



ANNUAL INFORMATION FORM

**(Except as otherwise noted the
information herein is given
as at December 31, 2011)**

March 22, 2012

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ABBREVIATIONS

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

Oil, Natural Gas Liquids and Natural Gas

bbl	barrel
Mbbl	thousand barrels
MMbbl	million barrels
bbl/d	barrel or barrels per day
Mcf	thousand cubic feet
MMcf	million cubic feet
Mcf/d	thousand cubic feet per day
MMcf/d	million cubic feet per day
Bcf	billion cubic feet
MMBtu	million British Thermal Units

Other

AECO	a natural gas storage facility located at Suffield, Alberta
API	American Petroleum Institute
°API	an indication of the specific gravity of crude oil measured on the API gravity scale. Liquid petroleum with a specified gravity of 28 °API or higher is generally referred to as light crude oil
BOE	barrel of oil equivalent of natural gas and crude oil on the basis of 1 BOE for 6 Mcf of natural gas. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf to 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
BOE/d	barrels of oil equivalent per day
m ³	cubic metres
MBOE	1,000 barrels of oil equivalent
M\$	thousands of dollars
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade
3D	three dimensional seismic

CONVERSIONS

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

To Convert From	To	Multiply By
Mcf	1,000 m ³ of gas	0.028
1,000 m ³ of gas	Mcf	35.493
bbl	m ³ of oil	0.158
m ³ of oil	bbl	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
GJ	MMBtu	0.950

DEFINITIONS

In this Annual Information Form, the following words and phrases have the meanings specified below, unless the context otherwise requires.

"ABCA" means the *Business Corporations Act* (Alberta), including the regulations promulgated thereunder, as amended from time to time.

"**Best estimate**" is 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 at least a 50 percent probability that the quantity actually recovered will equal or exceed the best estimate.

"BG" means BG International Limited, a wholly-owned subsidiary of BG Group PLC.

"**BG Sale Agreement**" means the Sale Agreement dated June 30, 2009 between the Company and BG in respect of the purchase of a 45% interest in Block 5(c) by BG.

"**Block 5(c)**" means the "Intrepid" Block 5(c), covering approximately 32,383 hectares (80,041 acres) located approximately 97 kilometres (60 miles) off the east coast of Trinidad in the Columbus Basin as described in and subject to the terms of the PSC.

"**Board**" means the board of directors of the Company.

"CCAA" means the *Companies' Creditors Arrangement Act*, including the regulations promulgated thereunder, as amended from time to time.

"**CCAA Proceedings**" means the proceedings commenced by the Company, Canadian Superior Trinidad and Tobago Limited (now Sonde Resources Trinidad and Tobago Limited) and Seeker under the CCAA pursuant to an order of the Court dated March 5, 2009.

"**Challenger**" means Challenger Energy Corp.

"**Challenger CCAA Proceedings**" means the proceedings commenced by Challenger and Challenger Energy Trinidad and Tobago Ltd. under the CCAA pursuant to an order of the Court dated February 27, 2009.

"**Crown Lands**" means leases granted by a Canadian Provincial authority.

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook.

"**Common Shares**" means the common shares in the capital of the Company.

"**Company**" or "**Sonde**" means Sonde Resources Corp. and all of its subsidiaries, unless the context otherwise requires.

"**Court**" means the Court of Queen's Bench of Alberta.

"**EPSA**" means the Exploration and Production Sharing Agreement dated August 27, 2008 between the Company and Joint Oil.

"**ETAP**" means Entreprise Tunisienne d'Activités Petroliques.

"**Federal Plan**" means the Framework as amended by the Update.

"**Framework**" means the 'Regulatory Framework for Air Emissions' paper released by the Government of Canada on April 26, 2007.

"**GLJ**" means GLJ Petroleum Consultants Ltd.

"**GLJ Report**" means the report dated February 23, 2012 prepared by GLJ evaluating the oil, NGL and natural gas reserves attributable to the properties of the Company effective December 31, 2011.

"**High estimate**" is 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 at least a 10 percent probability that the quantity actually recovered will equal or exceed the high estimate.

"Joint Oil" means the Joint Exploration, Production, and Petroleum Services Company that is owned equally by the Tunisian government via ETAP and the Libyan government via Libya Oil Holdings.

"Joint Oil Block" means the area covering approximately 310,799 hectares (768,000 acres) located approximately 121 kilometres (75 miles) offshore the Mediterranean Gulf of Gabes as described in and subject to the terms of the EPSA.

"Joint Oil Block JOA" means the joint operating agreement dated July 5, 2010 between the Company and Sahara in respect of the Joint Oil Block.

"LNG Project" means the proposed development of a LNG regasification project in U.S. federal waters offshore New Jersey.

"Mariner Block" means the "Mariner" Block, covering approximately 11,246 hectares (27,790 acres) located approximately 9 kilometres (5.6 miles) northeast of Sable Island, offshore Nova Scotia as described in and subject to the terms of the Mariner Exploration License 2409.

"MG Block" means the "Mayaro/Guayaguayare" Block, covering approximately 23,522 hectares (58,080 acres) located approximately 6.4 kilometres (4 miles) off the east coast of Trinidad in the Columbus Basin as described in and subject to the terms of the Exploration and Production License.

"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*.

"Niko" means Niko Resources Ltd.

"Niko Sale Agreement" means the Sale Agreement dated December 21, 2010 between the Company and Niko in respect of the purchase of the Company's interests in Block 5(c) and the assumption of certain liabilities in respect of the MG Block by Niko.

"NYSE Amex" means NYSE Amex LLC.

"OPEC" means the Organization of the Petroleum Exporting Countries.

"Options" means the options to acquire Common Shares issued under the stock option plan of the Company.

"Preferred Shares" means the preferred shares in the capital of the Company.

"PSC" means the Production Sharing Contract dated July 20, 2005 between the Company and the Government of the Republic of Trinidad and Tobago in respect of Block 5(c).

"Rights Plan" means the shareholder rights plan of the Company.

"Rights Plan Agreement" means the Shareholder Rights Plan Agreement dated June 3, 2010 between the Company and Valiant Trust Company.

"SEC" means the United States Securities and Exchange Commission.

"Seeker" means Seeker Petroleum Ltd.

"Series A Preferred Shares" means the Series A, 5% U.S. cumulative redeemable preferred shares in the capital of the Company.

"Series B Preferred Shares" means the Series B, 5% U.S. cumulative redeemable preferred shares in the capital of the Company.

"Shareholders" means the holders of Common Shares and **"Shareholder"** means any one of them.

"Swap Agreement" means the "Mariner" Block Swap Agreement dated August 27, 2008 between the Company and Joint Oil in respect of the Mariner Block.

"TSX" means the Toronto Stock Exchange.

"UN" means the United Nations.

"Update" means the 'Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions' paper released by the Government of Canada on March 10, 2008.

"U.S." or "United States" means the United States of America, its territories and possessions, any state of the United States, and the District of Columbia.

"West Coast" means West Coast Opportunity Fund, LLC.

"Zarat Field" means a portion of the Joint Oil Block surrounding the Zarat North 1 well, combined with an adjacent license owned by a third party.

GLOSSARY OF TECHNICAL TERMS

In this Annual Information Form, the following technical terms and acronyms have the meanings specified below.

"CBM" means coal based methane.

"contingent resources" are those quantities of crude oil and natural gas 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. The contingencies that prevent the classification of reserves are economic, legal and political. There is no certainty that it will be commercially viable to produce any portion of the contingent resources.

"crude oil" or "oil" as described in the COGE Handbook means a mixture consisting mainly of pentanes and heavier hydrocarbons that exists in the liquid phase in reservoirs and remains liquid at atmospheric pressure and temperature. Crude oil may contain small amounts of sulphur and other non-hydrocarbons but does not include liquids obtained from the processing of natural gas.

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

- (a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines and power lines, to the extent necessary in developing the reserves;
- (b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and the wellhead assembly;
- (c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and
- (d) provide improved recovery systems.

"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.

"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.

"development well" means a well drilled inside the established limits of an oil or gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.

"exploration costs" means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as "prospecting costs") and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

- (a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies (collectively sometimes referred to as "geological and geophysical costs");
- (b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence, and the maintenance of land and lease records;
- (c) dry hole contributions and bottom hole contributions;
- (d) costs of drilling and equipping exploratory wells; and
- (e) costs of drilling exploratory type stratigraphic test wells.

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

"field" means a defined geographical area consisting of one or more pools.

"future net revenue" means the estimated net amount to be received with respect to the development and production of reserves (including synthetic oil, coal bed methane and other non-conventional reserves) estimated using constant prices or forecast prices and costs.

"future prices and costs" means future prices and costs that are:

- (a) generally accepted as being a reasonable outlook of the future;
- (b) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which the Company 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 paragraph (a).

"GHG" means greenhouse gas.

"gross" means:

- (a) in relation to the Company's interest in production or reserves, its "company gross reserves", which are its working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of the Company;
- (b) in relation to wells, the total number of wells in which the Company has an interest; and
- (c) in relation to properties, the total area of properties in which the Company has an interest.

"LNG" means liquefied natural gas.

"natural gas" as described in the COGE Handbook, 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. Natural gas may contain sulphur or other non-hydrocarbon compounds.

"natural gas liquids" or **"NGL"** as described in the COGE Handbook, means those 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.

"net" means:

- (a) in relation to the Company's interest in production or reserves its working interest (operating or non-operating) share after deduction of royalty obligations, plus its royalty interests in production or reserves;
- (b) in relation to the Company's interest in wells, the number of wells obtained by aggregating the Company's working interest in each of its gross wells; and
- (c) in relation to the Company's interest in a property, the total area in which the Company has an interest multiplied by the working interest owned by the Company.

"non-associated gas" means an accumulation of natural gas in a reservoir where there is no crude oil.

"operating costs" or **"production costs"** means costs incurred to operate and maintain wells and related equipment and facilities, including applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities.

"possible reserves" are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible 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 plus probable reserves.

"production" means the cumulative quantity of petroleum that has been recovered at a given date.

"property" includes:

- (a) fee ownership or a lease, concession, agreement, permit, license or other interest representing the right to extract oil or gas subject to such terms as may be imposed by the conveyance of that interest;
- (b) royalty interests, production payments payable in oil or gas, and other non-operating interests in properties operated by others; and
- (c) an agreement with a foreign government or authority under which the Company participates in the operation of properties or otherwise serves as "producer" of the underlying reserves (in contrast to being an independent purchaser, broker, dealer or importer).

but does not include supply agreements, or contracts that represent a right to purchase, rather than extract, oil or gas.

"proved property" means a property or part of a property to which reserves have been specifically attributed.

"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.

"reserves" are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on: (a) analysis of drilling, geological, geophysical, and engineering data; (b) the use of established technology; and (c) specified economic conditions, which are generally accepted as being reasonable and shall be disclosed. Reserves are classified according to the degree of certainty associated with the estimates.

"reservoir" means a porous and permeable subsurface rock 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.

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

"undeveloped reserves" are those reserves expected to be recovered from known accumulations where a significant expenditure (e.g., when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned. In multi-well pools, it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to sub-divide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

"unproved property" means a property or part of a property to which no reserves have been specifically attributed.

"well abandonment costs" means costs of abandoning a well (net of salvage value) and of disconnecting the well from the surface gathering system. They do not include costs of abandoning the gathering system or reclaiming the well site.

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.

CURRENCY

All dollar amounts set forth in this Annual Information Form are expressed in Canadian dollars, except where otherwise indicated. References to Canadian dollars or "\$" are to the currency of Canada and references to U.S. dollars or "US\$" are to the currency of the United States.

The following table sets forth: (i) the exchange rate in effect at the end of each of the periods indicated; (ii) the average of exchange rates in effect on the first business day of each month during such periods; and (iii) the high and low exchange rates during each such periods, in each case based on the Bank of Canada noon buying rate for one Canadian dollar as expressed in U.S. dollars.

	Year ended December 31		
	2011	2010	2009
Rate at end of period	US\$0.9833	US\$1.0054	US\$0.9564
Average rate during period	US\$1.0111	US\$0.9674	US\$0.8757
High	US\$0.9480	US\$0.9278	US\$0.9748
Low	US\$1.0607	US\$1.0054	US\$0.7698

FORWARD-LOOKING INFORMATION

Certain information included in this Annual Information Form and the documents incorporated by reference herein constitutes forward-looking information under applicable securities legislation. Such forward-looking information is provided for the purpose of providing information about management's current expectations and plans relating to the future. Readers are cautioned that reliance on such information may not be appropriate for other purposes, such as making investment decisions. Forward-looking information typically contains statements with words such as "anticipate", "believe", "expect", "plan", "intend", "estimate", "propose", "project" or similar words suggesting future outcomes or statements regarding an outlook. Forward-looking information in this Annual Information Form and the documents incorporated by reference herein include, but is not limited to, information with respect to:

- volume and product mix of the Company's oil and gas production;
- future oil and gas prices and interest rates in respect of the Company's commodity risk management programs;
- future liquidity, creditworthiness and financial capacity;
- volumes and estimated value of the Company's oil and gas reserves and volumes of the Company's contingent resources;
- planned exploration and development activities;
- future results from operations and operating metrics;
- the life of each of the Company's reserves;
- future interest rates;
- future costs, expenses and royalty rates;
- future development, exploration and other expenditures;
- the amount and timing of future asset retirement obligations;
- the Company's tax pools; and
- source of funding for future exploration development activities.

Furthermore, information relating to "reserves" and "resources" are deemed to be forward-looking information, as it involves the implied assessment, based on certain estimates and assumptions, that the reserves and resources described can be recovered and profitable in the future. The assumptions relating to the reserves of the Company are discussed under "Statement of Reserves Data and Other Oil and Gas Information".

Forward-looking information is based on a number of factors and assumptions which have been used to develop such information but which may prove to be incorrect. Although the Company believes that the expectations reflected in such forward-looking information are reasonable, undue reliance should not be placed on forward-looking information because the Company can give no assurance that such expectations will prove to be correct. In addition to other factors and assumptions which may be identified in this Annual Information Form and the documents incorporated by reference herein, assumptions have been made regarding and are implicit in, among other things:

- the ability of the Company to receive approval by Joint Oil and implement a plan of development for the Joint Oil Block;
- entering into a unitization agreement for the Zarat Field;

- the ability of the Company to obtain financing on acceptable terms and the outcome of financing alternatives in North Africa;
- field production rates and decline rates;
- the ability of the Company to secure adequate product transportation and natural gas processing facilities;
- the impact of increasing competition in or near the Company's properties;
- the timely receipt of any required regulatory approvals;
- the ability of the Company to hire and retain qualified management, staff, equipment and services in a timely and cost efficient manner to develop its business;
- the Company's ability to operate the properties in a safe, efficient and effective manner;
- the ability to replace and expand oil and natural gas reserves through acquisition, development of exploration;
- the timing and costs of pipeline, storage and facility construction and expansion;
- future oil and natural gas prices;
- currency, exchange and interest rates;
- the regulatory framework regarding royalties, taxes and environmental matters; and
- the ability of the Company to successfully market its oil and natural gas products.

Readers are cautioned that the foregoing list is not exhaustive of all factors and assumptions which have been used.

By its nature, forward-looking information is subject to a number of risks and uncertainties, which could cause actual results or other expectations to differ materially from those anticipated, including those material risks set forth under "Risk Factors" in this Annual Information Form, "Risk Management" in the financial statements of the Company for the year ended December 31, 2011 and "Risk Management" and "Risk Assessment" in the management discussion and analysis of the Company for the year ended December 31, 2011. The Company is exposed to a number of operational risks inherent in exploiting, developing, producing and marketing crude oil and natural gas. These risks include but are not limited to:

- the unsettled and volatile political and security situations in Libya and Tunisia;
- the outcome of financing alternatives in North Africa;
- sufficient liquidity for future operations;
- cost of capital risk to carry out the Company's operations;
- economic risk of finding and producing reserves at a reasonable cost;
- reliance on reserve estimates for the year as well as on acquisitions;
- financial risk of marketing reserves at an acceptable price given market conditions;
- fluctuations in commodity prices, foreign exchange and interest rates;
- operational matters related to non-operated properties;
- delays in business operations, pipeline or facility restrictions, blowouts;
- debt service and indebtedness may affect the market price of the Common Shares;
- the continued availability of adequate debt and equity financing and cash flow to fund planned expenditures;

- unforeseen title defects;
- aboriginal land claims;
- increased competition and the lack of availability of qualified personnel or management;
- loss of key personnel;
- ability to attract key personnel;
- uncertainty of government policy changes;
- the risk of carrying out operations with minimal environmental impact;
- operational hazards and availability of insurance;
- industry conditions including changes in laws and regulations including the adoption of new environmental laws and regulations and changes in how they are interpreted and enforced;
- general economic, market and business conditions;
- competitive action by other companies;
- the ability of suppliers to meet commitments;
- stock market volatility;
- obtaining required approvals of regulatory authorities; and
- creditworthiness of counterparties.

The forward-looking information contained in this Annual Information Form and the documents incorporated by reference herein are made as of the date of such documents and the Company undertakes no obligation to update publicly or revise any forward-looking information, whether as a result of new information, future events or otherwise, except as required by applicable securities laws. The forward-looking information contained in this Annual Information Form and the documents incorporated by reference herein are expressly qualified by this cautionary statement.

