



ATHABASCA

OIL CORPORATION
Annual Information Form

FOR THE YEAR ENDED DECEMBER 31, 2012

March 28, 2013

TABLE OF CONTENTS

	Page
INTRODUCTORY INFORMATION	1
FORWARD LOOKING STATEMENTS	1
GLOSSARY OF DEFINED TERMS	4
ABBREVIATIONS	15
CONVERSIONS.....	15
CONVENTIONS	15
THE COMPANY	16
GENERAL DEVELOPMENT OF THE BUSINESS.....	18
DESCRIPTION OF ATHABASCA’S BUSINESS.....	22
INDEPENDENT RESERVE AND RESOURCE EVALUATIONS	29
OTHER OIL AND GAS INFORMATION	44
DIVIDENDS.....	50
DESCRIPTION OF CAPITAL STRUCTURE	50
CREDIT RATINGS.....	54
MARKET FOR SECURITIES	55
ESCROWED COMMON SHARES AND COMMON SHARES SUBJECT TO A CONTRACTUAL RESTRICTION ON TRANSFER	56
DIRECTORS AND OFFICERS	56
LEGAL PROCEEDINGS AND REGULATORY ACTIONS	61
INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS.....	61
TRANSFER AGENTS AND REGISTRARS	62
MATERIAL CONTRACTS	62
INDUSTRY CONDITIONS.....	62
INTEREST OF EXPERTS	68
RISK FACTORS	68
AUDIT COMMITTEE INFORMATION	95
ADDITIONAL INFORMATION.....	97
Schedule A	Report of Management and Directors on Oil and Gas Disclosure
Schedule B	Reports on Reserves Data by Independent Qualified Reserves Evaluators or Auditors and Reports on Resources Data By Independent Qualified Reserves Evaluators or Auditors
Schedule C	Audit Committee Mandate

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 treatment under governmental regulatory regimes and tax laws;
- the timing of receipt of regulatory approvals and Athabasca’s plans to submit additional regulatory applications;
- the timing of the hearing related to the Dover Oil Sands Project and the Company’s expectations with respect to the outcome of such hearing and its effect on the timing of the Dover Oil Sands Project Approval;
- the business strategy and 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 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 completion of the pipeline that is expected to be constructed from the Hangingstone Central Plant Facility to the Enbridge Cheecham Terminal and the expected capacity thereof;
- 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 Athabasca’s facilities and capacity thereof;
- Athabasca’s drilling plans;
- Athabasca’s plans for, and results of, exploration and development activities; and
- realization of the anticipated benefits of acquisitions and dispositions.

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 crude oil, bitumen blend, natural gas, and 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;
- future sources of funding for Athabasca's capital programs and Athabasca's ability to obtain financing on acceptable terms;
- Athabasca's future debt levels;
- 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 are 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;
- risks related to Athabasca's filings with taxation authorities, including the risk of tax reviews and reassessments;
- 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;
- the need to obtain regulatory approvals and maintain compliance with regulatory requirements;
- dependence on Phoenix as the joint venture participant in the Dover Oil Sands Project;
- 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;
- Athabasca's status and 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;
- the potential impact of the exercise of the Dover Put/Call Option on Athabasca;

- failure to meet the conditions precedent to the exercise by Athabasca of the Dover Put Option, including failure to receive the Dover Oil Sands Project Approval when anticipated or at all;
- failure to obtain necessary regulatory approvals for the completion of the exercise of the Dover Put/Call Option on the terms and conditions set forth in the Put/Call Option Agreement;
- 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;
- the potential for adverse consequences in the event that Athabasca defaults under certain of the PetroChina Transaction Agreements;
- 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;
- 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 for project facilities;
- failure by counterparties (including, without limitation, PetroChina International and Phoenix) to make payments or perform their operational or other obligations to the Company in compliance with the terms of contractual arrangements between the Company and such counterparties, including in compliance with the time schedules set out in such contractual arrangements, and the possible consequences thereof;
- aboriginal claims;
- 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 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.

"2006 Warrants" means warrants of the Company issued on September 1, 2006. Each 2006 Warrant entitled the holder to purchase one Common Share at any time on or prior to 4:00 p.m. (Calgary time) on August 31, 2011 at an exercise price of \$1.25 per Common Share. All of the 2006 Warrants have been exercised.

"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.

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

"Alberta Environment" means the Department of Environment and Water of the Government of Alberta.

"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.

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

"Avenir" means Avenir Consolidated Corporation, a corporation incorporated under the laws of the Province of Alberta.

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

“**Birch assets**” means the interests of Athabasca in approximately 470,000 acres of land 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.

“**Class B Common Shares**” means the class B common shares in the capital of the Company created and issued pursuant to the Plan of Arrangement, and which were removed from the Company’s authorized capital upon the completion of the Plan of Arrangement.

“**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”.

“**Credit Agreement**” means the agreement dated November 30, 2012, in respect of the Credit Facilities, between the Company and a syndicate of financial institutions.

“**Credit Facilities**” has the meaning given to that term under “Description of Capital Structure – Credit Facilities”.

“**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, 2012 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 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 from time to time, such additional assets, benefits and interests as may be acquired 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 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.

“**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, 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).

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

“**Dover West Sands Project 2**” 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 Projects**” means the proposed in-situ oil sands projects in respect of the Dover West Sands, including Dover West Sands Project 1 and Dover West Sands Project 2, 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 Credit Agreement.

“**ERCB**” means the Energy Resources Conservation Board of Alberta.

“**Excelsior**” means Excelsior Energy Limited.

“**Excelsior Series I Acquisition Warrants**” means warrants of the Company issued on November 9, 2010 in connection with the acquisition of Excelsior, each of which entitled the holder to purchase one Common Share at any time on or before November 9, 2012 at an exercise price of \$9.22 per Common Share.

“**Excelsior Series II Acquisition Warrants**” means warrants of the Company issued on November 9, 2010 in connection with the acquisition of Excelsior, each of which entitled the holder to purchase one Common Share at any time on or before November 9, 2012 at an exercise price of \$8.65 per Common Share.

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

“**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, 2012, 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 assets**” means the interests of Athabasca in approximately 394,000 acres of land primarily between townships 92 to 100, range 25, west of the fourth meridian in northeastern Alberta that are more particularly described under “Description of Athabasca’s Business – Thermal Oil Division – Grosmont assets”.

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

“**Hangingsstone assets**” means the interests of Athabasca in approximately 136,000 acres of land 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 – Hangingsstone assets”.

“**Hangingsstone Central Plant Facility**” has the meaning given to that term under “Description of Athabasca’s Business – Thermal Oil Division – Hangingsstone assets – Project Development”.

“**Hangingsstone Expansion**” has the meaning given to that term under “Description of Athabasca’s Business – Thermal Oil Division – Hangingsstone assets – Project Development”.

“**Hangingsstone Projects**” means Hangingsstone Project 1, Hangingsstone Project 2, Hangingsstone Project 3 and any future proposed in-situ oil sands projects in respect of the Hangingsstone assets.

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

“**Hangingsstone Project 2**” has the meaning given to that term under “Description of Athabasca’s Business – Thermal Oil Division – Hangingsstone 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”.

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

“**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.

“**Kaybob Area**” means the interests of Athabasca in approximately 413,000 acres of land that are located primarily between townships 62 to 65, 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 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.

“**Liege Acquisition**” has the meaning given to that term under “General Development of the Business – Three Year History – 2012”.

“**Light Oil assets**” means the interests of Athabasca in over 2.8 million acres of land 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 2,250,000 acres of land 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”.

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

“**MacKay and Dover assets**” means, collectively, the MacKay assets and the Dover assets.

“**MacKay assets**” means the former interests of the Participants, which following the Mackay Put Option Transaction are now 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 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 governed by the MacKay Joint Venture Agreement.

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

“**MacKay Oil Sands Project Approval**” means, as it pertains 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/Call Option**” means the options granted by each of the Company and Phoenix to one another pursuant to the Put/Call Option Agreement, to acquire all of the assets or shares of AOSC (MacKay) (or a wholly-owned subsidiary of AOSC (MacKay)), as the case may be, pursuant to the Put/Call Option Agreement, as described in greater detail under “General Development of the Business – Significant Transactions – The PetroChina Transaction – The Put/Call Options”. See also, “General Development of the Business – Significant Transactions – The PetroChina Transaction – Exercise of the MacKay Put/Call Option”.

“**MacKay Put Option Transaction**” means the exercise by the Company on December 23, 2011 of the MacKay Put/Call Option pursuant to the terms of the Put/Call Option Agreement and the transactions contemplated thereby, as described in greater detail under “General Development of the Business – Significant Transactions – The PetroChina Transaction – Exercise of the MacKay Put/Call Option”.

“**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: (i) 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 (ii) 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: (i) 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 (ii) 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**” means a non-revolving loan provided by Phoenix to the Company in the principal amount of \$430 million as part of the PetroChina Transaction, which was repaid in full on closing of the MacKay Put Option Transaction.

“**PetroChina Loan #2**” means a limited recourse, non-revolving, multi-draw credit facility provided by Phoenix to the Company as part of the PetroChina Transaction with a maximum principal amount of \$100 million, which was repaid in full and terminated in accordance with its terms on the closing of the MacKay Put Option Transaction.

“**PetroChina Loan #3**” means a limited recourse, non-revolving, multi-draw credit facility that was provided by Phoenix to the Company as part of the PetroChina Transaction with a maximum principal amount of \$560 million, which terminated in accordance with its terms as a result of the Company’s exercise of the Mackay/Put/Call Option.

“**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, which is described under “General Development of the Business – Three Year History – 2010”.

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

“**Probable Reserves**” or “**probable reserves**” has the meaning given to that term under “Independent 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, the Dover Call Option and the Dover Put 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.

“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 157,000 acres of land 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.

“**TAGD**” means thermal assisted gravity drainage.

“**Tax Act**” means the *Income Tax Act* (Canada).

“**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.

“**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”.

“**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
Mbbls/d	thousand barrels per day
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).

<u>To Convert From</u>	<u>To</u>	<u>Multiply By</u>
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

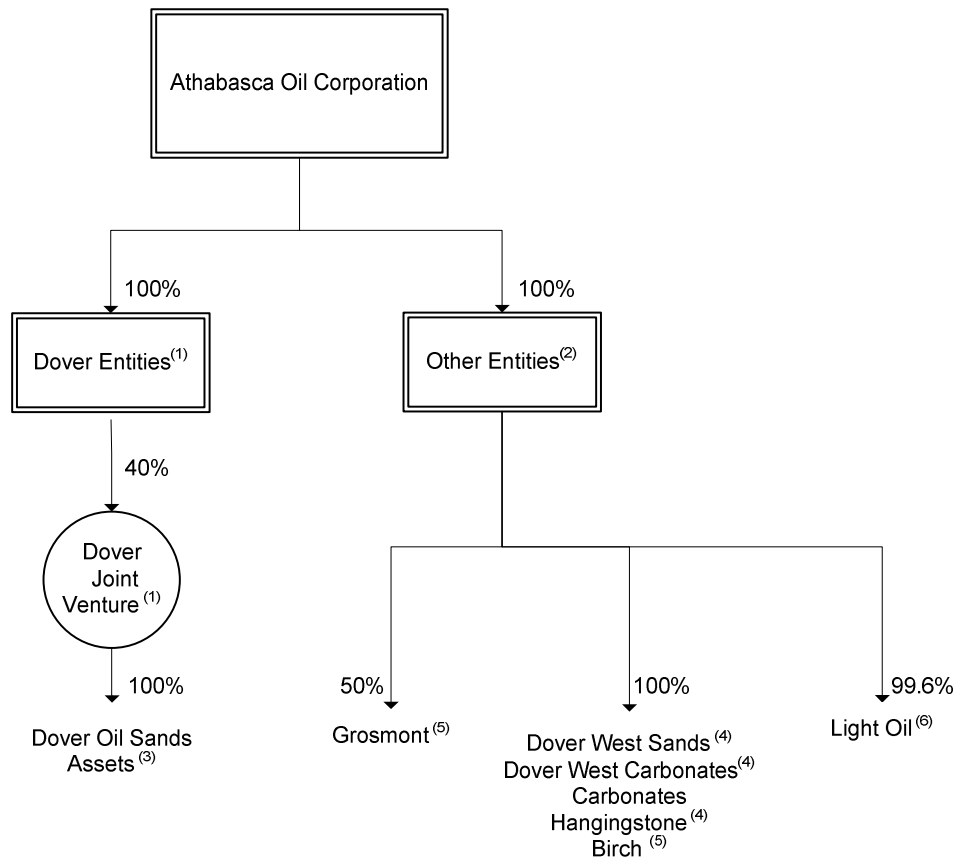
Name, Address and Incorporation

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, 2012, 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): (i) holds an undivided 40% working interest in the Dover assets; (ii) holds 40% of

- the issued and outstanding shares in the capital of Dover JV Operator; and (iii) is a Participant in the Dover Joint Venture as to a 40% Participating Interest. See “General Development of the Business – Significant Transactions – The PetroChina Transaction”.
- (2) The “Other Entities” are corporations and partnerships directly or indirectly wholly-owned by the Company: AOC Dover West Ltd., AOC Grosmont Corp., AOC Carbonates Corp., AOC Light Oil Corp., AOC (ELE) Corp., AOC Birch 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 and AOC Muskwa South 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 – Dover West assets” and “Description of Athabasca’s Business – Thermal Oil Division – Hangingstone assets” for a description of Athabasca’s 100% working interests in the Dover West assets and Hangingstone assets.
 - (5) See “Description of Athabasca’s Business – Thermal Oil Division – Birch assets” and “Description of Athabasca’s Business – Thermal Oil Division – Grosmont assets” for a description of Athabasca’s 100% working interest in the Birch assets and its 50% working interest in the Grosmont assets. 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 assets.
 - (6) See “Description of Athabasca’s Business – Light Oil Division” for a description of Athabasca’s 99.6% working 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:

