DeeThree Exploration Ltd.

ANNUAL INFORMATION FORM

FOR THE FINANCIAL YEAR ENDED DECEMBER 31, 2013

March 24, 2014

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DEFINITIONS

Certain terms and abbreviations used in this Annual Information Form are defined below:

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

"**affiliate**" or "**associate**" when used to indicate a relationship with a person or company, has the meaning set forth in the *Securities Act* (Alberta);

"**Board of Directors**" means the board of directors of the Corporation, as constituted from time to time, including where applicable, any committee thereof;

"**Brazeau Belly River Properties**" means the Corporation's petroleum and natural gas properties and related assets located in the Brazeau area of west central Alberta;

"**Common Shares**" means the common shares without par value in the capital of the Corporation;

"**Corporation**" or "**DeeThree**" means DeeThree Exploration Ltd.;

"**Credit Facility**" means a revolving demand credit facility;

"**December 2013 Offering**" means the bought-deal short-form prospectus financing of 4,370,000 Common Shares at a price of $9.25 per Common Share completed on December 6 and 17, 2013 for aggregate gross proceeds of $40,422,500;

"**December 2013 Private Placement**" means the private placement of 465,900 Flow-Through Shares at a price of $10.75 per Flow-Through Share completed on December 20, 2013 for aggregate gross proceeds of $5,008,425;

"**DeeThree Ltd.**" means DeeThree Exploration Ltd., which became a wholly owned subsidiary of the Corporation pursuant to the Amalgamation on June 25, 2009;

"**DPIIP**" means Discovered Petroleum Initially In Place which is defined as that quantity of oil that is estimated, as of a given date, to be contained in known accumulations prior to production. The recoverable portion of DPIIP includes production, reserves, and contingent resources; the remainder is unrecoverable. There is no certainty that it will be commercially viable to produce any portion of the resources. A recovery project cannot be defined for this volume of DPIIP at this time, and as such it cannot be further sub-categorized;

"**Effective Date**" means the effective date of this Annual Information Form, being March 24, 2014;

"**February 2013 Offering**" means the bought-deal short-form prospectus financing of 5,083,000 Common Shares at a price of $6.80 per Common Share completed on February 18, 2013 and March 12, 2013 for aggregate gross proceeds of $34,564,400;

"**Flow-Through Shares**" means Common Shares issued on a "flow-through" basis as defined in the Tax Act;

"**Lethbridge Commitment**" means the lease issuance, seismic and drilling commitment agreement entered into between the Corporation and a senior Canadian oil and gas producer, as amended, by which the Corporation acquired a portion of the Lethbridge Property in consideration of its commitment to drill wells and acquire seismic data on such lands;

"**Lethbridge Property**" means the Corporation's petroleum and natural gas properties and related assets located in the Lethbridge area of southern Alberta;

"**March 2011 Acquisition**" means the acquisition by the Corporation of certain of the Brazeau Belly River Properties and other petroleum and natural gas properties and related assets located in the west Pembina and Peace River Arch areas of northern Alberta for an aggregate purchase price of $125,000,000, subject to customary closing adjustments, pursuant to the terms of the March 2011 Acquisition Agreement and completed on March 22, 2011;

"**March 2011 Acquisition Agreement**" means the asset purchase and sale agreement dated as of February 17, 2011 in respect of the March 2011 Acquisition;

"**March 2012 Financing**" means the bought-deal short-form prospectus financing of 3,834,100 Flow-Through Shares at a price of $4.50 per Flow-Through Share completed on March 4, 2010 for aggregate gross proceeds of $17,253,450;

"**NI 51-101**" means National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* of the Canadian Securities Administrators;

"**NI 51-102**" means National Instrument 51-102 — *Continuous Disclosure Obligations* of the Canadian Securities Administrators;

"**October 2012 Financing**" means the bought-deal short form prospectus offering of 770,000 Flow-Through Shares at a price of $6.50 per Flow-Through Share and 3,139,500 Common Shares at a price of $5.50 per Common Share for aggregate gross proceeds of $22,272,250 completed on October 18, 2012.

"**Options**" means the stock options granted by the Corporation to purchase Common Shares;

"**OTCQX**" means the top tier of the United States Over-the-Counter market;

"**possible reserves**" means 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 recovering, gathering, treating, field or plant processing (for example, processing gas to extract natural gas liquids) and field storage of oil and gas;

"**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 being "proved reserves", "probable reserves" and "possible reserves";

"**Spring 2011 Prospectus Financing**" means the bought-deal short-form prospectus financing of 3,000,000 Flow-Through Shares and 26,795,000 Subscription Receipts at a price of $5.15 per Flow-Through Share and $4.30 per Subscription Receipt completed on March 11, 2011 for aggregate gross proceeds of $130,668,500;

"**Sproule**" means Sproule Associates Limited;

"**Sproule Report**" means the reserve report dated March 6, 2014 and prepared by Sproule in relation to the crude oil and natural gas reserves of the Corporation and the future net production revenues attainable thereto with an effective date of December 31, 2013;

"**Subscription Receipts**" means the subscription receipts issued pursuant to the Spring 2011 Prospectus Financing, which each Subscription Receipt exchangeable into one Common Share upon completion of the March 2011 Acquisition;

"**Tax Act**" means *the Income Tax Act* (Canada) and the regulations thereto, as may be amended from time to time;

"**Taxes**" means, with respect to any entity, all income taxes (including any tax on or based upon net income, gross income, income as specially defined, earnings, profits or selected items of income, earnings or profits) and all capital taxes, gross receipts taxes, environmental taxes, sales taxes, use taxes, ad valorem taxes, value added taxes, transfer taxes, franchise taxes, licence taxes, withholding taxes or other withholding obligations, payroll taxes, employment taxes, Canada or Québec Pension Plan premiums, excise, severance, social security premiums, workers' compensation premiums, employment insurance or compensation premiums, stamp taxes, occupation taxes, premium taxes, property taxes, provincial Crown royalties, windfall profits taxes, alternative or add-on minimum taxes, goods and services tax, customs duties or other taxes of any kind whatsoever, together with any interest and any penalties or additional amounts imposed by any taxing authority (domestic or foreign) on such entity or for which such entity is responsible, and any interest, penalties, additional taxes, additions to tax or other amounts imposed with respect to the foregoing;

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

"**TSXV**" means the TSX Venture Exchange Inc.;

"**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;

"**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 wellsite; and

"**working interest**" means the net interest held in an oil and natural gas property which normally bears its proportionate share of the costs of exploration, development and operations as well as any royalties or other production burdens.

MONETARY REFERENCES

All monetary references contained in this Annual Information Form are in Canadian dollars unless otherwise specified. All monetary references contained in the reserves data are in Canadian dollars.

ABBREVIATIONS

Crude Oils and Natural Gas Liquids		**Natural Gas**	
Bbl	Barrel	Mcf	Thousand cubic ft
Bbls	Barrels	MMcf	Million cubic ft
Bbls/d	Barrels per day	Mcf/d	Thousand cubic ft per day

Crude Oils and Natural Gas Liquids	
BOPD	Barrels of oil per day
MBbls	Thousand barrels
MMBbls	Million barrels
BOE	Barrels of oil equivalent
BOE/d	Barrels of oil equivalent per day
MBOE	Thousand of barrels of oil equivalent
MMBOE	Million of barrels of oil equivalent
NGLs	Natural gas liquids
MMbtu	Million British thermal units
WTI	West Texas Intermediate

Natural Gas	
MMcf/d	Million cubic ft per day
Gj	Gigajoules

Other	
M	1,000

BARREL OF OIL EQUIVALENCY

The calculation of barrels of oil equivalent (BOE) is based on a conversion ratio of six thousand cubic feet (Mcf) of natural gas for one barrel (Bbl) of oil based on an energy equivalency conversion method. A barrel of oil equivalent may be misleading, particularly if used in isolation. A BOE conversion ratio of 6Mcf:1Bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. **Given the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6 Mcf: 1 Bbl, utilizing a conversion ratio at 6 Mcf: 1 Bbl may be misleading as an indication of value.**

METRIC CONVERSION TABLE

The following table sets forth certain factors for converting metric measurements into imperial equivalents.

To convert from	To	Multiply by
BOE	Mcf	6.00
Mcf	Cubic metres (“m3”)	28.17
Cubic metres	Cubic ft	35.49
Bbls	Cubic metres (“m3”)	0.16
Cubic metres (“m3”)	Bbls	6.29
Feet (“ft”)	Metres	0.31
Metres	Feet (“ft”)	3.28
Miles	Kilometres (“Km”)	1.61
Kilometres (“Km”)	Miles	0.62
Acres	Hectares (“Ha”)	0.41

NON-GAAP MEASURES

Within this Annual Information Form, references are made to terms commonly used in the oil and natural gas industry. The term "netback" in this Annual Information Form is not a recognized measure under generally accepted accounting principles in Canada. The term "netback" is used as a key performance indicator and it is used by the Corporation to evaluate the operating performance of our petroleum and natural gas assets and is determined by deducting royalties and operating expenses from petroleum and natural gas revenue. Readers are cautioned; however, that this measure should not be construed as an alternative to net earnings or cash flow from operating activities determined in accordance with generally accepted accounting principles in Canada as an indication of the Corporation’s performance.

FORWARD LOOKING STATEMENTS

Certain statements contained in this Annual Information Form may constitute forward-looking statements. These statements relate to future events or the Corporation's future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek", "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "project", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe" and similar expressions. These statements involve known and unknown risks, uncertainties and other factors facing the Corporation. Risks, uncertainties and other factors may be beyond the Corporation's control and may cause actual results or events to differ materially from those anticipated in such forward-looking statements. The Corporation believes that the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in this Annual Information Form should not be unduly relied upon by investors. These statements speak only as of the date of this Annual Information Form and are expressly qualified, in their entirety, by this cautionary statement.

In particular, this Annual Information Form contains forward-looking statements, pertaining to the following:

- the Corporation's capital expenditure and investment program and the timing and results therefrom;
- drilling inventory, drilling plans and timing of drilling, completion and tie-in of wells;
- plans for facilities construction and completion and the timing and method of funding thereout;
- productive capacity of wells, anticipated or expected production rates and anticipated cases of commencement of production
- results of various projects of the Corporation;
- ability to lower cost structure in certain projects of the Corporation;
- productive capacity of wells, anticipated or expected production rates and anticipated dates of commencement of production;
- the impact of changes in oil and natural gas prices on cash flow;
- expectations regarding the ability to raise capital and to add to reserves;
- oil and natural gas production levels and sources of their growth;
- the performance characteristics of the Corporation's oil and natural gas properties;
- timing of development of undeveloped reserves;
- the existence, operation and strategy of the Corporation's commodity price risk management program;
- the Corporation's business, disposition and acquisition strategy, the criteria to be considered in connection therewith and the benefits to be derived therefrom;
- the impact of Canadian federal and provincial governmental regulation on the Corporation relative to other oil and gas issuers of similar size;
- future development and growth prospects;
- expected levels of royalties, operating costs, general administrative costs, costs of services and other costs and expenses;
- determination of future quantities of oil and natural gas reserves and the size of and future net revenues therefrom;
- ability to meet current and future obligations;
- the tax horizon and taxability of the Corporation;
- treatment under governmental regulatory regimes and tax laws;
- projections of market prices and costs;
- weighting of production between different commodities;
- supply and demand for oil and natural gas;
- the ability to obtain equipment, services and supplies in a timely manner to carry out its activities;
- the ability to market oil and natural gas successfully to current and new customers;
- the timing and costs of pipeline, terminal and storage facility construction and expansion and the ability to secure adequate product transportation;
- the ability to obtain financing on acceptable terms or at all;
- currency, exchange and interest rates;
- potential dispositions and acquisitions;

- the timely receipt of governmental approvals; and
- realization of the anticipated benefits of acquisitions and dispositions.