SHARE CONSOLIDATION

On June 3, 2010, the Company consolidated the Common Shares on a five-for-one basis. As such, unless otherwise specifically stated, information contained herein in respect of the Company's share capital which is: (i) as of a date that is prior to June 3, 2010, is presented on a pre-consolidation basis; and (ii) as of a date that is on or after June 3, 2010, is presented on a post-consolidation basis.

SONDE RESOURCES CORP.

General

The Company was incorporated pursuant to the provisions of the ABCA as "297272 Alberta Ltd." on March 21, 1983. Subsequently, the articles of the Company have been amended as follows:

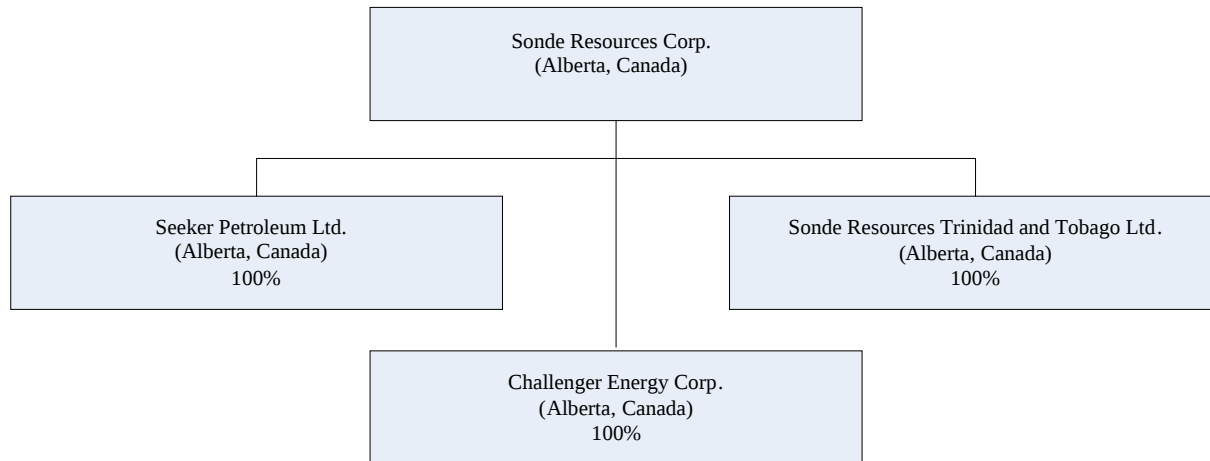
- on April 17, 1993 to change the name of the Company to "KapaIua Gold Mines Ltd." and to remove the private company restrictions;
- on November 16, 1993 to change the name of the Company to "Prize-Energy Inc." and to consolidate the issued and outstanding Common Shares on a one-for-five basis;
- on January 19, 1999 to permit the appointment of additional directors between annual meetings of Shareholders and to restate the articles in a consolidated form;
- on August 24, 2000 to change the name of the Company to "Canadian Superior Energy Inc." and to consolidate the issued and outstanding Common Shares on a one-for-two basis;
- on January 31, 2006 to add the Series A Preferred Shares to the authorized share capital of the Company;
- on February 3, 2010 to add the Series B Preferred Shares to the authorized share capital of the Company; and
- on June 3, 2010 to change the name of the Company to "Sonde Resources Corp." and to consolidate the issued and outstanding Common Shares on a one-for-five basis.

The Company is a reporting issuer, or the equivalent, in the provinces of British Columbia, Alberta, Saskatchewan, Ontario, Quebec, Manitoba, Nova Scotia and Newfoundland. The Common Shares are listed and posted for trading on the TSX and the NYSE Amex (the successor exchange to the American Stock Exchange) under the symbol "SOQ".

The head office of the Company is located at 3200, 500 – 4th Avenue S.W., Calgary, Alberta, T2P 2V6 and its registered office is located at 3700, 400 – 3rd Avenue S.W., Calgary, Alberta, T2P 4H2. In addition, the Company has offices located in Drumheller, Alberta, and Gammarth, Tunis, Tunisia. In 2011, the Company closed its offices in Jersey City, New Jersey and St. Clair, Port of Spain, Trinidad and Tobago.

Inter-Corporate Relationships

The percentage of votes attaching to all voting securities of the material subsidiaries beneficially owned, or controlled or directed, directly or indirectly, by the Company as at December 31, 2011, as well as the jurisdiction where the subsidiary was incorporated, continued, formed or organized, as the case may be, is set forth below.



Effective January 1, 2012, the Company amalgamated Seeker Petroleum Ltd., Sonde Resources Trinidad and Tobago Ltd. and Challenger Energy Corp. into Sonde Resources Corp., transferring all assets and obligations of the wholly-owned subsidiaries to the parent company. As a result, the Company no longer has any material subsidiaries.

Reorganizations

In September 2009 the Company completed its financial restructuring and emerged from protection under the CCAA. The Court issued its final approval order for the implementation of the plan of arrangement pursuant to the CCAA Proceedings and the Challenger CCAA Proceedings on September 15, 2009. The plan of arrangement resulted in the acquisition by the Company of Challenger by plan of arrangement pursuant to section 192 of the *Canada Business Corporations Act* and the sale of a 45% interest in Block 5(c). The Company retained a 25% interest in Block 5(c) following the plan of arrangement, as well as oil and gas assets in Western Canada, the East Coast (Mariner Block) and North Africa (Joint Oil Block) and a 100% interest in its LNG project in the United States. The Company issued approximately 27.4 million shares in connection with its acquisition of Challenger.

Aside from the CCAA Proceedings, the Challenger CCAA Proceedings and the amalgamation of Seeker, Sonde Resources Trinidad and Tobago Ltd. and Challenger into the Company, there have been no reorganizations of the Company or its subsidiaries within the three most recently completed financial years.

GENERAL DEVELOPMENT OF THE BUSINESS

General

The Company is engaged in the exploration for, and acquisition, development and production of, petroleum and natural gas with operations in Western Canada and North Africa. See "Statement of Reserves Data and Other Oil and Gas Information." The Company also reviews new drilling opportunities and potential acquisitions, both domestic and international, to supplement its exploration and development activities.

Three Year History

The following is a description of the general development of the business of the Company over the last three financial years. For a description of the business of the Company, see "Description of the Business".

2009

From February 2009 through September 2009, the Company and Challenger were involved in CCAA Proceedings and the Challenger CCA Proceedings, respectively. The Company emerged from CCAA protection on September 15, 2009.

On February 10, 2009, the Company announced its proposal to monetize a 25% or larger interest in Block 5(c) and its related discoveries, subject to acceptable terms and conditions, and subject to all required approvals.

On February 17, 2009, the Company received a demand letter from Canadian Western Bank for repayment of all amounts outstanding under the Company's \$45.0 million credit facility with Canadian Western Bank by February 23, 2009.

On February 23, 2009, the Company advised that it had reached an accommodation with Canadian Western Bank whereby the demand for repayment of all amounts outstanding under the Company's credit facility with Canadian Western Bank was extended to February 27, 2009 (further extended on March 2, 2009 to March 12, 2009). The credit facility had been permanently reduced the previous week from \$45.0 million to \$37.5 million with a payment of approximately \$7.5 million made to Canadian Western Bank by the Company from the sale of certain Western Canadian properties.

On March 3, 2009, the Company announced the successful flow testing of the "Endeavour" well, the third well drilled by the Company offshore Trinidad on Block 5(c).

On April 24, 2009, Messrs. Noval and Coolen ceased to be the Executive Chairman of the Board and the President, Chief Executive Officer and Chief Operating Officer of Corporation, respectively. Jake Harp was appointed Interim Chairman of the Board.

On April 30, 2009, Leif Snethun was appointed as the Chief Operating Officer of the Company.

On June 30, 2009, the Company entered into the BG Sale Agreement with respect of the purchase of its 45% interest in Block 5(c) by BG.

On September 9, 2009, the annual and special meeting of the Shareholders was held at which time the Shareholders approved the an arrangement involving the Company, Challenger and the shareholders of Challenger that provided for the acquisition of Challenger by the Company. In addition, at the meeting Shareholders elected Messrs. Brittain, Chronister, Funk, Roach, Turnbull and Watkins as directors.

On September 14, 2009, Marvin Chronister was appointed as the Chairman of the Board.

On September 15, 2009, the Company paid all amounts outstanding including accrued interest owed on its \$37.5 million credit facility with Canadian Western Bank and obtained a new \$25.0 million demand revolving credit facility with National Bank of Canada.

On September 15, 2009, pursuant to the CCAA Proceedings, the Company acquired Challenger, by way of a plan of arrangement, for consideration of approximately \$77.8 million, including assumed net debt of approximately \$54.4 million. Approximately 27,728,346 Common Shares were issued in exchange for all of the issued and outstanding common shares of Challenger. The Company also assumed 9,925,000 outstanding share purchase warrants of Challenger which were exercisable at a proportionally adjusted exercise price for Common Shares based on the same exchange ratio by which the Common Shares were issued for common shares of Challenger under the arrangement. All Challenger Share purchase warrants assumed by the Company have expired or were exercised.

On October 28, 2009, National Bank of Canada increased the Company's demand revolving credit facility from \$25.0 million to \$40.0 million. The credit facility is subject to its next scheduled review in April 2012.

On December 21, 2009, the Company announced that due to the current industry environment and market conditions, the Company allowed the Mayflower Exploration License 2406 and the Marauder Exploration License 2415, both offshore Nova Scotia, to lapse in favour of focusing on Trinidad and Tobago, Western Canada and North Africa. The Company extended the Mariner Exploration License 2409 until December 31, 2010.

2010

On January 18, 2010, James H.T. Riddell was appointed as a member of the Board.

On January 19, 2010, the Company completed a private placement of 114,424,238 Common Shares at a price of \$0.52 per Common Share for gross proceeds of approximately \$59.5 million.

On February 3, 2010, the Company converted the entire issued and outstanding Series A Preferred Shares in the aggregate principal amount of US\$15,000,000 owned by West Coast for an equal number of Series B Preferred Shares and 2,500,000 Common Share purchase warrants. Each Common Share purchase warrant entitles West Coast to purchase a Common Share until December 31, 2011 at a price of US\$0.65 per Common Share. For a description of the Series A Preferred Shares and the Series B Preferred Shares, see "Description of Share Capital - Series A Preferred Shares" and "Description of Share Capital - Series B Preferred Shares". For more information with respect to the conversion of the Series A Preferred Shares, see the Material Change Report of the Company dated February 4, 2010, a copy of which is available on SEDAR at www.sedar.com and is incorporated by reference herein.

On July 5, 2010, the Company and Sahara finalized the Joint Oil Block JOA. In addition, the two parties entered into a clarification agreement which, among other matters, gave Sahara until September 15, 2010 to pay its share of costs, plus interest, incurred after April 1, 2010. Sahara's failure to pay its share of costs, plus interest, when due would constitute a default under the terms of the Joint Oil Block JOA.

On September 16, 2010, the Company, as operator under the Joint Oil Block JOA, issued a Notice of Default to Sahara due to Sahara's failure to pay when due its share of joint account expenses associated with the Joint Oil Block. Under the terms of the Joint Oil Block JOA, a formal default period began five business days after issuance of that notice and Sahara had until October 15, 2010, to pay all outstanding joint account expenses associated with its 50% working interest in the Joint Oil Block.

On September 24, 2010, Robb Thompson resigned as the Chief Financial Officer of the Company.

On October 20, 2010, the Company announced that Sahara had failed to cure its default under the Joint Oil Block JOA and that the Company was therefore exercising its option to require that Sahara completely withdraw from the Joint Oil Block, thereby forfeiting its 50% working interest to the Company. In response, Sahara filed for creditor protection under the *Bankruptcy and Insolvency Act* (Canada), with the intention of making a proposal to its creditors (including the Company).

On October 21, 2010 Messrs. Schanck, Dirks and Barkwell were appointed the President and Chief Executive Officer, Chief Operating Officer, and Interim Chief Financial Officer of the Company, respectively.

On November 21, 2010, the Company announced that the Court had ruled in the Company's favour, dismissing the creditor protection previously afforded Sahara and lifting the stay protecting Sahara. As a result, Sahara was notified that Sonde was exercising its option to require that Sahara completely withdraw from the Joint Oil Block, thereby forfeiting its 50% working interest to the Company.

On December 15, 2010, Jack W. Schanck was appointed as a member of the Board.

On December 21, 2010, the Company entered into the Niko Sale Agreement with respect to the purchase of its interests in Block 5(c) by Niko for an aggregate purchase price of US\$87.5 million, to be satisfied at closing by the payment of US\$75.5 million in cash and the assumption of the Company's US\$12.0 million liability under the performance guarantee provided for in the MG Block. A US\$20 million debenture was provided by the Company to support the deposit made by Niko in the event that the Niko Sale was not completed. BG waived its right of first refusal with respect to the Niko Sale. The transaction closed on June 23, 2011, and the Company received an additional US\$1.5 million in purchase price adjustments. The Company ceased all operations in Trinidad and Tobago and completely exited the country effective September 30, 2011. For additional details refer to the Material Change Report of the Company dated December 29, 2010, a copy of which is available on SEDAR at www.sedar.com and is incorporated by reference herein.

In December 2010, the Mariner Exploration License 2409, its remaining asset in Eastern Canada, expired. As a result, Joint Oil had the right to put back and sell the overriding royalty to the Company for US\$12.5 million. This

right, which is referred to as the Mariner Swap Agreement, was exercised by Joint Oil in August 2011. The Company made a payment of US\$12.5 million on January 15, 2012. Prior to the payment, the Company confirmed that the EPSA remains in full force and effect.

2011

On January 11, 2011, the Company announced the successful drilling and production testing of its 100% working interest in the Zarat North -1 well on the Joint Oil Block. The well has been temporarily abandoned while the Company evaluates the recoverable reserve scenarios, development options and cost estimates for the field's development.

On February 24, 2011, the Company announced that it had sold its subsidiary, Liberty Natural Gas LLC, which owned a 100% working interest in the LNG Project to an entity related to West Face Capital Inc. for US\$1.0 million and an entitlement to receive a deferred cash consideration of US\$12.5 million payable upon Liberty Natural Gas LLC's first successful gas delivery. The sale had an effective date of February 22, 2011.

On April 5, 2011, W. Gordon Lancaster was appointed as a member of the Board and Chairman of the Audit Committee.

On May 25, 2011, Kurt A. Nelson was appointed as Chief Financial Officer.

On June 8, 2011, the Company declared Force Majeure on the Joint Oil Block because of UN sanctions adopted by the UN Security Council and Canada that prevented the Company from fulfilling its obligations under the EPSA.

On June 23, 2011, the Company completed the sale of its interests in Block 5(c) and the assumption of certain liabilities in respect of the MG Block through the Niko Sale Agreement for gross proceeds of US\$75.5 million plus purchase price adjustments of US\$1.5 million.

On September 23, 2011, the Company completed the acquisition of a block of producing and non-producing assets in Drumheller from a third party, which includes the bulk of producing interests in the Mannville "I" oil pool not previously owned by the Company for an aggregate purchase price of \$6.3 million.

On October 5, 2011, the Company lifted the Force Majeure Declaration on the Joint Oil Block as a result a result of the Government of Canada and the United Nations repealing their unilateral sanctions against Libya on September 22, 2011.

On November 23, 2011, the Company appointed Toufic Nassif as President of Sonde North Africa.

On December 30, 2011, the Company redeemed all 150,000 outstanding Series "B" Preferred Shares for an aggregate amount of US\$15,186,987.

On January 1, 2012, the Company amalgamated Seeker Petroleum Ltd., Challenger Energy Corp. and Sonde Resources Trinidad and Tobago Ltd. into Sonde Resources Corp.

On January 15, 2012, the Company received a one year extension on the first phase of the exploration period on the Joint Oil Block until December 23, 2013. In addition, Sonde paid to Joint Oil US\$12.5 million pursuant to the Mariner Swap Agreement.

On February 8, 2012, the Company completed the sale of 26,240 gross undeveloped acres (24,383 net acres) in its Kaybob Duvernay play in Alberta for aggregate proceeds of \$75 million. The sale resulted in a net gain of approximately \$73 million.

Significant Acquisitions

The Company did not complete any significant acquisitions during the year ended December 31, 2011 for which disclosure was required under Part 8 of NI 51-102.

DESCRIPTION OF THE BUSINESS

General

The Company is engaged in the exploration for, and acquisition, development and production of, petroleum and natural gas with operations in Western Canada and North Africa. See "Statement of Reserves Data and Other Oil and Gas Information." The Company also reviews new drilling opportunities and potential acquisitions, both domestic and international, to supplement its exploration and development activities.

Competitive Conditions

The oil and natural gas industry is intensely competitive in all its phases. The Company competes with numerous other participants in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. The Company's competitors include resource companies which have greater financial resources, staff and facilities than those of the Company. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery. The Company believes that its competitive position is equivalent to that of other oil and gas issuers of similar size and at a similar stage of development. See "Risk Factors - Competition".

Cycles

The development of oil and gas reserves is dependent on access to areas where exploration and production is to be conducted. Seasonal weather variations, including freeze-up and break-up, affect access in certain circumstances.