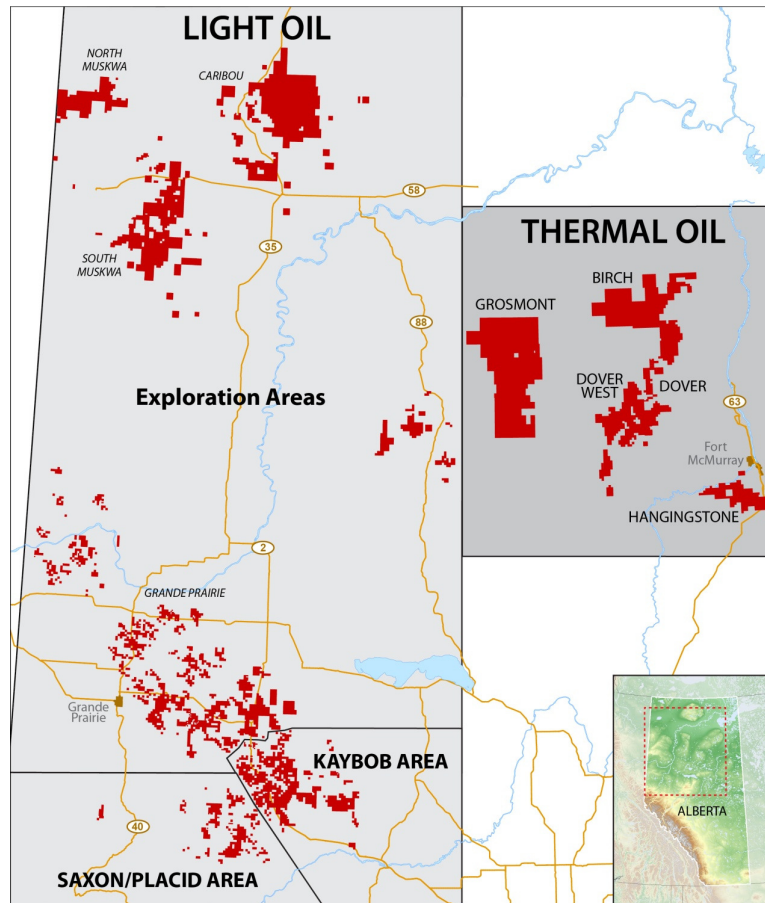
Thermal Oil Division

Athabasca currently has 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 emerging in-situ extraction technologies such as TAGD. As at December 31, 2012, 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”. The Company completed the MacKay Put Option Transaction on March 15, 2012 with the result that it no longer owns an interest in the MacKay assets. See “General Development of the Business – Significant Transactions – The PetroChina Transaction – Exercise of the MacKay Put/Call Option”.

Light Oil Division

In 2011, Athabasca announced the acquisition of a 100% interest in approximately 1.0 million acres of Alberta crown petroleum and natural gas leases in the Alberta Deep Basin, and that it had and commenced the execution of a multi-well drilling program to test the prospectivity of the Duvernay, Montney, Charlie Lake and Nordegg Formations for oil and liquids rich natural gas using the combined application of horizontal drilling and multi-stage fracture technology. Athabasca now holds over 2.8 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 principal Thermal Oil assets and Light Oil assets:



Athabasca’s strategy is to achieve approximately 50% of its production from its Thermal Oil Division and the balance of its production from its Light Oil Division.

Athabasca’s Independent Evaluators have assigned to Athabasca, in the aggregate, as at December 31, 2012, approximately 62.6 MMboe of Proved Reserves and 301.6 MMboe of Probable Reserves on a Gross Reserves basis, and approximately 10.6 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

Three Year History

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

2010

On February 10, 2010, the Company completed the PetroChina Transaction pursuant to which it sold all of the shares of AOSC Newco, a wholly-owned subsidiary of the Company that owned a 60% working interest in the MacKay and Dover assets, to Phoenix for cash consideration of \$1.9 billion. In addition: (a) the Company and

Phoenix entered into the PetroChina Loan Agreements; (b) 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; and (c) AOSC (MacKay) and AOC (Dover), respectively, entered into the MacKay Joint Venture and the Dover Joint Venture with Phoenix for the development of the MacKay Oil Sands Project and the Dover Oil Sands Project. Upon completion of the PetroChina Transaction, the Company redeemed the 2008 Notes with the proceeds of PetroChina Loan #1. See “General Development of the Business – Significant Transactions – the PetroChina Transaction”.

On March 22, 2010, the Plan of Arrangement became effective and pursuant thereto the Company paid the Special Dividend in the aggregate amount of approximately \$1.332 billion (\$4.25 per Common Share and Class B Common Share) utilizing a portion of the proceeds of the PetroChina Transaction. Pursuant to the Plan of Arrangement: (a) each outstanding 2006 Warrant was deemed to be exercised for one Common Share and the holder thereof became entitled to the Special Dividend; and (b) (i) each Common Share held by a Shareholder or warrant holder that so elected and certified that: (A) they were a resident of Canada; (B) they held their Common Shares as capital property; and (C) they were not exempt from tax under Part I of the Tax Act; was exchanged for one Class B Common Share; (ii) the Company declared and paid the Special Dividend in the aggregate amount of \$4.25 per share to the holders of Common Shares and Class B Common Shares, with the capital dividend portion of the Special Dividend being paid to holders of Class B Common Shares; and (iii) following the payment of the Special Dividend, each Class B Common Share was exchanged for one Common Share. Accordingly, following the completion of the Plan of Arrangement there were no authorized or issued Class B Common Shares and there was no change in the outstanding number of Common Shares, except for the 84,109,692 Common Shares that were issued upon the deemed exercise of the 2006 Warrants pursuant to the Plan of Arrangement.

On April 8, 2010, the Company completed its initial public offering of 75,000,000 Common Shares at a price of \$18.00 per share for gross proceeds of \$1.35 billion and the Common Shares began trading on the TSX.

On November 9, 2010, the Company completed the acquisition of all of the issued and outstanding common shares of Excelsior for aggregate consideration of \$11.2 million in cash and 9,284,528 Common Shares, together with the issue of the Excelsior Series I Acquisition Warrants and Excelsior Series II Acquisition Warrants in exchange for outstanding warrants to purchase common shares of Excelsior.

On December 21, 2010, Dover JV Operator submitted an application to the ERCB and Alberta Environment in respect of the Dover Oil Sands Project.

During Athabasca’s 2010 - 2011 drilling program, it drilled an additional 89 delineation wells in the Hangingstone, Dover West, Birch and Grosmont areas, which resulted in an increase of approximately 10% in Athabasca’s Best Estimate Contingent Resources. See “Independent Reserve and Resource Evaluations – Contingent Resource Estimates”.

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, 2011 using two, 250-metre horizontal wells and production from the test commenced in October 2011.

In September, 2011, Athabasca acquired a 100% working interest in 24,640 acres of oil sands leases located at Halfway Creek adjacent to Athabasca’s Hangingstone assets for a purchase price of \$53.6 million.

In October 2011, Athabasca submitted an application to the ERCB and Alberta Environment for a two phase TAGD demonstration project within the Dover West Carbonates.

In December, 2011, Athabasca submitted an application to the ERCB and Alberta Environment for a SAGD project with a 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/Call 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 repayment by Athabasca of PetroChina Loan #1 and PetroChina Loan #2. See “General Development of the Business – Significant Transactions – The PetroChina Transaction – Exercise of the MacKay Put/Call Option”.

2012

On March 15, 2012, the MacKay Put Option Transaction was completed and, as a result, Athabasca no longer owns a working interest in the MacKay assets. See “General Development of the Business – Significant Transactions – The PetroChina Transaction – Exercise of the MacKay Put/Call Option”.

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 the first half of 2012, Athabasca acquired a 100% interest in approximately 29,670 acres of oil sands leases in the Liege area, which are contiguous to its Dover West assets (the “**Liege Acquisition**”).

In October 2012, the 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. See “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 the Credit Agreement with a syndicate of financial institutions providing for the Credit Facilities in the aggregate amount of \$200 million. See “Description of Capital Structure – Credit Facilities”.

On November 27, 2012, the Board sanctioned a \$536 million development budget for the Hangingstone Project 1, which is expected to be comprised of a central processing facility and twenty SAGD well pairs on four well pads, and an additional budget of \$27 million for the construction of supporting infrastructure. The Board also approved the promotion of Bryan Gould to the position of President, who reports to Sveinung Svarte as Chief Executive Officer of the Company; the promotion of Ian Atkinson to the position of Senior Vice President, Thermal Oil; the promotion of Rob Bowie to the position of Vice President, Corporate Development; the promotion of Andre De Leebeek to the position of Vice President, Investor Relations; and the appointment of Rob Broen as Senior Vice President, Light Oil.

Recent Developments

The Dover JV Operator requested that the ERCB schedule a hearing in response to certain objections that were filed by the Fort McKay First Nation with respect to the Dover Oil Sands Project. The hearing is scheduled for April 23, 2013 and Athabasca expects that the hearing will be resolved in favour of the Dover Joint Venture if the parties are unable to settle the issues prior to the hearing. As a result, the Dover Oil Sands Project Approval is now expected to be received in 2013.

On March 11, 2013, Brent Heagy joined the Company as Chief Financial Officer and Rob Harding, who was previously Vice President, Finance and Chief Financial Officer of the Company, was appointed as Vice President, Corporate Services.

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. See “General Development of the Business – Three Year History”.

Significant Acquisitions

Athabasca did not complete any significant acquisitions during the year ended December 31, 2012 for which disclosure is required under Part 8 of NI 51-102.

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. 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 the 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 also 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

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/Call 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 subsidiary thereof) or AOC (Dover) (or a wholly-owned subsidiary thereof), for aggregate cash consideration of up to \$2 billion.

Exercise of the MacKay Put/Call Option

On December 23, 2011, the Company exercised the MacKay Put/Call Option. 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 amounts that were outstanding under PetroChina Loan #1 and PetroChina Loan #2. As a result of the completion of the MacKay Put Option Transaction, Athabasca no longer owns an interest in the MacKay assets.

DESCRIPTION OF ATHABASCA'S BUSINESS

Athabasca's Development Strategy for its Principal Properties

As at December 31, 2012, Athabasca's principal properties were the Hangingstone assets, the Dover West assets and the Dover assets in northeastern Alberta and the Light Oil assets in the Kaybob and Saxon/Placid Areas 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, 2012, Athabasca's Thermal Oil assets and Light Oil assets have been assigned in the aggregate, on a Gross Reserves basis, approximately 62.6 MMboe of Proved Reserves and 301.6 MMboe of Probable Reserves. Athabasca's Thermal Oil assets have also been assigned in the aggregate approximately 10.6 billion barrels of Best Estimate Contingent Resources by the Independent Evaluators on a Company Interest basis. See "Independent Reserve and Resource Evaluations". Athabasca's strategy is to develop these resources and to achieve approximately 50% of its production from its Thermal Oil assets and the balance of its production from its Light Oil assets.

Athabasca's 2013 activities are expected to be funded with existing cash and short term investments, cash flow from operations and by the Credit Facilities, if required. Athabasca's current business plan for developing its properties beyond 2013 anticipates that Athabasca will fund its activities and other requirements through some combination of cash flow from operations, the potential exercise of the Dover Put/Call Option, 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 availability of financing, the exercise of the Dover Put/Call Option, 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 51.4 MMbbls of Proved Reserves and 66.2 MMbbls of Probable Reserves on a Gross Reserves basis, and 912.7 MMbbls of Best Estimate Contingent Resources on a Company Interest basis, to the Hangingstone assets as at December 31, 2012. 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, which is expected to be comprised of a central processing facility and twenty SAGD well pairs on four well pads, and an additional budget of \$27 million for the construction of supporting infrastructure.

Front-end engineering and design was completed for Hangingstone Project 1 during 2012 and a majority of the long-lead equipment has been procured, including the evaporators, boilers, treaters, heat exchangers and glycol coolers. The central processing facility for Hangingstone Project 1 (the “**Hangingstone Central Plant Facility**”) is being designed as the central hub for all bitumen processing for this, as well as future, Hangingstone Projects. First steam from Hangingstone Project 1 is anticipated before year-end in 2014 and production is expected to commence in 2015. In order to achieve these targets, Athabasca must complete the following key project activities:

- 2013 – Complete detailed engineering, complete procurement of equipment, materials and services, complete civil road construction, complete site preparation, and commence facility construction and the drilling of the horizontal well pairs.
- 2014 – Complete horizontal well drilling, as well as facility construction, commissioning and start-up.

In the first half of 2013, Athabasca plans to submit a regulatory application for an incremental 70,000 bbls/d of production from Hangingstone Project 1 (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; and the second Hangingstone Expansion project (“**Hangingstone Project 3**”) is planned to have a production capacity of 30,000 bbls/d. Combined, Hangingstone Project 1, Hangingstone Project 2 and Hangingstone Project 3 would bring the overall production potential from the Hangingstone assets to more than 80,000 bbls/d.

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. As part of the agreement, Enbridge has agreed to construct a new 50-kilometre-long 16-inch pipeline from the Hangingstone Central Plant Facility 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 will have sufficient capacity to handle the production that is expected from both Hangingstone Project 1 and the Hangingstone Expansion.

