover Joint Venture Agreement;

  (ii) the Put/Call Option Agreement;

  (iii) the Umbrella Agreement.

In addition to the disclosure appearing elsewhere in this Annual Information Form with respect to the agreements relating to the PetroChina Transaction, see the sections entitled "The MacKay Joint Venture Agreement and the Dover Joint Venture Agreement", "The Put/Call Option Agreement" and the "Umbrella Agreement" under the

heading "The PetroChina Transaction – Summary of the PetroChina Transaction Agreements" in the Company's prospectus dated March 30, 2010 (the "**IPO Prospectus**"), which sections are incorporated by reference herein. Copies of these material contracts and the IPO Prospectus 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 and with respect to the pricing and taxation of oil and natural gas through agreements among the governments of Canada and Alberta, all of which should be carefully considered by investors in the oil and gas industry. All current legislation is a matter of public record and the Company is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry in western Canada.

Pricing and Marketing

Oil

The producers of oil are entitled to negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Worldwide supply and demand factors primarily determine oil prices; however, prices are also influenced by regional market and transportation issues. The specific price depends in part on oil quality, prices of competing fuels, distance to market, availability of transportation, value of refined products, the supply/demand balance and contractual terms of sale. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National Energy Board of Canada (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 is currently undergoing a consultation process to update the regulations governing the issuance of export licences. The updating process is necessary to meet the criteria set out in the federal *Jobs, Growth and Long-term Prosperity Act*, which received Royal Assent on June 29, 2012 (the "**Prosperity Act**"). In this transitory period, the NEB has issued, and is currently following an "Interim Memorandum of Guidance Concerning Oil and Gas Export Applications and Gas Import Applications under Part VI of the *National Energy Board Act*".

Natural Gas

Alberta's natural gas market has been deregulated since 1985. Supply and demand determine the price of natural gas and price is calculated at the sale point, being the wellhead, the outlet of a gas processing plant, on a gas transmission system such as the Alberta "NIT" (Nova Inventory Transfer), at a storage facility, at the inlet to a utility system or at the point of receipt by the consumer. Accordingly, the price for natural gas is dependent upon such producer's own arrangements (whether long or short term contracts and the specific point of sale). As natural gas is also traded on trading platforms such as the Natural Gas Exchange (NGX), Intercontinental Exchange or the New York Mercantile Exchange (NYMEX) 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 must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m^3/day) must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or for a larger quantity requires an exporter to obtain an export licence from the NEB.

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: (a) 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; (b) 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 (c) 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.

Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations that govern royalties, production rates and other matters. The royalty regime in a given province is a significant factor in the profitability of oil sands projects, crude oil, natural gas liquids, sulphur and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiation between the mineral freehold owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Royalties from production on Crown lands are determined by governmental regulation and are generally calculated as a percentage of the value of gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery and the type or quality of the petroleum product produced. Other royalties and royalty-like interests are carved out of the working interest owner's interest, from time to time, through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests, or net carried interests.

Occasionally the governments of the western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays or royalty tax credits and are generally introduced when commodity prices are low to encourage exploration and development activity by improving earnings and cash flow within the industry.

Alberta

Producers of oil and natural gas from Crown lands in Alberta are required to pay annual rental payments, currently at a rate of $3.50 per hectare, and make monthly royalty payments in respect of oil and natural gas produced.

Royalties are currently paid pursuant to "The New Royalty Framework" (implemented by the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*) and the "Alberta Royalty Framework", which was implemented in 2010.

Royalty rates for conventional oil are set by a single sliding rate formula, which is applied monthly and incorporates separate variables to account for production rates and market prices. The maximum royalty payable under the royalty regime is 40%. Royalty rates for natural gas under the royalty regime are similarly determined using a single sliding rate formula with the maximum royalty payable under the royalty regime set at 36%.

Oil sands projects are also subject to Alberta's royalty regime. Prior to payout of an oil sands project, the royalty is payable on gross revenues of an oil sands project. Gross revenue royalty rates range between 1-9% depending on the market price of oil, determined using the average monthly price, expressed in Canadian dollars, for WTI crude oil at Cushing, Oklahoma: rates are 1% when the market price of oil is less than or equal to $55 per barrel and increase for every dollar of market price of oil increase to a maximum of 9% when oil is priced at $120 or higher. After payout, the royalty payable is the greater of the gross revenue royalty based on the gross revenue royalty rate of 1-9% and the net revenue royalty based on the net revenue royalty rate. Net revenue royalty rates start at 25% and increase for every dollar of market price of oil increase above $55 up to 40% when oil is priced at $120 or higher. In addition, concurrent with the implementation of The New Royalty Framework, the Government of Alberta renegotiated existing contracts with certain oil sands producers that were not compatible with the new royalty regime.

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

The Government of Alberta has from time to time implemented drilling credits, incentives or transitional royalty programs to encourage oil and gas development and new drilling. For example, the Innovative Energy Technologies Program (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**"). Specifically:

- Coalbed methane wells will receive a maximum royalty rate of 5% for 36 producing months on up to 750 MMcf of production, retroactive to wells that began producing on or after May 1, 2010;
- Shale gas wells will receive a maximum royalty rate of 5% for 36 producing months with no limitation on production volume, retroactive to wells that began producing on or after May 1, 2010;
- Horizontal gas wells will receive a maximum royalty rate of 5% for 18 producing months on up to 500 MMcf of production, retroactive to wells that commenced drilling on or after May 1, 2010; and
- Horizontal oil wells and horizontal non-project oil sands wells will receive a maximum royalty rate of 5% with volume and production month limits set according to the depth of the well (including the horizontal distance), retroactive to wells that commenced drilling on or after May 1, 2010.

The Emerging Resource and Technologies Initiative will be reviewed in 2014, and the Government of Alberta has committed to providing industry with three years notice if it decides to discontinue the program.

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 license.

Alberta also has a policy of "shallow rights reversion" which provides for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for all leases and licenses. For leases and licenses issued subsequent to January 1, 2009, shallow rights reversion will be applied at the conclusion of the primary term of the lease or license.

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulation pursuant to a variety of provincial and federal environmental legislation, all of which is subject to governmental review and revision from time to time. Such legislation provides for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain oil and gas industry operations, such as sulphur dioxide and nitrous oxide. In addition, such legislation sets out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability and the imposition of material fines and penalties.

Federal

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

Alberta

The regulatory landscape in Alberta has undergone a transformation from multiple regulatory bodies to a single regulator for upstream oil and gas, oil sands and coal development activity. On June 17, 2013, the AER assumed the functions and responsibilities of the former ERCB, including those found under the *Oil and Gas Conservation Act* ("**ABOGCA**"). On November 30, 2013, the AER assumed the energy related functions and responsibilities of Alberta Environment and Sustainable Resource Development ("**AESRD**") in respect of the disposition and management of public lands under the *Public Lands Act*. On March 30, 2014, the AER is expected to assume the energy related functions and responsibilities of AESRD in the areas of environment and water under the *Environmental Protection and Enhancement Act* and the *Water Act*, respectively. 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 the transformation to a single regulator is the creation of 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.

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, licenses, registrations, approvals and authorizations for the purpose of achieving or maintaining an objective or policy resulting from the implementation of a regional plan. Among the measures to support the goals of the regional plans contained in the 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 oilsands area, which contains approximately 82% of the province's oilsands resources and much of the Cold Lake oilsands 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 petroleum and gas tenure issued in conservation and provincial recreation areas will include a restriction that prohibits surface access. In contrast, oilsands companies' tenure has been (or will be) cancelled in conservation areas and no new oilsands 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. The next regional plan to take effect is the South Saskatchewan Regional Plan ("**SSRP**") which covers approximately 83,764 square kilometres and includes 45% of the provincial population. The SSRP was released in draft form in 2013 and is expected to come into force on April 1, 2014.

With the implementation of the new Alberta regulatory structure under the AER, AESRD will remain responsible for development and implementation of regional plans. However, the AER will take on some responsibility for implementing regional plans in respect of energy related activities.

Liability Management Rating Programs

In Alberta, the AER implemented 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. The ABOGCA 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 becomes defunct. 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 licences and 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. Effective May 1, 2013, the AER implemented important changes to the AB LLR Program that resulted in a significant increase in the number of oil and gas companies in Alberta that are required to post security. Some of the important changes include:

- a 25% increase to the prescribed average reclamation cost for each individual well or facility (which will increase a licensee's deemed liabilities);

- a $7,000 increase to facility abandonment cost parameters for each well equivalent (which will increase a licensee's deemed liabilities); a decrease in the industry average netback from a five-year to a three-year average (which will affect the calculation of a licensee's deemed assets, as the reduction from five to three years means the average will be more sensitive to price changes); and

- a change to the present value and salvage factor, increasing to 1.0 for all active facilities from the current 0.75 for active wells and 0.50 for active facilities (which will increase a licensee's deemed liabilities).

The changes will be implemented over a three-year period, ending May 2015. The changes to the AB LLR Program stem from concern that the previous regime significantly underestimated the environmental liabilities of licensees.

Climate Change Regulation

Federal

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

On April 26, 2007, the Government of Canada released "Turning the Corner: An Action Plan to Reduce Greenhouse Gases and Air Pollution" (the "**Action Plan**") which set forth a plan for regulations to address both 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, sector-wide basis or company-by-company basis. Although the intention was for draft regulations aimed at implementing the Updated Action Plan to become binding on January 1, 2010, the only regulations being implemented are in the transportation and electricity sectors. The federal government indicates that it is taking a sector-by-sector regulatory approach to reducing GHG emissions and is working on regulations for other sectors. Representatives of the Government of Canada have indicated that the proposals contained in the Updated Action Plan will be modified to ensure consistency with the direction ultimately taken by the United States with respect to GHG emissions regulation. In June 2012, the second US-Canada Clean Energy Dialogue Action Plan was released. The plan renewed efforts to enhance bilateral collaboration on the development of clean energy technologies to reduce GHG emissions.

Alberta

As part of Alberta's 2008 Climate Change Strategy, the province committed to taking action on three themes: (a) conserving and using energy efficiently (reducing GHG emissions); (b) greening energy production; and (c) implementing carbon and capture storage.

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 CCEMA is based on an emissions intensity and aims for a 50% reduction from 1990 emissions relative to GDP by 2020. 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 facilities emitting more than 100,000 tonnes of GHGs a year are subject to compliance with the CCEMA. Alberta is the first jurisdiction in North America to impose regulations requiring large facilities in various sectors to reduce their GHG emissions.