With respect to forward-looking statements contained in this Annual Information Form, the Corporation has made assumptions regarding, among other things:

- the success of the Corporation's operation and exploration and development activities;
- the legislative and regulatory environments of the jurisdictions where the Corporation carries on business or has operations;
- levels of royalties, operating costs, general administrative costs, costs of services and other costs and expenses;
- commodity prices and royalty regimes;
- the impact of increasing competition;
- availability of skilled labour;
- timing and amount of capital expenditures;
- future exchange rates;
- the price of oil and natural gas;
- conditions in general economic and financial markets;
- availability of drilling and related equipment;
- royalty rates and future operating costs; and
- the Corporation's ability to obtain additional financing on satisfactory terms.

The Corporation's actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this Annual Information Form:

- general economic conditions in Canada and globally;
- the ability of management to execute its business plan;
- fluctuations in the prices of oil and natural gas, and interest and exchange rates;
- the risks of the oil and gas industry both domestically and internationally, such as operational risks in exploring for, developing and producing crude oil and natural gas and market demand;
- governmental regulation of the oil and gas industry, including environmental regulation;
- actions taken by governmental authorities, including increases in taxes and changes in government
- regulations and incentive programs;
- geological, technical, drilling and processing problems;
- risks and uncertainties involving geology of oil and gas deposits;
- risks inherent in marketing operations, including credit risk;
- the ability to enter into or renew leases;
- the uncertainty of reserves estimates and reserves life;
- the uncertainty of estimates and projections relating to production, costs and expenses;
- potential delays or changes in plans with respect to exploration or development projects or capital expenditures;
- availability of sufficient financial resources to fund the Corporation's capital expenditures;
- uncertainty of finding reserves, and developing and marketing those reserves;
- unanticipated operating events which could reduce production or cause production to be shut-in or delayed;
- incorrect assessments of the value of acquisitions;
- ability to locate satisfactory properties for acquisition or participation;
- shut-ins of connected wells resulting from extreme weather conditions;
- insufficient storage or transportation capacity;
- hazards such as fire, explosion, blowouts, cratering, and spills, each of which could result in substantial damage to wells, production facilities, other property and the environment or in personal injury;
- encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations;

- the ability to add production and reserves through development and exploration activities;
- the possibility that government policies or laws, including laws and regulations related to the environment, may change or governmental approvals may be delayed or withheld;
- uncertainty in amounts and timing of royalty payments;
- uncertainties inherent in estimating quantities of oil and natural gas reserves and cash flows to be derived therefrom;
- failure to obtain industry partner and other third party consents and approvals, as and when required;
- stock market volatility and market valuations;
- competition for, among other things, capital, acquisition of reserves, undeveloped land and skilled personnel;
- the availability of capital on acceptable terms or at all;
- failure to realize the anticipated benefits of acquisitions and dispositions; and
- the other factors considered under “Risk Factors” in the AIF which is incorporated by reference herein, and other filings with Canadian securities authorities.

Statements relating to “reserves” are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves exist in quantities predicted or estimated and that the reserves described can be profitably produced in the future.

Statements of test rates are not necessarily indicative of long-term performance or of ultimate recovery. Neither pressure transient analysis nor well-test interpretations have been carried out and the data should be considered to be preliminary until such analysis or interpretation has been done.

The Corporation has included the above summary of assumptions and risks related to forward-looking statements provided in this Annual Information Form in order to provide investors with a more complete perspective on the Corporation’s current and future operations and such information may not be appropriate for other purposes.

Additional information on these and other factors is available in the reports filed by the Corporation with Canadian securities regulators. The forward-looking statements or information contained in this Annual Information Form are made as of the date hereof.

Readers are cautioned that the preparation of financial statements in accordance with generally accepted accounting principles in Canada requires management to make certain judgments and estimates that affect the reported amounts of assets, liabilities, revenues and expenses. Estimating reserves is also critical to several accounting estimates and requires judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change, having either a negative or positive effect on net earnings as further information becomes available and as the economic environment changes. The information contained in this Annual Information Form, including the documents incorporated by reference herein, identifies additional factors that could affect the operating results and performance of the Corporation. Readers are encouraged to carefully consider those factors.

Readers are also cautioned against placing undue reliance on forward-looking information, which is given as of the date it is expressed in this AIF, or the MD&A disclosure incorporated by reference herein, and not to use future-oriented information or financial outlooks for anything other than their intended purpose. The forward-looking statements contained herein are expressly qualified in their entirety by this cautionary statement. The Corporation undertakes no obligation to publicly update or revise any forward-looking information in this AIF or the MD&A disclosure incorporated by reference herein whether as a result of new information, future events or otherwise, except as required by law.

DEETHREE EXPLORATION LTD.

General

DeeThree is a development and exploration focused oil and natural gas producer with its offices located in Calgary, Alberta. The Corporation's primary focus areas are the Lethbridge Properties and the Brazeau Belly River Properties, with minor properties located in Peace River Arch area of northern Alberta.

The Corporation was incorporated pursuant to the provisions of the ABCA on November 22, 2007 as "Royal Capital Corp." The Corporation amended its Articles to consolidate its outstanding Common Shares on a 12 for one basis on June 25, 2009 and also changed its name by Certificate of Amendment to "DeeThree Exploration Inc." on June 25, 2009. On January 1, 2010, the Corporation completed a vertical amalgamation with its wholly-owned subsidiary, DeeThree Ltd. The name of the Corporation was changed to "DeeThree Exploration Ltd." pursuant to the amalgamation that occurred on January 1, 2010.

The Corporation is a reporting issuer in every province of Canada except for Quebec. The Common Shares of the Corporation are listed on the TSX under the trading symbol "DTX" and on the OTCQX under the trading symbol of "DTHRF".

The Corporation's head office is located at 2200, 520 – 3rd Avenue S.W., Calgary, Alberta T2P 0R3, and the registered office is located at Suite 1000, 250 - 2nd Street, S.W., Calgary, Alberta, T2P 0C1.

The Corporation has no subsidiaries as at the date hereof.

GENERAL DEVELOPMENT OF THE BUSINESS

A detailed description on the significant developments of the business of the Corporation over the last three completed financial years is set out below.

2011

On February 11, 2011, the Corporation announced a decline in its reserves as at December 31, 2010 as compared to December 31, 2009 due to both a significant decline in current and future natural gas prices as well as the Corporation's shallow gas drilling results throughout 2010.

On February 17, 2011, the Corporation entered into the March 2011 Acquisition Agreement. On March 11, 2011, the Corporation completed the Spring 2011 Prospectus Financing and issued 3,000,000 Flow-Through Shares and 26,795,000 Subscription Receipts for aggregate gross proceeds of $130,668,500.

On March 24, 2011, the Corporation's lender approved a credit facility increase to $40,000,000; however, the Corporation elected an increase to only $20,000,000 in order to reduce standby fees associated with the unutilized balance.

The Corporation completed the March 2011 Acquisition on March 22, 2011. The purchase price was funded from the net proceeds from the sale of Subscription Receipts and cash on hand. Concurrently with the completion of the March 2011 Acquisition, the net proceeds from the sale of the Subscription Receipts were released by Olympia Trust Corporation and the Subscription Receipts were exchanged into Common Shares.

In April 2011, DeeThree entered into a farmout and joint venture agreement (the "**Western Lethbridge Farmout**") with a major oil and gas company with respect to a portion of the Lethbridge Property. The Western Lethbridge Farmout involved a four well commitment on a total of 15,815 acres of DeeThree's undeveloped land. The farmee was committed to drill four horizontal earning wells by December 31, 2011 and was responsible for 100% of the costs through completion to earn 60% working interest in the farmout lands with no payout terms. The farmee drilled on well, earned a 60% working interest in the well and in six sections of farmout lands, and has terminated the Western Lethbridge Farmout by paying a $3,000,000 termination fee to DeeThree.

In June 2011, DeeThree entered into a farmout and joint venture agreement (the "**Northern Lethbridge Farmout**") with a Calgary-based junior oil and gas company pursuant to which the farmee agreed to pay DeeThree $5,000,000 and committed to drill and complete, at its sole cost, risk and expense, two horizontal wells evaluating the Mississippian and/or upper Devonian formations on 58 sections of land located in the northern portion of DeeThree's Lethbridge Property. The farmee was responsible for 100% of the costs of the test wells through completion to earn a 60% working interest in seven sections of farmout lands (with no payout terms) for each well drilled. The test wells were to be drilled and completed prior to December 31, 2011. After fulfilling the two test well obligation, the farmee had the continuing right to elect to drill additional wells on similar terms and conditions until it had either elected to not drill an option well or had earned an interest in the balance of the 58 sections of lands. The farmee drilled one well and earned a 60% working interest in seven sections of farmout lands, defaulted on the remaining well commitment and paid DeeThree a $1,000,000 default payment.

In August 2011, DeeThree promoted Clayton Thatcher to Vice President, Exploration and Brendan Carrigy to Executive Vice President.

On September 28, 2011, the Corporation announced that due to its successful drilling results achieved year to date, the Corporation has increased its 2011 capital expenditure budget by $15 million.

On November 22, 2011, the Corporation announced that it has commenced trading on the OTCQX, the top tier of the U.S. Over-the-Counter market, under the symbol "DTHRF."

In December 2011, the authorized borrowing of the Credit Facility was increased to $50,000,000.

2012

On January 19, 2012, the Corporation announced an operational update and its 2012 guidance. The Corporation's Board of Directors approved a capital budget of $57 million focused entirely on the development and exploration of oil prospects. The capital was to be directed primarily towards the Corporation's properties in the Brazeau and Lethbridge areas. The Corporation's plans included the drilling of 8 gross (7.1 net) horizontal wells in the Brazeau area, a minimum of 2 gross (2.0 net) horizontal Bakken locations on the Lethbridge Property and up to 11 gross (11.0 net) Sunburst horizontal locations on the Lethbridge Property. The remaining 13% of the budget was to be allocated to additional strategic land purchases and other expenses. Average 2012 production was is expected to be in the range of 3,700 and 3,900 BOE/d excluding approximately 200 BOE/d of low netback natural gas that is currently shut-in and will remain shut-in indefinitely due to extreme depressed natural gas prices. The Corporation's 2012 exit rate was expected to be in the range of 4,300 BOE/d. The Corporation's average commodity price assumptions for 2012 were US $90.00 per barrel for WTI oil, $2.70 per GJ for AECO natural gas and a US/Canadian dollar exchange rate of CAD $1.03. On this basis, the Corporation expected to generate $40 - $42 million of cash flow throughout 2012. The Corporation intended to fund its capital program through internally generated cash flow and its current credit facility of $50 million. DeeThree expected to exit 2012 with a working capital deficit of approximately $35 million or approximately 0.8 times forecasted 2012 funds from operations.

On February 14, 2012, the Corporation announced the results of its fifth Bakken well on its Lethbridge Property and the termination of the Western Lethbridge Farmout. This Bakken well was flowed for clean-up for four days with final stabilizing flowing rates of approximately 550 Bbls/d of 30 degree API reservoir oil and 60 mscf/d of natural gas. The well was tied-in to DeeThree's extensive oil and gas processing infrastructure.

The farmee under the Western Lethbridge Farmout elected to terminate the agreement after having drilled only one well of the four well commitment. The farmee earned a 60% working interest in the well and in 6.0 sections of the farmout lands and has no right to earn additional interests in the farmout lands. A termination fee of $3,000,000 has been paid to DeeThree. The lands subject to the agreement are located approximately 41 kilometres from the Bakken discovery well described above and targeted a different Bakken interval.

On March 6, 2012, the Corporation announced an increase in its oil and gas reserves as at December 31, 2011 as compared to December 31, 2010.