Athabasca's decisions regarding the Hangingstone assets' ultimate production capacity, the initial development size 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. The Dover West assets comprise 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, 2012, approximately 2.93 billion barrels of Best Estimate Contingent Resources (on a Company Interest basis) and 87 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 Best Estimate Contingent Resources attributable to the Dover West Sands includes the assets that were acquired as part of the Liege Acquisition that was completed in the first half of 2012. The resources attributed to the Dover West Carbonates are contained in carbonate reservoirs and TAGD and SAGD, the recovery processes currently being considered to develop these resources, are considered to be "emerging technology" and "technology under development", respectively, in carbonate reservoirs. 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 and construction commenced in cooperation with a third party industry participant in 2011. The road was constructed during 2012.

Dover West Sands

Project Development

Athabasca is planning to develop the Dover West Sands using SAGD with a staged development strategy. Athabasca continues to evaluate the size and scope of the Dover West Sands Projects but currently expects that there will be eight Dover West Sands Projects in total. Management believes that the area could ultimately support production of up to 270,000 bbls/d, once fully developed. To advance the Dover West Sands Projects, Athabasca submitted an application to the ERCB and Alberta Environment in December of 2011 in respect of Dover West Sands Project 1. Regulatory approval for this project is expected in 2013.

Additionally, a regulatory application is expected to be submitted in 2014 in respect of the subsequent Dover West Sands Projects, the first of which ("**Dover West Sands Project 2**") is expected to have a planned production capacity of up to 40,000 bbls/d.

Dover West Carbonates

Project Development

In management's opinion, the work performed specific to the Dover West Carbonates suggests that this formation may be suitable to multiple in-situ extraction methods such as TAGD and SAGD.

The existing Contingent Resources assigned to the Dover West Carbonates assume that the assets will be developed using SAGD. However, Athabasca believes TAGD may be a superior in-situ recovery process which could take better advantage of the Dover West Carbonates' reservoir characteristics. Athabasca is devoting substantial resources to determine the optimal development and production methods for the Dover West Carbonates.

In 2011, Athabasca began conducting SAGD and TAGD field tests in the Dover West Carbonates. The SAGD field tests that were conducted in 2011 supported steam injection as a viable recovery process for the Dover West Carbonates. In 2011 and 2012, Athabasca conducted field tests which demonstrated the effectiveness of TAGD to heat the reservoir and mobilize and recover bitumen in the Dover West Carbonates. Athabasca is continuing to operate the TAGD field test in 2013 to obtain additional information about TAGD technology and the reservoir characteristics of the Dover West Carbonates.

The next step that is expected in Athabasca's development of the TAGD technology is a TAGD pilot and demonstration project. In October of 2011, Athabasca submitted an application to the ERCB and Alberta Environment for a pilot and demonstration project with a production capacity of up to 6,000 bbls/d to further evaluate bitumen recovery using TAGD. The pilot stage of the TAGD pilot and demonstration project is intended to test and evaluate energy balance and recovery factors from up to 42 tightly-spaced TAGD wells. The demonstration stage of the project will evaluate up to six well patterns and lengths. Regulatory approval for this TAGD pilot and demonstration project is expected in 2013. In 2012, Athabasca began the construction of a heater assembly facility outside of Strathmore, Alberta, to be utilized for the construction, assembly and testing of the TAGD heaters that are expected to be used as part of the TAGD pilot and demonstration project. Construction of the heater assembly facility building is expected to be completed in the first half of 2013.

For the Dover West Carbonates Projects, timing of the first commercial development is contingent on the performance of the TAGD pilot and demonstration project. Athabasca believes the Dover West Carbonates could ultimately support production of over 250,000 bbls/d, once fully developed.

Decisions regarding the ultimate production capacity, initial development size and pace of development of the Dover West Sands Projects and the Dover West Carbonates Projects will be based on methodologies and factors that are similar to those discussed above in respect of the Hangingstone Projects. See "Description of Athabasca's Business – Thermal Oil Division – Hangingstone assets – Project Development".

Dover assets

The Company owns an indirect 40% working interest in the Dover assets through the Dover Joint Venture with Phoenix, which holds the remaining 60% working interest.

If neither the Company nor Phoenix elects to exercise the Dover Put Option or the Dover Call Option, 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 – Significant Transactions – The PetroChina Transaction".

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 19, 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, 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, 2012. 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 the second stage, and the Dover Oil Sands Project 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 JV Operator has requested that the ERCB schedule a hearing in response to certain objections that were filed by the Fort McKay First Nation with respect to the Dover Oil Sands Project. The hearing is scheduled for April 23, 2013 and Athabasca expects that the hearing will be resolved in favour of the Dover Joint Venture if the parties are unable to settle the issues prior to the hearing. As a result, the Dover Oil Sands Project Approval is now expected in 2013.

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 acquired from the first phase of the MacKay Oil Sands Project. The Dover First Phase could begin production as early as mid-2017. The Dover Joint Venture has completed the field development plan detailing the execution strategy for the Dover First Phase initial development area. The initial facility engineering work and the design basis memorandum were completed in the fourth quarter of 2012 and it is expected that the engineering design and specification will begin in early 2013.

The timing for commencing and completing the Dover First Phase, as well as the subsequent phases of the Dover Oil Sands Project that will 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 and other factors.

Birch assets

Athabasca holds a 100% working interest in the Birch assets to which D&M has assigned approximately 2.1 billion barrels of Best Estimate Contingent Resources on a Company Interest basis, as at December 31, 2012. See "Independent Reserve and Resource Evaluations".

Management believes that the Birch assets have significant commercial development potential, which could potentially support a project or projects of up to 155,000 bbls/d. Athabasca initially planned to submit an application to the ERCB and Alberta Environment for a 12,000 bbls/d project in late 2012 or early 2013 but is now considering

increasing the planned production capacity for the Birch project to approximately 40,000 bbls/d and is re-evaluating the optimal timing for the regulatory application.

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 in which Athabasca has a 100% working interest.

During its 2011 - 2012 winter drilling season, Athabasca drilled 22 delineation wells and acquired 54 square kilometres of 3-D seismic data. These delineation activities were undertaken in order to support the initial project development that is referenced above. The Birch assets are vast and management considers them to be underexplored for their size and, as a result, management believes that through further evaluation work the Contingent Resources in the Birch assets may be increased.

Grosmont assets

The Grosmont assets represent a long-term opportunity which management believes has 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 currently devoting resources to unlock 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 assets are located within the Athabasca oil sands fairway of northeastern Alberta between townships 92 to 100, range 25, west of the fourth meridian, and ranges 1 to 5 west of the fifth meridian. The Grosmont assets represent 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 assets. 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. There is currently one successful pilot and one unsuccessful pilot test in the Grosmont Formation. GLJ has assigned approximately 418.3 MMBbls of Best Estimate Contingent Resources to the Grosmont assets on a Company Interest basis, as at December 31, 2012. The resources at Grosmont are contained in carbonate reservoirs and SAGD, the recovery process currently being considered to develop these resources, is considered to be "technology under development" in carbonate reservoirs. See "Independent Reserve and Resource Evaluations".

Light Oil Division

On March 8, 2011, Athabasca announced that it had acquired a 100% interest in over 1.0 million acres of Alberta crown petroleum and natural gas leases in northwestern Alberta, including rights in the Duvernay, Montney, Charlie Lake and Nordegg Formations. Throughout 2011 and 2012, Athabasca continued its strategic growth by acquiring additional interests in large tracts of land in northwestern Alberta, including in the Light Oil Exploration Areas. Athabasca now holds more than 2.8 million acres of petroleum and natural gas rights in its Light Oil asset areas.

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 sold through the Pembina Pipeline system and also receive Edmonton prices.

Kaybob Area

The Kaybob Area is located primarily between townships 62 to 65, ranges 14 to 22, west of the fifth meridian in northwestern Alberta, near the town of Fox Creek. As at December 31, 2012, the Kaybob Area was comprised of approximately 413,000 acres of land, of which approximately 10,000 acres had been developed and 403,000 acres remained undeveloped. The wells that have been drilled in the Kaybob Area to date have targeted primarily the Duvernay, Montney and Nordegg Formations.

During the second quarter of 2012, Athabasca completed the construction of a 100% owned, 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 24 MMcf/d of natural gas. The second Kaybob battery and related facilities (the "**Kaybob East Battery**") is located at 16-03-065-18-W5M and has a designed capacity of 13,000 bbls/d of oil and 12 MMcf/d of natural gas. The Kaybob East Battery was brought on stream late in the fourth quarter of 2012, and the construction of the pipeline connecting the Kaybob East Battery to the Main Light Oil Pipeline was completed in February of 2013 and is expected to be commissioned in the second quarter of 2013.

GLJ has assigned approximately 8.3 MMboe of Proved Reserves and 6.7 MMboe of Probable Reserves on a Gross Reserves basis to Athabasca's interests in the Kaybob Area, as at December 31, 2012. See "Independent Reserve and Resource Evaluations".

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, 2012, the Saxon/Placid Area was comprised of approximately 157,000 acres of land, of which approximately 6,000 acres were developed and 151,000 acres were undeveloped. The wells that have been drilled in the Saxon/Placid area to date have targeted primarily the Duvernay, Montney and Nordegg Formations.

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. The Kaybob East Battery, the Kaybob West Battery and the Saxon Battery, combined, are designed to have a total processing capacity of 36,000 bbls/d of oil production and 48 MMcf/d of gas production.

GLJ has assigned approximately 2.7 MMboe of Proved Reserves and 4.0 MMboe of Probable Reserves on a Gross Reserves basis to Athabasca's interests in the Saxon/Placid Area, as at December 31, 2012. See "Independent Reserve and Resource Evaluations".

Light Oil Exploration Areas

The Light Oil Exploration Areas include Athabasca's oil and gas interests in approximately 2,250,000 net acres of land that are located in northwestern Alberta: in the Grand Prairie area, primarily between townships 66 to 83, ranges 19 to 12, west of the sixth meridian; in the North Muskwa area, primarily between townships 114 to 118, ranges 7 to 12, west of the sixth meridian; in the South Muskwa area, primarily between townships 105 to 112,

ranges 1 to 7, west of the fifth meridian; and in 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 Nordegg Formation. In 2012, Athabasca completed three wells in the Charlie Lake Formation and it is currently considering tie-in options for the three wells in order to evaluate the longer term production potential of the area.

The modest exploration activity that has been conducted in the North Muskwa and South Muskwa areas has been focused on exploring the oil shale of the Muskwa Formation, and in the Caribou area, Athabasca's exploration activity has been targeted towards exploring for light oil in the carbonates of the Slave Point Formation.

GLJ has assigned approximately 0.2 MMboe of Proved Reserves and 0.1 MMboe of Probable Reserves on a Gross Reserves basis to Athabasca's interests in the Light Oil Exploration Areas, as at December 31, 2012. 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 company focused on the exploration for, and sustainable development and production of, bitumen, light oil and liquid rich natural gas; 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 will enable Athabasca to effectively identify, evaluate and execute on value added initiatives.

Personnel

As at December 31, 2012, Athabasca had 11 executive officers, 314 employees and 26 full-time consultants. One of Athabasca's executive officers is currently seconded to the Dover JV Operator.

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, 2012" 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 and are sub-categorized in Low Estimate, Best Estimate and High Estimate cases. 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 Athabasca's submission of regulatory applications for SAGD projects in respect of its Hangingstone assets, Dover West Sands assets and 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, Dover West Sands Project 1 and 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, 2012.

The reserve and Contingent Resource estimates set out below reflect Athabasca's 100% working interests (as at December 31, 2012) in the Hangingstone assets, Dover West Sands assets, Dover West Carbonates assets 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 assets.

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, 2012. The preparation date of the GLJ Report was March 15, 2013 and the preparation date of the D&M Report was March 11, 2013. 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 Contingent Resources data, including the associated 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 assets and Dover West Sands. 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 the Dover First Phase, Dover West Sands Project 1 and to the Light Oil assets, and by D&M to Hangingstone Project 1.