The SGER, effective July 1, 2007, applies to facilities emitting more than 100,000 tonnes of GHGs in 2003 or any subsequent year, 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. The SGER distinguishes between "Established Facilities" and "New Facilities". Established Facilities are defined as facilities that completed their first year of commercial operation prior to January 1, 2000 or that have completed eight or more years of commercial operation. Established Facilities are required to reduce their emissions intensity by 12% of their baseline emissions intensity for 2008 and subsequent years. Generally, the baseline for an Established Facility reflects the average of emissions intensity in 2003, 2004 and 2005. New Facilities are defined as facilities that completed their first year of commercial operation on December 31, 2000, or a subsequent year, and have completed less than eight

years of commercial operation, or are designated as New Facilities in accordance with the SGER. New Facilities are required to reduce their emissions intensity by 2% from 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, and 10% of their baseline in the eighth year. The CCEMA does not contain any provision for continuous annual improvements in emissions intensity reductions beyond those stated above.

The CCEMA provides that regulated emitters can meet their emissions intensity targets by contributing to the Climate Change and Emissions Management Fund at a rate of $15 per tonne of CO_2 equivalent. The funds contributed by industry to the Climate Change and Emissions Management Fund will be used to drive innovation and test and implement new technologies for greening energy production. Emissions credits can be purchased from regulated emitters that have reduced their emissions below the 100,000 tonne threshold or non-regulated emitters that have generated emissions offsets through activities that result in emissions reductions in accordance with established protocols published by the Government of Alberta.

Alberta is also the first jurisdiction in North America to direct dedicated funding to implement carbon capture and storage technology across industrial sectors. Alberta will invest $2 billion into demonstration 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 D&M (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 Institute of Chartered Accountants, 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 early 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 the Company'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 the Company will avoid future loss due to the occurrence of the risk factors described below or other unforeseen risks.

Risks Relating to Athabasca's Business

Substantial Capital Requirements and Liquidity Risk

Substantial capital expenditures will be required to fund the exploration and development of Athabasca's Thermal Oil assets and Light Oil assets. Athabasca's 2014 capital and operating budgets are intended to be funded with existing cash and short term investments, cash flow from operations and the Amended Credit Facilities or other debt financing. Beyond 2014, Athabasca will require additional capital to maintain its pace of development. Currently, management believes that Athabasca will fund its activities and other requirements beyond 2014 through some combination of cash flow from operations, the proceeds from the sale of Athabasca's interests in the Dover assets pursuant to the exercise of the Dover Put Option, additional debt, to the extent permitted by the Amended and Restated Credit Agreement and Note Indenture, and through possible future joint venture arrangements. However, there can be no assurance that the cash that may be generated from Athabasca's operations and/or the other sources of financing that are expected to be utilized will be available or sufficient to meet Athabasca's requirements, or if external sources of funding are available, that they will be available on terms that are acceptable to Athabasca. The Company's 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 appetite for investments in the energy industry and the Company's securities in particular. Additionally, Athabasca is restricted from selling assets pursuant to the terms of the Amended and Restated Credit Agreement and Note Indenture and from selling its interests in the Dover assets pursuant to the terms of the Dover Joint Venture Agreement.

The inability to access sufficient capital for Athabasca's operations and other requirements could result in, among other things, the default of the Company under the Amended and Restated Credit Agreement, the Note Indenture and/or Dover Joint Venture Agreement, and the inability of Athabasca 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 Athabasca's financial condition, results of operations and prospects.

Additional Funding Requirements

The Company's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times and from time to time, the Company may require additional financing in order to carry out its 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, the Company's access to additional financing may be affected.

Because of global economic volatility, the Company may from time to time have restricted access to capital and increased borrowing costs. Failure to obtain such financing on a timely basis could cause the Company to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Company's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect the Company's ability to expend the necessary capital to replace its reserves or to maintain its production. To the extent that external sources of capital become limited, unavailable or available on onerous terms, the Company's ability to make capital investments and maintain existing assets may be impaired, and its assets, liabilities, business, financial condition and results of operations may be affected materially and adversely as a result. In addition, the future development of the Company's 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 the Company's capital expenditure plans may result in a delay in development or production on the Company's properties.

Exercise of Dover Put/Call Option

The Company entered into the Put/Call Option Agreement providing for the Put/Call Options. The Company may exercise its right to require Phoenix to purchase or Phoenix may exercise the right to acquire, as the case may be, Athabasca's remaining 40% working interest in the Dover assets by acquiring the assets or shares of AOC (Dover) (or a wholly-owned subsidiary thereof), for aggregate cash consideration of $1.32 billion, subject to the terms and conditions contained in the Put/Call Option Agreement. See "General Development of the Business – Recent Significant Transactions – The PetroChina Transaction – The Put/Call Options".

Athabasca expects to exercise the Dover Put Option upon the receipt of the outstanding component of the Dover Oil Sands Project Approval, which is the approval of Alberta Environment. Failure to meet the conditions to the exercise of the Dover Put Option, including failure to receive the approval of Alberta Environment when anticipated or at all will prevent or delay Athabasca's ability to realize the benefits of the Dover Put Option, including the potential receipt of gross proceeds of up to $1.32 billion, subject to the terms and conditions contained in the Put/Call Option Agreement. See "General Development of the Business – Recent Significant Transactions – The PetroChina Transaction – The Put/Call Options". There are a number of factors that could delay or prevent the approval of Alberta Environment from being received, including factors outside of Athabasca's control such as Athabasca's inability to obtain any necessary information from (or otherwise receive the cooperation of) PetroChina International and/or Phoenix in relation to the receipt of such approvals, actions taken by third party stakeholders that have the effect of delaying or preventing the receipt of such approvals, or changes in federal or provincial laws and regulations that have the effect of delaying or preventing the receipt of such approvals. If a delay or failure to receive the necessary approval results in Athabasca failing to realize the potential benefits of the exercise of the Dover Put Option, such event could have a material adverse effect on Athabasca's business, financial condition, results of operations and prospects, and could negatively impact the market price of the Common Shares.

The decision of Phoenix to exercise its Dover Call Option is entirely at Phoenix's discretion when such option becomes exercisable. If the prospects for Dover Oil Sands Projects are particularly promising at the time the option become exercisable, Phoenix may elect to exercise the option and take advantage of the expected growth available from that project. If Phoenix exercises its call option with respect to the Dover Oil Sands Project, the Company will receive a one-time cash payment in respect of such option but will not be entitled to participate in any future growth or development of the project.

Athabasca may not have an immediate use for some or all of the cash proceeds received by it in connection with the exercise of the Dover Put Option or Dover Call Option, in which case Athabasca may be required to invest such cash proceeds in low return investments until an alternative investment opportunity is identified. Accordingly, it is possible that any future growth and development of Athabasca will not be derived from the Dover Oil Sands Projects. The foregoing factors could have a material adverse effect on Athabasca's business, financial condition, results of operations and prospects, and could negatively impact the market price of the Common Shares.

Effect of Default Under the PetroChina Transaction Agreements

If the Company becomes a Defaulting Participant under the Umbrella Agreement, then in addition to customary and industry standard remedies, the Company's interest in the Dover Joint Venture may, at the option of Phoenix, be acquired at a material discount. Any such event could have a material adverse effect on Athabasca's financial condition and results of operations and the market price of the Common shares. See "General Development of the Business – Recent Significant Transactions – The PetroChina Transaction" for details.

Counterparty Risks

Athabasca has entered into (or may in the future from time to time enter into) contractual relationships with various counterparties, including without limitation: PetroChina International and Phoenix in connection with the PetroChina Transaction Agreements; other joint venture participants; the issuers of securities in which Athabasca has or will invest cash balances from time to time; and counterparties to risk management contracts, marketing arrangements (including long term agreements for the supply of crude oil, natural gas, diluent and bitumen blend),

operating agreements, and with other suppliers of products and services. Athabasca is subject to the risk that such counterparties may default on their obligations under such agreements or arrangements, including as a result of liquidity requirements or insolvency. A failure by such counterparties to make payments or perform their operational or other obligations to Athabasca in compliance with the terms of such contractual arrangements could have a material adverse effect on Athabasca's business, financial condition, liquidity and results of operations.

Claims Made by Aboriginal Peoples

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 Athabasca's properties, which in turn could have a material adverse effect on Athabasca's business, financial condition, results of operations and prospects.

Fluctuations in Market Prices of Bitumen Blend, Crude Oil and Natural Gas

Athabasca's results of operations and financial condition will be dependent upon, among other things, the prices that it receives for the bitumen, bitumen blend, other bitumen products, crude oil or natural gas that it sells, and the prices that it receives for such products will be closely correlated to the price of crude oil. Historically, crude oil markets have been volatile and are likely to continue to be volatile in the future. Crude oil and natural gas prices have fluctuated widely during recent years and are subject to fluctuations in response to relatively minor changes in supply, demand, market uncertainty and other factors that are beyond Athabasca's control. These factors include, but are not limited to: global energy policy, including the ability of the Organization of the Petroleum Exporting Countries to set and maintain production levels and influence prices for crude oil; political instability and hostilities and the risk of hostilities; domestic and foreign supplies of crude oil; weather conditions; the overall level of energy demand; government regulations and taxes; currency exchange rates; the availability of transportation infrastructure; the effect of worldwide environmental and/or energy conservation measures; the price and availability of alternative energy supplies; and the overall economic environment.

Any prolonged period of low crude oil and/or natural gas prices could result in a decision by Athabasca or the Dover Joint Venture (as applicable) 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 Athabasca's results of operations and financial condition.

There is no generally recognized approach to determine the constant price for bitumen because the bitumen market is not yet mature and there are no published reference prices for bitumen. To price bitumen, marketers apply formulas that take as a reference point the prices published for crude oil of particular qualities such as Edmonton Light, Lloydminster Blend, or the more internationally known WTI. The price of bitumen fluctuates widely during the course of a year, with the lowest prices typically occurring at the end of the calendar year because of decreased seasonal demand for asphalt and other bitumen-derived products coupled with higher prices for diluents added to facilitate pipeline transportation of bitumen.

The market prices for heavy oil (which includes bitumen blends) are lower than the established market indices for light and medium grades of oil, due principally to diluent prices and the higher transportation and refining costs associated with heavy oil. Also, the market for heavy oil is more limited than for light and medium grades of oil, making it more susceptible to supply and demand fundamentals. Future price differentials are uncertain and any increase in the heavy oil differentials could have an adverse effect on Athabasca's results of operations and financial condition.

Athabasca conducts an assessment of the carrying value of its assets to the extent required by International Financial Reporting Standards. If crude oil prices decline, the carrying value of Athabasca's assets could be subject to downward revision, and Athabasca's earnings could be adversely affected.

General Economic Conditions, Business Environment and Other Risks

The business of Athabasca is subject to general economic conditions. Adverse changes in general economic and market conditions could negatively impact demand for crude oil, bitumen and bitumen blend, natural gas, 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, 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, Athabasca's ability to generate sufficient cash flow from operations to meet its current and future obligations, Athabasca's ability to access external sources of debt and equity capital, general economic and business conditions, Athabasca's 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 the Company and its subsidiaries, political and economic conditions in the geographic regions in which the Company and its subsidiaries operate, difficulty in obtaining necessary regulatory approvals, a significant decline in the Company's reputation, and such other risks and uncertainties, could individually or in the aggregate have a material adverse impact on Athabasca's 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 Athabasca's business, financial condition, liquidity and results of operations. There can be no assurance that any risk management steps taken by Athabasca with the objective of mitigating the foregoing risks will avoid future loss due to the occurrence of such risks.