Environmental Protection

The oil and gas industry is subject to environmental regulations pursuant to applicable legislation. Such legislation provides for restrictions and prohibitions on release or emission of various substances produced in association with certain oil and gas industry operations, and requires that well and facility sites be abandoned and reclaimed to the satisfaction of environmental authorities. As at December 31, 2011, the Company had recorded an obligation on its statement of financial position of \$26.3 million for the costs of decommissioning its oil and gas assets. The Company maintains an insurance program consistent with industry practice to protect against losses due to accidental destruction of assets, well blowouts, pollution and other operating accidents or disruptions. The Company also has operational and emergency response procedures and safety and environmental programs in place to reduce potential loss exposure. No assurance can be given that the application of environmental laws to the business and operations of the Company will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise adversely affect the Company's financial condition, results of operations or prospects. See "Risk Factors – Environmental Risks" and "Industry Conditions".

Employees

The Company has a total of 34 full-time employees and consultants in the Calgary office, with nine employees in its Drumheller, Alberta office, two consultants in its Tunis office and one consultant in Houston.

Foreign Operations

In addition to its Canadian operations, the Company is engaged in the exploration for oil and natural gas in offshore North Africa. International oil and gas operations are subject to inherent risks and uncertainties which are beyond the control of the Company, particularly those associated with exploring for, and developing, economic quantities of hydrocarbons, volatile commodity prices, political risks, foreign exchange rates, issues relating to global supply and demand, government regulations, and environmental matters. The Company's international exploration ventures may entail certain political and technical business risks. The Company's strategy is to mitigate such risks by aligning itself with partners and engaging personnel and consultants that have international experience. See "Risk Factors - Foreign Political and Security Issues", "Risk Factors - Foreign Operations", "Risk Factors - Foreign Legal Systems" and "Risk Factors - Foreign Currency Rates".

Social or Environmental Policies

The health and safety of employees, contractors and the public, as well as the protection of the environment, is of utmost importance to the Company. To this end, the Company has instituted health and safety policies and programs and endeavors to conduct its operations in a manner that will minimize both adverse effects and consequences of emergency situations by:

- complying with government regulations and standards, particularly relating to the environment, health and safety;
- conducting operations consistent with industry codes, practices and guidelines;
- ensuring prompt, effective response and repair to emergency situations and environmental incidents;
- providing training to employees and contractors to ensure compliance with corporate safety and environmental rules and procedures; and
- communicating openly with members of the public regarding its activities.

The Company believes that all employees have a vital role in achieving excellence in environmental, health and safety performance. This is best achieved through careful planning and the support and active participation of everyone involved.

PRINCIPAL PROPERTIES

A summary description of the Company's major producing and exploration properties is set out below. References to gross volumes refer to total production. References to net volumes refer to the Company's working interest share before the deduction of royalties payable to others.

Western Canada

The Company derives all of its production and cash flow from operations in Western Canada. The Company's Western Canadian oil and gas assets are primarily high working interest properties that are geographically concentrated in southern and west-central Alberta, the most significant being the Company's Southern Alberta cash generating unit ("CGU") (or Greater Drumheller, Alberta area), which accounts for approximately 80% of the Company's production. The balance of production largely comes from the Kaybob/Windfall and Boundary Lake/Eaglesham areas in west-central Alberta, with minor production in north-eastern British Columbia.

At December 31, 2011, the Company held 416,796 gross / 297,623 net acres in Western Canada the majority of which is operated by the Company. At March 23, 2012, the Company held 380,362 gross / 268,120 net acres in Western Canada as adjusted for the February 8, 2012, 26,420 gross / 24,383 net sale of interests in the Kaybob Duvernay play in Alberta and subsequent purchases.

Drumheller

Drumheller contains a wide variety of low-moderate risk operated development opportunities for oil, Cretaceous tight gas sands, and Cretaceous CBM, vertically-stacked on a concentrated, high working interest land position. Of particular importance are operated positions in six oil pools, the largest of which are the Mannville "I" pool (lower Cretaceous Ellerslie sandstone) and the Michichi Detrital pool (lower Cretaceous Detrital sandstone). The Company's plan was to drill three horizontal wells (03-04-29-19, 03-05-29-19 and 14-14-029-19) to test the crest of the structure, a pressure depleted area and the fringe of the pool. The results were not as expected but Sonde continues to evaluate new lift technology to enhance the total liquids production. At the same time, the Company acquired the remaining working interest in the Mannville "I" pool as well as other assets in the Drumheller area. This will allow a water flood of the Mannville "I" pool to potentially increase oil recovery. The Company subsequently drilled two additional wells in the Drumheller area (16-20-029-14 and 02-19-31-19), both horizontal wells. Two wells (3-17-31-17, horizontal and 13-16-03-17 vertical) were drilled at Michichi (Drumheller) and two minor wells drilled by a partner at (13-33-34-20 and 09-33-34-20. Production in the fourth quarter averaged 2,911 boepd.

In addition, the Company owns numerous locations in the form of both producing and suspended vertical wells that hold potential for re-development of existing zones and development of new, principally shallower non-producing zones. The Company plans to continue its work-over and re-development program targeting the Cretaceous Ellerslie, Glauconitic and Viking formations in these locations during 2012.

Kaybob/Windfall

With success in recent lease sales Sonde added acreage in the Ante Creek North area, Sonde owns 38,920 gross (38,920 net) high potential acres in the rapidly expanding Duvernay play. The Company is actively working to permit its inaugural drilling program and anticipates drilling in late 2012. In addition to the Duvernay, Sonde has 38,453 gross (38,453-net) acres of Montney rights at Waskahigan and Ante Creek North, near recently announced high-rate horizontal wells drilled by competitors. Sonde has been engaged in joint venture discussions with several industry and financial partners to provide financial leverage and risk-mitigation in the early phases of these plays.

International

Offshore North Africa (Tunisia and Libya)

The Company acquired the Exploration and Production Sharing Agreement for the 768,000 acre Joint Oil Block, offshore Tunisia and Libya, on August 27, 2008. The exploration work commitment for the first phase (four years) of the seven year exploration period includes three exploration wells, 500 square kilometres (311 square miles) of 3D seismic and one appraisal well. The Company holds a 100% working interest in the concession.

The appraisal well obligation was satisfied by drilling the Zarat North-1, which was temporarily abandoned on January 11, 2011 while the Company evaluates the recoverable reserve scenarios, development options and cost estimates for the field's development. The well was the third drilled on the large Zarat anticlinal feature, following two wells drilled by Marathon in 1992 and 1994, respectively. It encountered 240 net feet of gas/condensate and oil pay in the Eocene El Gueria limestone, with oil/water and gas/oil contacts at the same structural elevation found in the Marathon wells. Tested in three separate intervals, the Zarat North-1 flowed at sustained rates averaging eight MMcf/d of natural gas plus 750 bbl/d of condensate. The Company is currently evaluating the commercial development potential of the Zarat Field, as well as negotiating a unitization agreement with the owners of an adjacent concession. On December 21, 2011, the Company commenced the shooting of 512 square kilometres of 3D seismic around two potential exploration well locations in accordance with the requirements of the EPSA and completed the shoot in January 2012. On January 12, 2012, the Company received notice from Joint Oil extending the first phase of the exploration period one year, until December 23, 2013, subject to securing the services of a drilling rig and agreeing to a plan of development. On January 30, 2012, the Company announced that it began an initiative to identify and evaluate alternatives to finance the Company's remaining North Africa obligations.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

GLJ prepared the GLJ Report in accordance with NI 51-101. The GLJ Report evaluated, as at December 31, 2011, the oil, NGL and natural gas reserves attributable to the properties of the Company. All of the Company's reserves are located in the Canadian provinces of Alberta and British Columbia. No reserves have been attributed to the Joint Oil Block in North Africa.

The tables below are summaries of the oil, NGL and natural gas reserves of the Company and the net present value of future net revenue attributable to such reserves as summarized in the GLJ Report based on forecast price and cost assumptions. The tables summarize the data contained in the GLJ Report and as a result may contain slightly different numbers than such report due to rounding. Also due to rounding, certain columns may not add exactly.

The net present value of future net revenue attributable to the Company's reserves is stated without provision for interest costs and general and administrative costs, but after providing for estimated royalties, production costs, development costs, other income, future capital expenditures and well abandonment costs for only those wells assigned reserves by GLJ. It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to the Company's reserves estimated by GLJ represent the fair market value of those reserves. Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized herein. The recovery and reserve estimates of the Company's oil, NGL and natural gas reserves

provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates provided herein.

The values shown for income taxes and future net revenue after income taxes were calculated on a stand-alone basis in the GLJ Report. The values shown may not be representative of future income tax obligations, applicable tax horizon or after tax valuation.

The GLJ Report is based on certain factual data supplied by the Company and GLJ's opinions of reasonable practice in the industry. The extent and character of ownership and all factual data pertaining to the Company's petroleum properties and contracts (except for certain information residing in the public domain) were supplied by the Company to GLJ and accepted without any further investigation. GLJ accepted this data as presented and neither title searches nor field inspections were conducted.

Summary of Oil and Gas Reserves

Reserve Category	Gross Reserves			Net Reserves		
	Light and Medium Crude Oil	NGLs	Natural Gas	Light and Medium Crude Oil	NGLs	Natural Gas
	Mbbl	Mbbl	MMcf	Mbbl	Mbbl	MMcf
Proved						
Developed Producing	1,059	368	22,457	945	247	20,192
Developed Non-Producing	25	48	3,012	21	33	2,674
Undeveloped	0	0	2,823	0	0	2,615
Total Proved	1,085	416	28,292	966	280	25,482
Probable	899	190	13,266	747	127	11,720
Total Proved Plus Probable	1,984	606	41,518	1,713	407	37,202

Summary of Net Present Value of Future Net Revenue

Reserve Category	Before Future Income Tax Expenses and Discounted at (%/year)				
	0%	5%	10%	15%	20%
	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)
Proved					
Developed Producing	107,035	84,779	70,564	60,749	53,576
Developed Non-Producing	8,789	6,362	5,017	4,141	3,511
Undeveloped	4,403	2,767	1,738	1,074	637
Total Proved	120,227	93,908	77,318	65,964	57,724
Probable	83,222	52,499	36,287	26,706	20,554
Total Proved Plus Probable	203,448	146,407	113,605	92,670	78,278

Reserve Category	After Future Income Tax Expenses and Discounted at (%/year)				
	0%	5%	10%	15%	20%
	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)
Proved					
Developed Producing	107,035	84,779	70,564	60,749	53,576
Developed Non-Producing	8,789	6,362	5,017	4,141	3,511
Undeveloped	4,403	2,767	1,738	1,074	637
Total Proved	120,227	93,908	77,318	65,964	57,724
Probable	83,222	52,499	36,287	26,706	20,554
Total Proved Plus Probable	203,448	146,407	113,605	92,670	78,278

Total Future Net Revenue (Undiscounted)

Reserve Category	Revenue	Royalties	Operating Costs	Development Costs	Abandonment and Reclamation Costs	Future Net Revenue Before Future Income Tax Expenses	Future Income Tax Expenses	Future Net Revenue After Future Income Taxes Expenses
	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)
Total Proved	285,240	32,264	118,509	6,466	7,773	120,227	-	120,227
Total Proved Plus Probable	480,186	60,541	196,050	10,998	9,149	203,448	-	203,448

Future Net Revenue By Production Group

Reserve Category and Product Group	Future Net Revenue Before Future Income Tax Expenses and Discounted at 10%/year ⁽¹⁾	Unit Value Before Future Income Tax Expenses and Discounted at 10%/year
	(M\$)	(\$/BOE)
Total Proved		
Light and Medium Crude Oil	37,961	29.75
Associated Gas and Non-Associated Gas	37,725	10.12
Non-Conventional Oil and Gas Activities (CBM)	1,632	3.34
Total	77,318	14.08
Total Proved Plus Probable		
Light and Medium Crude Oil	57,001	25.48
Associated Gas and Non-Associated Gas	52,673	10.18
Non-Conventional Oil and Gas Activities (CBM)	3,931	4.33
Total	113,605	13.65

Note:

(1) Other revenue and costs not related to a specific production group have been allocated proportionately to production groups.

Summary of Pricing, Exchange Rate and Inflation Rate Assumptions

GLJ employed the following pricing, exchange rate and inflation rate assumptions as of December 31, 2011 in estimating the Company's reserves data, using forecast prices and costs.

Year	Inflation %	Bank of Canada Average Noon Exchange Rate	NYMEX WTI Near Month Futures Contract Crude Oil at Cushing Oklahoma	ICE BRENT Near Month Futures Contract Crude Oil FOB North Sea	Light Sweet Crude Oil (40 API, 0.3%\$) at Edmonton	Bow River Crude Oil Stream Quality at Hardisty	Lloyd Blend Crude Oil Stream Quality at Hardisty	WCS Crude Oil Stream Quality at Hardisty	Heavy Crude Oil Proxy (12 API) at Hardisty	Light Crude Oil (35 API, 1.2 %\$) at Cromer	Medium Crude Oil (29 API, 2.0%\$) at Cromer	Alberta NGLs			
												Spec Ethane	Edmonton Propane	Edmonton Butane	Edmonton Pentanes Plus
		\$US/\$	\$US/bbl	\$US/bbl	\$/bbl	\$/bbl	\$/bbl	\$/bbl	\$/bbl	\$/bbl	\$/bbl	\$/bbl	\$/bbl	\$/bbl	\$/bbl
2012	2	0.98	97.00	105.00	97.96	83.27	81.31	81.61	72.37	93.06	90.12	11.46	58.78	76.41	107.76
2013	2	0.98	100.00	105.00	101.02	84.35	82.33	82.63	73.60	94.96	92.94	13.67	60.61	78.80	108.09
2014	2	0.98	100.00	102.00	101.02	84.35	82.33	82.63	74.51	93.95	91.93	15.26	60.61	78.80	105.06
2015	2	0.98	100.00	100.00	101.02	84.35	82.33	82.63	74.51	93.95	91.93	16.85	60.61	78.80	105.06
2016	2	0.98	100.00	100.00	101.02	84.35	82.33	82.63	74.51	93.95	91.93	18.43	60.61	78.80	105.06
2017	2	0.98	100.00	100.00	101.02	84.35	82.33	82.63	74.51	93.95	91.93	20.02	60.61	78.80	105.06
2018	2	0.98	101.35	101.35	102.40	85.50	83.45	83.75	74.54	95.23	93.18	20.84	61.44	79.87	106.49
2019	2	0.98	103.38	103.38	104.47	87.23	85.14	85.44	77.09	97.16	95.07	21.25	62.68	81.49	108.65
2020	2	0.98	105.45	105.45	106.58	89.00	86.86	87.16	78.67	99.12	96.99	21.70	63.95	83.13	110.84
2021	2	0.98	107.56	107.56	108.73	90.79	88.62	88.92	80.28	101.12	98.95	22.14	65.24	84.81	113.08
2022+	2	0.98	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr

Year	Henry Hub NYMEX Near Month Contract	Midwest Price at Chicago	AECO/NIT Spot	Alberta Plant Gate				Saskatchewan Plant Gate		Sumas Spot	British Columbia		Sulphur FOB Vancouver	Alberta Sulphur at Plant Gate
				Spot Current [2012] \$	ARP	Aggregator	Alliance	Sask Energy	Spot		Westcoast Station 2	Spot Plant Gate		
	\$US/MMBtu	\$US/MMBtu	\$/MMBtu	\$/MMBtu	\$/MMBtu	\$/MMBtu	\$/MMBtu	\$/MMBtu	\$/MMBtu	\$/MMBtu	\$/MMBtu	\$/MMBtu	\$US/LT	\$/LT
2012	3.80	3.90	3.49	3.29	3.23	3.15	2.65	3.33	3.43	3.50	3.29	3.14	200.00	161.08
2013	4.50	4.60	4.13	3.93	3.85	3.76	3.33	3.95	4.07	4.20	3.93	3.78	175.00	135.57
2014	5.00	5.10	4.59	4.39	4.30	4.20	3.82	4.40	4.53	4.70	4.39	4.23	150.00	110.06
2015	5.50	5.60	5.05	4.84	4.74	4.64	4.31	4.84	4.99	5.20	4.85	4.69	125.00	84.55
2016	6.00	6.10	5.51	5.30	5.19	5.08	4.80	5.29	5.45	5.70	5.31	5.14	125.00	84.55
2017	6.50	6.60	5.97	5.75	5.64	5.51	5.29	5.74	5.91	6.20	5.77	5.60	127.50	87.10
2018	6.76	6.86	6.21	5.99	5.87	5.74	5.55	5.97	6.15	6.46	6.01	5.84	130.05	89.70
2019	6.89	6.99	6.33	6.11	5.98	5.85	5.67	6.08	6.27	6.59	6.13	5.95	132.65	92.36
2020	7.03	7.13	6.46	6.23	6.11	5.98	5.81	6.21	6.40	6.73	6.26	6.08	135.30	95.06
2021	7.17	7.27	6.58	6.36	6.23	6.10	5.95	6.33	6.52	6.87	6.38	6.21	138.01	97.83
2022+	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr

Notes:

- (1) Unless otherwise stated, the gas price reference point is the receipt point on the applicable provincial gas transmission system known as the plant gate.
- (2) The plant gate price represents the price before raw gas gathering and processing charges are deducted.
- (3) AECO – C Spot refers to the one month price averaged for the year.

The weighted average realized sales prices by the Company for the year ended December 31, 2011 was \$4.04/Mcf for natural gas, \$88.22/bbl for light and medium crude oil and \$62.79/bbl for NGLs. All figures are exclusive of royalties and transportation but include realized hedging gains and losses.