Set out below is a summary of Athabasca’s reserves, as well as the value of future net revenue of Athabasca from the reserves as at December 31, 2012, 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 qualifications relating to costs and other matters are included in the GLJ 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, 2012⁽¹⁾⁽²⁾⁽⁴⁾

Reserves Category	Bitumen		Light & Medium Oil		Shale Oil	
	Gross (Mbbls)	Net (Mbbls)	Gross (Mbbls)	Net (Mbbls)	Gross (Mbbls)	Net (Mbbls)
PROVED RESERVES						
Developed Producing	-	-	696.62	613.17	165.73	134.81
Developed Non-Producing	-	-	667.49	591.82	139.05	115.80
Undeveloped	51,439.39	37,875.98	218.98	206.87	178.20	144.89
TOTAL PROVED RESERVES	51,439.39	37,875.98	1,583.09	1,411.86	482.98	395.49
TOTAL PROBABLE RESERVES	290,814.25	231,469.95	1,670.58	1,444.02	1,132.37	885.63
TOTAL PROVED PLUS PROBABLE RESERVES	342,253.63	269,345.94	3,253.67	2,855.88	1,615.35	1,281.12

Reserves Category	Natural Gas (non-associated & associated)		Shale Gas		Natural Gas Liquids		Oil Equivalent	
	Gross (MMcf)	Net (MMcf)	Gross (MMcf)	Net (MMcf)	Gross (Mbbls)	Net (Mbbls)	Gross (MMboe)	Net (MMboe)
PROVED RESERVES								
Developed Producing	15,603.90	14,532.40	1,104.90	1,030.20	815.68	637.63	4,462.82	3,979.37
Developed Non-Producing	11,695.80	10,765.10	1,286.80	1,201.90	540.09	425.15	3,510.41	3,127.27
Undeveloped	12,105.00	11,287.60	1,188.00	1,108.30	587.75	477.97	54,639.82	40,771.70
TOTAL PROVED RESERVES	39,404.70	36,585.10	3,579.70	3,340.40	1,943.52	1,540.75	62,613.05	47,878.34
TOTAL PROBABLE RESERVES	29,525.90	27,138.70	7,921.20	7,379.70	1,773.41	1,348.96	301,631.79	240,901.62
TOTAL PROVED PLUS PROBABLE RESERVES	68,930.60	63,723.80	11,500.90	10,720.00	3,716.93	2,889.71	364,244.84	288,779.96

Summary of Net Present Values of Future Net Revenue – Forecast Prices and Costs as of December 31, 2012⁽¹⁾⁽²⁾⁽⁴⁾

RESERVES CATEGORY	Before Income Tax Discounted at (%/year)					After Income Taxes Discounted at (%/year)					Unit Value Before Income Tax at 10% Discount/ year	
	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	122,142	105,096	92,716	83,371	76,084	122,142	105,096	92,716	83,371	76,084	23.30	3.88
Developed Non-Producing	57,886	44,357	34,654	27,464	21,987	57,886	44,357	34,654	27,464	21,987	11.08	1.85
Undeveloped	1,770,724	826,041	421,754	224,106	117,091	1,750,965	820,632	420,177	223,619	116,933	10.34	1.72
TOTAL PROVED RESERVES	1,950,752	975,495	549,123	334,941	215,163	1,930,993	970,085	547,546	334,455	215,005	11.47	1.91
TOTAL PROBABLE RESERVES	8,109,461	2,933,597	1,050,893	231,921	(168,384)	6,065,087	2,125,893	674,639	34,116	(282,208)	4.36	0.73
TOTAL PROVED PLUS PROBABLE RESERVES	10,060,214	3,909,092	1,600,017	566,862	46,779	7,996,080	3,095,978	1,222,185	368,571	(67,204)	5.54	0.92

Future Net Revenue (Undiscounted) – Forecast Prices and Cost as of December 31, 2012⁽¹⁾⁽⁴⁾

<u>Reserves Category</u>	<u>Revenue (M\$)</u>	<u>Royalties (M\$)</u>	<u>Operating Costs (M\$)</u>	<u>Development Costs (M\$)</u>	<u>Abandonment and Reclamation Costs (M\$)</u>	<u>Future Net Revenue Before Future Income Tax Expenses (M\$)</u>	<u>Future Income Tax Expenses (M\$)</u>	<u>Future Net Revenue After Future Income Tax Expenses (M\$)</u>
PROVED RESERVES	4,559,077	1,150,952	764,253	677,219	15,900	1,950,752	19,759	1,930,993
PROBABLE RESERVES	24,709,151	5,260,851	6,337,541	4,909,764	91,533	8,109,461	2,044,374	6,065,087
PROVED PLUS PROBABLE RESERVES	29,268,227	6,411,803	7,101,795	5,586,983	107,433	10,060,214	2,064,134	7,996,080

Future Net Revenue by Production Group – Forecast Prices and Costs as of December 31, 2012⁽¹⁾⁽³⁾⁽⁴⁾

<u>RESERVES CATEGORY</u>	<u>Production Group</u>	<u>Future Net Revenue Before Income Taxes (Discounted at 10%/Year)</u>		
		<u>M\$</u>	<u>\$/BOE</u>	<u>\$/Mcf</u>
PROVED RESERVES	Light and Medium Crude Oil ⁽⁵⁾	55,265	30.42	5.07
	Natural Gas ⁽⁶⁾	83,165	11.68	1.95
	Shale Oil ⁽⁵⁾	13,880	18.22	3.04
	Bitumen	389,450	10.28	1.71
	Shale Gas ⁽⁶⁾	7,364	24.04	4.01
	TOTAL		549,123	11.47
PROVED PLUS PROBABLE RESERVES	Light and Medium Crude Oil ⁽⁵⁾	86,084	21.08	3.51
	Natural Gas ⁽⁶⁾	128,658	10.84	1.81
	Shale Oil ⁽⁵⁾	29,436	26.22	4.37
	Bitumen	1,323,938	4.92	0.82
	Shale Gas ⁽⁶⁾	31,901	13.53	2.25
	TOTAL		1,600,017	5.54

Reconciliation of Reserves by Principal Product Type – Forecast Prices and Costs as of December 31, 2012⁽¹⁾⁽²⁾⁽⁴⁾

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, 2012 against such reserves as at December 31, 2011, based on the forecast price and cost assumptions that are described in Note 1 below.

FACTORS	Bitumen			Light and Medium Oil		
	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, 2011	37.8	415.3	453.1	1.2	1.8	3.0
Discoveries	-	-	-	-	-	-
Extensions and Improved Recovery	-	-	-	0.7	0.1	0.8
Technical Revisions	51.4	(48.5)	2.9	(0.1)	(0.2)	(0.3)
Acquisitions	-	-	-	-	-	-
Dispositions ⁽⁷⁾	(37.8)	(76.1)	(113.9)	-	-	-
Economic Factors	-	0.1	0.1	-	-	-
Production	-	-	-	(0.2)	-	(0.2)
December 31, 2012	51.4	290.8	342.3	1.6	1.7	3.3

FACTORS	Conventional Natural Gas (non-associated & associated)			Natural Gas Liquids		
	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, 2011	12.1	18.4	30.4	0.5	0.7	1.2
Discoveries	-	-	-	0.1	0.1	0.2
Extensions and Improved Recovery	28.8	11.9	40.7	1.4	1.0	2.5
Technical Revisions	0.6	(0.8)	(0.2)	-	-	-
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-
Production	(2.1)	-	(2.1)	-	-	-
December 31, 2012	39.4	29.5	68.9	1.9	1.8	3.7

FACTORS	Shale Oil			Shale Gas		
	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, 2011	-	-	-	-	-	-
Discoveries	0.3	0.3	0.6	2.5	1.0	3.5
Extensions and Improved Recovery	0.2	0.9	1.1	1.2	6.9	8.1
Technical Revisions	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-
Production	-	-	-	(0.1)	-	(0.1)
December 31, 2012	0.5	1.1	1.6	3.6	7.9	11.5

FACTORS	Oil Equivalent		
	Gross Proved Reserves (MMboe)	Gross Probable Reserves (MMboe)	Gross Proved Plus Probable Reserves (MMboe)
December 31, 2011	41.4	420.9	462.4
Discoveries	0.8	0.5	1.3
Extensions and Improved Recovery	7.4	5.1	12.5
Technical Revisions	51.4	(48.9)	2.5
Acquisitions	-	-	-
Dispositions ⁽⁷⁾	(37.8)	(76.1)	(113.9)
Economic Factors	-	0.1	0.1
Production	(0.7)	-	(0.7)
December 31, 2012	62.6	301.6	364.2

Notes:

- (1) The pricing assumptions used by GLJ with respect to values of future net revenue as well as the inflation rates used for operating and capital costs are set forth below under “-GLJ Price Forecast”. 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) 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 reflect the Company’s indirect 40% working interests in the Dover assets which, as at December 31, 2012, were held directly by the Company’s wholly owned subsidiary, AOC (Dover).
- (5) Includes solution gas and other by-products.
- (6) Includes by-products but excludes solution gas.
- (7) Reflects the sale of the Mackay assets.

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, 2013 pricing models. A summary of selected price forecasts is set forth below.

Year	Oil Sands Inflation %	Bank of Canada Average Noon Exchange Rate (\$US/\$Cdn)	WTI 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)	Dilbit Stream Quality at Hardisty Current (\$Cdn/bbl)	Heavy Crude Oil (12° API) at Hardisty Current (\$Cdn/bbl)
2013	2.0	1.0	90.00	85.00	70.13	(5.00)	65.13	60.92
2014	2.0	1.0	92.50	91.50	76.15	(5.00)	71.15	68.36
2015	2.0	1.0	95.00	94.00	78.22	(3.90)	74.32	71.10
2016	2.0	1.0	97.50	96.50	80.29	(2.80)	77.49	73.02
2017	2.0	1.0	97.50	96.50	80.29	(1.75)	78.54	73.02
2018	2.0	1.0	97.50	96.50	80.29	(1.79)	78.51	73.02
2019	2.0	1.0	98.54	97.54	81.16	(1.82)	79.34	73.81
2020	2.0	1.0	100.51	99.51	82.79	(1.86)	80.93	75.32
2021	2.0	1.0	102.52	101.52	84.46	(1.89)	82.57	76.87
2022	2.0	1.0	104.57	103.57	86.16	(1.93)	84.23	78.44
2023+	Escalated oil, gas and product prices at 2.0% per year thereafter.							

Year	Natural Gas Liquids Edmonton Pentanes Plus (\$Cdn/bbl)	Diluent Transp. & Postings+ (\$Cdn/Bbl)	Diluent at Field ⁽¹⁾ Current (\$Cdn/bbl)	Transportation Current (\$Cdn/bbl)	Clastics Bitumen Wellhead Current ⁽¹⁾ (\$Cdn/bbl)	Carbonates Bitumen Wellhead Current ⁽²⁾ (\$Cdn/bbl)
2013	96.63	6.00	102.63	6.00	40.49	39.12
2014	97.91	6.00	103.91	6.00	48.54	47.32
2015	97.76	6.00	103.76	6.00	53.13	52.02
2016	100.36	6.00	106.36	6.00	56.55	55.45
2017	100.36	3.75	104.11	4.25	61.51	60.57
2018	100.36	1.50	101.86	2.50	64.92	64.11
2019	101.44	1.50	102.94	2.50	65.65	64.83
2020	103.49	1.50	104.99	2.25	67.41	66.58
2021	105.58	1.50	107.08	2.00	69.20	68.37
2022	107.71	1.50	109.21	2.00	70.66	69.82
2023+	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 32% condensate and 68% bitumen.

The weighted average realized sales prices for Athabasca for the year ended December 31, 2012 were \$77.43/bbl for conventional light and medium oil, \$3.02/Mcf for conventional natural gas, \$62.72/bbl for natural gas liquids, \$73.06/bbl for shale oil and \$3.47/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 and Dover West Sands Project 1, 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 wells that have been tested and not yet tied in, wells drilled near the end of the fiscal year or wells further away from Athabasca's gathering systems. In addition, such reserves may relate 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 lands that are contiguous to 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

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, 2010	-	-	-	-	-	-	-	-
2010	-	-	-	-	-	-	-	-
2011	38	38	1	1	8	8	-	-
2012	51	51	-	-	9	12	1	1

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, 2010	-	-	-	-	-	-
2010	-	-	-	-	-	-
2011	-	-	-	-	40	40
2012	-	-	1	1	54	55

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, 2010	285	285	-	-	-	-	-	-
2010	137	251	-	-	-	-	-	-
2011	202	416	2	2	16	16	1	1
2012	-	291	-	1	7	20	1	1

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, 2010	-	-	-	-	48	48
2010	-	-	-	-	23	42
2011	-	-	-	-	207	421
2012	1	1	7	7	4	298

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 (due to pricing, operating and capital expenditure fluctuations);
- changing technical conditions (production anomalies, such as water breakthrough, accelerated depletion);
- multi-zone developments (such as 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 (landowners, weather conditions, 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 estimated timing of the required approvals, construction, commissioning and start-up of Hangingstone Project 1, 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\$)
2013	104,826	354,645
2014	99,687	595,197
2015	85,242	967,351
2016	11,755	166,692
2017	11,990	49,209
Total for all remaining years	363,719	3,453,889
Total Undiscounted	677,219	5,586,983

Athabasca expects that existing working capital, cash flow from operations, the amounts available under the Credit Facilities, the proceeds from the potential exercise of the Dover Put/Call 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 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

The tables below reflect Athabasca's Contingent Resources and associated discounted future net revenues as of December 31, 2012, 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 assets.