On March 27, 2012, the Corporation completed the March 2012 Financing and issued 3,834,100 Flow-Through Shares for aggregate gross proceeds of $17,253,450.

The farmee under the Northern Lethbridge Farmout elected not to drill the second test well, and as a result, has paid DeeThree a termination fee of $1,000,000 pursuant to the original agreement.

On March 28, 2012, the Corporation provided an operational update on the Bakken and Brazeau Belly River drilling results, and an increase to the 2012 capital expenditures budget from $57 million to $82 million. The increase in capital budget was directed at accelerating the pace of the Corporation's exploration and development in the Bakken area of Lethbridge, which was expected to increase the 2012 exit production from 4,300 BOE/d to 5,000 BOE/d.

On March 29, 2012, the Corporation announced the financial and operational results for the year ended December 31, 2011 and the filing of the audited financial statements and related management discussion and analysis for the Corporation for the year ended December 31, 2011.

On May 9, 2012, the Corporation announced an update on its 2012 Bakken and Brazeau Belly River drilling program and its financial and operational results for the three months ended March 31, 2012, including results above expectations for the third and fourth Bakken wells. The Corporation also announced it had extended the primary lease term on the Lethbridge Commitment to November 30, 2015. In exchange for the lease extension, the Corporation surrendered 50,000 acres while still retaining 180,000 acres of prospective acreage for the Bakken area. The Corporation amended the Lethbridge Commitment effective May 1, 2012 to require the drilling of twelve wells over the next three year period. This amended commitment has now been fully satisfied.

On August 14, 2012, the Corporation announced its financial and operational results for the three and six months ended June 30, 2012, including an increase in its operating netback per barrel to $30.86 in the second quarter of 2012, being a 25% increase compared to the first quarter of 2012. The Corporation also announced an increase in its 2012 capital expenditures budget from $82 million to $110 million and updated its expected 2012 exit production to approximately 6,000 BOE/d.

On August 21, 2012, the Corporation announced the results of a reserves and resource evaluation conducted by Sproule Associates Limited in accordance with NI 51-101 on certain of the Corporation's Bakken assets as of July 31, 2012.

On September 10, 2012, the Corporation announced that a senior lender had committed to providing the Corporation with a $90 million revolving demand credit facility (previously defined as the "**Credit Facility**"). On October 9, 2012, the formal documentation providing for the Credit Facility was entered into with a syndicate of two lenders and proceeds drawn from the Credit Facility of approximately $55 million were used to pay out the Corporation's existing credit facility. The Credit Facility was expected to provide the Corporation with financial resources to accelerate the development and exploitation of its Bakken and Brazeau River Belly properties.

On October 18, 2012, the Corporation completed the October 2012 Offering, raising aggregate gross proceeds of $22,272,250 through the issuance of 3,139,500 Common Shares and 770,000 Flow-Through Shares.

On November 14, 2012, the Corporation announced its financial and operational results for the three and nine months ended September 30, 2012, including production for the third quarter averaging 4,692 BOE/d (68% oil and natural gas liquids and 32% natural gas), being an increase of 120% over the same quarter of 2011 and a 23% increase over the second quarter of 2012. Funds flow from operations grew to $14.3 million, representing a 276% increase from the third quarter of 2011 and a 45% improvement from the second quarter of 2012; and operating netback increased to $35.18/BOE from $22.36/BOE compared to the same quarter in 2012 and $30.86/BOE in the previous quarter, an increase of 57% and 14%, respectively. In addition, the Corporation announced that it intended to increase its 2012 capital budget by approximately $30 million to $140 million in total. The Corporation also announced that it had successfully invested $33.2 million in capital expenditures during the third quarter, which included the drilling of five net wells, achieving a 100% success rate.

On December 14, 2012, the Corporation announced that it had reached its targeted 2012 exit production rate of 6,000 BOE/d. The Corporation also entered into a farm-in agreement with a senior oil and gas producer pursuant to which it may earn a 100% working interest in up to 34 additional sections of Belly River petroleum and natural gas rights, directly offsetting the Corporation's existing core Brazeau Belly River property. The Corporation committed to drilling a minimum of three horizontal wells on the farm-in lands with a continuing rolling option thereafter in return for a 15% non-convertible overriding royalty.

2013

On February 19, 2013 and March 12, 2013, the Corporation completed the February 2013 Offering and issued 5,083,000 Common Shares for gross proceeds of $34,564,400.

On February 25, 2013, the Corporation announced an operational update and its guidance for 2013. The Corporation's Board of Directors approved a capital budget of approximately $150 million for 2013 to be focused entirely on the development and exploration of oil prospects. The capital was to be directed primarily towards the Brazeau and Lethbridge areas. The Corporation's plans included the drilling of 20 gross (20.0 net) wells in the Bakken locations on the Lethbridge Property and 11 gross (10.7 net) wells on the Brazeau Belly River Properties. Average 2013 production was forecast to be in the range of 6,800 to 7,000 BOE/d and the Corporation's 2013 exit rate was forecast to be in the range of 8,500 to 9,000 BOE/d. The Corporation's average commodity price assumptions for 2013 were US $95.00 per barrel for WTI oil, $3.20 per GJ for AECO natural gas and a US/Canadian dollar exchange rate of CAD $0.99. On this basis, the Corporation expected to generate approximately $100 million of cash flow in 2013. The Corporation planned to fund its 2013 capital program through internally generated cash flow and funds available under the Credit Facility.

On March 25, 2013, the Corporation provided an operational update on drilling results on the Brazeau Belly River Properties and also announced an increase in its oil and gas reserves as at December 31, 2012 as compared to December 31, 2011.

On March 27, 2017, the Corporation announced the financial and operational results for the year ended December 31, 2012 and the filing of the audited financial statements and related management discussion and analysis for the Corporation for the year ended December 31, 2012.

On April 8, 2013, the Corporation provided an operational update on drilling results on the Brazeau Belly River Properties and announced that a review of its 2013 capital program has been undertaken with the intent to further accelerate the exploitation of the Lethbridge Properties and the Brazeau Belly River Properties.

On April 24, 2013, the Corporation announced that the Credit Facility had been increased to $135 million from $90 million. The Corporation also announced and increase in its 2013 capital budget to $160 million and increases to its 2013 guidance. The increase in the 2013 capital budget was to facility infrastructure on the Lethbridge Properties and the Brazeau Belly River Properties to accommodate future production increases. Average 2013 production was forecast to be in the range of 7,600 to 8,000 BOE/d and the Corporation's 2013 exit rate was forecast to be in the range of 9,600 to 10,000 BOE/d. On this basis, the Corporation expected to generate approximately $120 million of cash flow in 2013.

On May 14, 2013, the Corporation announced an update on its 2013 drilling program and its financial and operational results for the three months ended March 31, 2013.

Kevin Andrus was appointed as a director of the Corporation on June 21, 2013.

On July 8, 2013, the Corporation provided an operational update in respect of drilling activities on the Lethbridge Properties and the Brazeau Belly River Properties, including 30-day initial test results of the significant horizontal wells it drilled in the spring of 2013.

On August 9, 2013, the Corporation announced its financial and operational results for the three and six months ended June 30, 2013. The Corporation also provided an operational update on the results of its 2013 drilling program on the Lethbridge Properties and the Brazeau Belly River Properties.

On August 14, 2013, the Corporation announced the results of a reserves and resource evaluation conducted by Sproule Associates Limited in accordance with NI 51-101 on the Brazeau Belly River Properties as of July 31, 2013.

On November 8, 2013, the Corporation announced its financial and operational results for the three and nine months ended September 30, 2013. The Corporation also provided an operational update on the results of its 2013 drilling program on the Lethbridge Properties and the Brazeau Belly River Properties. A $40 million increase in the Corporation's 2013 capital budget was also announced for a total budgeted amount of $200 million. The principal uses of the additional amount was to drill an additional four horizontal wells and to acquire lands in the Corporation's core areas. The Corporation also announced an increase in its forecasted 2013 exit production rate to the range of 10,000 to 10,500 BOE/d and an increase the Credit Facility to $165 million.

On December 6, 2013, the Corporation completed the December 2013 Offering, raising aggregate gross proceeds of $35,150,000 via the issuance of 3,800,000 Common Shares. On December 17, 2013, the underwriters in the December 2013 Offering exercised the over-allotment option and the Corporation issued an additional 570,000 Common Shares at a price of $9.25 per Common Share for gross proceeds of $5,272,500.

On December 18, 2013, the Corporation announced its guidance for 2014 and provided an operational update. A $230 million capital expenditure program was announce for 2014. This program was to focused on the further exploration and development of the Lethbridge Properties and the Brazeau Belly River Properties by the drilling of approximately 46 gross wells. The 2014 capital program is anticipated to be fully funded through internally generated funds from operations and the Credit Facility. 2014 production was forecast to be within the range of 11,500 to 11,700 BOE/d (81% crude oil and NGLs) with a targeted 2014 exit production rate of 13,000 – 13,500 BOE/d (82% crude oil and NGLs). The Company's average commodity price assumptions for 2014 were US$95.00 per barrel for WTI oil, $3.40 per GJ for AECO natural gas and a US/Canadian dollar exchange rate of CAD $0.95. On this basis, approximately $170 million of funds was forecast to be generated from operations in 2014. The Corporation planned to fund its 2014 capital program through internally generated cash flow and funds available under the Credit Facility.

On December 20, 2013, the Company completed the December 2013 Private Placement, raising aggregate gross proceeds of $5,008,425 via the private placement issuance of 465,900 Flow-Through Shares at a price of $10.75 per Flow-Through Share.

<u>2014</u>

On January 15, 2014, the Corporation provided an operational update in respect of drilling activities on the Brazeau Belly River Properties and that it had met its targeted 2013 production rate of 10,000 to 10,500 BOE/d, reaching a maximum of 10,200 BOE/d in December 2013.

On March 10, 2014, the Corporation announced an increase in its oil and gas reserves as at December 31, 2013 as compared to December 31, 2012.

<u>Significant Acquisitions</u>

DeeThree did not complete any significant acquisitions during its most recently completed financial year for which disclosure is required under Part 8 of National Instrument 51-102 Continuous Disclosure Obligations..

DESCRIPTION OF THE BUSINESS OF THE CORPORATION

General

The business plan of the Corporation is to create value-added growth in reserves, production and cash flow through the execution of management's integrated strategy of acquiring, exploring and developing high-quality, long life oil and gas reserves. The Corporation executes business plan by pursuing strategic acquisitions and conducting development programs on the Corporation's core properties in the Lethbridge area of southern Alberta and the Brazeau area of west central Alberta.

Competitive Conditions

There is strong competition relating to all aspects of the oil and natural gas industry. DeeThree actively competes for capital, skilled personnel, undeveloped land, reserve acquisitions, access to drilling rigs, service rigs and other equipment, access to processing facilities and pipeline and refining capacity, and in all other aspects of its operations with a substantial number of other organizations, many of which may have greater technical and financial resources than the Corporation. Some of those organizations not only explore for, develop and produce oil and natural gas but also carry on refining operations and market petroleum and other products on a world-wide basis and as such have greater and more diverse resources on which to draw.

Revenue Sources

For the year ended December 31, 2013, crude oil and natural gas liquids accounted for 93% of revenue before royalties and natural gas accounted for 7% of the revenues.

For the year ended December 31, 2012, crude oil and natural gas liquids accounted for 90% of revenue before royalties and natural gas accounted for 10% of the revenues.

For the year ended December 31, 2011, crude oil and natural gas liquids accounted for 71% of revenue before royalties and natural gas accounted for 29% of the revenues.

Cyclical and Seasonal Factors

The Corporation's operational results and financial condition are dependent on the prices of crude oil, natural gas liquids and natural gas. Prices for these commodities have fluctuated widely during recent years and are determined by supply and demand factors, including weather and general economic conditions, as well as conditions in other oil and natural gas regions. Any decline in prices could have an adverse effect on the Corporation's financial condition. The Corporation seeks to mitigate the price risks through its price risk management program.