Reconciliation of Corporation Gross Reserves by Product Type

The following table sets forth the changes the Company's reserve volume estimates made as at December 31, 2011 and the corresponding estimates as at December 31, 2010, using forecast prices and costs.

Factors	Light and Medium Crude Oil			CBM			Conventional Natural Gas			NGLs			Total Oil Equivalent		
	Gross Proved	Gross Probable	Gross Proved Plus Probable	Gross Proved	Gross Probable	Gross Proved Plus Probable	Gross Proved	Gross Probable	Gross Proved Plus Probable	Gross Proved	Gross Probable	Gross Proved Plus Probable	Gross Proved	Gross Probable	Gross Proved Plus Probable
	(Mbbbl)	(Mbbbl)	(Mbbbl)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(Mbbbl)	(Mbbbl)	(Mbbbl)	(MBOE)	(MBOE)	(MBOE)
Dec. 31, 2010	867	812	1,679	4,582	4,129	8,711	24,673	14,607	39,280	311	183	494	6,054	4,117	10,171
Extensions and Improved Recovery	175	72	245	--	--	--	3,242	(881)	2,359	110	32	142	825	(45)	780
Technical Revisions	157	(67)	90	384	24	408	9	(3,606)	(3,597)	58	(28)	30	279	(692)	(413)
Discoveries	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Acquisitions	84	87	171	--	--	--	2,394	734	3,128	23	7	30	506	217	723
Dispositions	(0)	--	(0)	--	--	--	(50)	(11)	(61)	(1)	(0)	(1)	(10)	(2)	(12)
Economic Factors	(1)	(4)	(6)	(1,574)	(1,444)	(3,018)	(950)	(325)	(1,275)	(7)	(4)	(11)	(429)	(303)	(732)
Production	(196)		(196)	(171)		(171)	(4,246)		(4,246)	(78)		(78)	(1,010)		(1,010)
Dec. 31, 2011	1,084	899	1,983	3,221	2,709	5,930	25,071	10,517	35,588	416	190	605	6,215	3,292	9,507

Proved Undeveloped Reserves

The following table sets forth the volumes of proved undeveloped reserves that were first attributed for each of the Company's product types for each of the most recent three financial years and, in the aggregate, before that time, using forecast prices and costs.

Financial Year End	Light and Medium Crude Oil		Natural Gas		NGLs	
	First Attributed (Mbbbl)	Cumulative at Year End ⁽¹⁾ (Mbbbl)	First Attributed (MMcf)	Cumulative at Year End ⁽¹⁾ (MMcf)	First Attributed (Mbbbl)	Cumulative at Year End ⁽¹⁾ (Mbbbl)
Prior to December 31, 2009	13	13	4,287	4,287	3	3
December 31, 2009	0	9	0	4,329	0	1
December 31, 2010	0	10	219	4,170	3	3
December 31, 2011	0	0	0	2,823	0	0

Note:

(1) Cumulative at year end is cumulative of previous year plus first attributed, less developed during the year.

Proved undeveloped reserves are generally those reserves related to planned infill drilling locations. The Company's proved undeveloped reserves are forecasted to be developed during the next two years.

Probable Undeveloped Reserves

The following table sets forth the volumes of probable undeveloped reserves that were first attributed for each of the Company's product types for each of the most recent three financial years and, in the aggregate, before that time, using forecast prices and costs.

Financial Year End	Light and Medium Crude Oil		Natural Gas		NGLs	
	First Attributed (Mbbbl)	Cumulative at Year End ⁽¹⁾ (Mbbbl)	First Attributed (MMcf)	Cumulative at Year End ⁽¹⁾ (MMcf)	First Attributed (Mbbbl)	Cumulative at Year End ⁽¹⁾ (Mbbbl)
Prior to December 31, 2009	567	567	5,946	5,946	15	15
December 31, 2009	0	536	0	5,328	0	10
December 31, 2010	0	458	65	4,751	1	9
December 31, 2011	0	549	0	3,368	0	9

Note:

(1) Cumulative at year end is cumulative of previous year plus first attributed, less developed during the year.

Probable undeveloped reserves relate to wells to be drilled, tied in and brought on-stream in future. The Company's probable undeveloped reserves are forecasted to be developed during the following two to four years in accordance with the Company's development program and budget.

Significant Factors and Uncertainties Affecting Reserves Data

The process of estimating reserves is 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 reserve estimates contained herein are based on current production forecasts, prices and economic conditions.

As circumstances change and additional data becomes available, reserve estimates also change. Estimates made are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and governmental restrictions.

Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. As a result, the subjective decisions, new geological or production information and a changing environment may impact these estimates. Revisions to reserve estimates can arise from changes in year-end oil and gas prices, and reservoir performance. Such revisions can be either positive or negative.

Future Development Costs

The following table sets forth the development costs deducted in the estimation in the GLJ Report of future net revenue attributable to proved reserves and proved plus probable reserves, using forecast prices and costs.

Year	Total Proved	Total Proved Plus Probable
	(M\$)	(M\$)
2012	739	1,808
2013	2,347	3,507
2014	1,948	3,361
2015	18	891
2016	1,082	1,082
Remaining Years	332	348
Total for all years undiscounted	6,466	10,998

The Company expects to fund its future development from internally generated cash flow from operations, debt (where deemed appropriate) and new equity issues (if available on favourable terms). In addition, the Company may consider farm-out arrangements for certain projects. The Company does not expect that the cost of funding will make the development of a property uneconomic for the Company, nor is it expected that the cost of such funding will impact the Company's reserves or future net revenue.

Oil and Gas Wells

The following table sets forth the number and status of wells in which the Company has a working interest as at December 31, 2011.

Location	Light and Medium Crude Oil				Natural Gas			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
British Columbia	-	-	-	--	1.0	0.8	5.0	1.2
Alberta	96.0	75.0	14.0	10.0	302.0	196.2	128.0	78.4
Saskatchewan	-	-	1.0	1.0	-	-	6.0	6.0
Total	96.0	75.0	15.0	11.0	303.0	197.0	139.0	85.6

Properties With No Attributed Reserves

The following table summarizes the undeveloped gross and net acres of properties with no attributed reserves in which the Company has an interest and also the number of net acres for which the Company's rights to explore, develop or exploit will, absent further action, expire within one year.

Location	Gross Acres	Net Acres	Net Acres Expiring Within One Year
British Columbia	30,533	9,807	0
Alberta	186,395	158,495	26,472
Saskatchewan	24,299	24,299	17,206
Offshore North Africa	768,000	768,000	0
Total	1,009,227	960,601	43,678

The EPSA provides for penalties for non-fulfillment of the minimum work program of US\$15 million per exploration well and up to US\$4 million for 3D seismic not completed. As at December 31, 2011, the estimated cost of drilling the three remaining exploration wells to satisfy the remaining work commitments on the Joint Oil Block, Offshore Tunisia and Libya, was US\$100 million to the Company with the potential for costs to exceed this amount.

Significant Factors or Uncertainties Relevant to Properties With No Attributed Reserves

In the Drumheller area of Alberta, the Company continues to evaluate development drilling and waterflood opportunities in six oil pools, the largest of which are the Mannville I pool (lower Cretaceous Ellerslie sandstone) and the Michichi Detrital pool (lower Cretaceous Detrital sandstone). In fourth quarter 2011 and first quarter 2012 the company drilled and completed an inaugural horizontal well in the Michichi Detrital pool, which at the end of the first producing month is currently producing as anticipated. In first quarter 2012 the company installed and tied-in the initial water injection wells supporting the Mannville I pool waterflood pilot; Sonde will begin water injection in late March or early April 2012.

In addition, the Company continues to pursue a work-over and re-development program targeting under-developed oil in the Cretaceous Ellerslie and Detrital formations, and the Mississippian Banff formation. This low-cost low-risk program achieved results in both 2010 and 2011, essentially eliminating Sonde's base production decline through January 2012.

Due to low product prices for natural gas, Sonde has elected to defer new drilling for most natural gas prospects in 2012. The Company has also assessed the economics of all wells and shut-in uneconomic wells.

Following the sale of 26,240 gross undeveloped acres for \$75 million in February 2012, Sonde owns 38,920 gross and net high potential acres in the rapidly expanding Duvernay play, including acreage added to the Ante Creek North area acquired in recent lease sales. In addition to the Duvernay, Sonde has 38,920 gross and net acres of Montney rights in the same area. Sonde may seek a partner to participate in this highly prospective area and, depending on the outcome of the financing alternatives in North Africa, hopes to initiate an inaugural drilling program in late 2012. Sonde has been engaged in joint venture discussions with several industry and financial partners to provide financial leverage and risk-mitigation in the early phases of these plays. No assurance can be provided that the Company will be successful in its efforts to secure a partner for the project. The Company intends to finance future Western Canada capital expenditures to the extent it can, with existing cash flow, and available debt capacity.

Forward Contracts

The Company may periodically enter into commodity sales agreements and certain derivative financial instruments to reduce its exposure to commodity price volatility. These financial instruments are to be entered into solely for hedging purposes and are not used for trading or other speculative purposes. On February 14, 2011, the Company entered into a commodity hedging contract which sets a floor of \$4.11 based on the AECO index on 5,000 GJ per day of natural gas from March 1, 2011 until December 31, 2011. The Company will receive the difference if gas goes below the contract price and remit to seller the amount that exceeds the contract price monthly. In return for

this contract, the Company issued a call option with a price of US\$100 on 250 bbl/d of crude oil from March 1, 2011 until December 31, 2012 based on the WTI index. The Company will remit to seller the amount that exceeds the contract price monthly.

Additional Information Concerning Abandonment and Reclamation Costs

The Company typically estimates well abandonment costs area by area. Such costs are included in the GLJ Report as deductions in arriving at future net revenue.

The expected total abandonment and disconnect costs, net of salvage value, included in the GLJ Report for 226 wells under the proved reserves category is \$7.8 million undiscounted (\$4.1 million discounted at 10%), of which a total of \$2.0 million undiscounted is estimated to be incurred in 2012, 2013 and 2014. This estimate does not include reclamation for surface leases and abandonment costs for wells without reserves.

The Company will be liable for its share of ongoing environmental obligations and for the ultimate reclamation of the properties held by it upon abandonment. Ongoing environmental obligations are expected to be funded out of cash flow.

Costs Incurred

The following table summarizes capital expenditures (including capitalized general and administrative expenses) incurred by the Company for the year ended December 31, 2011:

Property Acquisition Costs		Exploration Costs	Development Costs
Proved Properties	Unproved Properties		
(M\$)	(M\$)	(M\$)	(M\$)
6,242	5,250	14,124	37,509

Tax Horizon

Based on production from existing reserves, the Company estimates that it will not be required to pay income taxes in 2012 or 2013 and with continued exploration activity, the tax horizon could be pushed further.

Exploration and Drilling Activity

In 2011 the Company drilled 11 wells (8.9 net) in Western Canada. The Company implemented a plan to develop the Mannville “I” pool at Drumheller by drilling three horizontal wells (03-04-29-19, 03-05-29-19 and 14-14-029-19) to test the crest of the structure, a pressure depleted area and the fringe of the pool. While the results did not meet the Company’s expectations, the Company continues to evaluate new lift technology to enhance the total liquids production. In 2011 the Company acquired the remaining working interest in the Mannville “I” pool as well as other assets in the Drumheller area. This will allow the Company to water flood the Mannville “I” pool and potentially increase the oil recovery. In 2011 the Company also drilled a single well in the Windfall area (16-28-59-15), and two additional horizontal wells in the Drumheller area (16-20-029-14 and 02-19-31-19). Two wells (13-17-31-17, horizontal and 13-16-03-17 vertical) were drilled at Michichi (Drumheller), two minor wells drilled by a partner at (13-33-34-20 and 09-33-34-20), and the 04-07-054-17 farm out well in the Cardium for which no costs were incurred by the Company.

Production Estimates

The following tables sets forth for each product type the total volume of production estimated by GLJ in the GLJ Report for the first year reflected in the estimates of gross proved reserves and gross probable reserves and gross proved plus probable reserves as disclosed above.

Reserve Category - CGU	Light and Medium Crude Oil	Natural Gas	NGLs	Total Oil Equivalent
	(bbl/d)	(Mcf/d)	(bbl/d)	(BOE/d)
Proved				
Northern Alberta	60	772	3	191
Southern Alberta	454	9,769	160	2,241
Central Alberta	62	1,716	31	379
British Columbia	0	297	0	50
Total	576	12,554	194	2,861
Probable				
Northern Alberta	4	48	0	12
Southern Alberta	23	350	7	88
Central Alberta	5	245	4	49
British Columbia	0	4	0	1
Total	32	646	10	150
Total Proved Plus Probable				
Northern Alberta	64	820	3	203
Southern Alberta	476	10,118	167	2,329
Central Alberta	67	1,960	34	428
British Columbia	0	302	0	50
Total	607	13,200	204	3,011

Production Volume by Cash Generating Unit ("CGU")

The following table indicates the average daily production from each of the Company's important fields for the year ended December 31, 2011.

CGU	Light and Medium Crude Oil	Natural Gas	NGLs	Total Oil Equivalent	%
	(bbl/d)	(Mcf/d)	(bbl/d)	(BOE/d)	
Northern Alberta	61.4	1,074.3	5.9	246.3	9
Southern Alberta	414.7	9,299.7	193.9	2,158.5	77
Central Alberta	62.0	1,337.6	25.8	310.7	11
British Columbia	0.0	475.4	1.2	80.4	3
Total	538.1	12,186.9	226.7	2,795.9	100

Production History

The following table sets forth, on a quarterly basis for the year ended December 31, 2011, certain information in respect of production, product prices received, royalties paid, operating expenses and resulting netback.

	Three Months Ended			
	March 31, 2011	June 30, 2011	September 30, 2011	December 31, 2011
Average Daily Production Volume				
Light and Medium Oil (bbl/d)	469	463	631	587
NGL (bbl/d)	208	203	203	293
Natural Gas (Mcf/d)	12,377	11,509	12,673	12,186
Total (BOE/d)	2,740	2,584	2,946	2,911
Average Prices Received				
Light and Medium Oil (\$/bbl)	83.19	97.35	81.90	88.22
NGL (\$/bbl)	65.92	71.35	66.83	62.79
Natural Gas (\$/Mcf)	4.22	4.09	3.92	3.93
Total (\$/BOE)	38.34	41.29	39.01	40.13
Royalties Paid				
Light and Medium Oil (\$/bbl)	7.69	17.80	12.36	9.77
NGL (\$/bbl)	18.07	12.29	23.62	16.57
Natural Gas (\$/Mcf)	0.24	0.50	0.39	0.07
Total (\$/BOE)	1.81	7.25	4.76	3.91
Production Costs				
Light and Medium Oil and NGLs (\$/bbl)	14.59	13.14	14.90	16.53
Natural Gas (\$/Mcf)	2.46	2.28	2.52	2.79
Total (\$/BOE)	15.02	13.55	15.24	16.76
Transportation Costs				
Light and Medium Oil and NGLs (\$/bbl)	1.02	1.05	0.99	0.95
Natural Gas (\$/Mcf)	0.17	0.18	0.16	0.16
Total (\$/BOE)	1.05	1.09	1.00	0.95
Netback Received ⁽¹⁾				
Light and Medium Oil and NGLs (\$/bbl)	51.39	59.11	47.24	50.24
Natural Gas (\$/Mcf)	1.35	1.13	0.85	0.91
Total (\$/BOE)	20.46	19.40	18.01	18.51

Note:

(1) Netback is calculated by subtracting royalties, transportation and operating costs from revenues.

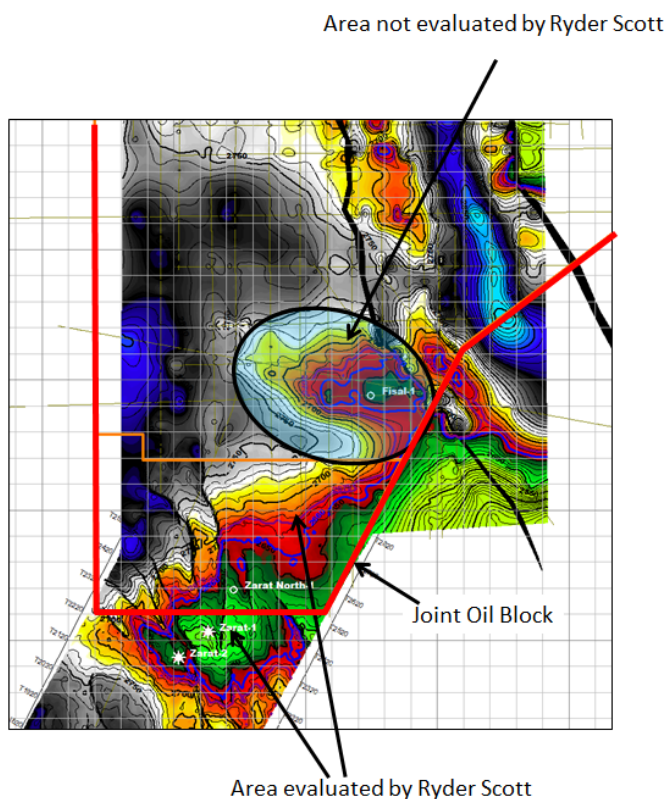
CONTINGENT RESOURCES

In January 2011, the Company completed the Zarat North 1 well in North Africa. The Company continued its evaluation of the reservoir and contracted with Ryder Scott (independent qualified petroleum consultants) who, working with other consultants, provided a Contingent Resource report effective November 1, 2011. In December 2011, the Company commenced the shooting of 512 square kilometers of 3D seismic around three potential exploration well locations in accordance with the requirements of the EPSA. The Company completed the shoot in January 2012. On January 12, 2012, the Company received notice from Joint Oil extending the first phase of the exploration period one year, until December 23, 2013, contingent upon commencement of the three exploratory well work commitment under the EPSA. The Company has initiated the process to secure a drilling rig for this program. In March 2012, the Company filed a Plan of Development with Joint Oil for the development of the Zarat field and it is actively engaged in discussions to unitize development of the Joint Oil Block with an adjacent license holder. In addition, the Company engaged an advisor to seek financing alternatives for the three exploratory well commitment. While the exploratory well commitment is supported by a US\$45 million corporate guarantee, the potential cost of drilling the three wells could exceed US\$100 million. No assurance can be provided that the Company will be successful in finding financing alternatives or that the commitment can be met without such alternatives.