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

CONTINGENT RESOURCE CATEGORY	Company Interest (MMbbls)	Before Income Tax Discounted at (%/year)					After Income Taxes Discounted at (%/year)				
		0% (MM\$)	5% (MM\$)	10% (MM\$)	15% (MM\$)	20% (MM\$)	0% (MM\$)	5% (MM\$)	10% (MM\$)	15% (MM\$)	20% (MM\$)
Grosmont Assets ⁽⁹⁾	-	-	-	-	-	-	-	-	-	-	-
D&M Report⁽⁶⁾											
<i>Existing Technology</i>											
Birch Assets ⁽¹⁵⁾	1,733	60,357	17,729	5,791	1,814	306	36,855	9,998	2,713	388	(434)
Hangingstone Assets ⁽¹⁵⁾	685	22,584	6,589	2,025	442	(187)	13,692	3,657	827	(133)	(497)
After-Tax Adjustment ⁽¹⁴⁾	-	-	-	-	-	-	20,184	6,619	2,659	1,251	660
Total Low Estimate⁽⁷⁾⁽¹¹⁾	5,065	147,070	42,252	13,010	3,311	(308)	109,531	29,850	8,091	1,063	(1,451)
Best Estimate⁽³⁾											
GLJ Report⁽⁵⁾											
<i>Existing Technology</i>											
Dover Assets ⁽¹⁷⁾	1,222	40,759	10,556	3,311	1,106	314	24,959	6,133	1,733	435	(6)
Dover West Sands ⁽¹⁶⁾	2,930	82,448	20,182	5,695	1,568	227	50,109	11,228	2,604	308	(352)
<i>Technology under Development or Emerging Technology⁽⁸⁾</i>											
Dover West Carbonates	3,001	99,567	28,026	9,401	3,365	1,075	61,112	16,469	5,040	1,414	89
Grosmont Assets ⁽¹²⁾	418	6,898	1,111	(187)	(466)	(482)	5,126	596	(365)	(536)	(513)
D&M Report⁽⁶⁾											
<i>Existing Technology</i>											
Birch Assets ⁽¹⁵⁾	2,111	84,465	21,587	6,504	1,940	294	51,659	12,345	3,128	436	(476)
Hangingstone Assets ⁽¹⁵⁾	913	33,495	9,022	2,739	656	(153)	20,422	5,103	1,213	(51)	(521)
After-Tax Adjustment ⁽¹⁴⁾	-	-	-	-	-	-	46,229	13,185	4,851	2,154	1,092
Total Best Estimate⁽⁷⁾⁽¹¹⁾	10,596	347,631	90,483	27,462	8,170	1,275	259,616	65,059	18,204	4,160	(688)
High Estimate											
GLJ Report⁽⁵⁾											
<i>Existing Technology</i>											
Dover Assets ⁽¹⁷⁾	1,618	56,299	15,111	4,861	1,706	571	34,510	8,867	2,631	766	127
Dover West Sands ⁽¹⁶⁾	4,286	135,824	31,874	9,030	2,729	692	82,916	18,204	4,522	944	(114)
<i>Technology under Development or Emerging Technology⁽⁸⁾</i>											
Dover West Carbonates	5,185	193,268	48,101	14,728	5,079	1,743	119,160	28,629	8,173	2,394	470
Grosmont Assets ⁽¹²⁾	1,876	47,722	10,389	2,127	82	(418)	35,545	7,131	1,079	(309)	(582)
D&M Report⁽⁶⁾											
<i>Existing Technology</i>											
Birch Assets ⁽¹⁵⁾	2,672	123,599	26,093	7,159	2,026	254	74,574	14,963	3,476	442	(547)
Hangingstone Assets ⁽¹⁵⁾	1,122	44,292	10,703	3,118	809	(49)	26,579	6,069	1,437	51	(442)
After-Tax Adjustment ⁽¹⁴⁾	-	-	-	-	-	-	74,344	18,972	6,444	2,703	1,314
Total High Estimate⁽⁷⁾⁽¹¹⁾	16,757	601,003	142,271	41,023	12,431	2,792	447,628	102,835	27,763	6,991	226

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 are 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 their economic status. The volumes of contingent bitumen resources in the above table were calculated at the outlet of the proposed extraction plant.

- (2) **“Low Estimate”** is a classification of estimated resources described in the COGE Handbook as being considered to be a conservative estimate of the quantity that will actually be recovered. It is likely that the actual remaining quantities recovered will exceed the Low Estimate. If probabilistic methods are used, there should be a 90% probability (P90) that the quantities actually recovered will equal or exceed the Low Estimate.
- (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) **“High Estimate”** is a classification of estimated resources described in the COGE Handbook as being considered to be an optimistic estimate of the quantity that will actually be recovered. It is unlikely that the actual remaining quantities recovered will exceed the High Estimate. If probabilistic methods are used, there should be a 10% probability (P10) that the quantities actually recovered will equal or exceed the High Estimate.
- (5) Based on the GLJ Report dated effective as of December 31, 2012.
- (6) Based on the estimates contained in the D&M Report dated effective as of December 31, 2012, but using GLJ’s pricing forecast for consistency.
- (7) These volumes are arithmetic sums of multiple estimates of contingent bitumen resources, which statistical principles indicate may be misleading as to volumes that may actually be recovered. Readers should give attention to the estimates of individual classes of resources and appreciate the differing probabilities of recovery associated with each class as explained. In particular, readers should be aware that the likelihood of attaining the sum of the High Estimate is extremely low and of the Low Estimate quite high.
- (8) Athabasca’s resources at its Dover West Carbonates and Grosmont assets are contained in carbonate reservoirs. SAGD, the in-situ bitumen recovery process utilized by GLJ in respect of Athabasca’s Dover West Carbonates and Grosmont assets, is considered by GLJ to be “technology under development” in carbonate reservoirs. TAGD is considered an “emerging technology”. 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 carbonate reservoirs. Although the SAGD technology has been developed for application to non-carbonate reservoirs, there are no known successful commercial projects that use SAGD or TAGD to recover bitumen from carbonate formations and 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: (i) the possibility of unexpected steam channeling which would increase steam requirements resulting in increased costs and potentially reduced economically recoverable bitumen volumes; (ii) 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 (iii) whether the technologies can 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 “technology under development” and “emerging technology” 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 project and/or the technology under development do not demonstrate potential commerciality in carbonate reservoirs 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 “Independent Reserve and Resource Evaluations”.
- (9) The GLJ Report does not calculate the discounted future net revenues associated with the Dover West Carbonates and Grosmont assets in the Low Estimate case because GLJ does not believe that a high certainty or Low Estimate case would be economic. Readers should be aware that if calculated, the discounted future net revenues associated with the Dover West Carbonates and Grosmont assets in the Low Estimate would likely be negative since the Low Estimate result would be realized only after considerable capital has been invested.
- (10) There is no certainty that it will be commercially viable to produce any portion of the resources.
- (11) Totals may not add due to rounding.
- (12) 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’s strategy is to continue delineation drilling efforts in the Grosmont assets in order to increase the resource base in respect of the assets. 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. Other than as noted above, 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.
- (13) The resource estimates set out in the above table reflect Athabasca’s December 31, 2012, 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 assets.
- (14) The after-tax net present value of Athabasca’s individual oil and gas properties reflects the tax burden on the properties on a stand-alone basis. It does not consider the business-entity-level tax situation, some of which is considered in the “after-tax adjustment” lines. The after-tax net present value also does not consider tax planning. The financial statements and the management’s discussion & analysis of Athabasca should be consulted for information at the business-entity-level.
- (15) The future net revenue estimates in respect of the Birch assets and Hangingstone assets were calculated by GLJ with reference to the D&M Report using mid-year discounting in accordance with the COGE Handbook.
- (16) Includes the properties acquired pursuant to the Liege Acquisition.

- (17) Athabasca's investment in the Dover assets is accounted for by the equity method and the resource and future net revenue estimates set out above 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 above totals, its Contingent Resources would total, 4,292 MMbbls (Low Estimate), 9,373 MMbbls (Best Estimate) and 15,141 MMbbls (High Estimate) and the associated future net revenue would be as follows:

CONTINGENT RESOURCE CATEGORY	Before Income Tax Discounted at (%/year)					After Income Taxes Discounted at (%/year)				
	0% (MM\$)	5% (MM\$)	10% (MM\$)	15% (MM\$)	20% (MM\$)	0% (MM\$)	5% (MM\$)	10% (MM\$)	15% (MM\$)	20% (MM\$)
Total Low Estimate	125,907	36,366	11,120	2,774	(302)	96,565	26,119	7,263	1,041	(1,164)
Total Best Estimate	306,873	79,928	24,152	7,064	961	234,657	58,926	16,471	3,724	(682)
Total High Estimate	544,705	127,160	36,161	10,725	2,222	413,118	93,967	25,132	6,225	99

OTHER OIL AND GAS INFORMATION

Oil & Gas Properties

As at December 31, 2012, Athabasca held approximately 4.4 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 2.8 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 a large scale leaseholder, Athabasca intends to opportunistically pursue acquisitions to complement its existing portfolio.

As at December 31, 2012, Athabasca had an interest in approximately 72 Gross Wells (68 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	36.0	35.7	29.0	26.6	65.0	62.3
Natural Gas Wells	2.0	1.4	5.0	5.0	7.0	6.4
TOTAL	38.0	37.1	34.0	31.6	72.0	68.7

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, 2012.
- (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 are wells that are capable of production but which, for a variety of reasons, are not currently producing.

The following table sets forth certain summary information in respect of Athabasca's Thermal Oil assets and Light Oil assets as at December 31, 2012.

Asset Area	Working Interest (%)	Approximate Net Acreage (acres)	Gross Proved Reserves (Bitumen) ⁽¹⁾⁽⁶⁾ (MMbbls)	Gross Probable Reserves (Bitumen) ⁽¹⁾⁽⁶⁾ (MMbbls)	Company Interest		
					Best Estimate Contingent Resources (Bitumen) ⁽¹⁾ (MMbbls)	Light Oil Assets Gross Proved Reserves ⁽¹⁾⁽⁶⁾ (MMboe)	Light Oil Assets Gross Probable Reserves ⁽¹⁾⁽⁶⁾ (MMboe)
Thermal Oil Assets							
Dover Assets ⁽³⁾	40	60,000 ⁽⁴⁾	-	137.6	1,222.5	-	-
Dover West Assets		240,000					
Dover West Sands	100		-	87.0	2,930.3 ⁽⁷⁾	-	-
Dover West Carbonates ⁽²⁾	100		-	-	3,001.2	-	-
Birch Assets	100	470,000	-	-	2,111.0	-	-
Hangingsstone Assets	100	136,000	51.4	66.2	912.7	-	-
Grosmont Assets ⁽²⁾	50	394,000	-	-	418.3	-	-
Light Oil Assets							
Kaybob Area	100	413,000	-	-	-	8.3	6.7
Saxon/Placid Area	97	157,000	-	-	-	2.7	4.0
Light Oil Exploration Areas	100	2,250,000	-	-	-	0.2	0.1
Other	100	280,000	-	-	-	-	-
Total⁽⁵⁾	N/A	4,400,000	51.4	290.8	10,596.0	11.2	10.8
Total excluding Dover⁽⁵⁾	N/A	4,340,000	51.4	153.2	9,373.5	11.2	10.8

Notes:

- (1) Based on the Independent Reports.
- (2) Athabasca's resources at its Dover West Carbonates and Grosmont assets are contained in carbonate reservoirs. SAGD, the in-situ bitumen recovery process utilized by GLJ in respect of Athabasca's Dover West assets and Grosmont assets, is considered by GLJ to be "technology under development" in carbonate reservoirs. TAGD is considered an "emerging technology". 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 carbonate reservoirs. Although the SAGD technology has been developed for application to non-carbonate reservoirs, there are no known successful commercial projects that use SAGD or TAGD to recover bitumen from carbonate formations and 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: (i) the possibility of unexpected steam channeling which would increase steam requirements resulting in increased costs and potentially reduced economically recoverable bitumen volumes; (ii) 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 (iii) whether the technologies can 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 "technology under development" and "emerging technology" 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 project and/or the technology under development do not demonstrate potential commerciality in carbonate reservoirs 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".
- (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 above 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) Totals may not add due to rounding.
- (6) 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.
- (7) Includes the properties acquired pursuant to the Liege Acquisition.

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, 2012:

	Gross Acres ⁽¹⁾⁽²⁾	Net Acres ⁽¹⁾⁽²⁾	Net Acres Expiring Within One Year ⁽¹⁾⁽²⁾
Alberta.....	4,872,731	4,382,577	4,160
Total.....	4,872,731	4,382,577	4,160

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.

The properties described above are planned for current and future development. See "Description of Athabasca's Business" and "Risk Factors" for a discussion of the anticipated development and production activities on these properties and the significant economic factors and uncertainties that may affect such activities.

Abandonment and Reclamation Costs

Athabasca follows the Canadian Institute of Chartered Accountants' 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, 2012, Athabasca's estimated total undiscounted amount required to settle the asset retirement obligations in respect of Athabasca's 503.7 net wells (585 gross wells), pipelines and other infrastructure, net of estimated salvage recoveries, was \$131.6 million. This includes amounts 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 \$35.0 million. Over the next three years, Athabasca expects to incur approximately \$8.5 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 \$107.4 million, undiscounted, and \$15.3 million, discounted at 10%.

Tax Horizon

For the fiscal year ended December 31, 2012, the Company paid no income tax. The Company does not expect to pay Canadian income taxes during the next five years. This estimate would be affected by, among other factors, the exercise of the Dover Put/Call Option, changes in or to the scope or costs of the Dover First Phase, 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, foreign exchange rates, operating costs, interest rates and the Company's other business activities. 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 – Tax Related Reviews" and "Risk Factors–Income Tax Matters".

Costs Incurred

The following table sets forth costs incurred by Athabasca for the year ended December 31, 2012:

Proved Property Acquisition Costs	Unproved Property Acquisition Costs	Exploration Costs	Development Costs
\$nil	\$180,578,000	\$263,761,000	\$636,125,000

Additionally, during the year ended December 31, 2012, the Company contributed \$8,195,000 to its equity investee AOC (Dover) which is developing the Dover Oil Sands Projects as part of the Dover Joint Venture and \$11,355,000 to AOSC (Mackay) which was developing the Mackay Oil Sands Project as part of the Mackay Joint Venture prior to the exercise of the Mackay Put/Call Option by the Company, which resulted in the Company no longer owning an interest in the MacKay assets.

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, 2012:

	Exploratory		Development		Total	
	Gross	Net	Gross	Net	Gross	Net
Oil wells	19.00	17.80	26.00	25.70	45.00	43.50
Bitumen wells	-	-	-	-	-	-
Gas wells	1.00	1.00	-	-	1.00	1.00
Service wells	40.00	40.00	2.00	2.00	42.00	42.00
Stratigraphic test wells	61.00	61.00	-	-	-	61.00
Dry holes	-	-	-	-	-	-
Total	121.00	119.80	28.00	27.70	88.00	147.50

Production Estimates

The following table sets out the volume of Athabasca's working interest production estimated by GLJ and D&M for 2013 in the estimates of future net revenue from Proved Reserves and Probable Reserves that are disclosed above under the heading "--Summary of Net Present Values of Future Net Revenue – Forecast Prices and Costs as of December 31, 2012".