Regulatory Approvals and Compliance

The construction, operation and decommissioning of Athabasca's oil sands and light oil projects are and will be conditional upon various environmental and regulatory approvals issued by governmental authorities, including but not limited to the approval of the AER. There is no assurance such approvals will be issued, or, once issued or renewed, that they will not contain terms and conditions which make such projects, uneconomic, or cause Athabasca to significantly alter such projects. Further, the construction, operation and decommissioning of Athabasca's projects will be subject to regulatory approvals and statutes and regulations relating to environmental protection and operational safety. Although Athabasca believes that its projects will be in general compliance with applicable environmental and safety regulatory approvals, statutes and regulations, risks of substantial costs and liabilities are inherent in its operations and there can be no assurance that substantial costs and liabilities will not be incurred or that its projects will be permitted to carry on operations. Moreover, it is possible that other developments, such as increasingly strict environmental and safety statutes, regulations and enforcement policies thereunder, and claims for damages to property or persons resulting from the operations of Athabasca's projects, could result in substantial costs and liabilities to Athabasca or delays to or abandonment of its projects.

Dependence on and Control by Joint Venture Participant

The Dover Joint Venture was formed on February 10, 2010. Dover JV Operator administers and manages the conduct of operations of the Dover Joint Venture.

The Dover Joint Venture Agreement provides for a Management Committee that is responsible for the overall management and direction of the operations and activities and has certain exclusive powers and authority to make decisions for the Participants concerning the Dover Oil Sands Project. In addition, Phoenix is entitled to nominate three directors and the Company is entitled to nominate two directors to the board of directors of Dover JV Operator. Except for matters requiring unanimous approval, Phoenix has a 60% voting majority on all matters to be decided by such Management Committees and boards of directors that require Majority Approval.

The Dover Joint Venture Agreement sets out certain matters requiring unanimous or other approvals of the Management Committee and boards of directors. As a result, the development, timing and other decisions relating to the Dover Oil Sands Project will depend on obtaining such approvals of the Management Committee or boards of directors. In instances where the approvals are not received or the Participants disagree, development of the Dover Oil Sands Project may be delayed or may not proceed at all. In addition, the development of the Dover Oil Sands Project will depend upon the financial strength and views of the Participants at the time such decisions are made.

Athabasca is also subject to the risk of default by Phoenix in meeting its funding commitments or other obligations to the Dover Oil Sands Project under the Dover Joint Venture. Such default by Phoenix may adversely affect the continuation of the Dover Oil Sands Project, which may adversely affect Athabasca. In addition, subject to certain conditions, Phoenix may sell its interest in Dover Joint Venture and the new participant may not have the resources or experience that Phoenix has.

For all of the reasons described above, Athabasca may fail to realize some or all of the anticipated benefits of the PetroChina Transaction, which could have a material adverse effect on Athabasca's financial condition, results of operations and prospects.

Development Schedules and Cost Over-Runs

Historically, oil sands projects have experienced capital cost over-runs due to a variety of factors. Prior to the onset of the global financial crisis in 2008, 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 Athabasca is defining its schedule for developing its oil sands, crude oil and natural gas resources (including obtaining regulatory approvals), and commencing and completing the construction of certain projects (including the 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 Athabasca's 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 Athabasca's future projects may have delays, interruption of operations or increased costs. Athabasca's ability to execute projects, and the performance of such projects, depends upon numerous factors beyond Athabasca's control, including:

- an inability to obtain adequate financing, or financing on terms satisfactory to Athabasca;
- 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 Athabasca's proprietary technology and/or that of Athabasca's 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 Athabasca's 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;
- currency fluctuations;
- changes in regulations; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, Athabasca could be unable to execute projects on time, on budget or at all or the projects may not perform to Athabasca's expectations or as required by regulatory approvals.

The cost to construct projects for the development of Athabasca's oil sands resources has not been fixed and remains dependent on many factors, some of which are beyond Athabasca's 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.

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 Athabasca's production revenues. Future Canadian/U.S. dollar exchange rates could accordingly affect the future value of Athabasca's resources as determined by independent evaluators.

Athabasca may in the future incur indebtedness at variable rates of interest that expose Athabasca to additional interest rate risk. If interest rates increase, Athabasca's debt service obligations on such variable rate indebtedness would increase even though the amount borrowed remains the same, and Athabasca's net income and cash flows would decrease. This could result in a reduced amount available to fund Athabasca's exploration and development activities, and could negatively impact the market price of the Common Shares. To the extent that Athabasca engages in risk management activities related to foreign exchange rates or interest rates, there is a credit risk associated with counterparties with whom Athabasca may contract.

Potential Profitability Depends Upon Factors Beyond the Control of Athabasca

The potential profitability of oil sands, petroleum and natural gas operations is dependent upon many factors beyond Athabasca's control. Profitability also depends on the costs of operations, including costs of labour, equipment, natural gas, diluent, electricity, environmental compliance or other production inputs. Such costs will fluctuate in ways Athabasca cannot predict and are beyond Athabasca's control, and such fluctuations will impact profitability and may eliminate profitability altogether. Additionally, due to worldwide economic uncertainty, the availability and cost of funds for development and other costs have become increasingly difficult, if not impossible, to project. These changes and events may materially affect the financial performance of Athabasca.

Future Acquisition and Joint Venture Activities May Have Adverse Effects

Athabasca may consider the acquisition of additional companies or assets in Athabasca's 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.

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, Athabasca's 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.

Reliance on, Competition for, Loss of, and Failure to Attract Key Personnel

The design, development and construction of, and commencement of operations at each of Athabasca's 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 Athabasca's projects and Athabasca's 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 the Dover JV Operator (in respect of the Dover Oil Sands Project) or by Athabasca (in respect of its other projects), 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 the Dover Oil Sands Project and Athabasca's other projects, and on the financial condition and performance of Athabasca. In addition, rising personnel costs would adversely impact the costs associated with the design, development and construction of, and commencement of operations at, the Dover Oil Sands Project and Athabasca's other projects, which could be significant and material.

Athabasca's 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. Athabasca does not have any key person insurance in effect. The contributions of the existing management team to Athabasca's 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 Athabasca will be able to continue to attract and retain all personnel necessary for the development and operation of its business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of management of Athabasca.

Global Financial Markets

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. While there are signs of economic recovery, these factors have negatively impacted company valuations and are likely to continue to impact the performance of the global economy going forward. Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and demand of these commodities due to the current state of the world economies, actions taken by the Organization of the Petroleum Exporting Countries and the ongoing global credit and liquidity concerns. This volatility may in the future affect the Company's ability to obtain equity or debt financing on acceptable terms.

Uncertainties Associated with Estimating Reserve and Resource Volumes

GLJ and D&M have completed geological evaluations of Athabasca's properties effective as of December 31, 2013. See "Independent Reserve and Resource Evaluations". There are numerous uncertainties inherent in estimating the

quantities of reserves and resources attributable to Athabasca's assets and the future cash flows attributed to such reserves and resources, including many factors beyond Athabasca's control, and no assurance can be given that the indicated level of reserves and resources will be realized. The reserves, resource and associated cash flow information set forth in this document are estimates only.

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 certain grades of bitumen. Moreover, short term factors relating to oil sands reserves and resources may impair the profitability of Athabasca's projects in any particular period.

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

Actual production revenues, taxes, development and operating expenditures and cash flows associated with Athabasca's 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 Athabasca intends 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 Athabasca's reserves since that date.

There is no certainty that any of Athabasca's assets will produce any portion of the volumes currently classified by the Independent Evaluators as "Proved Reserves", "Probable Reserves" or "Contingent Resources".

Status and Stage of Development

There is no assurance that any of Athabasca's oil sands properties will commence production, generate earnings, operate profitably or provide a return on investment in the future.

The Dover Oil Sands Project, the Hangingstone Projects, the Dover West Sands Projects, the Dover West Carbonates Projects and the Light Oil assets are all currently in the early stages of their development schedules, and all of Athabasca's other assets are currently in the early stages of exploration or development. There is a risk that one or all of the Dover Oil Sands Project, the Hangingstone Projects, the Dover West Sands Projects, the Dover West Carbonates Projects or any other proposed commercial development of Athabasca's assets, including in the

Light Oil assets, will not be completed on time or within the applicable capital cost estimates or at all. Additionally, there is a risk that one or all of the Dover Oil Sands Project, the Hangingstone Projects, the Dover West Sands Projects, the Dover West Carbonates Projects or any other proposed commercial development of Athabasca's 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 Dover Oil Sands Project, the Hangingstone Projects, the Dover West Sands Projects, the Dover West Carbonates Projects and of the Light Oil assets, various changes are likely to be made prior to completion. The commercial development application for the Dover Oil Sands Project was submitted on December 21, 2010. 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 and it is currently awaiting the approval of Alberta Environment to complete the Dover Oil Sands Project Approval.

The application for Athabasca's Hangingstone Project 1 was submitted on March 31, 2011 and regulatory approval was granted on October 4, 2012. The application for the Hangingstone Expansion was submitted on May 17, 2013. In October, 2011, Athabasca submitted an application for the TAGD Pilot and Demonstration Project and the approval of the AER was received on September 19, 2013 and the approval of Alberta Environment was received on December 17, 2013. An application was also submitted for Dover West Sands Project 1 in December of 2011. No commercial development applications for regulatory approval of the Dover West Carbonates Projects or any other commercial development of Athabasca's Thermal Oil assets (other than those described above) 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 Athabasca's various projects or to the scope of any of the projects.

As a result of the completion of the PetroChina Transaction and the formation of the Dover Joint Venture, the Dover Oil Sands Project is subject to a re-evaluation by the Participants. The Dover Oil Sands Project is also subject to revision as it continues through the later engineering stages and as specific enhancement opportunities are identified. Some changes to the Dover Oil Sands Project are virtually certain to occur and such changes may be material both in terms of design, timing and cost. Similar changes and revisions to the concepts for Hangingstone Project 1, the Hangingstone Expansion**,** Dover West Sands Project 1 and the Dover West Carbonates Projects, which may be material both in terms of design, timing and cost, are also virtually certain to occur.

In addition to the foregoing, there is also a risk that some or all of Athabasca's other assets may not be developed on a timely basis or at all. Numerous factors, many of which are beyond Athabasca's control, could impact Athabasca's ability to further explore and develop Athabasca's other assets and the timing thereof, including the risk factors set forth in this Annual Information Form.