Ryder Scott's Contingent Resource Report reflects a Best (2C) and a High estimate (3C) of 41.5 and 71.1 million boe, respectively, of sales hydrocarbons for the Company's gross interest in the Zarat Field, consisting of 75.8 and 122.6 Bcf of sales gas and 28.8 and 50.7 Mbbl of oil and condensate, for the Best and High estimates, respectively. The map below illustrates the area for which contingent resources have been assigned. Hydrocarbons from the Zarat Field are classified as contingent resources instead of reserves due to a number of contingencies involving future development of the resources, as described below.

The depletion scheme envisioned for the field is to concurrently produce the oil leg and the gas cap gas using six horizontal producing wells and one water disposal well. The base case field recovery factors are a range between the crude oil, condensate and gas cap plus solution volumes. The contingent resource volumes included in the report are estimates only and should not be construed as being exact quantities. The estimates may increase or decrease as a result of future technical data (including results from the 3D seismic program), evaluation studies, and unitization interest. There is no certainty that it will be commercially viable to produce any portion of the estimated resources.

Zarat Field, Offshore Tunisia



The contingencies that prevented the classification of the remaining recoverable quantities as reserves are economic, legal and political. At this time the economic status of the contingent resources assigned to that portion of the Zarat Field covered by the Joint Oil Block is undetermined. A detailed development plan has been prepared by a third party consultant for the entire Zarat field development, is being reviewed by the Company's management and thereafter will require approval of Joint Oil. Once potential markets, processing options, and pricing for the products are better known, development economics for the field will be completed. The Company submitted the Plan of Development to Joint Oil in early 2012. As mentioned previously, a unitization agreement and a development plan for the Zarat Field has not yet been approved. Completion of these milestones is required, together with approval of the timeline for development and proposed capital budget by the Board, before reserves will be assigned for the Joint Oil Block. There is a risk that these milestones may not be achieved as approval of the Plan of Development and agreement on unitization are outside of the control of the Company.

RISK FACTORS

An investment in Common Shares is subject to certain risks. Investors should carefully consider the risk factors set out below and consider all other information contained herein and in the Company's other public filings. In order to mitigate these risks, the Company has qualified technical and financial personnel, with experience in the areas of Canada and North Africa. Further, the Company has focused its foreign operations, and plans to target future operations, in known and prospective hydrocarbon basins in jurisdictions that have previously established long-term oil and gas ventures with oil and gas companies. Additional risks and uncertainties not currently known to the management of the Company may also have an adverse effect on the Company's business and the information set out below does not purport to be an exhaustive summary of all risks affecting the Company.

Substantial Capital Requirements

The Company anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future and the Company has significant work commitments in connection with the EPSA in North America. If the Company's revenues or reserves decline, it may limit the Company's ability to expend or access the capital necessary to undertake or complete future drilling programs and meet commitments. There can be no assurance that debt or equity financing or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Company. The inability of the Company to access sufficient capital for its operations could have a material adverse effect on the Company's financial condition, results of operations or prospects. Specifically, the Company needs a successful outcome to its financing alternatives in North Africa.

Additional financial information with respect to the foregoing is provided in the Company's financial statements and management discussion and analysis for the year ended December 31, 2011, copies of which are available on SEDAR at www.sedar.com.

North Africa

On August 27, 2008, the Company entered into the EPSA with a Tunisian company, Joint Oil. The governments of Tunisia and Libya own joint Oil equally. The EPSA contract area straddles the offshore border between Tunisia and Libya. Under terms of the EPSA, the Company is the operator. Under the EPSA, the minimum work program for the first phase (four years) of the seven-year exploration period includes the Zarat North-1 appraisal well, three exploration wells and 500 square kilometres of 3D seismic. The EPSA provides for penalties for non-fulfillment of the minimum work program of US\$15.0 million per exploration well and up to US\$4.0 million for 3D seismic not completed. The Company has provided a corporate security to a maximum of US\$49.0 million to secure its minimum work program obligations. On January 11, 2011, the Company announced the successful drilling and production testing of its 100% working interest in the Zarat North-1 well. The well has been temporarily abandoned in a manner allowing it to be utilized for future development purposes while the Company evaluates reservoir characteristics and development options on a field development. On December 21, 2011, the Company commenced the shooting of 512 square kilometres of 3D seismic around two potential exploration well locations in accordance with the requirements of the EPSA and completed the shoot in January 2012. On January 12, 2012, the Company received notice from Joint Oil extending the first phase of the exploration period one year, until December 23, 2013. On January 30, 2012, the Company announced that it began an initiative to identify and evaluate alternatives to finance the Company's remaining North Africa obligations. The Company estimates that the potential cost of drilling the three remaining wells could exceed US\$100 million. To assist the Company in financing this commitment, the Company is evaluating its financing options, which may include one or more transactions to sell, farm out, or enter into a joint venture. There can be no assurance that this review of alternatives will result in any specific strategic or financial transaction. The Company must unitize the discovered Zarat Field with the license holder on the southern border of the Joint Oil Block. Negotiations are underway but the outcome is uncertain at this time. A plan of development submitted on the Joint Oil Block must be approved as the unit plan of development and could delay the unitized Zarat Field development. The Company has issued letters of interest to acquire a drilling rig for the three well exploratory commitment. The availability and timing of finding a rig on acceptable terms may be

difficult. The political stability of Tunisia and Libya remains in question, which may affect the Company's activities on the Joint Oil Block.

Capital Markets

The market events and conditions witnessed over the past three financial years, including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions, have caused significant volatility in commodity prices and increases in the rates at which the Company is able to borrow funds for its capital programs. While there have been recent signs which may suggest the beginning of a global economic recovery, there can be no certainty regarding the timing or extent of a potential recovery, and such continued uncertainty in the global economic situation means that the Company, along with all other oil and gas entities, may continue to face restricted access to capital and increased borrowing costs. This could have an adverse effect on the Company, as its ability to make future capital expenditures is dependent on, among other factors, the overall state of the capital markets and investor appetite for investments in the energy industry generally and the Company's securities in particular.

Additional Funding Requirements

The Company's cash flow from its producing reserves is not currently and may not be sufficient to fund its ongoing activities at all times. From time to time, the Company may require additional financing in order to carry out its acquisition, exploration and development activities. Failure to obtain such financing on a timely basis could cause the Company to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Company's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect the Company's ability to expend the necessary capital to replace its reserves or to maintain its production. If the Company's cash flow from operations is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or available on favorable terms.

Issuance of Debt

From time to time the Company may enter into transactions to acquire assets or the shares of other corporations. These transactions may be financed partially or wholly with debt, which may increase the Company's debt levels above industry standards for oil and natural gas companies of similar size. Depending on future exploration and development plans, the Company may require additional debt financing that may not be available or, if available, may not be available on favorable terms. Neither the articles of the Company nor its by-laws limit the amount of indebtedness that the Company may incur. The level of the Company's indebtedness from time to time, could impair its ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise and could negatively affect the Company's debt ratings. This in turn, could have a material adverse effect on the Company's business, financial condition, results of operations and cash flow.

Exploration, Development and Production Risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of the Company depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, any existing reserves the Company may have at any particular time, and the production therefrom will decline over time as such existing reserves are exploited. A future increase in the Company's reserves will depend not only on its ability to explore and develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. No assurance can be given that the Company will be able to continue to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, management of the Company may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by the Company.

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

operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, availability of drilling rigs, support equipment, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, cratering, sour gas releases and spills, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or personal injury. In particular, the Company may explore for and produce sour natural gas in certain areas. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to the Company. In accordance with industry practice, the Company is not fully insured against all of these risks, nor are all such risks insurable. Although the Company maintains liability insurance in an amount that it considers consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits, in which event the Company could incur significant costs that could have a material adverse effect upon its financial condition. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks could have a material adverse effect on the Company.

Operational Dependence

Other companies operate some of the assets in which the Company has an interest. As a result, the Company will have limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect the Company's financial performance. The Company's return on assets operated by others will therefore depend upon a number of factors that may be outside of the Company's control, including the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

Project Risks

The Company will manage a variety of small and large projects in the conduct of its business. Project delays may delay expected revenues from operations. Significant project cost over-runs could make a project uneconomic. The Company's ability to execute projects and market oil and natural gas will depend upon numerous factors beyond the Company's control, including:

- the availability of drilling and related equipment;
- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of storage capacity;
- the supply of and demand for oil and natural gas;
- the availability of alternative fuel sources;
- the effects of inclement weather;
- unexpected cost increases;
- accidental events;

- currency fluctuations;
- changes in regulations;
- the availability and productivity of skilled labor; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, the Company may be unable to execute projects on time, on budget or at all, and may not be able to effectively market the oil and natural gas that it produces.

Availability of Drilling Equipment and Access

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment (typically leased from third parties) in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to the Company and may delay exploration and development activities. To the extent the Company is not the operator of its oil and gas properties, the Company will be dependent on such operators for the timing of activities related to such properties and will be largely unable to direct or control the activities of the operators.

Prices, Markets and Marketing of Crude Oil and Natural Gas

The marketability and price of oil and natural gas that may be acquired or discovered by the Company is and will continue to be affected by numerous factors beyond its control. The Company's ability to market its oil and natural gas may depend upon its ability to contract capacity on pipelines that deliver natural gas to commercial markets. The Company may also be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing and storage facilities and operational problems affecting such pipelines and facilities as well as extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business.

The Company's revenues, profitability and future growth and the carrying value of its oil and gas properties are substantially dependent on prevailing prices of oil and gas. The Company's ability to borrow and to obtain additional capital on attractive terms is also substantially dependent upon oil and gas prices. Prices for oil and gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond the control of the Company. These factors include economic conditions, in the United States, Canada, and North Africa, the actions of the OPEC and Russia, governmental regulation, political stability in the Middle East and elsewhere, the foreign supply of oil and gas, the price of foreign imports and the availability of alternative fuel sources. Any substantial and extended decline in the price of oil and gas would have an adverse effect on the Company's carrying value of its proved reserves, borrowing capacity, revenues, profitability and cash flows from operations.

Volatile oil and gas prices make it difficult to estimate the value of producing properties for acquisition and often cause disruption in the market for oil and gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

In addition, bank borrowings available to the Company in part determined by the Company's borrowing base. A sustained material decline in prices from historical average prices could reduce the Company's borrowing base, therefore reducing the bank credit available to the Company which could require that a portion, or all, of the Company's bank debt be repaid.

Pipeline and Processing Capacity

Although pipeline and facility expansions are ongoing, the lack of firm pipeline and natural gas processing capacity, together with interruptions in pipeline and processing service, continues to affect the oil and natural gas industry and potentially limit the ability to produce and market natural gas production.

Insurance

The Company's involvement in the exploration for and development of oil and natural gas properties may result in the Company becoming subject to liability for pollution, blow-outs, property damage, personal injury or other hazards. Although prior to conducting drilling and other field activities, the Company will obtain insurance in accordance with industry standards to address such risks, such insurance has limitations on liability that may not be sufficient to cover the full extent of such liabilities. In addition, such risks may not, in all circumstances be insurable or, in certain circumstances, the Company may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of such uninsured liabilities would reduce the funds available to the Company. The occurrence of a significant event that the Company is not fully insured against, or the insolvency of the insurer of such event, could have a material adverse effect on the Company's financial position, results of operations or prospects.

Hydraulic Fracturing

Concern has been expressed over the potential environmental impact of hydraulic fracturing operations, including water aquifer contamination, other qualitative and quantitative effects on water resources as large quantities of water are used, and injected fluids either remain underground or flow back to the surface to be collected, treated and disposed of. Regulatory authorities in certain jurisdictions have announced initiatives in response to such concerns. Federal, provincial and local legislative and regulatory initiatives relating to hydraulic fracturing, as well as governmental reviews of such activities could result in increased costs, additional operating restrictions or delays, and adversely affect the Company's production. Public perception of environmental risks associated with hydraulic fracturing can further increase pressure to adopt new laws, regulation or permitting requirements or lead to regulatory delays, legal proceedings and/or reputational impacts. Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to operational delay, increased operating costs, and third-party or governmental claims. This could also increase the Company's cost of compliance and doing business as well as delay the development of hydrocarbon (natural gas and oil) resources from shale formations, which may not be commercial without use of hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that the Company is ultimately able to produce from its reserves.

In the event federal, provincial, local, or municipal legal restrictions are adopted in areas where the Company is currently conducting, or in the future plans to conduct operations, the Company may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from the drilling of wells. In addition, if hydraulic fracturing becomes subject to increased regulation, the Company's fracturing activities could become subject to additional permitting requirements and result in permitting delays as well as potential increases in costs. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that the Company is ultimately able to produce from its reserves.

Legal Proceedings

The Company may from time to time be subject to litigation and regulatory proceedings arising in the normal course of its business. The Company cannot determine whether such litigation and regulatory proceedings will, individually or collectively, have a material adverse effect on its business, results or operations and financial condition. To the extent expenses incurred in connection with litigation or any potential regulatory proceeding or action (which may include substantial fees of lawyers and other professional advisors and potential obligations to indemnify officers and directors who may be parties to such actions) are not covered by available insurance, such expenses could adversely affect the Company's cash position.

Environmental Risks

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 international conventions and international, national, provincial, state and local law and regulation. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and 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 such legislation can require significant expenditures and a breach of same can result in the imposition of clean-up orders, fines and/or penalties, some of which may be material, as well as possible forfeiture of requisite approval obtained from the various governmental authorities. The discharge of GHG emissions and other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Company to incur costs to remedy such discharge. Although the Company 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 adversely affect its financial condition, results of operations or prospects. See "Industry Conditions".

Canadian Tax Considerations

As the Company is engaged in the oil and natural gas business its operations are subject to certain unique provisions of the *Income Tax Act* (Canada) and applicable provincial income tax legislation relating to characterization of costs incurred in their businesses which effects whether such costs are deductible and, if deductible, the rate at which they may be deducted for the purposes of calculating taxable income. The Company has reviewed its historical income tax returns with respect to the characterization of the costs incurred in the oil and natural gas business as well as other matters generally applicable to all corporations including the ability to offset future income against prior year losses. The Company has filed or will file all required income tax returns and believes that it is full compliance with the provisions of the *Income Tax Act* (Canada) and applicable provincial income tax legislation, but such returns are subject to reassessment. In the event of a successful reassessment of the Company it may be subject to a higher than expected past or future income tax liability as well as potentially interest and penalties and such amount could be material.

Foreign Operations

International operations in North Africa are subject to political, economic and other uncertainties, including, among others: risk of war, risk of terrorist activities, border disputes, sanctions by other governments that limit or prevent certain actions, expropriation, renegotiations or modification of existing contracts, restrictions on repatriation of funds, import, export and transportation regulations and tariffs, taxation policies including royalty and tax increases and retroactive tax claims, exchange controls, limits on allowable levels of production, currency fluctuations, labor disputes, sudden changes in laws, government control over domestic oil and gas pricing, and other uncertainties arising out of foreign government sovereignty over the Company's international operations. See Risk Factors – North Africa.

Furthermore international oil and gas operations in offshore North Africa involve substantial costs and are subject to certain risks owing to the underdeveloped nature of the oil and gas industry in Libya and Tunisia. The oil and gas industry in Libya and Tunisia is not as developed as the oil and gas industry in Canada. As a result, drilling and development operations may take longer to complete and may cost more than similar operations in Canada. The availability of technical expertise, specific equipment and supplies is more limited in various countries than in Canada and the United States. Such factors may subject oil and gas operations in other countries to economic and operating risks not experienced in Canada.

Foreign Legal Systems

Tunisia and Libya have less developed legal systems than in Canada which may result in risks such: as (i) effective legal redress in the courts of such jurisdictions, whether in respect of a breach of law or regulation, or, in an ownership dispute, being difficult to obtain; (ii) a higher degree of discretion on the part of governmental authorities; (iii) the lack of judicial or administrative guidance on interpreting applicable rules and regulations; (iv) inconsistencies or conflicts between and within various laws, regulations, decrees, orders and resolutions; or (v)

relative inexperience of the judiciary and courts in such matters; in certain jurisdictions the commitment of local business people, government officials and agencies and the judicial system to abide by legal requirements and negotiated agreements may be more uncertain, creating particular concerns with respect to licenses and agreements for business. These may be susceptible to revision or cancellation and legal redress may be uncertain or delayed. There can be no assurance that joint ventures, licenses, license applications or other legal arrangements will not be adversely affected by the actions of government authorities and the effectiveness of and enforcement of such arrangements in these jurisdictions cannot be assured.