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)
Proved Reserves						
Kaybob Area	1,179	14,798	628	250	1,462	4,767
Saxon/Placid Area	102	4,215	318	67	816	1,325
Light Oil Exploration Areas	8	320	3	-	-	65
Total Proved Reserves	1,289	19,333	949	317	2,278	6,157

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)
Probable Reserves						
Kaybob Area	589	3,605	170	135	272	1,541
Saxon/Placid Area	9	538	108	185	1,390	623
Light Oil Exploration Areas	-	52	1	-	-	9
Total Probable Reserves	598	4,195	279	320	1,662	2,173

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)
Proved + Probable Reserves						
Kaybob Areas	1,768	18,403	798	385	1,735	6,308
Saxon/Placid Areas	110	4,753	426	252	2,206	1,948
Light Oil Exploration Areas	8	372	4	-	-	74
Total Proved + Probable Reserves	1,886	23,528	1,228	637	3,941	8,330

Both the Kaybob Area and Saxon/Placid Area are estimated to account for greater than 20% of Athabasca's 2013 production volumes. Estimated 2013 production volumes for the Kaybob Area are 4,767 boe/d on a total proved basis and 6,308 boe/d on a proved plus probable basis. For the Saxon/Placid Area, estimated 2013 production volumes are 1,325 boe/d on a total proved basis and 1,948 boe/d on a proved plus probable basis.

Production History

The following table sets forth on a quarterly basis for the year ended December 31, 2012, certain information in respect of production, product prices received, royalties paid, operating expenses and the resulting netbacks.

	Quarter Ended 2012				Year Ended
	Mar. 31	June 30	Sept. 30	Dec. 31	Dec. 31, 2012
Average Daily Production ⁽¹⁾					
Light and Medium Oil (bbls/d)	613	256	322	1,372	642
Natural Gas (Mcf/d)	4,293	2,584	2,437	13,294	5,664
NGLs (bbls/d)	38	21	35	250	86
Shale Oil (bbls/d)	63	3	39	252	90
Shale Gas (Mcf/d)	-	-	-	811	204
Total (Boe/d)	1,430	711	803	4,225	1,796

	Quarter Ended 2012				Year Ended
	Mar. 31	June 30	Sept. 30	Dec. 31	Dec. 31, 2012
Average Prices Received					
Light and Medium Oil (\$/bbl)	82.45	77.47	79.02	74.83	77.43
Natural Gas (\$/Mcf)	2.39	1.97	2.30	3.56	3.02
NGLs (\$/bbl)	76.55	71.85	68.57	59.09	62.72
Shale Oil (bbls/d)	77.24	44.18	78.19	71.62	73.06
Shale Gas (Mcf/d)	-	-	-	3.47	3.47
Total (\$/boe)	47.98	37.36	45.51	43.93	44.26
Royalties Paid					
Light and Medium Oil (\$/bbl)	(1.15)	(2.39)	(2.96)	(4.04)	(3.06)
Natural Gas (\$/Mcf)	(0.19)	(0.05)	(0.08)	(0.19)	(0.16)
NGLs (\$/bbl)	(11.60)	(15.44)	(10.15)	(4.15)	(6.25)
Shale Oil (bbls/d)	(3.27)	-	(2.62)	(0.20)	(1.00)
Shale Gas (Mcf/d)	-	-	-	(0.02)	(0.02)
Total (\$/boe)	(1.51)	(1.49)	(1.99)	(2.16)	(1.95)
Operating Expenses ⁽²⁾					
Light and Medium Oil (\$/bbl)	(13.51)	(29.15)	(21.50)	(11.72)	(15.11)
Natural Gas (\$/Mcf)	(2.20)	(4.88)	(3.66)	(2.00)	(2.54)
NGLs (\$/bbl)	(13.33)	(29.35)	(22.31)	(12.03)	(14.25)
Shale Oil (bbls/d)	(14.33)	(28.56)	(19.73)	(11.46)	(13.04)
Shale Gas (Mcf/d)	-	-	-	(1.90)	(1.90)
Total (\$/boe)	(13.39)	(29.21)	(21.68)	(11.87)	(14.98)
Netback Received ⁽³⁾					
Light and Medium Oil (\$/bbl)	67.78	45.94	54.55	59.07	59.27
Natural Gas (\$/Mcf)	-	(2.96)	(1.44)	1.37	0.32
NGLs (\$/bbl)	51.62	27.06	36.10	42.92	42.22
Shale Oil (bbls/d)	59.65	15.62	55.85	59.96	59.02
Shale Gas (Mcf/d)	-	-	-	1.55	1.55
Total (\$/boe)	33.09	6.65	21.84	29.91	27.34

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 barrel 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, 2012.

	Light and Medium (bbls/d)	Natural Gas (Mcf/d)	NGLs (bbls/d)	Shale Oil (bbls/d)	Shale Gas (Mcf/d)	Oil Equivalent (boe/d)
Kaybob Area	359	3,262	54	81	182	1,068
Saxon/Placid Area	282	2,314	30	9	21	711
Light Oil Exploration Areas	1	89	1	-	-	17
Total	642	5,664	86	90	204	1,796

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 that will 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 expects 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 Credit Agreement, and other factors that the Board may deem relevant.

Pursuant to the Credit Agreement, the Company is prohibited from paying dividends to Shareholders while any borrowings or other obligations are outstanding under the 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 Credit Facilities that are described below.

As at December 31, 2012, 400,424,480 Common Shares were issued and outstanding and no first preferred shares or second preferred shares were issued and outstanding. In addition, 12,715,170 Stock Options and 5,714,082 RSUs, were issued and outstanding on December 31, 2012.

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 located at www.sedar.com.

Credit Facilities

On November 30, 2012, the Company entered into the 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 “**Credit Facilities**”). The 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**”); and (c) a \$100 million credit facility (the “**Tranche B 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, such that the aggregate amount available under the Credit Facilities will continue to be \$200 million.

The Company has the option of utilizing the Credit Facilities by way of: (i) Canadian prime rate based Canadian dollar advances; (ii) U.S. base rate based United States dollar advances; (iii) Canadian dollar bankers’ acceptances; (iv) LIBOR based United States dollar advances; and (v) 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 Credit Agreement) and varying between the Borrowing Base Credit Facilities and the Tranche B 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 Credit Facilities.

The Credit Facilities 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 Credit Facilities have a one year term-out period and are repayable in full at the end of such one year term-out period, subject to the annual extension provision. The Borrower is permitted to permanently prepay all or any part of the 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.

The Credit Facilities include various restrictive covenants that, subject to certain exceptions, 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 and asset acquisitions; provide financial assistance; amend material contracts; enter into certain production sales

agreements and currency or interest rate hedging agreements; and undertake material changes in their businesses, or enter into mergers, amalgamations, consolidations and reorganizations.

The 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 material contracts; change of control; cessation of business; insolvency and bankruptcy events; and material judgments, liens or orders. Some of these events of default allow for notice and cure periods and are subject to materiality thresholds.

The 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 28, 2013, Athabasca had issued \$2.6 million in letters of credit that are secured by the Credit Facilities, but had not borrowed or drawn any other amounts under the 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.

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 enter into, or the associated costs of: (i) 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 (ii) 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 CCC+ 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 B 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 on the Notes 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 B 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 other service fees 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		Volume
	High (\$/share)	Low (\$/share)	
2013			
March (1 to 27)	10.03	8.38	31,489,060
February	11.28	9.91	23,505,025
January	11.05	10.30	16,034,396
2012			
December	11.19	9.63	27,885,552
November	12.35	10.55	20,768,825
October	13.50	11.97	30,190,399
September	14.05	12.89	18,159,556
August	13.98	12.05	22,046,463
July	13.21	11.36	39,684,648
June	11.38	9.91	38,761,484
May	11.93	9.95	51,060,599
April	11.62	10.04	31,718,932
March	12.48	10.66	23,500,858
February	12.74	11.72	26,669,508
January	13.02	10.94	24,285,223

Prior Sales

The following is a description of securities of the Company that were issued in the financial year ended December 31, 2012 that are not listed or quoted on a marketplace:

- (a) the Company granted an aggregate of 3,539,001 RSUs to acquire an aggregate of 3,539,001 Common Shares, each with an exercise price of \$0.10;
- (b) the Company granted an aggregate of 5,453,565 Stock Options to acquire an aggregate of 5,453,565 Common Shares with a weighted average exercise price of \$11.29; and
- (c) the Company issued \$550,000,000 aggregate principal amount of Senior Secured Notes on November 19, 2012. See “General Development of the Business – Three Year History – 2012” and “Description of Capital Structure – Senior Secured Notes”.

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

The following table sets forth, as at December 31, 2012, the number of Common Shares held, to the knowledge of the Company, in escrow (including Common Shares subject to a pooling agreement), or that are subject to a contractual restriction on transfer, and the percentage that number represents of the outstanding Common Shares.

Designation of class	Number of Common Shares held in escrow or that are subject to a contractual restriction on transfer	Percentage of class
Common Shares ⁽¹⁾	1,494,767	0.37%

Note:

- (1) Pursuant to declarations of trust entered into by Avenir, as trustee, with certain employees, directors, officers and other service providers (collectively, “**Service Providers**”) of the Company, a total of 1,494,767 Common Shares representing 0.37% of the Common Shares are held in trust by Avenir pending the satisfaction of certain “**Length of Service Requirements**” by the applicable Service Provider, unless the Common Shares are earlier released in the event of: (i) the death of the Service Provider; (ii) a Change of Control (as defined in the applicable agreements) of the Company; or (iii) a determination by the Board to allow earlier release (collectively, the “**Trust Arrangements**”). The Length of Service Requirements vary for each Service Provider but the Trust Arrangements generally provide for annual or bi-annual releases of the Common Shares in equal amounts over periods ranging from two to four years. In particular, subject to the early release provisions described above, the following number of Common Shares will be released from the Trust Arrangements at the following times: 497,502 Common Shares between January and June 2013; and 997,265 Common Shares between July and December 2013. The Company has the right to acquire Common Shares subject to the Trust Arrangements from a Service Provider for a nominal purchase price (\$0.01 per Common Share in certain circumstances and \$0.001 per Common Share in other circumstances) if the Service Provider resigns, is terminated for “just cause”, is terminated without “just cause” in certain circumstances, or ceases to be a director (where applicable). During the period that the Common Shares held by a Service Provider are subject to the Trust Arrangements, the Service Provider is entitled to vote such Common Shares and to receive directly without any trust restriction any dividends thereon notwithstanding that the conditions to the release of such Common Shares to the Service Provider have not been satisfied. Accordingly, the Special Dividend was paid directly to the Service Providers and is not held in trust under the Trust Arrangements.

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	Director	Chairman and Chief Executive Officer of Charger Energy Corp. Prior thereto, a director and President and Chief Executive Officer 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 is a Fellow of the Canadian Institute of Chartered Accountants.	November 14, 2006

Name and Place of Residence	Office	Principal Occupation	Director Since
Gary Dundas ⁽²⁾⁽³⁾⁽⁴⁾ Alberta, Canada	Director	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
Ronald J. Eckhardt ⁽³⁾ Alberta, Canada	Director	Mr. Eckhardt is currently retired. Prior thereto, Executive Vice President, North American Operations of Talisman Energy Inc., a publicly traded energy company listed on the TSX from October 2003 to September 2009.	April 1, 2012
William Gallacher ⁽³⁾⁽⁴⁾ Alberta, Canada	Chairman of the Board and Director	President and Chief Executive 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, President and Chief Executive Officer of Avenir Operating Corp., the administrator of Avenir Diversified Income Trust, from January 2003 until January 1, 2011. Mr. Gallacher has also been the President of Avenir, a private equity firm owned by Mr. Gallacher, since 1997.	August 23, 2006
Marshall McRae ⁽²⁾⁽⁴⁾ Alberta, Canada	Director	Independent financial and management consultant since August 2009. Prior thereto, 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.	October 30, 2009
Sveinung Svarte ⁽³⁾ Alberta, Canada	Chief Executive Officer and a Director	Chief Executive Officer of the Company since November 28, 2012 and was President and Chief Executive Officer of the Company from January 8, 2007 until November 28, 2012. Prior thereto, Vice President, Oilsands at Total E&P Canada Ltd. (a private oil and gas company and subsidiary of Total S.A., a publicly traded integrated international oil and gas company listed on the NYSE and the Paris Bourse), from 2004 until July 2005 when Total E&P Canada Ltd. acquired Deer Creek Energy Limited. Thereafter, Mr. Svarte served as the Vice President, Corporate Development of Total E&P Canada Ltd.	October 19, 2006