Bitumen Recovery Processes

The recovery of bitumen using SAGD and TAGD processes is subject to uncertainty. TAGD is in its initial stages of testing and has not been used in a commercial project. The SAGD bitumen recovery process is relatively immature. There can be no assurance that Athabasca's operations will produce bitumen at the expected levels or on schedule. This is particularly true in respect of Athabasca's Dover West assets and Grosmont assets, because in those areas a significant quantity of Athabasca's bitumen resources are located in carbonate reservoirs, whereas in other areas Athabasca's bitumen resources are found in clastic reservoirs. All of the commercially viable SAGD recovery projects undertaken to date in Alberta have targeted clastic reservoirs.

SAGD, the in-situ bitumen recovery process considered by GLJ in respect of Athabasca's Dover West Carbonates and Grosmont assets, has not to date been applied successfully in an analogue to the subject reservoirs. TAGD, an

alternative process being considered by Athabasca, is an experimental technology. The commercial viability of SAGD technology has been demonstrated successfully for application to certain non-carbonate reservoirs. There are, however, no successful commercial projects that use SAGD or TAGD to recover bitumen from carbonates. The successful development of Athabasca's carbonate reservoirs depends on, among other things, the successful development and application of SAGD, TAGD or other recovery processes to the subject reservoirs. Presently, there exists a large range in the expected recoverable volumes, the lower end of which may not be economically viable. The principal risks associated with SAGD and/or TAGD recovery in carbonate reservoirs are: (a) the possibility of unexpected steam channeling which would increase steam requirements resulting in increased costs and potentially reduced economically recoverable bitumen volumes; (b) the ability to efficiently drain the matrix porosity; (c) potential mechanical operating problems due to production of fines which could cause wellbore plugging and reduced bitumen production rates and potential interruption of surface production operations; and (d) uncertainty as to whether the technologies may be economically applied on a commercial scale. Although the technical risks associated with SAGD have been accounted for in the GLJ Report, the timeline for verification of the viability of these technologies has inherent uncertainty. Development will involve significant capital expenditures and a lengthy time to project payout, and project payout is not assured. If a pilot and/or demonstration project do not demonstrate potential commerciality in the subject reservoirs or a good analogue, then Athabasca's projects on these assets may not proceed and this may occur only after significant expenditures have been incurred by Athabasca. With respect to Athabasca's Grosmont assets, Athabasca has not prepared a development plan or timeline for the area, and is monitoring industry activity toward demonstrating successful development and production methods for the Grosmont Formation. See "Description of Athabasca's Business – Thermal Oil Division – Grosmont assets" and "Independent Reserve and Resource Evaluations".

Therefore, Athabasca's ability to develop its bitumen resources that are located in carbonate reservoirs on a commercially viable scale is contingent upon one or more of the following events occurring: Athabasca using existing SAGD technology to successfully exploit carbonate reservoirs; Athabasca adapting existing SAGD technology such that it can be successfully used to exploit carbonate reservoirs; or, Athabasca developing or acquiring new technology, such as TAGD, that can be used to successfully exploit carbonate reservoirs. There can be no assurance that existing SAGD technologies will prove to be viable for the commercial exploitation of bitumen located in carbonate reservoirs, that existing SAGD technologies can be modified in such a manner as to be made to be viable for the commercial exploitation of bitumen located in carbonate reservoirs, or that new technologies, such as TAGD, will be developed or acquired by Athabasca that will be viable for the commercial exploitation of bitumen located in carbonate reservoirs. The development of such recovery processes will involve significant capital expenditures and a lengthy time to project payout, and project payout is not assured.

Current SAGD technology requires a significant amount of natural gas and other fuels in the production of steam that is used in the recovery process. The amount of steam required in the production process can also vary and affect costs. Athabasca has no operating history with respect to the average operating steam to oil ratio for its projects. Should the actual average operating steam to oil ratio in commercial operations be higher than Athabasca's estimates, it may result in some or all of the following: an increase in operating costs; lower bitumen production; or, the requirement for additional facilities. If one or more of these events occurs it is possible that the affected project could become uneconomic, which could have a material adverse effect on Athabasca's results of operations and financial condition.

In addition, should Athabasca encounter the existence of adverse reservoir conditions during the development of its oil sands or carbonates projects, ultimate bitumen recovery levels achieved by Athabasca utilizing the SAGD and/or TAGD recovery processes may be negatively affected. Such adverse reservoir conditions could include, but are not limited to, the following: regional poor quality geological features; depleted or partially depleted associated gas caps due to prior gas production; the existence of bottom or top water, inter-formation water, or other thief zones; or the absence of an overlying cap rock. TAGD technology also requires a significant amount of electricity to provide power to the downhole conduction heaters.

Any of these events could have a material adverse impact on the future operating activities conducted at, and the economic performance of, Athabasca's projects, which in turn could have a material adverse impact on Athabasca's results of operations and financial condition thereby adversely affecting the value and trading price of the Common Shares.

Hydraulic Fracturing

Hydraulic fracturing involves the injection of water, sand and small amounts of additives under pressure into rock formations to stimulate the production of oil and natural gas. Specifically, hydraulic fracturing enables the production of commercial quantities of oil and natural gas from reservoirs that were previously unproductive. Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to operational delays, increased operating costs or third party or governmental claims, and could increase Athabasca's 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 Athabasca is ultimately able to produce from its reserves.

Expiration of Leases, Licenses or Permits

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

Crude Oil and Natural Gas Exploration, Development and Production

Crude oil and natural gas exploration involves a high degree of risk and there is no assurance that expenditures made by Athabasca 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.

Gathering and Processing Facilities and Pipeline Systems

Athabasca currently delivers its products through gathering, and processing facilities and pipeline systems, some of which it does not own. To the extent that Athabasca relies on third-party infrastructure, the amount of oil and natural gas that Athabasca will be able to produce and sell will be subject to the accessibility, availability, proximity and capacity of gathering, and processing facilities and pipeline systems that are owned and operated by third parties. Although pipeline expansions are ongoing, the lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to produce and to market oil and natural gas production. In addition, the pro-rationing of capacity on inter-provincial pipeline systems also continues to affect the ability to export oil and natural gas. The lack of availability of capacity in any of the gathering, processing and pipeline systems, and in particular the processing facilities, could result in Athabasca's inability to realize the full economic potential of its production or in a reduction of the price offered for Athabasca's production. 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 and it is projected to continue in this upward trend. 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 Athabasca's business and, in turn, Athabasca's financial condition, results of operations and cash flows.

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. These recommendations include, among others, the imposition of higher standards for all DOT-111 tank cars carrying crude oil and the increased auditing of shippers to ensure they properly classify hazardous materials and have adequate safety plans in place. The increased regulation of rail transportation may reduce the ability of railway lines to alleviate pipeline capacity issues and add additional costs to the transportation of crude oil by rail.

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

Availability of Drilling Equipment and Access

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 Athabasca 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 Athabasca's 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 Athabasca's drilling operations. One or more of these events could have a material adverse effect on Athabasca's results of operations and financial condition.

Operating Costs

The operating costs of the projects undertaken by Athabasca 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 Athabasca's 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 affect on Athabasca's results of operations and financial condition.

Diluent, Natural Gas and Utility Supply and Costs

Extracting bitumen using SAGD or TAGD 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 steam-oil-ratio (or 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.

Athabasca's 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 Athabasca is unable to source a stable supply of natural gas and/or diluent at economic prices, one or more of Athabasca's projects may become uneconomic, which could have a material adverse effect on Athabasca's 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 Athabasca's overall operating cost, decreasing its net revenues and negatively impacting the overall profitability of its heavy oil and bitumen projects.

In the case of extracting bitumen using TAGD technology, a significant amount of electricity to provide power to the downhole conduction heaters would be required.

Gas Over Bitumen

Some of Athabasca's 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, Athabasca's 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 ERCB shut-in these, as well as other wells. There are also natural gas zones in several of Athabasca's 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 Athabasca's bitumen resources, there may be a loss of steam or steam chamber pressure during the SAGD bitumen extraction process, which could adversely affect Athabasca's 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 Athabasca's oil sands leases will not pose a risk to Athabasca's ability to recover the bitumen resources on these properties using SAGD technology, and such risk could have a material adverse effect on Athabasca's business, financial condition, liquidity and results of operations.

Environmental Considerations

The operations of Athabasca 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, Athabasca's competitive position within the oil sands and petroleum and natural gas industries may be adversely affected, as many industry players have greater resources than Athabasca.

No assurance can be given that future environmental approvals, laws or regulations will not adversely impact Athabasca's ability to develop and operate its oil sands or light oil projects or increase or maintain production or will not increase unit costs of production, or to realize other business opportunities from its 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 Athabasca 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. In addition, such legislation sets out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites. Compliance with environmental

legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require Athabasca to incur costs to remedy such discharge. Although Athabasca believes that it is in material compliance with current applicable environmental legislation no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on Athabasca's business, financial condition, results of operations and prospects.

Liability Management

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 becomes defunct. These programs generally involve an assessment of the ratio of a licensee's deemed assets to deemed liabilities. If a licensee's deemed liabilities exceed its deemed assets, a security deposit is required. Changes of the ratio of Athabasca's 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. See "Industry Conditions".

Climate Change

The Company's exploration and production facilities and other operations and activities emit GHGs which may require the Company to comply with GHG emissions legislation at the provincial or federal level. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place. As a signatory to the UNFCCC and as a participant to the Copenhagen Agreement (a non-binding agreement created by the UNFCCC), the Government of Canada announced on January 29, 2010 that it will seek a 17% reduction in GHG emissions from 2005 levels by 2020. These GHG emission reduction targets are not binding, however. Some of the Company's significant facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage GHG emissions. The direct or indirect costs of compliance with these regulations may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. Given the evolving nature of the debate related to climate change and the control of GHGs and resulting requirements, it is not possible to predict the impact on the Company and its operations and financial condition.

United States Climate Change Legislation

Environmental legislation regulating carbon fuel standards in jurisdictions that import crude and synthetic crude oil in the United States could result in increased costs and/or reduced revenue for oil sands companies such as Athabasca. 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.

Extent of, and Cost of Compliance with, Government Regulation

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 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 Athabasca's projects, delay or increase Athabasca's costs, either of which may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

In order to conduct oil and gas operations, Athabasca will require regulatory permits, licenses, registrations, approvals and authorizations from various governmental authorities. There can be no assurance that Athabasca will be able to obtain all of the permits, licenses, registrations, approvals and authorizations that may be required to conduct operations that it may wish to undertake. In addition to regulatory requirements pertaining to the production, marketing and sale of oil and natural gas mentioned above, the Company's 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).

Income Tax Matters

Income tax provisions, including current and future income tax assets and liabilities in Athabasca's 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 Athabasca's specific situation. In addition, there can be no assurance that the Canada Revenue Agency or a provincial or other tax agency will agree with Athabasca's tax filing positions or will not change its administrative practices to the detriment of Athabasca or its Shareholders and creditors. Athabasca's business and operations are complex and Athabasca has executed a number of significant financings, acquisitions, dispositions, reorganizations, joint ventures and business combinations over the course of its history. The computation of income taxes payable as a result of these transactions involves many complex factors as well as Athabasca's interpretation of and compliance with relevant tax legislation and regulations. While Athabasca believes that its tax filing positions are supportable under applicable law, a number of Athabasca's 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 Athabasca and the ultimate value of Athabasca's 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 Athabasca.