The exploration and development of oil and natural gas reserves is dependent on access to areas where production is to be conducted. In Alberta, access is affected by seasonal weather conditions, including freeze-up and break-up.

Potential Acquisitions

The Corporation is constantly in the process of evaluating potential acquisitions of oil and natural gas assets which individually or together could be material. As of the date hereof, no agreement on the price or terms of any potential material acquisitions has been reached and it cannot be predict whether any current or future opportunities will result in one or more acquisitions for the Corporation.

Environmental Policies

The Corporation is committed to managing and operating in a safe, efficient, environmentally responsible manner and to continually improving our environmental, health, safety and social performance. To fulfill this commitment, our operating practices and procedures are consistent with the requirements established for the oil and gas industry. Key environmental considerations include spill management, waste management plans, lease and right-of-way management, natural and historic resource protection, water conservation and liability management (including site assessment and remediation). These practices and procedures apply to the Corporation’s employees and consultants.

The Corporation believes that it meets all existing environmental standards and regulations and sufficient amounts are included in the Corporation’s capital expenditure budget to continue to meet current environmental protection requirements.

The Corporation expects to incur abandonment and reclamation costs as existing oil and gas properties are abandoned. In 2013, expenditures for normal compliance with environmental regulations as well as expenditures for above normal compliance were not material.

Employees/Consultants

As at December 31, 2013, the Corporation has 26 employees and 7 full-time and part-time consultants whose services are used on a regular basis for day-to-day operations.

PRINCIPAL PRODUCING PROPERTIES

The following is a description of the material oil and natural gas properties, pipelines, facilities and installations in which the Corporation has an interest. The production data noted below represents the Corporation’s share of sales volumes before deduction of royalties.

Lethbridge, Alberta - The Alberta Bakken Play

The Lethbridge Properties are located in southern Alberta, approximately 70 kilometers south of Lethbridge (TWP 3, Range 17, W4M). This operated property consists of an average working interest of approximately 100 percent in approximately 254,412 gross (253,223 net) undeveloped acres and 50,890 gross (48,733 net) developed acres as at December 31, 2013. The majority of oil production from this property was from the new horizontal oil wells producing from the Bakken formation.

Throughout 2013, the Corporation drilled 17 gross horizontal Bakken wells with a 100% success rate. All of these wells are currently on production. The Corporation also implemented a gas injection pilot project and constructed a new oil battery. Production during the 2013 year averaged 3,768 BOE/d and was comprised of 89% crude oil and liquids and 11% natural gas.

The Corporation plans to drill approximately 18 gross (18.0 net) horizontal multi-frac wells on the Lethbridge Property in 2014. To accommodate the additional production, a new 8,000 barrel per day oil battery has been constructed. At December 31, 2013, the Corporation has a remaining inventory of 250 gross (250 net) drilling locations.

Brazeau, Alberta - The Belly River Play

The Brazeau property is located in west central Alberta, approximately 160 kilometres southwest of Edmonton (TWP 47, Range 14, W5M). This operated property consists of an average working interest of approximately 85 percent in approximately 33,600 gross (27,066 net) undeveloped acres and 26,720 gross (22,746 net) developed acres as at December 31, 2013. The majority of oil production from this property was from the new horizontal oil wells producing from various intervals within the Belly River formation. The Corporation is developing the Brazeau property using horizontal and multi-stage fracturing technologies that improves recovery from the oil charged tight sandstones. The Corporation is in various stages of testing up to seven different Belly River intervals.

In the year ended December 31, 2013, the Corporation drilled 17 gross (16.9 net) horizontal oil wells in the Belly River formations of Brazeau, successfully testing six different sands in the area. Production during the 2013 year averaged 2,768 BOE/d and was comprised of 74% crude oil and liquids and 26% natural gas. Given the multi-zone potential in the area, DeeThree has a drilling inventory of up to 250 locations The Corporation entered into a farm-in agreement in December 2012 with a senior oil and gas producer pursuant to which the Corporation may earn a 100%

working interest in up to 34 additional sections of Belly River petroleum and natural gas rights, directly offsetting the Corporation's existing core Brazeau Belly River property. The Corporation committed to drilling a minimum of three horizontal wells on the farm-in lands with a continuing rolling option thereafter in return for a 15% non-convertible overriding royalty. DeeThree had drilled all three wells by June of 2013.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Relevant Dates

The date of the report by Sproule is December 31, 2013 and the preparation date of that report is March 6, 2014. As of the preparation date, DeeThree and its independent reserves evaluator, Sproule, are not aware of any new information (other than commodity pricing assumptions which may differ from those used in this analysis) which could materially impact this evaluation.

The effective date of the reserves estimates and revenue projection in this report is December 31, 2013.

Estimates of reserves and projections of production were generally prepared using data current to December 31, 2013. No drilling results were used past December 31, 2013.

Disclosure of Reserves Data

All oil and natural gas reserve information contained in this Annual Information Form has been prepared and presented in accordance with NI 51-101. The tables below are a summary of the oil, NGL and natural gas reserves of the Corporation and the net present value of future net revenue attributable to such reserves as evaluated in the Sproule Report based on forecast price and cost assumptions. The tables summarize the data contained in the Sproule 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.

Reserves Estimates

The reserves of the Corporation were evaluated by Sproule, as set out in the Sproule Report dated March 6, 2014, in which Sproule has evaluated, as of December 31, 2013, the oil and natural gas reserves attributable to all of the properties of the Corporation. The information was prepared between January 2014 and March 6, 2014.

The following information is a summary of reserves data and related information contained in the Sproule Report. All of the oil and gas properties to which reserves have been attributed are located in the Province of Alberta, Canada. The Sproule Report also presents the estimated net value of future revenue of the Corporation's properties before and after Taxes, at various discount rates. Assumptions and qualifications relating to costs, prices for future production and other matters are summarized in the notes to the following tables.

The information concerning oil and gas reserves includes forward-looking statements relating to future net revenues, forecast capital expenditures, future development plans and costs related thereto, forecast operating costs and anticipated production and abandonment costs. Refer to "*Forward-Looking Statements*" and "*Risk Factors*" in this Annual Information Form.

All estimates of future revenues made by Sproule in the Sproule Report are stated after the deduction of royalties, and capital and operating costs, but before consideration of income taxes and indirect costs such as administrative, overhead and miscellaneous expenses. It should not be assumed that the estimates of the present value of future net revenues presented in the following tables represent the fair market value of the reserves. There can be no assurance that the forecast price and cost assumptions contained in the Sproule Report will be consistent with actual prices and costs and variances could be material. Other assumptions and qualifications relating to costs and other matters are included in the Sproule Report and summarized in the notes to the following tables. The recovery and reserves estimates described herein are estimates only. The actual reserves may be greater or less than those calculated and differences may be material. For more information on the risks involved, see "*Risk Factors*" in this Annual Information Form.

Summary of Oil and Gas Reserves Effective December 31, 2013

The following table outlines the light crude oil and gas reserves of the Corporation on a forecasted pricing basis, by product type on a gross (before royalties) and net (after royalties) basis:

	Light Oil		**Natural Gas**		**NGLs**		**BOE**	
	Gross *(mbbls)*	**Net *(mbbls)***	**Gross *(MMcf)***	**Net *(MMcf)***	**Gross *(mbbls)***	**Net *(mbbls)***	**Gross *(MBOE)***	**Net *(MBOE)***
Proved								
Developed producing	8,828.3	6,331.7	24,740	21,887	1,073.8	727.0	14,025.4	10,706.5
Developed non-producing	230.1	180.1	1,959	1,627	31.8	21.5	588.4	472.6
Undeveloped	8,895.0	7,402.0	12,309	10,709	724.3	547.4	11,670.9	9,734.1
Total proved	17,953.5	13,913.8	39,007	34,222	1,830.0	1,295.9	26,284.7	20,913.3
Probable	9,787.2	7,530.1	15,640	13,589	734.2	501.9	13,128.1	10,296.7
Total proved plus probable	27,740.7	21,444.0	54,647	47,810	2,564.1	1,797.7	39,412.8	31,210.0

Figures may not add due to rounding.

Net Present Values of Future Net Revenue

The net present values of future net revenue of the Corporation's reserves at December 31, 2013 at various discount rates on a before tax and after tax basis and on a forecasted pricing basis, are outlined below:

	Before Income Taxes (1) Discounted At				
	0%	**5%**	**10%**	**15%**	**20%**
(000s)	***($)***	***($)***	***($)***	***($)***	***($)***
Proved					
Developed producing	484,776	378,849	315,061	272,533	242,124
Developed non-producing	15,850	12,920	10,878	9,389	8,262
Undeveloped	366,557	252,547	182,195	134,914	101,179
Total proved	867,183	644,315	508,134	416,836	351,564
Probable	527,132	302,098	195,582	136,106	99,009
Total proved plus probable	1,394,315	946,413	703,716	552,942	450,574

Note:
(1) Estimates of future net revenue do not represent fair market value.

	After Income Taxes (1) Discounted At				
	0%	**5%**	**10%**	**15%**	**20%**
(000s)	***($)***	***($)***	***($)***	***($)***	***($)***
Proved					
Developed producing	452,164	357,391	299,874	261,180	233,271
Developed non-producing	11,887	9,650	8,092	6,956	6,096
Undeveloped	275,053	183,657	126,863	88,527	61,120
Total proved	739,105	550,698	434,829	356,663	300,487
Probable	395,702	223,903	142,147	96,270	67,557
Total proved plus probable	1,134,807	774,600	576,976	452,933	368,044

Note:
(1) Estimates of future net revenue do not represent fair market value.

Total Future Net Revenue

The following table provides a breakdown of the various components of total future net revenue on an undiscounted basis for proved and proved plus probable reserves:

(000s)	Revenue ($)	Royalties ($)	Operating Costs ($)	Capital Development Costs ($)	Well Abandonment and Reclamation Costs ($)	Future Net Revenue Before Income Taxes ($)	Future Income Tax Expenses ($)	Future Net Revenue After Income Taxes (1) ($)
Proved	1,958,155	415,893	440,057	224,935	10,087	867,183	128,078	739,105
Probable	1,155,968	255,240	267,574	103,555	2,466	527,132	131,431	395,702
Total proved plus probable	3,114,123	671,133	707,631	328,490	12,553	1,394,315	259,509	1,134,807

Net Present Value of Future Net Revenue by Production Group (Forecast Prices and Costs)

Reserves Category	Production Group	Future Net Revenue Before Income Taxes (3) (discounted at 10%/year) ($000s)	Future Net Revenue Before Income Taxes (3) (discounted at 10%/year) ($/BOE)
Proved	Light oil (1)	494,393	25.34
	Natural gas (2)	13,740	9.77
Probable	Light oil (1)	191,317	
	Natural gas (2)	4,266	
Proved plus probable	Light oil (1)	685,710	23.39
	Natural gas (2)	18,006	9.51

Notes:

(1) Including solution gas and other by-products.
(2) Including by-products but excluding solution gas.
(3) Unit values of $/BOE are based on Corporation net reserves. Estimates of future net revenue do not represent fair market value.

Pricing Assumptions

Forecast Prices Used in Estimates

The following tables set forth the benchmark reference prices, as at December 31, 2013 used in preparing the Corporation's reserves data. These price assumptions were provided to DeeThree by Sproule and were Sproule's then current forecasts at the date of the Sproule Report.