Name and Place of Residence	Office	Principal Occupation	Director Since
Ian Atkinson Alberta, Canada	Senior Vice President, Thermal Oil	Senior Vice President, Thermal Oil since November 28, 2012. Prior thereto, Vice President, Geoscience, Technology and Reservoir of the Company from January 8, 2007 to November 28, 2012. Prior thereto, Vice President of Morpheus Energy Corporation (a private oil and gas company), from February 2002 to July 2006 and Manager, Engineering at Quarry Oil & Gas Ltd. from January 2001 to February 2002.	N/A
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	Senior Vice President, Light Oil	Senior Vice President, Light Oil of the Company since November 26, 2012. Prior thereto, Mr. Broen worked at Talisman Energy Inc. (“ Talisman ”) for 18 years, most recently as Senior Vice-President, North American Shale from April 2012 to November 2012. Prior thereto, Mr. Broen served as President and a director of Talisman Energy USA Inc. from 2009 to April 2012, Vice-President, North America HSE and Stakeholder Relations at Talisman during 2008/2009, Vice President of North America Strategy Implementation at Talisman during 2008, and prior thereto, Mr. Broen served in various other management positions in Engineering and Operations with Talisman.	N/A
Andre De LeeBeeck Alberta, Canada	Vice President, Investor Relations	Vice President, Investor Relations 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
Bryan Gould Alberta, Canada	President	President of the Company since November 28, 2012. Vice President, Corporate Development of the Company from October 2009 to November 28, 2012. Prior thereto, Mr. Gould served as Vice President, Business Development of Shell Canada Limited, a subsidiary of Royal Dutch Shell plc (a publicly traded integrated oil and gas company) from the Spring of 2007 until September 2009 and held various other technical and managerial assignments with Shell Canada/Royal Dutch Shell plc beginning in June of 1982.	N/A

Name and Place of Residence	Office	Principal Occupation	Director Since
Rob Harding Alberta, Canada	Vice President, Corporate Services	Vice President, Corporate Services of the Company since March 11, 2013. Prior thereto, Vice President, Finance and Chief Financial Officer of the Company from June 1, 2008 until March 11, 2013. From September 2007 to May 2008, Controller of the Company. Prior thereto, Controller at Total E&P Canada Ltd. (a private oil and gas company and subsidiary of Total S.A., a publicly traded integrated international oil and gas company listed on the NYSE and the Paris Bourse), from October 2004 until August 2007.	N/A
Brent Heagy Alberta, Canada	Chief Financial Officer	Chief Financial Officer of the Company since March 11, 2013. Prior thereto, from January 1, 2011 until April 2, 2012, Mr. Heagy was Senior Vice President, Finance and Chief Financial Officer of Provident Energy Ltd., the entity resulting from the reorganization of Provident Energy Trust into a corporate structure, which was completed on January 1, 2011. Prior thereto, Senior Vice President, Finance and Chief Financial Officer of Provident Energy Trust from October 1, 2010 until January 1, 2011. Prior thereto, Executive Vice President and Chief Financial Officer of Zargon Energy Trust from September 13, 2004 until September 30, 2010.	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 (a publicly traded integrated energy company), from April 2000 to April 2008.	N/A
Don Verdonck Alberta, Canada	Vice President	Seconded to Dover Operating Corp. 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. Prior thereto, General Manager, Thermal of Total E&P Canada Ltd. (a private oil and gas company and subsidiary of Total S.A., a publicly traded integrated international oil and gas company listed on the NYSE and the Paris Bourse) from June 2005 to November 2006, and Manager, Development at Pengrowth Corporation, the administrator of Pengrowth Energy Trust, from June 2004 to June 2005.	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.

As at December 31, 2012, the directors and executive officers of the Company, as a group, beneficially owned, controlled or directed, directly or indirectly, an aggregate of 32,709,493 Common Shares, representing 8% 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: (i) 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 (ii) 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 and Mr. Gallacher are directors 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: (i) 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 (ii) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

Conflicts of Interest

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

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

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

Legal Proceedings

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

Regulatory Actions

During the year ended December 31, 2012 there were: (i) no penalties or sanctions imposed against the Company by a court relating to securities legislation or by a securities regulatory authority; (ii) 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 (iii) 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, 2012, 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, 2012:

- (a) the following agreements relating to the PetroChina Transaction:
 - (i) the Dover Joint Venture Agreement;
 - (ii) the Put/Call Option Agreement;
 - (iii) the Umbrella Agreement;
- (b) the Rights Plan referred to under the heading “Description of Capital Structure – Shareholder Rights Plan”.

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 located 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. It is not expected that any of these regulations or controls will affect the Company’s operations in a manner materially different than they will affect other companies of similar size. 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 primarily determines oil prices. The specific price depends in part on oil quality, prices of competing fuels, distance to market, the availability of transportation, the value of refined products, the supply/demand balance and contractual terms of sale. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National

Energy Board of Canada (the “NEB”). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB. The NEB is currently undergoing a consultation process to update the current regulations governing the issuance of export licences. The updating process is necessary to meet the criteria set out in the federal *Jobs, Growth and Long-term Prosperity Act*, which received Royal Assent on June 29, 2012 (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) or the New York Mercantile Exchange (NYMEX) in the United States, spot and future prices can be set by such supply and demand. 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 m³/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 became effective on January 1, 1994. In the context of energy resources, Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to the total supply of goods of the party maintaining the restriction as compared to the proportion prevailing in the most recent 36 month period; (ii) impose an export price higher than the domestic price (subject to an exception with respect to certain measures which only restrict the volume of exports); and (iii) disrupt normal channels of supply.

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

Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations which govern royalties, production rates and other matters. The royalty regime in a given province is a significant factor in the profitability of 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. Effective January 1, 2011, the maximum royalty payable under the royalty regime was set at 40%. The royalty curve for conventional oil announced on May 27, 2010 amends the price component of the conventional oil royalty formula to moderate the increase in the royalty rate at prices higher than \$535/m³ compared to the previous royalty curve.

Royalty rates for natural gas under the royalty regime are similarly determined using a single sliding rate formula incorporating separate variables to account for production rates and market prices. Effective January 1, 2011, the maximum royalty payable under the royalty regime was set at 36%. The royalty curve for natural gas announced on May 27, 2010 amends the price component of the natural gas royalty formula to moderate the increase in the royalty rate at prices higher than \$5.25/GJ compared to the previous royalty curve.

Oil sands projects are also subject to the 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 and 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, concurrently 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 current royalty regime.

Producers of oil and natural gas from freehold lands in Alberta are required to pay annual freehold production taxes. The level of the freehold production tax is based on the volume of monthly production and a specified rate of tax for both oil and gas.

The Innovative Energy Technologies Program (the "IETP"), which is currently in place, 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.

The Government of Alberta currently has in place two royalty programs, both of which commenced in 2008 with the intention to encourage the development of deeper, higher cost oil and gas reserves. A five-year program for conventional oil exploration wells over 2,000 metres provides qualifying wells with up to a \$1 million or 12 months of royalty relief, whichever comes first, and a five-year program for natural gas wells deeper than 2,500 metres provides a sliding scale royalty credit based on depth of up to \$3,750 per metre. On May 27, 2010, the natural gas deep drilling program was amended, retroactive to May 1, 2010, by reducing the minimum qualifying depth to 2,000 metres, removing a supplemental benefit of \$875,000 for wells exceeding 4,000 metres that are spudded subsequent to that date, and including wells drilled into pools drilled prior to 1985, among other changes.

On November 19, 2008, the Government of Alberta announced the introduction of a five-year program of transitional royalty rates with the intent of promoting new drilling. The five-year transition option is designed to provide lower royalties at certain price levels in the initial years of a well's life when production rates are expected to be the highest. Under this program, companies drilling new natural gas or conventional deep oil wells between 1,000 and 3,500 metres receive a one-time option, on a well-by-well basis, to adopt either the new transitional royalty rates or those outlined in the royalty regime. These options expired on February 15, 2011 and on January 1, 2014, all producers operating under the transitional royalty rates will automatically become subject to the royalty regime. Production from wells operating under the transitional royalty rates will not be subject to the royalty curves for conventional oil and natural gas.

On March 17, 2011, the Government of Alberta approved the *New Well Royalty Regulation* providing for the permanent implementation of a formerly temporary royalty program which provides for a maximum 5% royalty rate for eligible new wells for the first 12 productive months or until the regulated "volume cap" is reached.

In addition to the foregoing, 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 at that time if it decides to discontinue the program.

Land Tenure

The respective provincial governments predominantly own 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. Holders of leases or licences that have been continued indefinitely prior to January 1, 2009 will receive a notice regarding the reversion of the shallow rights, which will be implemented three years from the date of the notice. Leases and licences granted prior to January 1, 2009, but continued after that date, are not subject to shallow rights reversion until they continue past their primary term (at which time the application of deep rights reversion occurs). Afterwards, the holders of such agreements will be served with shallow rights reversion notices based on vintage and location similar to leases and licences that were already continued as of January 1, 2009. The order in which these agreements will receive reversion notices will depend on their vintage and location.

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation, all of which is subject to governmental review and revision from time to time. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations, such as sulphur dioxide and nitrous oxide. In addition, such legislation sets out the requirements for the satisfactory 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 for pollution damage, and the imposition of material fines and penalties.

On a Federal level and pursuant the *Prosperity Act*, the Government of Canada amended or appealed several pieces of federal environmental legislation and in addition, created a new federal environment assessment regime. 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.

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 region-specific land use plans in order to manage the combined impacts of existing and future land use within a specific region and the incorporation of a cumulative effects management approach into such plans.

The *Alberta Land Stewardship Act* (the “ALSA”) was proclaimed in force in Alberta on October 1, 2009 and provides the legislative authority for the Government of Alberta to implement the policies contained in the ALUF. Regional plans established pursuant to the ALSA will be 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, leases, licenses, 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 effect on September 1, 2012. The LARP covers approximately 93,212 square kilometres and is in the northeast corner of Alberta. The region includes a substantial portion of the Athabasca oilsands area, which contains approximately 82% of the provinces oilsands resource and much of the Cold Lake oilsands area. LARP establishes six new conservation areas, bringing the total conserved land in the region to two million hectares, or 22%—an area three times the size of Banff National Park. The Alberta government plans to pay \$30 million to producers whose leases will be cancelled in areas set aside for conservation. Oil and gas companies will be allowed to continue to operate in conservation and recreation areas while oilsands companies’ tenures will be cancelled. New petroleum

and gas tenure sold in conservation areas will include a restriction that prohibits surface access. Application procedures for activities and facilities in the LARP, regulated by the Energy Resources Conservation Board and the Alberta Utilities Commission, respectively, have been changed to accommodate the new restrictions set out in the LARP. The LARP is the first of seven regions to get a land use plan. The next will be the South Saskatchewan region.

Climate Change Regulation

Federal

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, which will be applied to regulated sectors on a facility-specific, sector-wide or a company-by-company basis. Facility-specific targets apply to the upstream oil and gas, oil sands, petroleum refining and natural gas pipelines sectors. Unless a minimum regulatory threshold applies, all facilities within a regulated sector will be subject to the emissions intensity targets. Although the intention was for draft regulations for the implementation of the Updated Action Plan to become binding on January 1, 2010, the only regulations announced pertain to carbon dioxide emissions from coal-fired generation of electricity (finalized in summer 2012). Further, 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. As a result, it is unclear to what extent implementation of the proposals contained in the Updated Action Plan will occur.

The United States Environmental Protection Agency (the “**EPA**”) has indicated its intention to impose GHG emissions standards for fossil fuel-fired power plants by specifying that it would issue final regulations by May 26, 2012, and with respect to refineries, specifying that it will issue proposed regulations by December 10, 2011 and finalized regulations by November 10, 2012. The EPA did not meet the December 10, 2011 deadline or the November 10, 2012 deadline. However, in March 2012, the EPA proposed a strict GHG standard on new power plants only. While it is expected that this rule could encourage building new natural gas power plants rather than coal plants, the actual effect of the new rule will not be able to be quantified for some time.

Alberta

Alberta enacted the *Climate Change and Emissions Management Act* (the “**CCEMA**”) on December 4, 2003, amending it 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 approach similar to the Updated Action Plan and aims for a 50% reduction from 1990 emissions relative to GDP by 2020.

Alberta facilities emitting more than 100,000 tonnes of GHGs a year are subject to compliance with the CCEMA. Similar to the Updated Action Plan, the CCEMA and the associated *Specified Gas Emitters Regulation* make a distinction 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 to 88% of their baseline for 2008 and subsequent years, with their baseline being established by the average of the ratio of the total annual emissions to production for the years 2003 to 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 *Specified Gas Emitters Regulation*. New Facilities are required to reduce their emissions intensity by 2% from baseline in the fourth year of commercial operation, 4% of baseline in the fifth year, 6% of baseline in the sixth year, 8% of baseline in the seventh year, and 10% of baseline in the eighth year. Unlike the Updated Action Plan, the CCEMA does not contain any provision for continuous annual improvements in emissions intensity reductions beyond those stated above.

The CCEMA contains compliance mechanisms that are similar to the Updated Action Plan. Regulated emitters can meet their emissions intensity targets by contributing to the Climate Change and Emissions Management Fund at a rate of \$15 per tonne of CO₂ equivalent. Unlike the Updated Action Plan, CCEMA contains no provisions for an increase to this contribution rate. Emissions credits can be purchased from regulated emitters that have reduced their emissions below the 100,000 tonne threshold or non-regulated emitters that have generated emissions offsets through activities that result in emissions reductions in accordance with established protocols published by the Government of Alberta.

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: (i) 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; (ii) received by an Expert or by the "designated professionals" of such Expert, after the time specified above; or (iii) 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.

The Company has developed an Enterprise Risk Management process to identify, evaluate and plan mitigation measures for the material risks that the Company faces. The Enterprise Risk Management process is overseen by an internal committee which reports to management of the Company. Additionally, management reviews with the Board the severity and likelihood of the Company's principal and emerging risks and the effectiveness of the Company's risk mitigation measures that are identified through the Enterprise Risk Management process.