Impact of Royalty Regimes on Operating Cash Flow

Athabasca's revenue and expenses are and will continue to be, as its oil sands projects and Light Oil assets are developed and become operational, directly affected by the royalty regime applicable to such assets. The economic benefit of future capital expenditures for such projects is, in many cases, dependent on a satisfactory royalty regime. There can be no assurance that the Government of Canada or the Province of Alberta will not adopt new royalty regimes which will make capital expenditures uneconomic or that the regime currently in place will remain unchanged. An increase in royalties would reduce Athabasca's earnings and could make future capital expenditures or Athabasca's operations uneconomic and could, in the event of a material increase in royalties, make it more difficult to service and repay Athabasca's debt. Any material increase in royalties would also significantly reduce the value Athabasca's associated assets.

Geopolitical Risks

Political events throughout the world that cause disruptions in the supply of oil continuously affect the marketability and price of oil and natural gas acquired or discovered by the Company. 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 the Company's net production revenue. In addition, the Company's oil and natural gas properties, wells and facilities could be the subject of a terrorist

attack. If any of the Company's properties, wells or facilities are the subject of terrorist attack it may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. The Company does not have insurance to protect against the risk from terrorism.

Abandonment and Reclamation Costs

Estimates of Athabasca's 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 Athabasca or the operator of Athabasca's 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 Athabasca's projects.

Exploration, Development and Production Risks

Athabasca's 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, the Company may explore for and produce sour natural gas in certain areas. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to the Company. 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 Athabasca's business, financial condition, results of operations and prospects.

As is standard industry practice, Athabasca is not fully insured against all of these risks, nor are all such risks insurable. Although Athabasca maintains liability insurance in an amount that it considers consistent with industry practice, the liabilities associated with certain risks could exceed policy limits, in which event Athabasca 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. Athabasca's 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.

Management 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 Athabasca 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 Athabasca, which could have a material adverse effect on the financial condition, results of operations and cash flows of Athabasca.

Long Term Reliance on Third Parties

Athabasca will be obliged to enter into long term arrangements with third parties in order to construct and operate the Hangingstone Projects, the Dover West Sands Projects, the Dover West Carbonates Projects, and in respect of the Dover Oil Sands Project, and any other bitumen recovery, crude oil or natural gas development project that it 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. Athabasca 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 Athabasca will not be obliged to fund the creation of necessary resources, which could increase Athabasca's operating costs and thereby adversely affect Athabasca's results of operations and financial condition.

Reliance on Third Party Infrastructure

The projects that Athabasca 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 Athabasca's results of operations and financial condition.

Seasonality

The level of activity in the Canadian oilsands 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 Athabasca operates) 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 the goods and services of the Company.

Hedging Risks

The nature of Athabasca's operations will result in exposure to fluctuations in commodity prices. Athabasca may use financial instruments and physical delivery contracts to hedge its exposure to these risks. If Athabasca engages in hedging it 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, Athabasca could lose the cost of floors or a fixed price could limit Athabasca from receiving the full benefit of commodity price increases. If Athabasca enters into hedging arrangements, it may suffer financial loss if it is unable to commence operations on schedule, production falls short of the hedged volumes, 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 it unable to produce sufficient quantities of bitumen, crude oil or natural gas to fulfill its obligations.

Athabasca may also hedge its 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, Athabasca could lose the cost of ceilings or a fixed price could limit it from receiving the full benefit of commodity price decreases.

Internal Controls

Effective internal controls are necessary for Athabasca to provide reliable financial reports and to help prevent fraud. Although Athabasca undertakes a number of procedures in order to help ensure the reliability of its financial reports, including those imposed on it under Canadian securities laws, Athabasca cannot be certain that such measures will ensure that Athabasca 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 Athabasca's results of operations or cause it to fail to meet its reporting obligations. If Athabasca or its independent auditors discover a material weakness, the disclosure of that fact, even if quickly remedied, could reduce the market's confidence in Athabasca's consolidated financial statements and harm the trading price of the Common Shares.

Insurance Risks

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

Litigation Risks

In the normal course of Athabasca's operations, it 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, property damage, property taxes, land rights, the environment and contract disputes. The outcome with respect to outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to Athabasca and as a result, could have a material adverse effect on Athabasca's assets, liabilities, business, financial condition and results of operations. Even if Athabasca prevails in any such legal proceeding, the proceedings could be costly and time-consuming and would divert the attention of management and key personnel from Athabasca's business operations, which could adversely affect its financial condition.

Effect of Change of Control Under the PetroChina Transaction Agreements

Phoenix is entitled to its call right pursuant to the Dover Call Option for the shares of AOC (Dover) (or a wholly-owned subsidiary thereof) upon a change of control of any of the Company or AOC (Dover) (or a wholly-owned subsidiary thereof). This provision could deter third parties from either seeking to acquire the Company or seeking to elect a majority of directors of the Company who are not included in the slate of directors proposed by management of the Company, which could in turn have an adverse effect on the market price or trading volume of the Common Shares. See "General Development of the Business – Recent Significant Transactions – The PetroChina Transaction" for details.

Effect of Competition on Athabasca

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. Athabasca will compete with other bitumen producers, and competes with producers of crude oil, natural gas and SCO. Some of the conventional producers that Athabasca competes with have lower operating costs than Athabasca and many of them have greater resources then Athabasca. Certain of Athabasca's competitors may have greater resources to source, attract, and retain the personnel, materials and services that Athabasca will require to conduct its operations. The petroleum industry also competes with other industries in supplying energy, fuel and related products to consumers.

A number of companies other than Athabasca 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, Athabasca's results of operations and cash flow.

Title to Assets

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise. The actual interest of the Company in properties may, accordingly vary from the Company's records. If a title defect does exist, it is possible that the Company may lose all or a portion of the properties to which the title defect relates, which may have a material adverse effect on Athabasca's business, financial condition, results of operations and prospects. There may be valid challenges to title or legislative changes which affect Athabasca's title to the oil and natural gas properties Athabasca controls that could impair Athabasca's activities on them and result in a reduction of the revenue received by Athabasca.

Credit Facility Arrangements

The Company currently has the Amended Credit Facilities and the amount authorized thereunder is dependent on the borrowing base determined by its lenders. The Company is required to comply with covenants under the Amended Credit Facilities which may, in certain cases, include certain financial ratio tests, which from time to time either affect the availability, or price, of additional funding and in the event that the Company does not comply with these covenants, the Company's access to capital could be restricted or repayment could be required. Events beyond the Company's control may contribute to the failure of the Company to comply with such covenants. A failure to comply with covenants could result in the default under the Amended Credit Facilities, which could result in the Company being required to repay amounts owing thereunder. Even if the Company is able to obtain new financing, it may not be on commercially reasonable terms or terms that are acceptable to the Company. If the Company is unable to repay amounts owing under the Amended Credit Facilities, the lenders under the Amended Credit Facilities could proceed to foreclose or otherwise realize upon the collateral granted to them to secure the indebtedness. The acceleration of the Company's indebtedness under one agreement may permit acceleration of indebtedness under other agreements that contain cross default or cross-acceleration provisions. In addition, the Amended Credit Facilities may impose operating and financial restrictions on the Company that could include restrictions on, the payment of dividends, repurchase or making of other distributions with respect to the Company's securities, incurring of additional indebtedness, 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.

Breach of Confidentiality

While discussing potential business relationships or other transactions with third parties, the Company may disclose confidential information relating to the business, operations or affairs of the Company. Although confidentiality agreements are generally signed by third parties prior to the disclosure of confidential information, a breach could put the Company at competitive risk and may cause significant damage to its business. The harm to the Company's 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, the Company will be able to obtain equitable remedies, such as injunctive relief, from a court of competent jurisdiction in a timely

manner, if at all, in order to prevent or mitigate any damage to its business that such a breach of confidentiality may cause.

Forward-Looking Information May Prove Inaccurate

Shareholders and prospective investors are cautioned not to place undue reliance on the Company's 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".

Cost of New Technologies

The oil industry is characterized by rapid and significant technological advancements and introductions of new products and services utilizing new technologies. Other oil 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 Athabasca. There can be no assurance that Athabasca 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 Athabasca or implemented in the future may become obsolete. In such case, Athabasca's business, financial condition and results of operations could be affected adversely and materially. If Athabasca is unable to utilize the most advanced commercially available technology, its business, financial condition and results of operations could also be adversely affected in a material way.

Alternatives to and Changing Demand for Petroleum Products

Fuel 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 and other liquid hydrocarbons. Athabasca cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on Athabasca's business, financial condition, results of operations and cash flows.

Expansion into New Activities

The operations and expertise of the Company's management are currently focused primarily on oil and gas production, exploration and development in the Western Canada Sedimentary Basin. In the future the Company 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 the Company's exposure to one or more existing risk factors, which may in turn result in the Company's future operational and financial conditions being adversely affected.

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 the Company'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 the Company'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 the Company'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, the Company'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 the Company's Shareholders, subject to the rules of the TSX or such other stock exchange on which the Company's securities may be listed from time to time. The Company may make future acquisitions or enter into financings or other transactions involving the issuance of securities. In addition, pursuant to the Stock Option Plan and the RSU Plan, the Company may issue Stock Options and RSUs exercisable to acquire up to 10% of the number of Common Shares outstanding at any given time. If the Company issues any additional Common Shares, the percentage ownership of existing Shareholders will be reduced and diluted.

Dividend Policy

Other than the Special Dividend, the Company has never declared or paid any cash dividends on its Common Shares. 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, contractual restrictions and financing agreement covenants, including those contained in the Amended and Restated Credit Agreement and Note Indenture, and other factors that the Board may deem relevant. For a description of the restrictions that are contained in the Credit Agreement and Note Indenture that relate to the Company'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.

Risks Related to the Senior Secured Notes

The rights of the holders of Senior Secured Notes are subject to the terms of the Collateral Agent Agreement.

The rights of the holders of the Senior Secured Notes with respect to the collateral securing the Senior Secured Notes and the guarantees issued in connection therewith, are substantially limited by the terms of the Collateral Agent Agreement, even during an event of default. Under the Collateral Agent Agreement, at any time during the Standstill Period (as defined therein) and thereafter (if the holders of the obligations secured by the first-priority liens: (a) shall have commenced and be diligently pursuing the exercise of their rights or remedies with respect to all or any material portion of the applicable collateral in which they have been granted a security interest or (b) are stayed or otherwise precluded from pursuing such rights or remedies pursuant to applicable laws or insolvency

proceedings), any actions that may be taken with respect to or in respect of the collateral securing the Senior Secured Notes and the related guarantees, including the ability to cause the commencement of enforcement proceedings against the collateral and to control the conduct of such proceedings and the approval of amendments to, releases of the collateral from the lien of and waivers of past defaults under such documents relating to the collateral, will be at the direction of the holders of the obligations secured by the first-priority liens, and the holders of the Senior Secured Notes secured by second-priority liens may be adversely affected.