	Light Oil			Natural Gas	NGL			
Year	WTI Cushing Oklahoma 40º API (US$/bbl)	Edmonton Par Price 40º API (Cdn$/bbl)	Western Canada Select 20.5º API (Cdn$/bbl)	AECO Gas Price ($/MMBtu)	Pentanes plus FOB Field Gate ($/bbl)	Butanes FOB Field Gate ($/bbl)	Inflation rates (%/Yr)	Exchange rate ($US/$Cdn)
2013 (Actual)	97.98	93.24	74.20	3.13	104.86	70.29	0.8	0.971
2014	94.65	92.64	77.81	4.00	103.50	69.05	1.5	0.94
2015	88.37	89.31	75.02	3.99	99.78	66.57	1.5	0.94
2016	84.25	89.63	75.29	4.00	100.14	66.81	1.5	0.94
2017	95.52	101.62	85.36	4.93	113.53	75.74	1.5	0.94
2018	96.96	103.14	86.64	5.01	115.24	76.88	1.5	0.94
2019	98.41	104.69	87.94	5.09	116.97	78.03	1.5	0.94
2020	99.89	106.26	89.26	5.18	118.72	79.20	1.5	0.94
2021	101.38	107.86	90.60	5.26	120.50	80.39	1.5	0.94
2022	102.91	109.47	91.96	5.35	122.31	81.60	1.5	0.94
2023	104.45	111.12	93.34	5.43	124.14	82.82	1.5	0.94

Year	Light Oil WTI Cushing Oklahoma 40° API (US$/bbl)	Edmonton Par Price 40° API (Cdn$/bbl)	Western Canada Select 20.5° API (Cdn$/bbl)	Natural Gas AECO Gas Price ($/MMBtu)	NGL Pentanes plus FOB Field Gate ($/bbl)	Butanes FOB Field Gate ($/bbl)	Inflation rates (%/Yr)	Exchange rate ($US/$Cdn)
2024	106.02	112.78	94.74	5.52	126.01	84.06	1.5	0.94

In 2013, the Corporation received a weighted average price of $3.42 per Mcf (before transportation, marketing fees and hedging) for natural gas and $81.82 per Bbl for light oil and NGLs.

Reconciliation of Changes In Reserves And Future Net Revenue

Reconciliation of Reserves by Principal Product Type Based on Forecast Prices and Costs

The following tables set forth a reconciliation of the changes in gross total company working interest reserve volumes as at December 31, 2013 against such gross reserves as at December 31, 2012 based on the forecast prices and costs assumptions:

	Light Oil			Natural Gas		
	Proved *(MMcf)*	Probable *(MMcf)*	Proved plus Probable *(MMcf)*	Proved *(mbbls)*	Probable *(mbbls)*	Proved plus Probable *(mbbls)*
December 31, 2012	10,469.8	4,293.9	14,763.7	19.285	7,777	27,062
Discoveries, Extensions and Improved Recovery	6,052.9	6,665.0	12,717.9	15,443	7,118	22,462
Infills	852.3	224.5	1,076.8	2,041	538	2,579
Economic Factors	40.4	21.4	61.8	(48)	42	(7)
Acquisitions	133.3	18.9	152.2	841	(795)	46
Technical Revisions	2,304.7	(1,436.5)	868.2	5,051	960	6,011
Production	(1,899.9)	0	(1,899.9)	(3,606)	0	(3,606)
December 31, 2013	17,953.5	9,787.2	27,740.7	39,007	15,640	54,647

	Natural Gas Liquids			Total		
	Proved *(mbbls)*	Probabl e *(mbbls)*	Proved plus Probable *(mbbls)*	Proved *(MBOE)*	Probable *(MBOE)*	Proved plus Probable *(MBOE)*
December 31, 2012	673.5	239.9	913.4	14,357.5	5,830.6	20,187.4
Discoveries, Extensions and Improved Recovery	1,009.1	449.3	1,458.1	9,635.7	8,300.8	17,936.5
Infills	138.2	36.4	174.6	1,330.7	350.5	1,6881.2
Economic Factors	3.3	0	3.3	35.7	28.3	64.0
Acquisitions	45.7	3.1	48.8	319.1	(110.5)	208.6
Technical Revisions	81.6	5.4	87	3,228.1	(1,271.1)	1,957.0
Production	(121.1)	0	(121.1)	(2,622.1)	0	(2,622.1)
December 31, 2013	1,830.0	734.1	2,564.1	26,284.7	13,128.0	39,412.6

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

ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Undeveloped Reserves

Proved and probable undeveloped reserves have been estimated in accordance with procedures and standards contained in the COGE Handbook.

At December 31, 2013, 11,671 MBOE or 44.4% of DeeThree's total proved reserves and 8,873 MBOE or 67.6% of DeeThree's total probable reserves were undeveloped. Undeveloped reserves are attributable to activity primarily scheduled over 2014 through 2033.

The timing of initial undeveloped reserves assignments as at December 31, 2013 over the prior three years in the forecast prices and costs case is indicated in the attached table from the Sproule Report.

Corporation Gross Reserves First Attributed By Year

Product Type	Units	Prior Years(1)	2011	2012	2013
Proved Undeveloped					
Light Oil	mbbls	0.0	0.0	4,710.8	3,471.9
Natural Gas	MMcf	0.0	0.0	3,139.0	2,953.0
Natural Gas Liquids	mbbls	0.0	0.0	74.8	320.1
Total: Oil Equivalent	MBOE	0.0	0.0	5,308.8	4,284.2
Probable Undeveloped					
Light Oil	mbbls	0.0	350.0	1,499.3	3,815.6
Natural Gas	MMcf	0.0	46.0	1,079.0	1,417.0
Natural Gas Liquids	mbbls	0.0	0.0	47.2	391.0
Total: Oil Equivalent	MBOE	0.0	357.7	1,726.3	4,442.8

Note:

(1) Figures in this column represent cumulative reserves attributed prior to 2011.

Proved and probable undeveloped reserves are attributed by Sproule in accordance with standards and procedures contained in the COGE Handbook. In general, once proved and/or probable undeveloped reserves are identified they are scheduled into the Corporation's development plans. Currently, the Corporation plans to develop the majority of its proved and probable undeveloped reserves within two years. However, if the economic climate is not conducive to developing these reserves within two years, the Corporation may, in its discretion, defer the development into the future. There are a number of factors that could result in delays or cancelled development plans. These factors would include, but are not limited to, changing economic and technical conditions, surface access issues and the availability of services.

Significant Factors or Uncertainties

The process of evaluating reserves is inherently complex. It requires significant judgment and decision-making on the basis of the available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance become 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. Factors and assumptions that affect these reserve estimates include, among other things: (i) historical production in the area compared with production rates from analogous producing areas; (ii) initial production rates; (iii) production decline rates; (iv) ultimate recovery of reserves; (v) success of future development activities; (vi) marketability of production; (vii) effects of government regulations; and (viii) other government levies imposed over the life of the reserves.

As circumstances change and additional data become available, reserve estimates also change. Estimates 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. Revisions to reserve estimates can arise from changes in year-end prices, reservoir performance and geologic conditions or production. These revisions can be either positive or negative.

The evaluated oil and gas properties of the Corporation have no material extraordinary risks or uncertainties beyond those that are inherent in an oil and gas producing company.

Future Development Costs

The following table provides information regarding the development costs deducted in the estimation of future net revenue attributable to the Corporation's reserves.

($000s) Year	**Total Proved Reserves using forecast prices and costs**	**Total Proved Plus Probable Reserves using forecast prices and costs**
2014	170,551	212,330
2015	54,384	116,039
Remaining	0	121
Total Undiscounted	224,935	328.490
Total Discounted at 10%	210,459	304,476

The Corporation's source of funding for future development costs of its reserves will be derived from a combination of working capital, funds from operations, debt and new equity. Management does not anticipate that the costs of funding referred to above will materially affect the Corporation's disclosed reserves and future net revenues or will make the development of any of the Corporation's properties uneconomic.

ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Oil and Gas Wells

The following table sets forth the number and status of wells in which the Corporation had a working interest as at December 31, 2013:

	Light Crude Oil Wells				**Natural Gas Wells**			
	Producing		**Non-Producing**		**Producing**		**Non-Producing**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Alberta	202	187	61	43	188	161	49	34
Total	202	187	61	43	188	161	49	34

Properties with No Attributed Reserves

The following table summarizes, as of December 31, 2013, DeeThree's undeveloped lands and the net acreage of undeveloped lands where the rights to explore, develop and exploit are expected to expire within one year.

	Acres		
	Gross	**Net**	**Net Acres Expiring Within One Year**
Alberta	334,252	311,268	11,976

Forward Contracts

As at December 31, 2013, the Corporation had the following forward contracts in place.

Period	Commodity	Type of Contract	Quantity	Pricing Point	Contract Price
Jan. 1/14 – Dec.31/14	Crude oil	Collar	1,000 BBls/d	*WTI – NYMEX*	US$85.00/bbl (floor) - US$97.00/bbl (cap)
Jan. 1/14 – Dec.31/14	Crude oil	Collar	500 BBls/d	*WTI - NYMEX*	CAD$92.50/bbl (floor) - CAD$102.01/bbl (cap)
Jan. 1/14 – Dec.31/14	Crude oil	Collar	500 BBls/d	*WTI – NYMEX*	CAD$90.00/bbl (floor) - CAD$101.25/bbl (cap)
Jan. 1/14 – Dec.31/14	Crude oil	Collar	500 BBls/d	*WTI – NYMEX*	CAD$90.00/bbl (floor) - CAD$107.85)/bbl (cap)

The Corporation entered into the forward contracts set out below following December 31, 2013.

Period	Commodity	Type of Contract	Quantity	Pricing Point	Contract Price
Mar. 1/14 – Dec. 31/14	Crude Oil	Swap	500 BBls/d	*WTI-NYMEX*	CAD$105.20/bbl
Mar. 1/14 – Dec. 31/14	Crude Oil	Swap	500 BBls/d	*WTI-NYMEX*	CAD$106.00/bbl
April 1/14 – Oct. 31/14	Natural Gas	Swap	2,500 GJs/d	*AECO*	CAD$4.11/gj
Feb. 1/14 – Dec. 31/14	Natural Gas	Swap	2,000 GJs/d	*AECO*	CAD$3.975/gj
Mar. 1/14 – Dec. 31/14	Natural Gas	Swap	1,000 GJs/d	*AECO*	CAD$4.31/gj

As at December 31, 2013, the Corporation had the following foreign currency exchange risk management contract in place.

Period	Currency	Type of Contract	Quantity	Pricing Point (CDN$/US$)
Jan.1/14 – Dec.31/14	US$	Average Rate Range Bonus Accumulator	US$2,500,000	Target - $1.0825 CDN/US$ +$1,500 Bonus/day [(1)]

Note:

(1) The Corporation can earn a bonus payout of up to $1,400/day depending on the period in which the exchange rate remains in the applicable range of less than $1.0825.

The Corporation entered into the interest rate swap contract set out below following December 31, 2013.

Period	Amount	Fixed Rate	Index
Feb. 18/14 – Feb. 18/16	$40 million	1.44%	CDOR

Additional Information Concerning Abandonment and Restoration Costs

The Corporation typically estimates well abandonment costs area by area. Such costs are included in the Sproule Report as deductions in arriving at future net revenue. The expected total abandonment costs, net of estimated salvage value, included in the Sproule Report for 425 net wells under the proved reserves category is $10.1 million undiscounted ($2.6 million discounted at 10%), of which a total of $0.7 million is estimated to be incurred in 2014, 2015 and 2016. This estimate does not include expected reclamation costs for surface leases. The Corporation 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.

Tax Horizon

The Corporation is not expected to pay income taxes for 2013, its most recently completed financial year. The Corporation is unlikely to be taxable in 2014 given the current price environment and its capital spending plans.

Costs Incurred

The following table summarizes certain expenditures for the Corporation during the year ended December 31, 2013. All costs were incurred in Alberta, Canada.