Foreign Currency Rates

A significant amount of the Company's activities are transacted in or referenced to the currencies of the United States and Tunisia. The Company's revenues, operating costs and certain of its payments in order to maintain property interests are to be in the local currency of the jurisdiction where the applicable property is located. As a result, fluctuations in the currencies of the United States and Tunisia against the Canadian dollar, and each of those currencies against currencies in jurisdictions where properties of the Company are located, could result in unanticipated fluctuations in the Company's financial results which are denominated in Canadian dollars. The Company does not currently manage its exposure to fluctuations in currency exchange rates.

Competition

The Company actively competes for reserve acquisitions, exploration leases, licences and concessions and skilled industry personnel with a substantial number of other oil and gas companies, many of which have significantly greater financial resources than the Company. The Company's competitors include major integrated oil and natural gas companies and numerous other independent oil and natural gas companies and individual producers and operators. Competition may also be presented by alternate energy sources.

The oil and gas industry is highly competitive. The Company's competitors for the acquisition, exploration, production and development of oil and natural gas properties, and for capital to finance such activities, include companies that have greater financial and personnel resources available to them than the Company.

Certain of the Company's customers and potential customers are themselves exploring for oil and gas, and the results of such exploration efforts could affect the Company's ability to sell or supply oil or gas to these customers in the future. The Company's ability to successfully bid on and acquire additional property rights, to discover reserves, to participate in drilling opportunities and to identify and enter into commercial arrangements with customers will be dependent upon developing and maintaining close working relationships with its future industry partners and joint operators and its ability to select and evaluate suitable properties and to consummate transactions in a highly competitive environment.

Reserve Replacement

The Company's future oil and natural gas reserves, production, and cash flows to be derived therefrom are highly dependent on the Company successfully acquiring or discovering new reserves. Existing reserves and production will decline over time without the continual additions of new reserves. A future increase in the Company's reserves will depend not only on the Company's ability to develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. There can be no assurance that the Company's future exploration and development efforts will result in the discovery and development of additional commercial accumulations of oil and natural gas.

Reliance on Industry Partners

In order to carry out certain of its business and operations, the Company relies on its industry partners (certain of which include suppliers, contractors and joint venture parties and operators). Accordingly, the Company is exposed to third party risk. Should such industry partners fail to fulfill those duties and obligations each owes to the Company, such failure could have a material adverse effect on the Company's business and/or operations.

Reliance on Key Employees

The Company's success depends in large measure on certain key personnel. The loss of the services of such key personnel could have a material adverse effect on the Company. The Company does not have key person insurance in effect for management. The contributions of these individuals to the Company's immediate 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 the Company 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 the Company's management.

Permits, Licences and Approvals

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

Royalties, Incentives and Production Taxes

In addition to federal regulations, each province has legislation and regulations which govern land tenure, royalties, production rates, environmental protection and other matters. The royalty regime is a significant factor in the profitability of oil and natural gas production. Royalties payable on production from lands other than Crown Lands are determined by negotiations between the mineral owner and the lessee. Crown royalties are determined by government regulation and are generally calculated as a percentage of the value of the gross production, and the rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date and the type or quality of the petroleum product produced.

From time to time, the Governments of Canada, Alberta and British Columbia have established incentive programs which have included royalty rate reductions, royalty holidays and tax credits for the purpose of encouraging oil and natural gas exploration or enhanced planning projects.

Land Tenure

Crude oil and natural gas located in the Canadian western provinces is owned predominantly by the respective provincial governments. 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. Oil and natural gas located in such provinces can also be privately owned 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.

Title to Properties

Although title reviews may be conducted prior to the purchase of 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 the Company's claim which could result in a reduction of the revenue received by the Company.

Reserve and Resource Information

The reserve and recovery information contained in the GLJ Report are only estimates and the actual production and ultimate reserves from the Company's properties may be greater or less than the estimates prepared in such report. The GLJ Report has been prepared using certain commodity price assumptions which are described in the notes to the reserve tables. If lower prices for crude oil, natural gas liquids and natural gas are realized by the Company and substituted for the price assumptions utilized in the report, the present value of estimated future net cash flows for the Company's reserves would be reduced and the reduction could be significant, particularly based on the constant price case assumptions. Exploration for oil and natural gas involves many risks, which even a combination of

experience and careful evaluation may not be able to overcome. There is no assurance that further commercial quantities of oil and natural gas will be discovered by the Company.

References to "contingent resources" do not constitute, and should be distinguished from, references to "reserves". Reserves are estimated remaining quantities of crude oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on the analysis of drilling, geological, geophysical, and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable. Contingent resources are those quantities of crude oil and natural gas 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. The contingencies that prevent the classification of reserves are economic, legal and political. There is no certainty that it will be commercially viable to produce any portion of the contingent resources.

Dilutive Effect of Financings and Acquisitions

The Company may make future acquisitions or enter into financing or other transactions involving the issuance of securities of the Company which may be dilutive to its current shareholders.

Dividends

The Company has not paid any dividends on its outstanding Common Shares nor is expected to in the near future.

Third Party Credit Risk

The Company may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production and other parties. In the event such entities fail to meet their contractual obligations to the Company, such failures could have a material adverse effect on the Company and its cash flow from operations. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in the Company's ongoing capital program, potentially delaying the program and the results of such program until the Company finds a suitable alternative partner.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

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

Hedging

In 2011 the Company entered into agreements to receive fixed prices on a portion of the Company's natural gas production to offset the risk of revenue losses if commodity prices decline; however, if commodity prices increase beyond the levels set in such agreements, the Company will not benefit from such increases and the Company may nevertheless be obligated to pay royalties on such higher prices, even though not received by it, after giving effect to such agreements. In return for fixing this natural gas price, the Company sold a call option on a portion of 2011 and 2012 oil production. Similarly, from time to time the Company may enter into agreements to fix the exchange rate of Canadian to United States dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar; however, if the Canadian dollar declines in value compared to the United States dollar, the Company will not benefit from the fluctuating exchange rate.

Aboriginal Claims

The Canadian First Nations have made rights and title claims to a significant portion of Western Canada. At present the Company is unable to assess what, if any, impact such claims will have on the business and operations that it conducts in Western Canada.

Conflict of Interest

Certain of the directors and officers of the Company are also directors and officers of other oil and gas companies involved in natural resource exploration and development, and conflicts of interest may arise between their duties as officers and directors of the Company and as officers and directors of such other companies. Such conflicts must be disclosed in accordance with, and are subject to such other procedures and remedies as apply under the ABCA.

INDUSTRY CONDITIONS

The oil and natural gas industry is subject to extensive controls and regulations governing its operations (including land tenure, exploration, environmental, development, production, refining, transportation, and marketing) imposed by legislation enacted by various levels of government and with respect to export and taxation of oil and natural gas by agreements among the governments of Canada, British Columbia, Alberta and Saskatchewan, among others, (including the governments of the United States, Tunisia and Libya), all of which should be carefully considered by investors in the oil and gas industry. It is not expected that any of these controls or regulations will affect the Company's operations in a manner materially different than they would affect other oil and gas companies of similar size. All current legislation is a matter of public record and the Company is currently unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of environmental legislation and regulations relevant to the oil and gas industry in the jurisdictions in which the Company has developed producing reserves.

Canadian Government Regulations

Canada is a signatory to the United Nations Framework Convention on Climate Change and the Kyoto Protocol thereunder but has announced that it is withdrawing from the Kyoto Protocol. The Canadian federal government originally indicated an intention to regulate the emissions of GHGs from a range of industries in the Framework. The Framework was updated on March 10, 2008 pursuant to the Update. The Federal Plan outlines a number of policies to reduce the GHG intensity of regulated facilities. New facilities (currently defined as those facilities whose first year of operation is 2004 or later) would face intensity reduction requirements beginning in their fourth year of commercial production of 2% per year from their "baseline" emissions intensity (which baseline is the emissions intensity for such facility's third year of commercial production) until at least 2020. Compliance options for new facilities under the Federal Plan include making emissions intensity improvements; making investments in certified carbon capture and storage projects; buying offsets or emissions performance credits; and for a portion of each entity's emissions reduction obligations, making payments of \$15 per tonne until 2012, \$20 per tonne in 2013 and an escalating annual rate per tonne thereafter; to the federal technology fund.

The Federal Plan also includes proposed requirements to be implemented by the Canadian federal government which would govern the emission of industrial air pollutants. Certain of the proposed requirements include fixed emissions caps, an emissions credit trading system, and several options from which companies can choose to meet their GHG emission reduction targets. At present, the status of its proposals is unclear. The Canadian federal government has repeatedly stated that it intends to align their GHG emission reduction policies with those of the United States, and it is willing to wait until the United States has developed its framework before implementing any policies here in Canada. As such, and given the current political climate in Washington, it is unclear if, when, or in what form, the Federal Plan will be implemented.

Several of the provinces and territories are working together with various American states to develop a cap and trade system. It remains to be seen whether the Canadian federal government would adopt such an approach, but given its statements regarding aligning policy with the United States, this will likely depend on whether the United States adopts a cap and trade system. No assurance can be given that either a modified Federal Plan or a North American

cap and trade system will or will not be implemented, or what kinds of obligations may be imposed under such a system.

In February 2009, the United States and Canada established the 'Clean Energy Dialogue' in order for the two countries to collaborate on the development of clean energy science and technologies to reduce GHG emissions and combat climate change. A number of working groups have been created to develop recommendations for joint initiatives.

At the July 2009 G8 Summit in Italy, Canada and the other G8 members agreed to work together toward achieving at least a 50 percent reduction of global GHG emissions by 2050. Canada reiterated its commitment to this goal at the June 2010 G8 Summit in Huntsville, Ontario.

In December 2009, Canada participated in the COP 15 in Denmark, the goal of which was to reach a new agreement for fighting global climate change. COP 15 resulted in the non-binding Copenhagen Accord, whereby Canada and the other participating countries committed to implementing quantified economy-wide emissions targets by 2020. Canada submitted its GHG emission reduction targets on January 30, 2010, noting that: (a) its target is a 17 percent reduction from a baseline of 2005 emission levels (which target is aligned with the final economy-wide emissions target and base year of the United States); and (b) its submission is dependant on the other parties to the Copenhagen Accord submitting emissions targets and mitigation actions in accordance with such Accord.

There has been much public debate surrounding Canada's ability to meet emission reduction targets and the strategies proposed for controlling climate change and GHG emissions. It is likely that any such strategies which are eventually adopted by the Canadian government will materially impact the nature of oil and gas operations, including those carried out by the Company. At present, it is not possible to predict the impact such strategies will have on the business, operations and/or finances of the Company.

Alberta

Environmental legislation in the Province of Alberta has largely been consolidated into the *Environmental Protection and Enhancement Act* (Alberta), the *Water Act* (Alberta), and the *Oil and Gas Conservation Act* (Alberta). These statutes impose environmental standards, require compliance, reporting and monitoring obligations, and impose penalties. In addition, the emissions reduction requirements in the *Climate Change and Emissions Management Act* (Alberta) came into effect on July 1, 2007. Under this legislation, Alberta facilities emitting more than 50,000 tonnes of GHG emissions per year must report such emission to Alberta Environment and Water and to Environment Canada while facilities emitting more than 100,000 tonnes of GHG emissions per year must reduce their emissions intensity by 12 percent. The Company has four options to choose from in order to meet the reduction requirements outlined in this legislation, and these are: making improvement to operations that result in reductions; purchasing emission credits from other sectors or facilities that have reduced their emissions below the required emission intensity reduction levels; purchasing off-set credits from other sectors or facilities that have emissions below the 100,000 tonne threshold and are voluntarily reducing their emissions in Alberta; or contributing to the 'Climate Change and Emissions Management Fund'. The Company can choose one of these options or a combination thereof, however it should be noted that the price of off-set credits could be raised, and the required reductions in GHG emissions intensity presently set forth could be increased to unspecified levels.

In January of 2008 Alberta introduced its Climate Change Strategy which includes three broad themes: (i) conserving and using energy efficiently; (ii) implementing carbon capture and storage; and (iii) greening energy production. Under the Climate Change Strategy, Alberta has indicated its intention to meet the following emission reduction targets: a 20 megatonne reduction by 2010, a 50 megatonne reduction by 2020 and a 200 megatonne reduction by 2050, all while maintaining economic growth. In furtherance of this Climate Change Strategy, the Government of Alberta has begun enacting legislation including the *2009 Carbon Capture and Storage Funding Act* and the *2010 Carbon Capture and Storage Statutes Amendment Act*.

British Columbia

British Columbia's Oil and Gas Activities Act regulates the oil and gas industry, including imposing environmental standards, requiring compliance, reporting and monitoring obligations and imposing penalties.

On February 27, 2007, the Government of British Columbia unveiled the BC Energy Plan, which outlines the province's energy strategy. The BC Energy Plan sets targets for reducing GHG emissions, promoting investments in innovation, and sustainable environmental management. The BC Energy Plan's objectives are to achieve clean energy through conservation and energy efficient practices, and to increase competitiveness in order to attract new investment in the oil and natural gas industry. The changes proposed include: (i) the creation of policies and measures for the reduction of emissions; (ii) the elimination of routine flaring at producing wells; (iii) the establishment of the Innovative Clean Energy Fund, in order to find new technologies that will help solve energy and environmental issues; (iv) a new Oil and Gas Technology Transfer Incentive Program, which encourages the research, development and use of innovative technologies to responsibly develop new oil and gas reserves and increase recoveries from existing reserves; and (v) the development of unconventional resources such as tight gas and coalbed gas.

In furtherance of these initiatives, the Government of British Columbia introduced the *Carbon Tax Act* on July 1, 2008. The carbon tax applies to fuels such as gasoline, diesel, natural gas, propane and coal, and it is revenue-neutral, meaning tax revenues will be returned to taxpayers through reductions in other provincial taxes.

On May 29, 2008, the Government of British Columbia enacted the *Greenhouse Gas Reduction (Cap and Trade) Act*, which allows for participation in the Western Climate Initiative cap and trade system currently being developed by a group of Canadian Provinces and US States. The proposed system establishes a limit on GHG emissions, and allows regulated emitters to buy/sell GHG emission allowances or offset credits. The emitter is obliged to obtain GHG emission allowances (compliance units) which are equal to the amount of GHG emissions released within a certain period of time, which are then to be surrendered to the Government of British Columbia as proof of compliance.

In support of an eventual cap and trade system, British Columbia has also enacted certain regulations under the *Greenhouse Gas Reduction (Cap and Trade) Act*, including the *Reporting Regulation* which was approved by the Governor in Council on November 25, 2009. The *Reporting Regulation* sets out the requirements for the reporting of greenhouse gas emissions from facilities in British Columbia emitting 10,000 tonnes or more of carbon dioxide equivalent emissions per year beginning on January 1, 2010. Those reporting operations with emissions of 25,000 tonnes or greater are required to have emissions reports verified by a third party. Additional regulations that will further enable British Columbia to implement a cap and trade system are currently under further development.

DIVIDENDS

The Company has not declared or paid any dividends on the Common Shares since incorporation. It is not currently expected that dividends will be paid in respect of the Common Shares during the current phase of development of the Company's business and operations. The payment of dividends in the future will be at the discretion of the Board and will be dependent on the future earnings and financial condition of the Company and such other factors as the Board considers appropriate.

Dividends of US\$0.6 million, US\$ Nil and US\$ Nil were paid by the Company in each of the years ended December 31, 2009, 2010 and 2011, respectively, to various holders of the Series A Preferred Shares.

Dividends of US\$ Nil, US\$0.9 million and US\$1.0 million were paid by the Company in each of the years ended December 31, 2009, 2010 and 2011, respectively, to various holders of the Series B Preferred Shares.

DESCRIPTION OF SHARE CAPITAL

The Company's authorized share capital consists of an unlimited number of Common Shares and an unlimited number of Preferred Shares, issuable in series. As of the date hereof, 62.3 million Common Shares and no Series A or Series B Preferred Shares are issued and outstanding. For more information with respect to the conversion of the

Series A Preferred Shares and the redemption of the Series B Preferred Shares, see "General Development of the Business - Recent Developments.

Common Shares

The holders of Common Shares are entitled to notice of and to vote at all meetings of Shareholders (except meetings at which only holders of a specified class or series of shares are entitled to vote) and are entitled to one vote per Common Share. The holders of Common Shares are entitled to receive such dividends as the Board may declare and, upon liquidation, to receive such assets of the Company as are distributable to holders of Common Shares.

Preferred Shares

The Preferred Shares may be issued in one or more series with each series to consist of such number of shares as may, before the issue of the series, be fixed by the Board. The Board is authorized, before the issue of the series, to determine the designation, rights, restrictions, conditions and limitations attaching to the Preferred Shares of each series. The Preferred Shares of each series rank equally with respect to the payment of dividends and the distribution of assets in the event of liquidation, dissolution or winding-up and in priority to the Common Shares and any other shares of the Company ranking junior to the Preferred Shares. In addition, if any amount of a fixed cumulative dividend or an amount payable on return of capital in respect of shares of a series of Preferred Shares is not paid in full, the shares of the series are entitled to participate ratably with the shares of any other series of the same class in respect of such amounts.

The Series A Preferred Shares were converted to Series B Preferred shares on February 3, 2010. On December 30, 2011, the Company redeemed the 150,000 Series B Preferred Shares previously outstanding.