In addition, the Collateral Agent Agreement and the Note Indenture contain certain provisions benefiting lenders under the obligations secured by first-priority liens, including provisions requiring the Indenture Trustee not to object following the filing of insolvency proceedings to a number of important matters regarding the collateral securing the Senior Secured Notes and the obligations secured by first-priority liens. After such filing, the value of the collateral could materially deteriorate and holders of the Senior Secured Notes would be unable to raise an objection. In addition, the right of holders of obligations secured by priority liens to foreclose upon and sell such collateral upon the occurrence of an event of default also would be subject to limitations under applicable bankruptcy laws if the Company or any of its subsidiaries become subject to a bankruptcy proceeding.

During the Standstill Period, the holders of the Senior Secured Notes shall not be permitted to institute or commence, or join with any other person in instituting or commencing, any insolvency proceedings or take any steps or proceedings in connection therewith.

The value of the collateral securing the Senior Secured Notes and the related guarantees may not be sufficient to satisfy the Company's obligations under the Senior Secured Notes.

No appraisal of the value of the collateral securing the Senior Secured Notes and the related guarantees was undertaken in connection with the offering of the Senior Secured Notes and certain of Athabasca's assets were excluded from the collateral securing the Senior Secured Notes and the related guarantees. The fair market value of the applicable collateral is subject to fluctuations based on factors that include, among others, general economic conditions and similar factors including the price of bitumen, bitumen blend, other bitumen products, crude oil or natural gas. There can be no assurance that bitumen, bitumen blend, other bitumen products, crude oil or natural gas prices will increase in the future. If bitumen, bitumen blend, other bitumen products, crude oil or natural gas prices were to significantly decline, the value of the collateral securing the Senior Secured Notes may not be sufficient to repay all of the Company's indebtedness, including the Senior Secured Notes. The amount to be received upon a sale of the collateral would be dependent on numerous factors, including, but not limited to, the actual fair market value of the collateral at such time, the timing and the manner of the sale and the availability of buyers. By its nature, portions of the collateral may be illiquid and may have no readily ascertainable market value. In the event of a foreclosure, liquidation, bankruptcy or similar proceeding, the collateral may not be sold in a timely or orderly manner and the proceeds from any sale or liquidation of the collateral may not be sufficient to pay the Company's obligations pursuant to the Senior Secured Notes.

In addition, under the Note indenture, the Company may incur additional debt that will be secured by first-priority liens on the collateral securing the Senior Secured Notes and the related guarantees or by liens on assets that are not pledged to the holders of Senior Secured Notes, all of which would effectively rank senior to the Senior Secured Notes and the related guarantees to the extent of the value of the collateral. Moreover, any collateral securing the Senior Secured Notes and the related guarantees will be shared by additional indebtedness that may be secured on a second lien basis, including, but not limited to, any additional notes.

To the extent the collateral securing the Senior Secured Notes and the related guarantees is encumbered by pre-existing liens, liens permitted under the Note Indenture and other rights, including liens on excluded assets, such as those securing hedges, purchase money obligations and capital lease obligations granted to other parties (in addition to the holders of obligations secured by first-priority liens), those parties have or may exercise rights and remedies with respect to the collateral that could adversely affect the value of the collateral and the ability of the Collateral Agent, the Indenture Trustee or the holders of the Senior Secured Notes to realize or foreclose on the collateral. Consequently, liquidating the collateral may not result in proceeds in an amount sufficient to pay amounts due under the Senior Secured Notes after satisfying the obligations. If the proceeds of any sale of the collateral are not

sufficient to repay all amounts due on the Senior Secured Notes, the holders of the Senior Secured Notes (to the extent not repaid from the proceeds of the sale of the collateral) would have only an unsecured, unsubordinated claim against the Company's and the applicable guarantors' remaining assets. Additionally, pursuant to the Collateral Agent Agreement, under various circumstances the collateral securing the Senior Secured Notes and the related guarantees will be released automatically.

Structural Subordination

The Company's operations are primarily conducted by its subsidiaries. The Company must rely upon distributions, dividends and other payments from its subsidiaries to generate the funds necessary to pay the principal of and interest on the Senior Secured Notes. The ability of the Company's subsidiaries to pay distributions, dividends and other payments to the Company may be restricted by, among other things, the availability of cash flows from operations, applicable corporate and other laws and other agreements of Athabasca. In the event of a bankruptcy, liquidation or reorganization of the Company, the Senior Secured Notes will be subordinated to the indebtedness and other obligations owed to the creditors of the Company's subsidiaries, except to the extent that guarantees of the Senior Secured Notes are provided by such subsidiaries and are capable of being effectively enforced. Only the subsidiaries of the Company that are guarantors under the Note Indenture have provided guarantees pursuant to which holders of the Senior Secured Notes will be entitled to seek redress from such subsidiaries.

The Company may not be able to repurchase the Senior Secured Notes upon a Change of Control.

If the Company experiences a Change of Control (as defined in the Note Indenture), the Company may be required to make an offer to repurchase all of the outstanding Senior Secured Notes prior to their maturity at 101% of their principal amount, plus accrued and unpaid interest, if any, to, but not including, the purchase date. Additionally, under the Amended Credit Facilities, a change of control (as defined in the Amended and Restated Credit Agreement) is expected to constitute an event of default that would permit the lenders to accelerate the maturity of borrowings under such facilities and terminate their commitments to lend. The source of funds for any repurchase of the Senior Secured Notes and repayment of any borrowings under the Amended Credit Facilities would be the Company's available cash or cash generated from its subsidiaries' operations or other sources, including borrowings, sales of assets or sales of equity. The Company 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 Senior Secured Notes and repay any of the Company's other indebtedness that may also become due. As a result, the Company 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, the Company's ability to repurchase the Senior Secured Notes may also be limited by law.

Holders of the Senior Secured Notes may not be able to determine when a Change of Control giving rise to their right to have the Senior Secured Notes repurchased has occurred following a sale of "substantially all" of the Company's assets.

The definition of Change of Control in the Note Indenture includes a phrase relating to the sale of "all or substantially all" of the Company's assets. There is no precise established definition of the phrase "substantially all" under applicable law. Accordingly, the ability of a holder of Senior Secured Notes to require the Company to repurchase its Senior Secured Notes as a result of a sale of less than all the Company's assets to another person may be uncertain.

Guarantor Release

A guarantor under the Note Indenture will be automatically released from its guarantee upon the occurrence of certain events, including the following:

- in connection with any sale of all of the Capital Stock (as defined in the Note Indenture) of such guarantor to a person that is not (either before or after giving effect to such transaction) a subsidiary of the Company, if the sale is permitted under the Note Indenture;

- if the Company designates such guarantor as an unrestricted subsidiary in accordance with the applicable provisions of the Note Indenture; or
- upon the release or discharge of the guarantee of such guarantor in respect of, or direct obligation of such guarantor as a borrower under, the Amended Credit Facilities and certain other debt or upon the release or discharge of the other guarantee or other indebtedness which resulted in the creation of such guarantee, except a discharge or release by or as a result of payment under such guarantee or direct obligation or a full and complete discharge of the Amended Credit Facilities.

If any such guarantee is released, no holder of Senior Secured Notes will have a claim as a creditor against any such former guarantor and the indebtedness and other liabilities, including trade payables and preferred stock, if any, whether secured or unsecured, of such former guarantor will be effectively senior to the claim of any holders of the Senior Secured Notes.

Credit ratings may not reflect all risks of an investment in the Senior Secured Notes and may change.

Credit ratings may not reflect all risks associated with an investment in the Senior Secured Notes. Any credit ratings applied to the Senior Secured Notes are an assessment of the Company's ability to pay its obligations. Consequently, real or anticipated changes in the credit ratings will generally affect the market value of the Senior Secured Notes. The credit ratings, however, may not reflect the potential impact on the value of the Senior Secured Notes of risks related to structure, market or other factors that are described under the heading "Risk Factors" herein. The Company is under no obligation to maintain any credit rating with credit rating agencies and there is no assurance that any credit rating assigned to the Senior Secured Notes will remain in effect for any given period of time or that any rating will not be lowered or withdrawn entirely by the relevant rating agency. A lowering, withdrawal or failure to maintain any credit ratings applied to the Senior Secured Notes may have an adverse effect on the market price or value and the liquidity of the Senior Secured Notes.

A lowering or withdrawal of the ratings assigned to the Company's debt securities by rating agencies may increase the Company's future borrowing costs and reduce its access to capital.

Credit ratings could be lowered or withdrawn entirely by a rating agency if, in that rating agency's judgment, future circumstances relating to the basis of the rating, such as adverse changes, so warrant. Consequently, real or anticipated changes in the Company's credit ratings will generally affect the market value of the Senior Secured Notes. Credit ratings are not recommendations to purchase, hold or sell the Senior Secured Notes. Additionally, credit ratings may not reflect the potential effect of risks relating to the structure or marketing of the Senior Secured Notes.

Any future lowering of the Company's ratings likely would make it more difficult or more expensive to obtain additional debt financing. If any credit rating initially assigned to the Senior Secured Notes is subsequently lowered or withdrawn for any reason, holders may not be able to resell their Senior Secured Notes without a substantial discount.

Certain bankruptcy and insolvency laws may impair the Indenture Trustee's and the Collateral Agent's ability to receive payment and enforce remedies under the Senior Secured Notes.

The rights of the Indenture Trustee and the Collateral Agent to enforce remedies may be significantly impaired by the provisions of applicable Canadian bankruptcy, insolvency, and other restructuring legislation if the benefit of such legislation is sought with respect to the Company or the guarantors of the Senior Secured Notes. For example, both the BIA and the CCAA contain provisions enabling an "insolvent person" to obtain a stay of proceedings against its creditors and others and to prepare and file a proposal or plan for consideration by all or some of its creditors to be voted on by the various classes of its creditors. Such a proposal or plan, if accepted by the requisite majorities of creditors and approved by the court, may be binding on all creditors within each affected class, such as holders of the Senior Secured Notes, including those creditors who did not vote to accept the proposal. Moreover, this legislation permits, in certain circumstances, an insolvent debtor to retain possession and administration of its property, even though it may be in default under the applicable debt instrument.

The powers of the court under the BIA and particularly under the CCAA have been exercised broadly to protect a restructuring entity from actions taken by creditors and other parties. Accordingly, if the Company or the applicable guarantors were to become subject to proceedings pursuant to such Canadian bankruptcy or insolvency legislation, following commencement of or during such a proceeding, payments under the Senior Secured Notes may be stayed or discontinued, the Indenture Trustee and the Collateral Agent may be unable to exercise their rights under the Note Indenture (including in relation to collateral securing the Senior Secured Notes) and holders of the Senior Secured Notes may not be compensated for any delays in payments, if any, of principal and interest.