Nature of Cost Incurred	Year Ended December 31, 2013 ($000)
Property Acquisition (Divestiture) Costs	
Proved Properties	11,694
Unproved Properties	-
Exploration	23,027
Development	177,164
Total	211,885

Exploration and Development Activities

The Corporation participated in the drilling and completion of 35 gross (34.1 net) wells in 2013, 17 (17 net) of which were drilled on the Lethbridge Properties, 17 gross (16.9 net) were drilled on the Brazeau Belly River Properties and 1 gross (0.3 net) wells were drilled at Peace River Arch Montney. The following table summarizes the Corporation's drilling results.

	Exploration		Development		Total	
	Gross	Net	Gross	Net	Gross	Net
Natural gas	-	-	-	-	-	-
Crude oil and NGLs	4	3.97	28	27.22	32	31.19
Standing	-	-	-	-	-	-
Dry and abandoned	3	2.97	-	-	3	2.97
Total wells	7	6.93	28	27.22	35	34.15
Success rate (%)		57		100		91
Average working interest (%)		99		97		98

In 2014, the Corporation expects to drill a total of approximately 46 horizontal oil wells on the Lethbridge Properties (18 wells) and the Brazeau Belly River Properties (28 wells).

Future Development Costs

The following table sets forth development costs deducted in the estimation of our future net revenue attributable to the reserve categories noted below.

	Forecast Prices and Costs	
Year	Proved Reserves ($000s)	Proved Plus Probable Reserves ($000s)
2014	170,551	212,330
2015	54,384	116,039
2016	-	-
2017	-	-
2018	-	-
Remaining	-	121
Total (Undiscounted)	224,935	328,490
Total (Discounted at 10%)	210,459	304,476

The Corporation expects to fund the development costs of its reserves through a combination of internally generated cash flow, debt and equity issuances. There can be no guarantee that funds will be available or that our Board of Directors will allocate funding to develop all of the reserves attributed in the Sproule Report. Failure to develop those reserves could have a negative impact on the Corporation's future cash flow.

Production Estimates

The following table is a summary of the working interest (prior to royalties) volume of the Corporation's estimated production for 2014, which is reflected in the estimate of future net revenue in the Sproule Report based on the forecast price tables contained above.

Reserve Category	Light and Medium crude Oil (bbls/d)	Natural Gas (mcf/d)	Natural Gas Liquids (bbls/d)	Oil Equivalent (BOE/d)	%
Proved					
Lethbridge	4,894	4,920	124	5,838	48.4
Brazeau	3,371	10,379	708	5,809	48.2
Other	92	1,795	20	411	3.4
Total Proved	8,357	17,094	852	12,058	
Proved plus Probable					
Lethbridge	5,107	5,114	130	6,089	46.0
Brazeau	3,975	11,757	799	6,734	50.9
Other	94	1,823	20	418	3.1
Total Proved plus Probable	9,176	18,692	949	13,241	

Production History

The following tables summarize certain information in respect of the Corporation's production, product prices received, royalties paid, operating expenses and resulting netback for the indicated periods during the financial year ended December 31, 2013.

	Q1 31-Mar-13	Q2 30-Jun-13	Q3 30-Sep-13	Q4 31-Dec-13
Average Daily Production				
Oil (Bbls/d)	3,924	4,550	5,765	6,547
NGL (Bbls/d)	289	346	323	369
Gas (mcf/d)	10,279	10,093	8,910	10,251
BOE/d	5,926	6,578	7,573	8,625
Average Price Received				
Oil ($/Bbl)	73.46	83.92	98.26	77.62
NGL ($/Bbl)	49.33	47.29	57.21	38.87
Gas ($/mcf)	3.43	3.79	2.33	4.00
Combined ($/BOE)	57.17	66.62	80.03	65.37
Royalties				
Combined ($/BOE)	12.08	12.72	19.28	16.21
Operating Expenses				
Combined ($/BOE)	8.10	10.74	10.46	10.03
Transportation ($/BOE)	1.84	2.59	2.18	1.75
Netback Received				
Combined ($/BOE)	35.15	40.57	48.11	37.38

The following table summarizes the Corporation's average daily net production volumes during the year ended December 31, 2013.

	Light Oil *(Bbls/d)*	Conventional Natural Gas *(Mcf/d)*	NGLs *(Bbls/d)*	Equivalent Barrels *(BOE/d)*
Alberta				
Lethbridge	3,343	2,529	4	3,768
Brazeau	1,746	4,355	295	2,768
Other	116	2,997	34	648
Total	5,205	9,881	332	7,184

Other Oil and Natural Gas Information

Land Holdings

The Corporation's developed and undeveloped landholdings as at December 31, 2013 are set forth in the following table:

	Undeveloped		Developed		Total	
	Gross *(acres)*	Net *(acres)*	Gross *(acres)*	Net *(acres)*	Gross *(acres)*	Net *(acres)*
2013						
Lethbridge	254,412	253,223	50,890	48,773	305,302	301,996
Brazeau	33,600	27,066	26,720	22,746	60,320	49,812
Peace River Arch	42,560	28,837	51,612	25,290	94,172	54,127
Other	3,680	2,142	7,040	4,474	10,720	6,616
Total	334,252	311,268	136,262	101,283	470,514	412,551

INDUSTRY CONDITIONS

The oil and natural gas industry is subject to extensive laws and regulations governing its operations (including land tenure, exploration, development, production, refining, transportation, and marketing) imposed by various levels of governments and with respect to pricing and taxation of oil and natural gas by agreements between the federal government and the Alberta provincial government, all of which should be carefully considered by investors in the oil and gas industry. Furthermore, the Corporation is subject to various market forces, such as pipeline capacity and increased environmental activism, the effects of which cannot be accurately predicted. Although the Corporation does not expect that any of these factors will affect the Corporation's operations in a manner materially different than they would affect other oil and gas companies of similar size, any of these factors could materially impact the Corporation.

Outlined below are some of the principal aspects of the legislation, regulations and agreements governing the oil and gas industry and factors that could affect the industry as a whole.

Pricing and Marketing

In Canada, the market determines the price of oil since negotiations of sales contracts are done directly between oil producers and oil purchasers. The price depends in part on oil quality, prices of competing fuels, distance to market, and the value of refined products. Oil exports may be made under export contracts having terms not exceeding one year in the case of light oil, and not exceeding two years in the case of heavy oil, provided that an order approving any such export has been approved by the National Energy Board of Canada (the "**NEB**"). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB and the issue of such a licence requires the approval of the Government of Canada.

Similarly, the price of natural gas and NGL sold is determined by negotiation between buyers and sellers. Natural gas and NGL exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that export contracts in excess of two years must continue to meet certain criteria prescribed by the NEB and the Government of Canada. Natural gas exports for a term of less than two years must be made pursuant to an NEB order, or, in the case of exports for a longer duration, pursuant to an NEB licence and the issuance of such license requires a public hearing and Government of Canada approval.

The provincial governments of Alberta also regulate the removal of gas from its jurisdiction for consumption elsewhere based upon such factors as reserve availability, transportation arrangements and market considerations.

Royalties

The royalty regime is a significant factor on profitability. Alberta has legislation and regulations which govern royalties. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production, and the royalty rate payable generally depends in part on the prescribed reference prices for the oil and natural gas, well productivity, geographical location, field discovery date, method of recovery and the type or quality of the petroleum product produced.

Royalties payable on production from lands other than Crown lands are determined by negotiation between the mineral freehold owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Other royalties and royalty-like interests are, from time to time, carved out of the working interest owner's interest through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests, or net carried interests.

Environmental Regulation

Federal

Canada is a signatory to the United Nations Framework Convention on Climate Change and the Kyoto Protocol thereunder but has announced in December 2011 that it is withdrawing from the Kyoto Protocol.

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 greenhouse gas ("**GHG**") emissions by 2050. Canada reiterated its commitment to this goal at the June 2010 G8 Summit in Huntsville, Ontario.

The Canadian federal government released an action plan, "Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions" (the "**Action Plan**") in March 2008, which set forth a plan for regulations to address both GHG and air pollution. The Action Plan outlines a number of policies to reduce GHGs intensity of regulated facilities. New facilities (which are 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 Action 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 $20 per tonne in 2013 and an escalating annual rate per tonne thereafter; to the federal technology fund.

The Action 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 Action 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.

DeeThree will continue to monitor the policies of the Government of Canada and any resulting legislation with respect to GHG emissions.

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 emission reduction requirements in the *Climate Change and Emissions Management Act* (Alberta) (the "**CCEMA**") came into effect on July 1, 2007. The CCEMA is based on an emissions intensity approach similar to the Action Plan and aims for a 50% reduction from 1990 emissions relative to GDP by 2020.

Pipeline Capacity

Due to the advance in drilling technology, there has been significant growth in crude production volumes over the last several years in Western Canada and North Dakota. Although pipeline expansions are ongoing, the lack of firm pipeline capacity continues to affect the oil and natural gas producers in Western Canada and limit the ability to produce and to market natural gas production. This has led to a widening of, and increase volatility in, the light oil pricing differential between WTI and Edmonton Par and the medium/heavy oil pricing differential between WTI and Cromer/WCS/Hardisty. Although more producers are increasingly turning to rail as an alternative means of transportation, the lack of firm pipeline capacity continues to affect oil and gas producers. In addition, the pro-rationing of capacity on the inter provincial pipeline systems also continues to affect the ability to export oil and natural gas.

Land Tenure

The Alberta provincial government predominantly owns crude oil and natural gas located in Alberta. The Alberta provincial government grants the right to explore for and produce oil and natural gas pursuant to leases, licences, and permits for varying terms, and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. Private ownership of oil and natural gas also exists in Alberta and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

The province of Alberta has implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or license.

The province of Alberta also has a policy of "shallow rights reversion" which provides for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for all leases and licenses. For leases and licenses issued subsequent to January 1, 2009, shallow rights reversion will be applied at the conclusion of the primary term of the lease or license. Holders of leases or licences that have been continued indefinitely prior to January 1, 2009 will receive a notice regarding the reversion of the shallow rights, which will be implemented three years from the date of the notice. Leases and licences granted prior to January 1, 2009, but continued after that date, are not subject to shallow rights reversion until they continue past their primary term (at which time the application of deep rights reversion occurs). Afterwards, the holders of such agreements will be served with shallow rights reversion notices based on vintage and location similar to leases and licences that were already continued as of

January 1, 2009. The order in which these agreements will receive reversion notices will depend on their vintage and location.

Seasonality

The level of activity in the Canadian oil and gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments may at times restrict the movement of drilling rigs and other heavy equipment, thereby reducing activity levels. Also, certain oil and natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain.

RISK FACTORS

Overview

The Corporation's business consists of the exploration and development of oil and gas properties in Alberta. There are a number of inherent risks associated with the exploration, development and production of oil and gas reserves. Many of these risks are beyond the control of the Corporation.

An investment in the Common Shares involves a number of risks. In addition to the other information contained in this Annual Information Form, investors should give careful consideration to the following, factors, which are qualified in their entirety by reference to, and must be read in conjunction with, the detailed information appearing elsewhere in this Annual Information Form. If any of the following events described as risks or uncertainties actually occurs, the business, prospects, financial condition and operating results of the Corporation would likely suffer, possibly materially. In that event, the market price of the Common Shares could decline and investors could lose all or part of their investment. Additional risks and uncertainties presently unknown, or that are not believed to be material at this time, may also impair or have a material adverse effect on the Corporation's operations. In addition to the risks described elsewhere and the other information contained in this Annual Information Form, prospective investors should carefully consider each of and the cumulative effect of all of the following risk factors. References in the below Risk Factors to "we", "our" or "us" refer to the management of the Corporation.

Nature of Business

An investment in the Corporation should be considered highly speculative due to the nature of the Corporation's involvement in the exploration for, and the acquisition, development, production and marketing of, oil and natural gas reserves and its current stage of development. Oil and gas operations involve many risks which even a combination of experience and knowledge 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 or acquired by the Corporation.