Rights Plan

The Company adopted the Rights Plan in accordance with the Rights Plan Agreement. Pursuant to the terms of the Rights Plan Agreement, the Rights Plan will expire on the date that the annual meeting of Shareholders to be held in 2013 terminates unless re-approved by the Shareholders. For more information with respect to the Rights Plan, see the Information Circular of the Company dated August 12, 2009 and the Rights Plan Agreement, copies of which are available on SEDAR at www.sedar.com and are incorporated by reference herein.

MARKET FOR SECURITIES

The Common Shares are listed and posted for trading on the TSX and the NYSE Amex under the symbol "SOQ". The following table sets forth the price ranges and volume of Common Shares traded as reported by the TSX for the periods indicated.

2011	High (\$)	Low (\$)	Close (\$)	Volume
January	4.50	3.25	4.08	6,407,200
February	4.39	3.55	3.80	4,490,700
March	3.81	2.94	3.45	1,583,200
April	3.45	2.82	3.04	831,300
May	3.23	2.44	3.18	1,386,500
June	3.15	2.52	3.13	1,586,200
July	3.27	2.61	2.78	1,864,700
August	2.90	2.02	2.85	1,478,100
September	2.92	2.25	2.41	2,966,900
October	3.03	2.15	2.95	1,942,000
November	2.97	2.31	2.38	805,000
December	2.77	2.22	2.65	1,015,000

PRIOR SALES

During the year ended December 31, 2011, a total of 1,984,500 Options, being the only unlisted securities of the Company that were issued, were granted are as follows:

Date of Grant	Number of Options	Exercise Price
January 12, 2011	876,000	\$4.30
January 18, 2011	40,000	\$4.14
January 28, 2011	16,000	\$3.89
May 27, 2011	730,000	\$2.86
June 24, 2011	50,000	\$2.81
August 16, 2011	150,000	\$2.50
September 9, 2011	5,000	\$2.62
October 4, 2011	22,500	\$2.27
November 14, 2011	75,000	\$2.73
November 16, 2011	20,000	\$2.65

ESCROWED SECURITIES

To the knowledge of management of the Company, none of its securities are subject to escrow conditions or contractual restrictions on transfer.

DIRECTORS AND OFFICERS

Directors and Officers

The following sets forth, as at the date hereof, the residence of the directors and executive officers of the Company, their offices or positions with the Company, their principal occupations during the past five years and the period during which each director has served as a director. The term of the directors' office expires at the next annual meeting of Shareholders.

Name and Residence	Office or Position	Director Since	Principal Occupation During the Last Five Years
Kerry R. Brittain ⁽¹⁾⁽³⁾ Texas, United States	Chairman of the Board	September 2009	From July 2007 to present, in private law practice advising companies on acquisitions and domestic and international transactions. Prior thereto, from July 2002 to July 2007, Senior Vice President, General Counsel and Secretary for Harvest Natural Resources Inc., a U.S. public oil and gas company.
Marvin M. Chronister ⁽⁴⁾ Texas, United States	Director	September 2009	From June 2006 to present, an energy finance and operational consultant. Prior thereto, from August 2004 to June 2006, Financial Operations Practice Director of Jefferson Wells International, Inc., a financial consulting firm.
Jack W. Schanck Alberta, Canada	President and Chief Executive Officer and Director	December 2010	From December 2010 to present, Chief Executive Officer and President of Sonde. Prior thereto, from 2007 to 2009, Managing Partner of Tecton Energy, LLC, a private oil and gas company. Prior thereto, from 2005 to 2007, Chief Executive Officer of SouthView Energy LP, a predecessor entity of Tecton Energy, LLC.
Dr. James M. Funk ⁽³⁾⁽⁴⁾ Pennsylvania, United States	Director	September 2009	From January 2004 to present, President and Geologist of J.M Funk & Associates, Inc., a private oil and gas consulting company.
W. Gordon Lancaster ⁽¹⁾⁽²⁾ British Columbia, Canada	Director	April 2011	From November 2009 to present, an independent business consultant. From January 2004 to November 2009, Chief Financial Officer of Ivanhoe Energy Inc., a public oil and gas company.
Dr. William J.F. Roach ⁽⁴⁾ Alberta, Canada	Director	September 2009	From January 2012 to present, Chief Executive Officer of Cavalier Energy Inc., a private oil sands company. From October 2010 to December 2011, Chief Executive Officer of Calera Corporation, a carbon capture company. Prior thereto, from October 2004 to October 2010, President and Chief Executive Officer of UTS Energy Inc., a public oil and gas company.
Gregory G. Turnbull ⁽¹⁾⁽²⁾⁽³⁾ Alberta, Canada	Director	September 2009	From July 2002 to present, a partner with the law firm of McCarthy Tétrault LLP.
James H.T. Riddell ⁽²⁾⁽⁴⁾ Alberta, Canada	Director	January 2010	From June 2002 to present, President and Chief Operating Officer of Paramount Resources Ltd., a public oil and gas company and from February 2010 to present, President and Chief Executive Officer of Trilogy Energy Corp., a public oil and gas company. Prior thereto, from February 2005 to February 2010, President and Chief Executive Officer of Trilogy Energy Ltd., a public oil and gas company.

Name and Residence	Office or Position	Director Since	Principal Occupation During the Last Five Years
William Dirks Alberta, Canada	Chief Operating Officer	N/A	From October 2010 to present, Chief Operating Officer of the Company. Prior to that, from 2005-2010, Managing Partner of Tecton Energy, LLC, a privately-owned exploration and production company he co-founded; from 2001-2005 President of Samson Canada Ltd. and Vice President of Business Development for Samson Resources, both privately-held exploration and production companies. Prior experience, from 1981-1999, was a series of assignments for the Royal Dutch / Shell Group of companies.
Kurt A. Nelson Texas, United States	Chief Financial Officer	N/A	From May 2011 to present, Chief Financial Officer of the Company. Prior thereto, from November 2001 to May 2008, Vice President and Chief Accounting Officer for Harvest Natural Resources, Inc. a public oil and gas company.

Notes:

- (1) Member of the Audit Committee.
- (2) Member of the Compensation Committee.
- (3) Member of the Corporate Governance Committee.
- (4) Member of the Health, Safety, Environment and Reserves Committee.

As at December 31, 2011, the directors and executive officers of the Company, as a group, beneficially owned, directly or indirectly, or exercised control or direction over 290,000 Common Shares representing less than one percent of the issued and outstanding Common Shares.

Corporate Cease Trade Orders or Bankruptcies

To the knowledge of management, no director or executive officer of Sonde is, or has been, within the past 10 years before the date hereof, a director or executive officer of any issuer that, while that person was acting in that capacity: (i) was the subject of a cease trade or similar order or an order that denied the issuer access to any exemption under securities legislation for a period of more than 30 consecutive days; or (ii) was subject to an event that resulted, after the person ceased to be a director or executive officer, in the issuer being the subject of a cease trade or similar order or an order that denied the issuer access to any exemption under securities legislation for a period of more than 30 consecutive days, other than:

- Mr. Riddell was a director and executive officer of Paramount Resources Ltd., the general partner of T.T.Y. Paramount Partnership No. 5, a limited partnership engaged in oil and gas exploration and development activities. A cease trade order against T.T.Y. Paramount Partnership No. 5 was issued by the Quebec Securities Commission in 1999 for failing to file its June 30, 1998 financial statements in Quebec. The cease trade order was revoked on April 9, 2008. T.T.Y. Paramount Partnership No. 5 was dissolved on July 21, 2008.

To the knowledge of management, no director, executive officer of Sonde or controlling Shareholder is, or has been, within the past 10 years before the date hereof, a director or executive officer of any issuer that, while that person was acting in that capacity or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets, other than:

- Messrs. Brittain, Chronister, Funk, Roach and Turnbull were appointed directors of the Company in connection with the completion of the CCAA Proceeding;
- Mr. Turnbull was a director of Action Energy Inc., a corporation engaged in the exploration, development and production of oil and gas in Western Canada. Action Energy Inc. was placed in receivership on October 28, 2009 by its major creditor and Mr. Turnbull resigned as a director immediately thereafter;

- Mr. Chronister was a director of Saratoga Resources, Inc., a corporation engaged in the production, development and acquisition of natural gas and crude oil properties. Saratoga Resources, Inc. filed a voluntary petition for reorganization under Chapter 11 of the *US Bankruptcy Code* in March 2009. Mr. Chronister left the board of directors of Saratoga Resources, Inc. in April, 2009; and
- Mr. Riddell was a director of Jurassic Oil and Gas Ltd., a private oil and gas company, within one year of such company becoming bankrupt. Jurassic Oil and Gas Ltd.'s bankruptcy was subsequently annulled.

Personal Bankruptcies

To the knowledge of management, no director, executive officer of Sonde or controlling Shareholder has, within the 10 years before the date hereof, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or became subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold such person's assets.

Penalties or Sanctions

To the knowledge of management, no director, executive officer of Sonde or controlling Shareholder has: (i) been subject to any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority, other than penalties for late filing of insider reports; or (ii) been subject to 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 directors and/or officers of other private and public companies. Some of these private and public companies may, from time to time, be involved in business transactions or banking relationships which may create situations in which conflicts might arise. Any such conflicts shall be resolved in accordance with the procedures and requirements of the relevant provisions of the ABCA, including the duty of such directors and officers to act honestly and in good faith with a view to the best interests of the Company.

AUDIT COMMITTEE

Composition of the Audit Committee

The Audit Committee operates pursuant to a charter that sets out its responsibilities and composition requirements. A copy of the charter is attached to this Annual Information Form as Appendix "C". The Audit Committee consists of Messrs. Lancaster (Chair), Brittain and Turnbull. All members of the Audit Committee are independent and financially literate (as determined by National Instrument 52-110, *Audit Committees*). In addition, Mr. Lancaster is a "financial expert" as defined under National Instrument 52-110, *Audit Committees*.

In considering criteria for the determination of financial literacy, the Board looked at the ability to read and understand a balance sheet, an income statement and cash flow statement of a public company as well as the director's past experience in reviewing or overseeing the preparation of financial statements. The following sets out the education and experience of each director relevant to the performance of his duties as a member of the Audit Committee.

W. Gordon Lancaster

Gord Lancaster is a Chartered Accountant and completed a 20-year career in public accounting with Deloitte & Touche with the last five years as a partner in that firm's Vancouver office. He spent the next 27 years as a Chief Financial Officer of large and medium sized publicly traded companies. Mr. Lancaster also currently serves as the Chair of the audit committee of a TSX listed forestry company and as a member of the audit committee for a TSX and HKSE listed coal mining company. Mr. Lancaster is a Chartered Accountant certified in British Columbia and is a member of the Institute of Corporate Directors. For more information with respect to Mr. Lancaster's principal occupations during the past five years, see "Directors and Officers".

Kerry R. Brittain

Kerry Brittain is currently in private law practice advising companies on acquisitions and domestic and international transactions and has over 35 years' experience in the oil and gas industry. Mr. Brittain holds a Bachelor of Arts degree and a Juris Doctor degree. For more information with respect to Mr. Brittain's principal occupations during the past five years, see "Directors and Officers".

Gregory G. Turnbull, QC

Gregory Turnbull is a partner of McCarthy Tétrault LLP and has over 30 years' experience in the legal, oil and gas industries. Mr. Turnbull currently also serves as a director of Crescent Point Energy Corp., Storm Resources Ltd., Heritage Oil Plc., Hyperion Exploration Corp., Porto Energy Corp., Hawk Exploration Ltd., and Sunshine Oilsands Ltd. Mr. Turnbull holds a Bachelor of Arts (Honours) degree and a Bachelor of Laws degree and was called to the Alberta bar in 1980. For more information with respect to Mr. Turnbull's principal occupations during the past five years, see "Directors and Officers".

Auditors' Fees

Deloitte & Touche LLP is the external auditor of the Company and is independent to the Company within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta. Fees paid to the Company's auditors for the years ended December 31, 2011 and 2010 are detailed below.

Fee	For the year ended December 31, 2011	For the year ended December 31, 2010
Audit Fees	\$329,600	\$281,295
Audit-Related Fees ⁽¹⁾	\$162,526	\$102,394
Tax Fees ⁽²⁾	\$152,168	\$88,963
Other Fees ⁽³⁾	\$24,398	\$58,366
Total	\$668,692	\$531,018

Notes:

- (1) "Audit-Related Fees" include the aggregate fees paid to the external auditors for services related to the audit services, including reviewing quarterly financial statements and management's discussion thereon, conversion to International Financial Reporting Standards and consulting with the Board and Audit Committee regarding financial reporting and accounting standards.
- (2) "Tax Fees" include the aggregate fees paid to external auditors for tax compliance, tax advice, tax planning and advisory services, including namely preparation of tax returns.
- (3) "All Other Fees" include the aggregate fees paid to the external auditors for assurance procedures in connection with filings statements and information circulars and services related to offerings.

All permissible categories of non-audit services to be provided by the external auditor must be pre-approved by the Audit Committee subject to certain statutory exceptions.

LEGAL AND REGULATORY PROCEEDINGS

Except as disclosed herein, Sonde is not a party to any legal proceeding nor was it a party to, nor is or was any of its property the subject of any legal proceeding, during the year ended December 31, 2011, nor is management of the Company aware of any such contemplated legal proceedings, which involve a claim for damages, exclusive of interest and costs, that may exceed 10% of the current assets of the Company.

During the year ended December 31, 2011, there were no: (i) penalties or sanctions imposed against the Company by a court relating to securities legislation or by a securities regulatory authority; (ii) 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; or (iii) settlement agreements the Company entered into before a court relating to securities legislation or with a securities regulatory authority.

In December 2009, a class action lawsuit was commenced in the United States District Court of the Southern District of New York against certain former executive officers of the Company for allegedly violating the United States Securities and Exchange Act of 1934 by failing to disclose information concerning its prospects in Trinidad and Tobago. In addition, in May and June 2010, two proposed class action lawsuits were commenced in the Ontario Superior Court of Justice. The actions are made against different groups of former executives and directors of the Company. One of the actions alleged oppression and improper option granting practices and includes the Company

and Challenger, a wholly owned subsidiary of the Company, as defendants. The actions contain various claims relating to allegations of misrepresentation and failure to disclose information concerning the Company's activities in Trinidad and Tobago. The class action lawsuits purported to be brought on behalf of purchasers of common shares of the Company from January 14, 2008, to February 17, 2009.

The parties to the class actions entered into a final stipulation of settlement (the "Stipulation") providing, among other things, for the full and final disposition of the litigation, with prejudice and without costs, by the establishment of a US\$5.2 million settlement fund by the Defendants' insurers for the benefit of a settlement class consisting of all those who purchased securities of the Company between January 14, 2008, and February 17, 2009. Subsequently, the Stipulation was approved by the U.S. and Canadian courts. Notice was given to the classes of possible claimants and the Company was notified by counsel on January 11, 2012, that the litigation is complete and all parties are released.

In addition, the Company is involved in various claims and litigation arising in the ordinary course of business. In the opinion of the Company such claims and litigation are not expected to have a material effect on the Company's financial position or its results of operations. The Company maintains insurance, which in the opinion of the Company, is in place to address any future claims as to matters insured.

INTERESTS OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Except as disclosed herein, no director or executive officer of the Company, or any person or company that is the beneficial owner of, or who exercises control or direction of, more than 10% of the Common Shares or any associate or affiliate of any of the foregoing persons has had any material interest, direct or indirect, in any transaction in the three most recently completed financial years or during the current financial year that has materially affected or will materially affect Sonde.

TRANSFER AGENT AND REGISTRAR

Valiant Trust Company at 310, 606 - 4th Street S.W., Calgary, Alberta, T2P 1T1, is the transfer agent and registrar for the Common Shares.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, the Company has not entered into any material contracts within the most recently completed financial year, or before the most recently completed financial year that are still in effect, other than:

- Rights Plan Agreement - see "Description of Share Capital - Rights Plan"; and

INTERESTS OF EXPERTS

Reserve estimates contained in this Annual Information Form have been prepared by GLJ. As at December 31, 2011, the effective date of those estimates, and as of the date hereof, the principals, directors, officers and associates of GLJ, as a group, owned, directly or indirectly, less than one percent of the outstanding Common Shares.

Contingent resource estimates contained in this Annual Information Form have been prepared by Ryder Scott. As at December 31, 2011, the effective date of those estimates, and as of the date hereof, the principals, directors, officers and associates of Ryder Scott, as a group, owned, directly or indirectly, less than one percent of the outstanding Common Shares.

Deloitte & Touche LLP is the external auditor of the Company and is independent within the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

ADDITIONAL INFORMATION

Additional information relating to the Company may be found at www.sedar.com. Specifically, information as to directors' and officers' remuneration and indebtedness, principal holders of the Company's securities and securities authorized for issuance under equity compensation plans is contained in the Information Circular of the Company prepared in connection with the most recent annual meeting of Shareholder that involved the election of directors. Additional financial information is provided in the Company's financial statements and management discussion and analysis for the year ended December 31, 2011.

APPENDIX "A"

REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

Terms to which a meaning is ascribed in National Instrument 51-101, *Standards of Disclosure for Oil and Gas Activities* have the same meaning herein.

To the Board of Directors of Sonde Resources Corp. (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2011. The reserves data are estimates of proved and probable reserves and related future net revenue as at December 31, 2011, 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%, included in the reserves data of the Company evaluated by us for the year ended December 31, 2011, and identifies the respective portions thereof that we have evaluated and reported on to the Company's management and Board of Directors.