The ability of the Collateral Agent to realize upon the collateral securing the Senior Secured Notes will be subject to certain bankruptcy and insolvency law limitations if the Company or the guarantors were to file for protection under (or otherwise become subject to) a bankruptcy or restructuring statute.

Under the CCAA, secured creditors may be stayed or prevented from repossessing their security from a debtor company in a CCAA proceeding without approval from the court supervising the proceeding, and may be prevented from disposing of security repossessed from such debtor without court approval. In CCAA proceedings, the debtor may continue to retain collateral, including cash collateral, even though the debtor is in default under applicable debt instruments.

Under Canadian bankruptcy and insolvency statutes, a court may grant an order authorizing interim financing which ranks in priority to the claim of any other secured creditor of the debtor. In such a circumstance, the court must consider a number of factors, including whether any creditor may be materially prejudiced. The court may provide protections in the face of material prejudice. However, this power is discretionary, and the Company cannot predict when, or whether, the Collateral Agent could realize upon the collateral or whether, or to what extent, holders of the Senior Secured Notes would be compensated for any delay in payment or loss of value of the collateral.

Applicable statutes allow courts, under specific circumstances, to void the guarantees of certain of the guarantors of the Senior Secured Notes.

The Company's creditors or the creditors of one or more guarantors could challenge the guarantees of the Senior Secured Notes as a fraudulent transfer, conveyance or preference or on other grounds under applicable Canadian federal or provincial law. While the relevant laws vary from one jurisdiction to another, the entering into of the guarantees of the Senior Secured Notes by certain guarantors could be found to be a fraudulent transfer, conveyance or preference or otherwise void if a court were to determine that:

- the guarantor delivered its guarantee with the intent to defeat, hinder, delay or defraud its existing or further creditors;
- the guarantor did not receive fair consideration for the delivery of the guarantee; or
- the guarantor was insolvent at the time it delivered the guarantee.

To the extent a court voids a guarantee of the Senior Secured Notes as a fraudulent transfer, preference or conveyance or holds it unenforceable for any other reason, holders of Senior Secured Notes would cease to have any direct claim against the applicable guarantor. If a court were to take this action, the guarantor's assets would be applied first to satisfy the guarantor's liabilities, including trade payables and preferred stock claims, if any, before any portion of its assets could be distributed to the Company to be applied to the payment of the Senior Secured Notes. If a court were to conclude that a guarantee should be subordinated for equitable reasons to claims of other creditors of a guarantor, then those other creditors must be satisfied before any portion of the assets of that guarantor would be available to satisfy the guarantee. If that were to occur, the guarantor's remaining assets may not be sufficient to satisfy the claims of the holders of the Senior Secured Notes relating to any voided portions or subordinated portions of the relevant guarantee of the Senior Secured Notes.

In addition, the corporate or partnership statutes or other instruments governing the applicable guarantors may also have provisions that serve to protect each guarantor's creditors from impairment of its capital from financial assistance given to its insiders where there are reasonable grounds to believe that, as a consequence of this financial assistance, the guarantor would be insolvent or the book value, or in some cases the realizable value, of its assets

would be less than the sum of its liabilities and its issued and paid-up capital. While the applicable corporate or partnership laws may not prohibit financial assistance transactions and a guarantor is generally permitted flexibility in its financial dealings, the applicable corporate or partnership laws may place restrictions on each guarantor's ability to give financial assistance in certain circumstances. A court may also, in certain circumstances, hold that the guarantees should be subordinated for equitable reasons to claims of other creditors of a guarantor.

The Company's indebtedness could adversely affect its financial condition and prevent the Company from fulfilling its obligations under the Senior Secured Notes.

Following the offering of the Senior Secured Notes, the Company has a significant amount of indebtedness. The Note Indenture and Amended and Restated Credit Agreement contain restrictive covenants that may limit the Company's ability to engage in activities that may be in its long-term best interest. The Company's failure to comply with those covenants could result in an event of default which, if not cured or waived, could result in the acceleration of all the Company's debt.

Despite the Company's current level of indebtedness, the Company and its subsidiaries may still be able to incur substantially more debt. This could further exacerbate the risks to the Company's financial condition described above.

The Company and its subsidiaries may be able to incur significant additional indebtedness in the future, including availability for additional borrowings of $350 million under the Amended Credit Facilities.

Although the Note Indenture and the Amended Credit Facilities contain restrictions on the incurrence of additional indebtedness, these restrictions are subject to a number of qualifications and exceptions, and the additional indebtedness incurred in compliance with these restrictions could be substantial. If the Company incurs any additional indebtedness that ranks equally with the Senior Secured Notes, subject to collateral arrangements, the holders of that debt will be entitled to share rateably with holders of the Senior Secured Notes in any proceeds distributed in connection with any insolvency, liquidation, reorganization, dissolution or other winding up of the Company. This may have the effect of reducing the amount of proceeds paid to holders of the Senior Secured Notes. These restrictions also will not prevent the Company from incurring obligations that do not constitute indebtedness.

In addition, if the Company were to incur substantial additional indebtedness, the risks related to the Company's level of indebtedness could intensify. Specifically, a high level of indebtedness could have important consequences to the holders of the Senior Secured Notes, including:

- making it more difficult for the Company to satisfy its obligations with respect to the Senior Secured Notes and its other debt;
- limiting the Company's ability to obtain additional financing to fund future working capital, capital expenditures, acquisitions or other general corporate requirements, or requiring the Company to make non-strategic divestitures;
- requiring a substantial portion of the Company's cash flows to be dedicated to debt service payments instead of other purposes, thereby reducing the amount of cash flow available for working capital, capital expenditures, acquisitions and other general corporate purposes;
- increasing the Company's vulnerability to general adverse economic and industry conditions;
- exposing the Company to the risk of increased interest rates as borrowings under its Amended Credit Facilities are expected to be at variable rates of interest;
- limiting the Company's flexibility in planning for and reacting to changes in the industry in which it competes;
- placing the Company at a disadvantage compared to other, less leveraged competitors who may be able to take advantage of opportunities that the Company's indebtedness would prevent it from doing; and
- increasing the Company's cost of borrowing.

The Company may not be able to generate sufficient cash to service all of its indebtedness, including the Senior Secured Notes, and may be forced to take other actions to satisfy its obligations under its indebtedness, which may not be successful.

The Company's ability to make scheduled payments on or refinance its debt obligations, including the Senior Secured Notes, depends on its financial condition and operating performance, which are subject to prevailing economic and competitive conditions and to certain financial, business, legislative, regulatory and other factors beyond the Company's control. The Company may be unable to maintain a level of cash flows from operating activities sufficient to permit the Company to pay the principal, premium, if any, and interest on its indebtedness, including the Senior Secured Notes.

If the Company's cash flows and capital resources are insufficient to fund its debt service obligations, the Company could face substantial liquidity problems and could be forced to reduce or delay investments and capital expenditures or to dispose of material assets or operations, seek additional debt or equity capital or restructure or refinance its indebtedness, including the Senior Secured Notes. The Company may not be able to effect any such alternative measures, if necessary, on commercially reasonable terms or at all and, even if successful, those alternative actions may not allow the Company to meet its scheduled debt service obligations.

The Company's inability to generate sufficient cash flows to satisfy its debt obligations, or to refinance its indebtedness on commercially reasonable terms or at all, would materially and adversely affect the Company's financial position and results of operations and the Company's ability to satisfy its obligations under the Senior Secured Notes.

If the Company cannot make scheduled payments on its debt, the Company will be in default and holders of the Senior Secured Notes could declare all outstanding principal and interest to be due and payable and the Company could be forced into bankruptcy or liquidation. All of these events could result in purchasers losing their investment in the Senior Secured Notes.

The terms of the Note Indenture restrict the Company's current and future operations, particularly its ability to respond to changes or to take certain actions.

The Note Indenture contains a number of restrictive covenants that impose significant operating and financial restrictions on the Company and may limit the Company's ability to engage in acts that may be in its long-term best interest, including restrictions on the Company's ability to:

- incur additional indebtedness and guarantee indebtedness;
- pay dividends or make other distributions or repurchase or redeem shares;
- prepay certain debt;
- issue certain preferred shares or similar equity securities;
- make loans and investments;
- sell, transfer or otherwise dispose of assets;
- incur or permit to exist certain liens;
- enter into transactions with affiliates;
- enter into agreements restricting the Company's subsidiaries' ability to pay dividends or make other distributions; and
- consolidate, amalgamate, merge or sell all or substantially all of the Company's assets.

As a result of these restrictions, the Company may be:

- limited in how it conducts its business;
- unable to raise additional debt or equity financing to operate during general economic or business downturns; or
- unable to compete effectively or to take advantage of new business opportunities.

Additionally, a breach of the covenants or restrictions under the Note Indenture could result in an event of default thereunder and under the instruments related to Company's other indebtedness, including the Amended Credit Facilities. Such an event of default or cross-default may allow the relevant creditors to accelerate the related debt (including terminating any outstanding hedging arrangements).

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 "C".

Composition of the Audit Committee and Relevant Education and Experience

The Audit Committee currently consists of Messrs. McRae (chair), Buchanan and Dundas. Each of the members of the Audit Committee is considered "independent" and "financially literate" within the meaning of NI 52-110.

Mr. McRae is the Interim Executive Vice President and Chief Financial Officer of Black Diamond Group Limited. Prior thereto, Mr. McRae was 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 (a publicly traded energy and environmental services trust listed on the TSX) and its successor corporation, CCS Corporation (a private energy and environmental services company) from August 2002 until August 2009. Mr. McRae is also a director and chairman of the Audit Committee of Gibson Energy Inc. Mr. McRae has over 25 years of experience in senior operating and financial management positions with a number of publicly traded and private companies, including Versacold Corporation and Mark's Work Wearhouse Limited. 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. Buchanan is the Chief Executive Officer and a Director of Spyglass Resources Corp. Prior thereto, Mr. Buchanan was the Chairman and Chief Executive Officer of Charger Energy Corp. from September 2010 until March 28, 2013. Prior thereto, Mr. Buchanan was the President and Chief Executive Officer of Provident Energy Ltd., the administrator of Provident Energy Trust, a diversified energy income trust with investments in upstream oil and gas production and natural gas liquids midstream services from March 2001 to April 2010. Mr. Buchanan also is currently a Director of Pembina Pipeline Corporation. In 1993, Mr. Buchanan established Founders Energy Ltd., a junior oil and gas company listed on the TSX that was subsequently converted into Provident Energy Trust in 2001. Mr. Buchanan held a number of positions with Founders Energy Ltd., including Executive Vice President, Corporate Development, Chief Financial Officer, President and Chief Executive Officer. Mr. Buchanan obtained a Bachelor of Commerce degree from the University of Calgary in 1979 and a Chartered Accountant designation from the Institute of Chartered Accountants of Alberta in 1982. Mr. Buchanan was elected as a Fellow of the Chartered Accountants in 2010.