Exploration, Development and Production Risks

Oil and natural gas exploration involves a high degree of risk, which even a combination of experience, knowledge and careful evaluation may not be able to overcome. There is no assurance that expenditures made on future exploration by the Corporation will result in new discoveries of oil or natural gas in commercial quantities. It is difficult to project the costs of implementing an exploratory drilling program due to the inherent uncertainties of drilling in unknown formations, the costs associated with encountering various drilling conditions such as over pressured zones, tools lost in the hole and changes in drilling plans and locations as a result of prior exploratory wells or additional seismic data and interpretations thereof. The long-term commercial success of the Corporation will depend on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. No assurance can be given that the Corporation will be able to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, the Corporation may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic.

Future oil and gas exploration may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other 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, 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. In addition, oil and gas operations are subject to the risks of exploration, development and production of oil and natural gas properties, including encountering unexpected formations or pressures, premature declines of reservoirs, blow-outs, cratering, sour gas releases, fires and spills. Losses resulting from the occurrence of any of these risks could have a materially adverse effect on future results of operations, liquidity and financial condition.

Prices, Markets and Marketing of Crude Oil and Natural Gas

Oil and natural gas are commodities whose prices are determined based on world demand, supply and other factors, all of which are beyond the control of the Corporation. World prices for oil and natural gas have fluctuated widely in recent years. Any material decline in prices could result in a reduction of net production revenue. Certain wells or other projects may become uneconomic as a result of a decline in world oil prices and natural gas prices. All of these factors could result in a material decrease in the Corporation's future net production revenue, causing a reduction in its oil and gas acquisition and development activities. In addition, bank borrowings available to the Corporation are expected to be determined in part by the borrowing base of the Corporation. A sustained material decline in prices from historical average prices could limit the Corporation's borrowing base, therefore reducing the bank credit available to the Corporation, and could require that a portion of any existing bank debt of the Corporation be repaid.

In addition to establishing markets for its oil and natural gas, the Corporation must also successfully market its oil and natural gas to prospective buyers. The marketability and price of oil and natural gas which may be acquired or discovered by the Corporation will be affected by numerous factors beyond its control. The Corporation will be affected by the differential between the price paid by refiners for light quality oil and the grades of oil produced by the Corporation. The ability of the Corporation to market its natural gas may depend upon its ability to acquire space on pipelines which deliver natural gas to commercial markets. the Corporation will also likely be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing facilities and related to operational problems with such pipelines and facilities and 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 Corporation has limited direct experience in the marketing of oil and natural gas.

Substantial Capital Requirements: Liquidity

The Corporation anticipates that it will make capital expenditures for the acquisition, exploration and development and production of oil and natural gas reserves in the future. If the Corporation's revenues or reserves decline, as a result of lower oil and natural gas prices or otherwise, the Corporation may have limited ability to expend the capital necessary to undertake or complete future drilling programs to replace its reserves or to maintain its production. 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 Corporation. The inability of the Corporation to access sufficient capital for its operations could have a material adverse effect on the Corporation's financial condition, results of operations or prospects.

Additional Funding Requirements

From time to time, the Corporation may require additional financing in order to carry out its oil and gas acquisition, exploration and development activities. Such equity and/or debt financing may not be available or if available, may not be on favourable terms. Failure to obtain acceptable financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. Additionally, debt financing obtained may increase the Corporation's debt levels above industry standards.

Moreover, future activities may require the Corporation to alter its capitalization significantly, which may impact its financial condition.

Capital Markets

As a result of the weakened global economic situation, the Corporation along with all participants in the oil and gas industry will have restricted access to capital and increased borrowing costs. The lending capacity of all financial institutions has diminished and risk premiums have increased independent of the Corporation's business and asset base. As future capital expenditures will be financed out of cash generated from operations, borrowing and possible future equity sales, the Corporation's ability to do so is dependent on, among other factors, the overall state of capital markets and investor demand for investments in the energy industry and the Corporation's securities in particular. To the extent that external sources of capital become limited or unavailable or available on onerous terms, the Corporation's ability to make capital investments and maintain existing assets may be impaired, and its assets, liabilities, business, financial condition and results of operations may be materially and adversely affected as a result.

Significant Fluctuations in Market Price of Common Shares

The trading price of the Common Shares has been and may continue to be subject to significant fluctuations, which may be based on factors unrelated to its financial performance or prospects. These factors include macroeconomic developments in North America, Europe, and globally, and market perceptions of the attractiveness of particular industries. The price of the Common Shares may also be significantly affected by changes in commodity prices, currency exchange fluctuation or in the Corporation's financial condition or results of operations. Other factors unrelated to the performance of the Corporation that may have an effect on the price of the securities of the Corporation include the following: the extent of analytical coverage available to investors concerning the business of the Corporation may be limited if investment banks with research capabilities do not follow the Corporation's securities; lessening in trading volume and general market interest in the Corporation's securities may affect an investor's ability to trade significant numbers of securities of the Corporation; the size of the Corporation's public float may limit the ability of some institutions to invest in the Corporation's securities. If an active market for the securities of the Corporation does not continue, the liquidity of an investor's investment may be limited and the price of the securities of the Corporation may decline.

Possible Failure to Realize Anticipated Benefits of Acquisitions

Achieving the benefits of any future acquisitions the Corporation may complete depends in part on successfully consolidating functions and integrating operations, procedures and personnel in a timely and efficient manner, as well as the Corporation's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Corporation. The integration of acquired businesses requires the dedication of substantial management effort, time and resources which may divert management's focus and resources from other strategic opportunities and from operational matters during this process. The integration process may result in the loss of key employees and the disruption of ongoing business, customer and employee relationships that may adversely affect the Corporation's ability to achieve the anticipated benefits of these and future acquisitions.

Insurance

Oil and natural gas exploration operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, cratering and oil spills, each of which could result in substantial damage to oil and natural gas wells, production facilities or other property and the environment or in personal injury. In accordance with industry practice, the Corporation is not fully insured against all of these risks, nor are all such risks insurable. Although the Corporation maintains liability insurance in an amount which it considers adequate and consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits, in which event the Corporation could incur significant costs that could have a material adverse effect upon its financial condition.

Competition

The petroleum industry is competitive in all its phases. The Corporation competes with numerous other participants in the search for the acquisition of oil and natural gas properties and in the marketing of oil and natural gas. The Corporation’s competitors include oil and gas companies which have greater financial resources, staff and facilities than those of the Corporation. The Corporation’s ability to increase reserves in the future will depend not only on its ability to develop its present properties, but also on its ability to select and acquire suitable producing properties or prospects for exploratory drilling. Competitive factors in the distribution and marketing of oil and natural gas include price and methods of reliability of delivery.

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 state and/or provincial and municipal Laws and regulations. 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 the applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to foreign governments and third parties and may require the Corporation to incur costs to remedy such discharge. 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 the Corporation’s financial condition, results of operations or prospects.

Reserve Replacement

The Corporation's future oil and natural gas reserves, production and cash flows to be derived therefrom are highly dependent on the Corporation successfully acquiring or discovering new reserves. Without the continual addition of new reserves, any existing reserves the Corporation 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 Corporation's reserves will depend not only on the Corporation’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 Corporation's future exploration and development efforts will result in the discovery and development of additional commercial accumulations of oil and natural gas.

Risks Associated with Acquisitions

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

Although title and environmental reviews are conducted prior to any purchase of resource assets, such reviews cannot guarantee that any unforeseen defects in the chain of title will not arise to defeat the Corporation’s title to certain assets or that environmental defects or deficiencies do not exist.

Reliance on Operators and Key Employees

To the extent that the Corporation is not the operator of some of its oil and gas properties, the Corporation will be dependent on such operators for the timing of activities related to such properties and will largely be unable to direct or control the activities of the operators. In addition, the Corporation's success depends in large measure on certain key executive personnel. The loss of the services of such key personnel could have a material adverse effect on the Corporation. The Corporation does not have key person insurance in effect for management. The contributions of these individuals to the immediate operations of the Corporation 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 Corporation 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, discretions, integrity and good faith of the management of the Corporation.

Permits and Licenses

The operations of the Corporation may require licenses and permits from various governmental authorities. There can be no assurance that the issuer will be able to obtain all necessary license and permits that may be required to carry out exploration and development at its projects.

Dilution

The Corporation may make future acquisitions or enter into financings or other transactions involving the issuance of securities of the Corporation which may be dilutive.

Title of Properties

Although title reviews will be done according to industry standards prior to the purchase of most oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat the claim of the Corporation which could result in a reduction of the revenue received by the Corporation.

Hedging

From time to time the Corporation may enter into agreements to receive fixed prices on its oil and 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 Corporation will not benefit from such increases. Similarly, from time to time the Corporation 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 Corporation would not benefit from the fluctuating exchange rate for the fixed price agreement amount.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights to portions of western Canada. The Corporation is not aware that any claims have been made in respect of its assets, however, if a claim arose and was successful this could have an adverse effect on the Corporation and its operations.

Delays in Business Operations

In addition to the usual delays in payments by purchasers of oil and natural gas to the Corporation or to the operator, and the delays by operators in remitting payment to the Corporation, payments between these parties may be delayed due to restrictions imposed by lenders, accounting delays, delays in the sale or delivery of products, delays in the connections of wells to a gathering system, adjustment for prior periods, or recovery by the operator of expenses incurred in the operation of the properties. Any of these delays could reduce the amount of cash flow available for the business of the Corporation in a given period and expose the Corporation to additional third party credit risks.

Changes in Legislation

The return on an investment in securities of the Corporation is subject to changes in Canadian federal and provincial tax Laws and government incentive programs and there can be no assurance that such Laws or programs will not be changed in a manner that adversely affects the Corporation of the holding and disposing of the securities of the Corporation.

Seasonality

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

Rail Transportation

In response to recent train derailments occurring in the United States and Canada in 2013, U.S. regulators are implementing or considering new rules to address the safety risks of transporting crude oil by rail. On January 23, 2014, the National Transportation Safety Board issued a series of recommendations to address safety risks, including (i) requiring expanded hazardous material route planning for railroads to avoid populated and other sensitive areas, (ii) to develop an audit program to ensure rail carriers that carry petroleum products have adequate response capabilities to address worst-case discharges of the entire quantity of product carried on a train, and (iii) to audit shippers and rail carriers to ensure they are properly classifying hazardous materials in transportation and that they have adequate safety and security plans in place. Additionally, on February 25, 2014 the U.S. Department of Transportation issued an emergency order requiring all persons, prior to offering petroleum crude oil into transportation, to ensure such product is properly tested and classed and to assure all shipments by rail of petroleum crude oil be handled as a Packing Group I or II hazardous material. Such tests help determine how likely the fuel is to ignite and dictate what type of rail car can be used for shipment. The introduction of these or other regulations that result in new requirements addressing the type, design, specifications or construction of rail cars used to transport crude oil could result in severe transportation capacity constraints during the period in which new rail cars are retrofitted or constructed to meet new specifications. On March 6, 2014, the U.S. Department of Transportation issued an amended emergency order, offering more details on testing requirements of oil transported by rail and cautioned companies against circumventing the rules. The amended emergency order offers new standards on how frequently testing of crude oil has to be done. Testing must now be conducted within the reasonable, recent past to determine the flash point and boiling point of crude oil. The amended emergency order also warns companies not to re-label crude as a more generic category of flammable liquid in an attempt to get around the testing.

DeeThree does not currently own or operate rail transportation facilities or rail cars and does not ship a significant amount of its production via rail; however, the adoption of any regulations that impact the testing or rail transportation of crude oil could increase the Corporation’s costs of doing business and limit its ability to transport and sell its crude oil at favorable prices at market centers throughout Canada and the United States, the consequences of which could have a material adverse effect on the Corporation’s financial condition, results of operations and cash flows.