Independent Qualified Reserves Evaluator	Description and Preparation Date of Evaluation Report	Location of Reserves (Country)	Net Present Value of Future Net Revenue (10% discount rate)			
			Audited (M\$)	Evaluated (M\$)	Reviewed (M\$)	Total (M\$)
GLJ Petroleum Consultants	February 9, 2012	Canada	Nil	113,605	Nil	113,605

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied.
6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their 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., Alberta, Canada,
February 23, 2012

(signed) "John H. Stilling" _____
John H. Stilling, P. Eng.
Vice President

APPENDIX "B"

REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

Terms to which a meaning is ascribed in National Instrument 51-101, *Standards of Disclosure for Oil and Gas Activities* have the same meaning herein.

Management of Sonde Resources Corp. (the "Company") is 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 and probable reserves and related future net revenue as at December 31, 2011, estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated the Company's reserves data. The report of the independent qualified reserves evaluator is presented in Appendix "A" to the Annual Information Form of the Company, effective as at December 31, 2011.

The Health, Safety, Environment and Reserves Committee of the Board of Directors of the Company has:

- (a) reviewed the Company's procedures for providing information to the independent qualified reserves evaluator;
- (b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and
- (c) reviewed the reserves data with management and the independent qualified reserves evaluator.

The Health, Safety, Environment and Reserves Committee of the Board of Directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The Board of Directors has, on the recommendation of the Health, Safety, Environment and Reserves Committee Committee, approved:

- (a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information;
- (b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluator on the reserves data; and
- (c) the content and filing of this report.

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

(signed) "Jack W. Schanck"

Jack W. Schanck
Chief Executive Officer

(signed) "William Dirks"

William Dirks
Chief Operating Officer

(signed) "William Roach"

William J.F. Roach
Director

(signed) "James M. Funk"

James M. Funk
Director

Dated March 22, 2012

APPENDIX "C"



AUDIT COMMITTEE CHARTER

1. **Audit Committee**

The Board of Directors (the "Board") of Sonde Resources Corp. (the "Corporation") has established an audit committee (the "Audit Committee" or the "Committee").

The primary objective of the Audit Committee is to act as a liaison between the Board and the Corporation's independent external auditor and to assist the Board in fulfilling its oversight responsibilities with respect to:

- (a) the financial statements and other financial information provided by the Corporation to its shareholders, the public and others;
- (b) the Corporation's compliance with legal and regulatory requirements;
- (c) the qualification, independence and performance of the external auditors; and
- (d) the Corporation's risk management and internal financial and accounting controls, and management information systems.

Although the Committee has the powers and responsibilities set forth in this Charter, the role of the Committee is oversight. The members of the Committee are not full-time employees of the Corporation and may or may not be accountants or auditors by profession or experts in the fields of accounting or auditing and, in any event, do not serve in such capacity. Consequently it is not the duty of the Committee to conduct audits or to determine that the Corporation's financial statements and disclosures are complete and accurate and are in accordance with generally accepted accounting principles and applicable rules and regulations. These are the responsibilities of management.

2. **Composition of Committee**

- (a) the Audit Committee will consist of at least three directors. All members of the Committee must be independent as defined in applicable securities laws (subject to permitted exemptions under those laws) and the rules of any stock exchange on which the Corporation's securities are listed for trading.
- (b) each member of the Audit Committee must be financially literate, or become financially literate within a reasonable period of time following his or her appointment to the Committee (provided that the Board has determined that this will not materially adversely affect the ability of the Committee to satisfy its responsibilities). A member is financially literate under applicable securities laws if he or she has the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of the issues that can reasonably be expected to be raised by the Corporation's financial statements.

3. **Appointment of Committee Members**

Members of the Audit Committee will be appointed by the Board and re-appointed at the meeting of the Board immediately following each annual meeting of shareholders. Committee members will hold office until the next annual meeting or earlier if their successors are appointed, they are removed by the Board or they cease to be directors of the Corporation.

4. **Compensation of Committee Members**

The Board will fix the remuneration of the members of the Audit Committee and may provide additional remuneration to the Chair of the Committee. Other than as remuneration for acting in his or her capacity as a member of the Board or any Board committee, or as a part-time chair or vice- chair of the Board or any Board committee, or as otherwise permitted by applicable securities laws, no consulting, advisory or other compensatory fee will be paid to a member of the Audit Committee by the Corporation or any subsidiary of the Corporation.

5. **Vacancies**

When a vacancy occurs in the membership of the Audit Committee, it may be filled by the Board and must be filled by the Board if the membership of the Committee as a result of the vacancy is less than three directors. Any member may be removed or replaced at any time by the Board. Any member will cease to be a member upon ceasing to be a director.

COMMITTEE PROCEDURES

6. **Committee Chair**

The Board will appoint a Chair for the Audit Committee.

7. **Absence of Committee Chair**

If the Chair is not present at any meeting of the Audit Committee, one of the other members of the Committee present at the meeting will be chosen by the Committee to preside at the meeting.

8. **Secretary of Committee**

The Secretary of the Company shall be the secretary to the Committee unless the Committee designates otherwise.

9. **Meetings**

The Audit Committee will meet at least four times per year. All Committee members are expected to attend each meeting, in person or by telephone - or video-conference. The Committee shall only act on the affirmative vote of a majority of members. A resolution in writing, signed by all the Audit Committee members entitled to vote on that resolution at a meeting of the Committee, is as valid as if it had been passed at a meeting of the Committee.

10. **Notice of Meetings**

- (a) A meeting of the Audit Committee may be called by any member of the Committee, by the Chairman of the Board, the chief executive officer or the chief financial officer of the Corporation (or persons holding equivalent offices) or by the external auditor. Notice of the time and place of a meeting will be given in writing or by electronic communication to each member of the Committee

and to the external auditor prior to the time fixed for the meeting.

- (b) A member of the Audit Committee may in any manner waive notice of a Committee meeting. Attendance of a member at a Committee meeting is a waiver of notice of the meeting, except where a member attends a meeting for the express purpose of objecting to the transaction of any business on the grounds that the meeting is not lawfully called.

11. Quorum and Participation

- (a) A majority of the number of members of the Audit Committee appointed by the Board constitutes a quorum at any meeting of the Committee.
- (b) A member of the Audit Committee may, if all the members of the Committee consent, participate in a meeting of the Committee by means of a telephonic, electronic or other communication facility that permits all participants to communicate adequately with each other during the meeting. A member participating in a Committee meeting by those means is deemed to be present at that meeting.

12. Attendance by External Auditor and Others

- (a) The external auditor is entitled, at the expense of the Corporation, to attend and be heard at every meeting of the Audit Committee, and, if so requested by a member of the Committee, shall attend every meeting of the Committee held during the term of office of the external auditor.
- (b) At the invitation of the Chair of the Audit Committee, one or more officers or employees of the Corporation or directors who are not members of the Committee may attend a meeting of the Committee.

13. Procedure, Records and Reporting

The chair of the Committee shall report regularly to the Board on the Committee's activities, findings and recommendations. Minutes of all meetings shall be made available to the Board, and all information reviewed and discussed by the Committee at any meeting shall be retained and made available for examination by the Board upon request of the chair.

14. Independent Advisors

The Audit Committee may engage independent counsel and other advisors as it determines necessary to carry out its duties. Furthermore, the Committee has the authority to set and pay the compensation for any such advisors which are employed by the Committee. The Corporation will provide the Committee adequate funds to cover fees and other costs incurred in carrying out its duties and responsibilities.

15. Review of Committee Performance and Charter

At least annually the Committee will review its performance and effectiveness and report the results to the Board. The annual review will include an assessment of the adequacy of this Charter and the Committee will recommend any proposed changes to the Board for approval.

16. Duties and Reliance

- (a) In exercising their powers and discharging their duties under this charter and applicable law, each

member of the Audit Committee must (i) act honestly and in good faith with a view to the best interests of the Corporation and (ii) exercise the care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances.

- (b) Each member of the Audit Committee will be entitled to reasonable reliance, or reliance in good faith, on:
 - (i) financial statements of the Corporation represented to the member of the Committee by an officer of the Corporation or in a written report of the external auditor of the Corporation to reflect fairly the financial condition of the Corporation;
 - (ii) the Corporation's disclosure compliance system and on the Corporation's officers, employees and others whose duties would in the ordinary course have given them knowledge of the relevant facts; and
 - (iii) a report, statement or opinion of an expert, being a person or company whose profession gives authority to a statement made in a professional capacity by the person or company including, without limitation, an accountant, actuary, appraiser, auditor, engineer, financial analyst, geologist or lawyer.

MANDATE OF COMMITTEE

17. External Auditor

- (a) The external auditor will report directly to the Audit Committee, be responsible for planning with the Corporation and carrying out the audit of the annual financial statements (and any requested review of quarterly financial statements) and ultimately be accountable to the Audit Committee and the Board as the representatives of the shareholders.
- (b) The Audit Committee will recommend to the Board:
 - (i) the external auditor to be nominated for the purpose of preparing or issuing an auditor's report or performing other audit, review or attest services for the Corporation; and
 - (ii) the compensation of the external auditor.
- (c) The Audit Committee will be directly responsible for overseeing the work of the external auditor engaged for the purpose of preparing or issuing an auditor's report or performing other audit, review or attest services for the Corporation, including the following:
 - (i) review of the mandate of the external auditor, including the annual engagement letter, audit plan, audit scope and the factors considered in determining the audit scope, including the major risk factors; and confirmation as to whether or not any limitations have been placed on the scope or nature of the external auditor's audit procedures;
 - (ii) review of significant accounting and reporting principles, practices and procedures applied by the Corporation in preparing its financial statements, including discussions with the external auditor of its judgments about the quality, not just the acceptability, of the Corporation's accounting principles used in financing reporting;
 - (iii) review of the independence of the external auditor, and obtain from the external auditors, at least annually, a formal written statement delineating all relationships between the

external auditors and the Company as contemplated by Independence Standards Board Standard No. 1, Independence Discussions with Audit Committees;

- (iv) review any rotation of the partners assigned to the audit in accordance with applicable laws and professional standards, the internal quality control findings of the external auditor's firm and peer reviews;
 - (v) review of the performance of the external auditor, including the relationship between the external auditor and management and the evaluation of the lead partner of the external auditor;
 - (vi) termination or resignation of the external auditor if circumstances warrant, after due inquiry and discussion with management and the external auditor;
 - (vii) resolution of disagreements between management and the external auditor regarding financial reporting;
 - (viii) review of material written communications between the external auditor and management;
 - (ix) review of the annual management letter from the external auditor regarding internal controls and opportunities for improvement or efficiency, plus management's response and follow-up in respect of any identified weakness; and
 - (x) communication with the external auditor regarding such other matters as are required by the Canadian Institute of Chartered Accountants Handbook and other professional standards.
- (d) As necessary or desirable, but in any case at least quarterly the Audit Committee will meet or communicate directly with the external auditor and members of management, in separate executive sessions, as required or appropriate to discharge the responsibilities of the Committee. The Committee will discuss with the external auditor, without management being present, (a) the quality of the Corporation's financial and accounting personnel, and (b) the completeness and accuracy of the Corporation's financial statements. Also, the Committee will elicit the comments of management regarding the responsiveness of the external auditors to the Corporation's needs.
- (e) The Audit Committee will have a predetermined arrangement with the external auditor that it will advise the Committee, through its Chair and management of the Corporation, of any matters identified through procedures followed for the review of interim quarterly financial statements of the Corporation, and that such notification is to be made prior to the related press release. The Audit Committee will also receive a written confirmation provided by the external auditor at the end of each of the first three quarters of the year that it has nothing to report to the Committee, if that is the case, or the written enumeration of required reporting issues.

18. Non-Audit Services

- (a) The Audit Committee will pre-approve all non-audit services to be provided to the Corporation or its subsidiaries by the external auditor.
- (b) The Audit Committee may delegate to one or more of its members the authority to pre-approve non-audit services. The pre-approval of non-audit services by any member to whom authority has been delegated must be presented to the Committee at its first scheduled meeting following such pre-approval.

- (c) Pre-approval of *de minimus* non-audit services will be satisfied if:
 - (i) the aggregate amount of all the non-audit services that were not pre-approved is reasonably expected to constitute no more than five per cent of the total amount of fees paid by the Corporation and its subsidiaries to the Corporation's external auditor during the fiscal year in which the services are provided;
 - (ii) the Corporation or the subsidiary, as the case may be, did not recognize the services as non-audit services at the time of the engagement; and
 - (iii) the services are promptly brought to the attention of the Audit Committee and approved, prior to the completion of the audit, by the Committee or by one or more of its members to whom authority to grant such approvals has been delegated by the Committee.
- (d) Pre-approval of non-audit services will also be satisfied if the Audit Committee adopts specific policies and procedures for the engagement of non-audit services and:
 - (i) the pre-approval policies and procedures are detailed as to the particular service;
 - (ii) the Audit Committee is informed of each non-audit service; and
 - (iii) the procedures do not include delegation of the Audit Committee's responsibilities to management.

19. **Financial and Other Disclosure**

- (a) The Audit Committee will review, discuss with management (and the external auditor where required or appropriate) and, if required or appropriate, approve or recommend that the Board approve the following Corporation documents prior to public disclosure:
 - (i) annual audited financial statements and related management's discussion and analysis;
 - (ii) quarterly unaudited financial statements and related management's discussion and analysis;
 - (iii) certifications by the chief executive officer and chief financial officer of annual and quarterly filings, disclosure controls and procedures and internal controls over financial reporting;
 - (iv) news releases announcing financial results, containing financial information based on unreleased financial results or non-GAAP financial measures or providing earnings guidance or forward-looking financial information; and
 - (v) financial information contained in any annual information form, information circular, prospectus, take-over bid circular, issuer bid circular or rights offering circular.
- (b) The Audit Committee will be satisfied that adequate procedures are in place for the review of the Corporation's public disclosure of financial information extracted or derived from the Corporation's financial statements and will periodically assess the adequacy of those procedures.

- (c) The Audit Committee will review the disclosure required by applicable securities laws to be included in its annual information form and cross-referenced in management information circular to solicit proxies from the shareholders of the Corporation for the purpose of electing directors to the Board. That disclosure will consist of the text of this charter, the composition of the Audit Committee, the relevant education and experience of Committee members, reliance on certain exemptions from securities laws relating to audit committees, oversight of the nomination and compensation of the external auditor, policies and procedures for non-audit services and external auditor service fees.

20. **Financial Reporting Processes**

- (a) The Audit Committee will review with management and the external auditor:
 - (i) the appropriateness of the Corporation's accounting principles and policies and financial reporting;
 - (ii) any changes to the Corporation's accounting principles and policies and financial reporting as such changes are recommended by management or the external auditor;
 - (iii) the accounting treatment of significant risks and uncertainties;
 - (iv) key estimates and judgments of management that may be material to the Corporation's financial reporting;
 - (v) significant changes to the audit plan, if any; and
 - (vi) Any serious disputes or difficulties with management encountered during the audit and the cooperation received by the external auditor during its audit, including access to all requested records, data and information.
- (b) The Audit Committee will in particular review the following specific matters, where material:
 - (i) the effect of regulatory and accounting initiatives;
 - (ii) extraordinary transactions;
 - (iii) the use of special purpose entities;
 - (iv) off-balance sheet transactions;
 - (v) financial risk management, including the use of derivatives;
 - (vi) asset retirement or reclamation obligations;
 - (vii) pension obligations;
 - (viii) commitments, contingencies and guarantees; (ix) related party transactions;
 - (ix) actual or pending legal claims, tax or regulatory matters; and
 - (x) any other matters of accounting or auditing risk.

21. **Other Responsibilities**

- (a) The Audit Committee will establish procedures for:
 - (i) the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal accounting controls or auditing matters; and
 - (ii) the confidential, anonymous submission by employees of the Corporation of concerns regarding questionable accounting or auditing matters.
- (b) The Audit Committee will review on a timely basis all discovered incidents of fraud within the Corporation, regardless of monetary value;
- (c) The Audit Committee will oversee any auditing or accounting reviews or similar procedures or investigations and may conduct its own investigations with full access to books, records, facilities and personnel of the Corporation.
- (d) The Audit Committee will at least annually provide oversight of the Corporation's risk management policies.
- (e) The Audit Committee will review and approve the Corporation's policies regarding officer and director expenses, perquisites and use of corporate assets, and may review expenses actually incurred by the chief executive officer and other senior officers.
- (f) The Audit Committee will review and approve the Corporation's hiring policies regarding partners, employees and former partners and employees of the present and any former external auditor of the Corporation.
- (g) Review with management, internal audit and the external auditors the methods used to establish and monitor the Corporation's policies with respect to unethical or illegal activities by Corporation employees that may have a material impact on the financial statements.
- (h) Generally as part of the review of the annual financial statements, receive a report(s), at least annually, concerning legal, regulatory and compliance matters that may have a material impact on the financial statements.
- (i) Coordinate with the Reserves Committee as necessary concerning the disclosure of information with respect to the Corporation's oil and gas reserves, including the Corporation's procedures for complying with the disclosure requirements and restrictions of applicable regulations.
- (j) Review with the external auditor the internal controls on computerized information system controls and security.
- (k) The Audit Committee will review and/or approve any other matters specifically delegated to the Committee by the Board and undertake on behalf of the Board such other activities as may be necessary or desirable to assist the Board in fulfilling its responsibilities.

Approved by the Board of Directors on March 22, 2012.