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 2013 capital and operating budgets are intended to be funded with existing cash and short term investments, cash flow from operations and the Credit Facilities, if required. Beyond 2013, Athabasca will require additional capital to maintain its pace of development. Athabasca may also require additional capital or an acceptable alternate form of security to file an objection against any possible tax reassessments (see "--Tax Related Reviews" below). Currently, management believes that Athabasca will fund its activities and other requirements beyond 2013 through some combination of cash flow from operations, the potential exercise of the Dover Put/Call Option, a reasonable level of debt 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. Additionally, Athabasca is restricted from selling assets pursuant to the terms of the Credit Agreement and Note Indenture and from selling 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 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.

Tax Related Reviews

Athabasca is currently undergoing tax related reviews, including a review of the capital treatment of the PetroChina Transaction and Special Dividend. While the final outcome of such reviews cannot be predicted with certainty and could be material, Athabasca believes its positions as filed are supportable under applicable law and the Company has not currently recognized a provision in its financial statements for any potential reassessments. In the event that the Company is reassessed, the Company would be required to deposit cash or an acceptable alternate form of security with the relevant taxing authority in order to file an objection against such reassessment, the amount of which deposit could be material. If the Company does not have available cash on hand to fund such deposit, the Company may be required to seek additional financing for such purpose. No assurance can be given that any such financing would be available in whole or in part, or if available, that the terms thereof would be commercially reasonable.

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.

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 ERCB. 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.

There is a risk that certain details of the Dover Oil Sands Project's planned development will change with participation from Phoenix. 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, the Dover West Sands Projects and the Dover West Carbonates 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 operations 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 increased materially in value against the United States dollar. Material increases in the value of the Canadian dollar negatively affect commodity prices valued in United States dollars thereby reducing 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.

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, 2012. See "Independent Reserve and Resource Evaluations". There are numerous uncertainties inherent in estimating the quantities of reserves and resources attributable to Athabasca's assets, including many factors beyond Athabasca's control, and no assurance can be given that the indicated level of reserves and resources will be realized. In general,

estimates of recoverable reserves and resources are based upon a number of factors and assumptions made as of the date on which the reserves and resource estimates were determined, such as geological and engineering estimates which have inherent uncertainties, the assumed effects of regulation by governmental agencies and 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. 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 and cash flows derived from 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 valuations. 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

Athabasca has only recently commenced production from its Light Oil Division and there is no assurance that any of its oil sands properties will commence production or that any of its properties will 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 planned 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, and regulatory approval is now expected in 2013. The application for Athabasca's Hangingstone Project 1 was submitted on March 31, 2011 and regulatory approval was granted on October 4, 2012. In October, 2011 Athabasca submitted an application for a two phase TAGD pilot/demonstration project for its Dover West Carbonates assets and the application for Dover West Sands Project 1 was submitted in December, 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) has 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, 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 either a pilot or 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 these 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 utilized by GLJ in respect of Athabasca's Dover West Carbonates and Grosmont assets, is considered by GLJ to be "technology under development" in carbonate reservoirs. TAGD is considered an "emerging technology". 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 carbonate reservoirs. Although the SAGD technology has been developed for application to non-carbonate reservoirs, there are no known successful commercial projects that use SAGD or TAGD to recover bitumen from carbonate formations and 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: (i) the possibility of unexpected steam channeling which would increase steam requirements resulting in increased costs and potentially reduced economically recoverable bitumen volumes; (ii) 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 (iii) whether the technologies can 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 "technology under development" and "emerging

technology” 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 project and/or the technology under development do not demonstrate potential commerciality in carbonate reservoirs 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 hydrocarbon (oil and natural gas) production. Specifically, hydraulic fracturing is being used to produce 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 net revenues to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards, environmental damage and various field operating conditions could greatly increase the cost of operations and may adversely affect the production from successful wells. Field operating conditions include, but are not limited to, delays in obtaining regulatory 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 close 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, processing 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, processing 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. 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.

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 materially adversely affect Athabasca's ability to process its production and to 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.

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. See "General Development of the Business – Significant Transactions – The PetroChina Transaction – The Put/Call Options".

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 Projects, 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 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.

Athabasca also has an option to sell its interest in the Dover Oil Sands Projects to Phoenix under certain circumstances. Failure to meet the conditions to the exercise of the Dover Put Option, including failure to receive the Dover Oil Sands Project Approval when anticipated or at all would 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. See "General Development of the Business – Significant Transactions – The PetroChina Transaction – The Put/Call Options". There are a number of factors that could delay or prevent the Dover Oil Sands Project Approval 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 approvals 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.

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.

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.

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 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 – Significant Transactions – The PetroChina Transaction" for details.

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 affect 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 generation, handling, use, storage, transportation, treatment and disposal of hazardous substances and waste and in connection with spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with 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 regulations no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on Athabasca's business, financial condition, results of operations and prospects.

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 in Alberta or that may be enacted in other provinces. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place. As a signatory to the United Nations Framework Convention on Climate Change (the "UNFCCC") and 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. Although it is not the case today, 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 and have a material adverse impact on Athabasca.

In order to conduct oil and gas operations, Athabasca will require licenses and permits from various governmental authorities. There can be no assurance that Athabasca will be able to obtain all of the licenses and permits that may be required to conduct operations that it may wish to undertake.

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 continue to 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 subject to 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, including hazards such as fire, explosion, blowouts, cratering, sour gas releases and spills and other environmental hazards. The typical risks and hazards could result in substantial damage to wells, production facilities, other property and the environment or personal injury. 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. 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.

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 Dover Oil Sands Project, the Hangingstone Projects, the Dover West Sands Projects, the Dover West Carbonates Projects, 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.

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 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, particularly in light of the current economic situation. 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.

The Fort McKay First Nation has made certain objections in respect of the Dover Oil Sands Project and a hearing has been scheduled with the ERCB to consider the issues that have been raised. While Athabasca anticipates a favourable outcome, the objections that have been raised have the potential to delay, or possibly even prevent, the receipt of the Dover Oil Sands Project Approval.

Seasonality

The level of activity in the Canadian oil sands industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Also, certain oil 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 activities.

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 or is 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

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. 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 – 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. The Dover Joint Venture and Athabasca will compete with other bitumen, crude oil and natural gas producers, other producers of SCO blends and other

producers of conventional crude oil. Some of the conventional producers have lower operating costs than Athabasca is anticipated to have and many of them have greater resources than Athabasca has. 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 to defeat Athabasca's claim. The actual interest of the Company in properties may, therefore, 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 proposed legislative changes which affect title, to the oil and natural gas properties Athabasca controls that, if successful or made into law, 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 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 its 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 Company's 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 Credit Facilities, the lenders under the 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 Company's 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 of 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 this 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 materially adversely affected. If Athabasca is unable to utilize the most advanced commercially available technology, its business, financial condition and results of operations could be materially adversely affected.

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.

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: (i) actual or anticipated fluctuations in Athabasca's quarterly results of operations; (ii) actual or anticipated changes in crude oil, bitumen blend, natural gas, SCO and other diluent prices; (iii) recommendations by securities research analysts; (iv) changes in the economic performance or market valuations of other companies that investors deem comparable to Athabasca; (v) addition or departure of the Company's executive officers and other key personnel; (vi) release or expiration of lock-up or other transfer restrictions on outstanding Common Shares; (vii) sales or perceived sales of additional Common Shares; (viii) significant acquisitions or business combinations, strategic partnerships, joint ventures or capital commitments by or involving Athabasca or its competitors; and (ix) 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 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: (i) 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 (ii) 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 that it sells. 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 hereby (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 Credit Facilities, a change of control (as defined in the 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 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 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 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 *Bankruptcy and Insolvency Act* (Canada) (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 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, together with letters of credit of \$2.6 million, expected availability for additional borrowings of \$197.4 million under the Credit Facilities.

Although the Note Indenture and the 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 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 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 Information Circular certain information concerning the constitution of its Audit Committee and its relationship with its independent auditor, as set forth in the following:

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 has been an independent financial and management consultant since August 2009. Prior thereto, Mr. McRae was Chief Financial Officer of CCS Inc., administrator of CCS Income Trust (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 Chairman and Chief Executive Officer of Charger Energy Corp. Prior thereto, Mr. Buchanan was the President and Chief Executive Officer 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 Hawk Exploration Ltd. and 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. Dundas is 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, which was completed on January 1, 2011. 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, 2012 (\$)	Fees Paid to Auditor in Year Ended December 31, 2011 (\$)
Audit Fees ⁽¹⁾	369,510	291,570
Audit-Related Fees ⁽²⁾	81,250	93,390
Tax Fees ⁽³⁾	405,976	240,502
All Other Fees ⁽⁴⁾	3,200	2,500
Total	859,936	627,962

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, 2011 and December 31, 2012, 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, 2012, 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, 2012, 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:

- (d) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information;
- (e) the filing of the reports of the independent qualified reserves evaluators on the reserves data and resources data; and
- (f) 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*”
Chief Executive Officer

(signed) “*Ian Atkinson*”
Senior Vice President, Thermal Oil

(signed) “*Ronald J. Eckhardt*”
Director

(signed) “*William Gallacher*”
Director

Dated March 28, 2013

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, 2012. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2012, 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, 2012, and identifies the respective portions thereof that we have evaluated and reported on to the Company’s board of directors:

<u>Independent Qualified Reserves Evaluator</u>	<u>Description and Preparation Date of Evaluation Report</u>	<u>Location of Reserves (Country or Foreign Geographic Area)</u>	<u>Net Present Value of Future Net Revenue (before income taxes, 10% discount rate - MM\$)</u>			
			<u>Audited</u>	<u>Evaluated</u>	<u>Reviewed</u>	<u>Total</u>
GLJ Petroleum Consultants	Corporate Summary March 15, 2013	Canada	—	1,003	—	1,003

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, March 19, 2013.

“ORIGINALLY SIGNED BY”

Caralyn P. Bennett, 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, 2012. The resources data are estimates of low, best and high estimates of contingent and related future net revenue as at December 31, 2012, 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, 2012, and identifies the respective portions thereof that we have evaluated and reported on to the Company’s board of directors:

Independent Qualified Reserves Evaluator and Resource Category	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 March 15, 2013	Canada	—	18,407	—	18,407

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, March 19, 2013.

“ORIGINALLY SIGNED BY”

Caralyn P. Bennett, P. Eng.

Vice-President

NATIONAL INSTRUMENT FORM 51-102F2

REPORT ON RESERVES DATA

To the board of directors of Athabasca Oil Corporation (the “Company”):

1. We have prepared an evaluation of the Company’s reserves data as at December 31, 2012. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2012, estimated using forecast prices and costs. The numbers presented below are based on a sensitivity case that uses prices from GLJ. This was done at the request of the Company.
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, 2012, 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 – GLJ Pricing)			
			Audited MM\$	Evaluated MM\$	Reviewed MM\$	Total MM\$
DeGolyer and MacNaughton Canada Limited	Appraisal Report as of December 31, 2012 on the Hangingstone Property owned by Athabasca Oil Corporation in Alberta, Canada dated March 11, 2013	Canada	-	612	-	612

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. 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:

DeGolyer and MacNaughton Canada Limited, Calgary, Alberta, dated March 11, 2013.

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, 2012. The resources data are estimates of low, best and high estimates of contingent resources and related future net revenue as at December 31, 2012, 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.
3. 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) .
4. 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.
5. The following table sets forth the estimated net present value of future net revenue of the Company (before 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, 2012, 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⁾ – GLJ Pricing Before income tax, 10% discount rate		
			Low Estimate MM\$	Best Estimate MM\$	High Estimate MM\$
			After income tax, 10% discount rate		
DeGolyer and MacNaughton Canada Limited	Report as of December 31, 2012 on the Contingent Resources attributable to Certain Bitumen Accumulations for Athabasca Oil Corporation in Alberta, Canada dated March 11, 2013	Canada	7,941	9,421	10,487
			5,457	6,371	7,290

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 before deduction of royalties payable to others.

6. In our opinion, the resources data evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook.
7. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

8. Because the resources data are based on judgements regarding future events, actual results will vary and the variations may be material.
9. 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 March 11, 2013.

DEGOLYER and MACNAUGHTON CANADA
LIMITED

“ORIGINALLY SIGNED BY”

Douglas S. Christie, P. Geol.

**SCHEDULE “C”
AUDIT COMMITTEE MANDATE**

ATHABASCA OIL CORPORATION

AUDIT COMMITTEE MANDATE

The Audit Committee (**Committee**) of the board of directors (**Board**) of Athabasca Oil Corporation (**Company**) has the oversight responsibility and specific duties described below and shall comply with the requirements of applicable laws.

COMPOSITION

The Committee will be comprised of at least three directors or such greater number as the Board may determine from time to time. Except to the extent that the Board determines that an exemption contained in National Instrument 52-110 issued by the Canadian Securities Administrators or its successor instrument (**NI 52-110**) is available and determines to rely thereon, all Committee members will be independent within the meaning of NI 52-110.

All Committee members will be “financially literate” (as defined in NI 52-110) unless the Board determines that an exemption under NI 52-110 from such requirement in respect of any particular member is available and determines to rely thereon.

Committee members will be appointed and removed by the Board. The Committee Chair will be appointed by the Board.

RESPONSIBILITIES

The Committee’s primary purpose is to assist the Board in fulfilling its oversight responsibilities with respect to (i) the integrity of annual and quarterly financial statements to be provided to the Company’s shareholders and regulatory bodies; (ii) compliance with accounting and finance based legal and regulatory requirements; (iii) the external auditor’s qualifications, independence and compensation, and communicating with the external auditor; (iv) the system of internal accounting and financial reporting controls that management has established; (v) performance of the external audit process and of the external auditor; (vi) financial policies 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