Mr. Dundas is an independent businessman. Mr. Dundas was the Vice President, Finance and Chief Financial Officer of AvenEx Energy Corp., the entity resulting from the reorganization of Avenir Diversified Income Trust into a corporate structure, from January 1, 2011 until March 28, 2013. Prior thereto, Mr. Dundas was Vice President, Finance and Chief Financial Officer of Avenir Operating Corp., the administrator of Avenir Diversified Income Trust, from January 2003 until January 1, 2011. Before joining Avenir Operating Corp., Mr. Dundas held a number of positions at Maxx Petroleum Ltd. (a publicly traded junior exploration and production company listed on the TSX) from 1994 to 2001, including Vice-President, Finance and Chief Financial Officer. Mr. Dundas obtained a Bachelor of Commerce degree from the University of Calgary in 1976, a Certified Management Accountant designation from the Society of Management Accountants of Alberta in 1983, and a Masters in Business Administration degree from the University of Calgary in 1991.

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, 2013 ($)	Fees Paid to Auditor in Year Ended December 31, 2012 ($)
Audit Fees[1]	422,370	369,510
Audit-Related Fees[2]	3,150	81,250
Tax Fees[3]	262,475	405,976
All Other Fees[4]	3,200	3,200
Total	691,195	859,936

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, 2012 and December 31, 2013, represent the subscription fees for a tax research tool.

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, 2013, which may be found on SEDAR at www.sedar.com.

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

REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

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, which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2013, estimated using forecast prices and costs.

Independent qualified reserves evaluators have evaluated the Company's reserves data. The reports of the independent qualified reserves evaluators are presented below.

The Reserves and Health, Safety and Environmental 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 with management and the independent qualified reserves evaluators.

The Reserves and Health, Safety and Environmental 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 and Health, Safety and Environmental Committee, approved:

(a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information;

(b) the filing of the reports of the independent qualified reserves evaluators on the reserves data and resources data; and

(c) the content and filing of this report.

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

(signed) "*Sveinung Svarte*"
President and Chief Executive Officer

(signed) "*Rob Broen*"
Chief Operating Officer

(signed) "*Ronald J. Eckhardt*"
Director

(signed) "*Gary Dundas"*
Director

Dated March 18, 2014

SCHEDULE "B"
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 51-102F2
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, 2013. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2013, estimated using forecast prices and costs.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

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

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions in the COGE Handbook.

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2013, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator	Description and Preparation 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	Corporate Summary January 31, 2014	Canada	—	1,040,295	—	**1,040,295**

5. In our opinion, the reserves 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 reserves that we reviewed but did not audit or evaluate.

6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

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

EXECUTED as to our report referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, February 7, 2014.

"ORIGINALLY SIGNED BY"

Todd J. Ikeda, P. Eng.
Vice-President

REPORT ON 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 resources data as at December 31, 2013. The resources data are estimates of low, best and high estimates of contingent resources and related future net revenue as at December 31, 2013, estimated using forecast prices and costs.

2. The resources data are the responsibility of the Company's management. Our responsibility is to express an opinion on the resources data based on our evaluation.

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

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the resources data are free of material misstatement. An evaluation also includes assessing whether the resources data are in accordance with principles and definitions in the COGE Handbook.

4. The following table sets forth the estimated future net revenue of the Company (before deduction of income taxes) attributed to best estimate contingent resources estimated using forecast prices and costs and calculated using a discount rate of 10%, evaluated by us for the year ended December 31, 2013, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's board of directors:

Independent Qualified Resource Evaluator	Description and Preparation Date of Evaluation Report	Location of Resources (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate - MM$)			
			Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants	Corporate Summary January 31, 2014	Canada	—	15,102	—	**15,102**

5. In our opinion, the 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 resources that we reviewed but did not audit or evaluate.

6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

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

8. Contingent resources evaluated in this report were assigned in regions with lower core-hole drilling density than the reserve regions and are outside current areas of application for development. These resource estimates are not classified as reserves at this time, pending further reservoir delineation, project application, facility and reservoir design work. Contingent resources entail commercial risk not applicable to reserves, which have not been included in the net present valuation. There is no certainty that it will be commercially viable to produce any portion of the contingent resources.

EXECUTED as to our report referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, February 7, 2014.

"ORIGINALLY SIGNED BY"

Todd J. Ikeda, P. Eng.
Vice-President

NATIONAL INSTRUMENT FORM 51-102F2

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, 2013. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2013, estimated using forecast prices and costs.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

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

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions in the COGE Handbook.

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2013, and identifies the respective portions thereof that we have evaluated and reported on to the Company's management:

Independent Qualified Reserves Evaluator	Description & Preparation Date of Evaluation Report	Location of Reserves	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate)			
			Audited MM$	Evaluated MM$	Reviewed MM$	Total MM$
DeGolyer and MacNaughton Canada Limited	Appraisal Report as of December 31, 2013 on the Hangingstone Property owned by Athabasca Oil Corporation in Alberta, Canada dated January 31, 2013	Canada	-	1,057	-	1,057

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

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

Executed as to our report referred to above:

DeGolyer and MacNaughton Canada Limited, Calgary, Alberta, dated January 31, 2014.

DEGOLYER and MACNAUGHTON CANADA LIMITED

"ORIGINALLY SIGNED BY'

Douglas S. Christie, P.Geol.

REPORT ON RESOURCES DATA
BY
INDEPENDENT QUALIFIED RESERVES EVALUATOR
CONTINGENT RESOURCES
NET PRESENT VALUE OF FUTURE NET REVENUE

To the board of directors of Athabasca Oil Corporation (the "**Company**"):

1. We have prepared an evaluation of the Company's resources data as at December 31, 2013. The resources data are estimates of Low, Best and High estimates of contingent resources and related future net revenue, estimated using forecast prices and costs.

2. The resources data are the responsibility of the Company's management. Our responsibility is to express an opinion on the resources data based on our evaluation.

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

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the resources data are free of material misstatement. An evaluation also includes assessing whether the resources data are in accordance with principles and definitions in the COGE Handbook.

4. The following table sets forth the estimated net present value of future net revenue of the Company (before and after deduction of income taxes) attributed to low, best and high estimates of contingent resources, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, evaluated by us for the year ended December 31, 2013, and identifies the respective portions thereof that we have evaluated and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator	Description & Preparation Date of Evaluation Report	Location of Resources	Estimated Company Share Net Present Value of Future Net Revenue of Contingent Resources[1] Before income tax, 10% discount rate		
			Low Estimate MM$	Best Estimate MM$	High Estimate MM$
DeGolyer and MacNaughton Canada Limited	Report as of December 31, 2013 on the Contingent Resources attributable to Certain Bitumen Accumulations for Athabasca Oil Corporation in Alberta, Canada dated February 3, 2014	Canada	4,518	6,269	6,170
			After income tax, 10% discount rate		
			Low Estimate MM$	Best Estimate MM$	High Estimate MM$
			1,981	3,077	2,977

Notes:
1. Estimated Company Share Net Present Value Future Net Revenue of Contingent Resources include the Company's Participating Interest in the Birch and Hangingstone areas after deduction of royalties payable to others.

5. In our opinion, the 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 resources data that we reviewed but did not audit or evaluate.

6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

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

8. Contingent resources evaluated in this report were assigned in regions with lower core-hole drilling density than the reserve regions and are outside current areas of application for development. These resource estimates are not classified as reserves at this time, pending further reservoir delineation, project application, facility and reservoir design work. Contingent resources entail commercial risk not applicable to reserves, which have not been included in the net present valuation. There is no certainty that it will be commercially viable to produce any portion of the contingent resources.

EXECUTED as to our report referred to above:

DeGolyer and MacNaughton Canada Limited, Calgary, Alberta, dated February 3, 2014.

DEGOLYER and MACNAUGHTON CANADA LIMITED

"ORIGINALLY SIGNED BY'

Douglas S. Christie, P. Geol.

SCHEDULE "C"
AUDIT COMMITTEE MANDATE

ATHABASCA OIL CORPORATION

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 and strategies including capital structure; (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, and 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. 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 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 Generally Accepted Accounting Principles (**GAAP**) 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 Leadership

24. Review the Company's financial strategy considering current and future business needs, capital markets and the Company's credit rating (if any).

25. Review the Company's capital structure including debt and equity components, current and expected financial leverage, and interest rate and foreign currency exposures and, in the Committee's discretion, make recommendations to the Board for consideration.

26. Review the financing of the Company's Annual Operating and Capital Plan and, in the Committee's discretion, make recommendations to the Board for consideration.

27. Periodically review and, in the Committee's discretion, recommend changes to the Company's dividend policy to the Board for consideration.

Financial Management

28. Review proposed dividends to be declared and, in the Committee's discretion, make recommendations to the Board for consideration.

29. Regularly review current and expected future compliance with covenants under all financing agreements.

30. 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.

31. Review the Company's compliance with required tax remittances and other deductions required by applicable law.

Financial Risk Management

32. Discuss 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. Discuss

major financial risk exposures and steps management has taken to monitor and control such exposures. Receive reports from management with respect to risk assessment, risk management and major financial risk exposures.

33. Regularly review the financial risks 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.

34. Annually review the insurance program including coverage for property damage, business interruption, liabilities, and directors and officers.

35. Review any other significant financial exposures of the Company to the risk of a material financial loss including tax audits or other activities.

36. 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.

Transactions

37. Review any proposed issues of securities of the Company or proposed issues of securities of the subsidiaries of the Company to parties not affiliated with the Company and, in the Committee's discretion, make recommendations to the Board for consideration. When applicable, review the related securities filings and make recommendations to the Board for consideration.

38. Review any proposed material issues of debt including public and private debt, credit facilities with banks and others, and other credit arrangements such as capital and operating leases and, in the Committee's discretion, make recommendations to the Board for consideration. When applicable, review the related securities filings and make recommendations to the Board for consideration.

39. Receive reports on significant, non-material issues of or changes to debt including public and private debt, credit facilities with banks and others, and other credit arrangements such as capital and operating leases.

40. Review any proposed repurchases of shares, public and private debt or other securities and, in the Committee's discretion, make recommendations to the Board for consideration.

Committee Reporting

41. Following each meeting of the Committee, report to the Board on the activities, findings and any recommendations of the Committee.

42. 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.

43. 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.

44. Prepare any reports required to be prepared by the Committee under applicable law.

Committee Meetings

45. 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.

46. Meet in separate, non-management, closed sessions with the external auditor at each regularly scheduled meeting.

47. Meet in separate, non-management, in camera sessions at each regularly scheduled meeting.

48. Meet in separate, non-management, closed sessions with any other internal personnel or outside advisors, as needed or appropriate.

Committee Governance

49. 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

50. Have the sole authority to retain, oversee, compensate and terminate independent advisors to assist the Committee in its activities.

51. 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

52. With the CG Committee, the Board and the Board Chair, respond to potential conflict of interest situations, as required.

53. Carry out any other appropriate duties and responsibilities assigned by the Board.

54. 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