Income Taxes

The Corporation will file all required income tax returns and believes that it will be in full compliance with the provisions of the *Income Tax Act* (Canada) and all applicable provincial tax legislation. However, such returns are subject to reassessment by the applicable taxation authority. In the event of a successful reassessment of the

Corporation, whether by re-characterization of exploration and development expenditures or otherwise, such reassessment may have an impact on current and future Taxes payable.

Assessments of Value of Acquisitions

Acquisitions of oil and gas issuers and oil and gas assets are typically based on engineering and economic assessments made by independent engineers and the Corporation's own assessments. These assessments both will include a series of assumptions regarding such factors and recoverability and marketability of oil and gas, future prices of oil and gas and operating costs, future capital expenditures and royalties and other government levies which will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond the Corporation's control. In particular, the prices of and markets for oil and natural gas products may change from those anticipated at the time of making such assessment. In addition, all such assessments involve a measure of geologic and engineering uncertainty which could result in lower production and reserves than anticipated. Initial assessments of acquisitions may be based on reports by a firm of independent engineers that are not the same as the firm the Corporation uses for its year end reserve evaluations. Because each of these firms may have different evaluation methods and approaches, these initial assessments may differ significantly from the assessments of the firm used by the Corporation. Any such instance may offset the return on and value of the Common Shares.

Borrowing

The amount authorized under the Credit Facility is dependent on the borrowing base determined by the lenders. There is no guarantee that the Credit Facility would provide sufficient liquidity. The Corporation's lenders are provided with security over substantially all of the assets of the Corporation. The Corporation is required to comply with covenants under the Credit Facility which may, in certain cases, include certain financial ratio tests, which from time to time either affect the availability, or price, of additional funding and in the event that the Corporation does not comply with these covenants, access to capital could be restricted or repayment could be required. Events beyond the control of the Corporation may contribute to a failure of the Corporation to comply with such covenants. A failure to comply with covenants could result in the default under the Credit Facility, which could result in a requirement to repay amounts owing thereunder. In such event, even if the Corporation is able to obtain new financing, it may not be on commercially reasonable terms or terms that are acceptable. If the Corporation is unable to repay amounts owing under the Credit Facility, the lenders could proceed to foreclose or otherwise realize upon the collateral granted to them to secure the repayment of the indebtedness. The acceleration of the indebtedness under one agreement may permit acceleration of indebtedness under other agreements that contain cross default or cross-acceleration provisions.

Our lenders under the Credit Facility use the Corporation’s reserves, commodity prices, applicable discount rate and other factors, to periodically determine the Corporation’s borrowing base. A material decline in commodity prices could reduce the borrowing base, reducing the funds available to under the Credit Facility which could result in the requirement to repay a portion, or all, of the indebtedness.

Variations in Foreign Exchange Rates and Interest Rates

World oil and gas prices are quoted in United States dollars and the price received by Canadian producers is therefore affected by the Canadian/United States dollar exchange rates, which will fluctuate over time. In recent years, the Canadian dollar has increased materially in value against the United States dollar. Material increases in the value of the Canadian dollar negatively impact the Corporation’s production revenues. Future Canadian/United States dollar exchange rates could accordingly impact the future value of the Corporation’s reserves as determined by independent evaluators.

To the extent that the corporation engages in risk management activities related to foreign exchange rates, there is a credit risk associated with counterparties with which the Corporation may contract.

An increase in interest rates could result in a significant increase in the amount the Corporation pays to service debt, which could negatively impact the market price of the Shares.

Third Party Credit Risk

The Corporation is or 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 Corporation, such failures could have a material adverse effect on the Corporation and its cash flow from operations.

Reserves and Estimated Future Net Cash Flows

There are numerous uncertainties inherent in estimating quantities of reserves and cash flows to be derived therefrom, including many factors that are beyond the control of the Corporation. The reserve and cash flow information set forth herein represent estimates only. These evaluations include a number of assumptions relating to factors such as initial production rates, production decline rates, ultimate recovery of reserves, timing and amount of capital expenditures, marketability of production, future prices of oil and natural gas, operating costs, royalties and government royalties and levies that may be imposed over the producing life of the reserves. These assumptions were based on price forecasts in use at the date the relevant evaluations were prepared and many of these assumptions are subject to change and are beyond the control of the Corporation. Actual production and cash flows derived therefrom will vary from these evaluations, and such variations could be material. The foregoing evaluations are based in part on the assumed success of exploitation activities intended to be undertaken in future years. The reserves and estimated cash flows to be derived therefrom contained in such evaluations will be reduced to the extent that such exploitation activities do not achieve the level of success assumed in the evaluations.

Cost of New Technologies

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

Hydraulic Fracturing

Hydraulic fracturing involves the injection of water, sand and small amounts of additives under pressure into rock formations to stimulate hydrocarbon (oil and natural gas) production. Specifically, hydraulic fracturing is used to produce commercial quantities of oil and natural gas from reservoirs that were previously unproductive. Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to operational delays, increased operating costs, third party or governmental claims, and could increase the costs of compliance and doing business. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that the Corporation is ultimately able to produce from its reserves.

Forward-Looking Information May Prove to be Inaccurate

Investors are cautioned not to place undue reliance on forward-looking information. By its nature, forward-looking information involves numerous assumptions, known and unknown risks and uncertainties, of both a general and specific nature, that could cause actual results to differ materially from those suggested by the forward-looking information or contribute to the possibility that predictions, forecasts or projections will prove to be materially inaccurate.

Additional information on the risks, assumptions and uncertainties are found in this Annual Information Form under the heading "Forward Looking Statements".

DIVIDENDS

The Corporation has not declared or paid any dividends since incorporation. Any decision to pay dividends on the Common Shares will be made by the Board of Directors on the basis of the Corporation's earnings, financial requirements and other conditions existing at the relevant time.

DESCRIPTION OF CAPITAL STRUCTURE

Credit Facility

The Corporation had the Credit Facility with a syndicate of lenders with an authorized borrowing base of $165,000,000 with interest charged at a rate per annum equal to the Canadian prime rate during said period plus the applicable margin, being a range of 0.5% to 2.5%, as determined by the Corporation's debt to cash flow ratio. Standby fees associated with this facility are charged based on the applicable rate, being within a range of 0.2% to 0.45% per annum on the undrawn portion of the facility, as determined by the Corporation's debt to cash flow ratio. Under the Credit Facility, the Corporation is required to maintain a current ratio of not less than 1:1. The current ratio is calculated as current assets (excluding mark-to-market unrealized gains) plus any undrawn availability in the Credit Facility vs. current liabilities (excluding mark-to-market unrealized losses and any amounts outstanding in the Credit Facility).

The borrowing base of the Credit Facility is generally subject to review and redetermination by the lenders on an annual basis or in the event of a change in our borrowing base properties (due to a disposition of assets beyond certain defined limits or a change which results in a material adverse effect, as determined by the lenders). The borrowing base is scheduled for review on or before May 31, 2014 and there can be no assurance that the current borrowing base level will be increased or maintained.

Share Capital

The following is a description of the rights, privileges, restrictions and conditions attaching to our share capital.

Common Shares

The Corporation is authorized to issue an unlimited number of Common Shares and preferred shares. As of December 31, 2013, an aggregate of 81.6 million Common Shares were issued and outstanding. As at the Effective Date, there are 82.0 million Common Shares issued and outstanding. 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. Holders of Common Shares are entitled to receive, if, as and when declared by the Board of Directors, such dividends as may be declared thereon by the Board of Directors from time to time. In the event of the liquidation, dissolution or winding-up of the Corporation, or any other distribution of assets among its shareholders for the purpose of winding-up its affairs, holders of Common Shares, are entitled to share equally, share for share, in the remaining property.

Preferred Shares

The Corporation is authorized to issue an unlimited number of preferred shares without nominal or par value. The Board of Directors may issue preferred shares at any time and from time to time in one or more series and shall fix the number of preferred shares in such series and determine the designation, rights, privileges, restrictions and conditions attaching the preferred shares. The preferred shares shall be entitled to priority over our Common Shares and over any other of our shares ranking junior to the preferred shares with respect to priority in the payment of dividends if, as and when declared by the Board of Directors and the receipt of property remaining upon liquidation, dissolution or winding-up. There are currently no preferred shares issued or outstanding.

MARKET FOR SECURITIES

The Common Shares are listed and posted for trading on the TSX under the symbol "DTX" and on the OTCQX under the symbol "DTHRF".

The following table sets forth the price range (high and low closing prices) in Canadian dollars of Common Shares and volume traded on the TSX, for the periods indicated.

	High	Low	Volume
2013			
January	7.55	6.49	10,025,454
February	6.92	6.06	6,740,954
March	6.80	6.16	7,513,201
April	7.99	5.77	11,725,038
May	8.36	7.07	8,480,695
June	7.69	6.84	5,711,326
July	8.40	7.63	6,588,928
August	9.39	8.00	6,289,595
September	9.94	9.02	4,111,785
October	9.75	8.96	5,770,094
November	9.87	8.27	9,099,575
December	9.72	8.29	4,863,013
2014			
January	9.80	8.44	9,605,189
February	9.32	8.43	7,375,755
March 1 - 21	9.89	8.66	6,093,885

Note:
(1) From March 1, 2013 to March 21, 2014.

DIRECTORS AND OFFICERS

The following table sets forth the names and municipalities of residence of the current directors and executive officers of the Corporation, their respective positions and offices with the Corporation and date first appointed or elected as a director and/or officer and their principal occupation(s) within the past five years.

Name, Occupation and Security Holding

Name and Municipality of Residence	Position Held and Date Appointed	Principal Occupation
Michael Kabanuk Cochrane, Alberta	Executive Chairman of the Board of Directors (July 22, 2008)	Mr. Kabanuk was Chief Operating Officer and Vice-President, Operations at Cyries Energy Inc. from May 2004 to March 2008. Prior thereto, Mr. Kabanuk was Vice-President, Operations of Cequel Energy Inc. from July 2003 to May 2004, and prior thereto was the Operations Manager of Cequel Energy Inc. from January 24, 2002 to August 7, 2003.

Name and Municipality of Residence	Position Held and Date Appointed	Principal Occupation
Martin Cheyne Calgary, Alberta	President, Chief Executive Officer and Director (January 24, 2007)	Mr. Cheyne has been the President, Chief Executive Officer and a director of the Corporation since January 24, 2007. Mr. Cheyne has been a director of Phoenix Oilfield Hauling, a public company listed on the TSXV, since May 2006. Mr. Cheyne was President, CEO and a director of Dual Exploration Inc. from July 2005 to December 2006. Prior thereto, Mr. Cheyne was President, CEO and a director of Devlan Exploration Inc. from November 1995 to July 2005.
Dennis Nerland [1][2][3] Calgary, Alberta	Director (November 22, 2007)	Mr. Nerland has been a partner with the law firm Shea Nerland Calnan since 1990 practicing primarily in the areas of tax and trust law. Mr. Nerland is a current and past director of a number of private and public companies listed on the TSXV and the TSX and is currently a trustee of a number of private investment trusts. Mr. Nerland has a Bachelor of Laws degree from the University of Calgary, a Master of Arts degree (Economics) from Carleton University and a Bachelor of Science degree (Economics and Mathematics) from the University of Calgary. He is a member of the Law Society of Alberta. Mr. Nerland has completed the Rotman/Haskayne Directors Education Program and received the designation of ICD.D. Mr. Nerland has also completed the Rotman Financial Literacy Program.
Bradley Porter[1][2][3][4] Okotoks, Alberta	Director (January 24, 2007)	Mr. Porter was Executive Vice President, COO and a director of Dual Exploration Inc. from July 2005 to December 2006. Prior thereto, Mr. Porter was Executive Vice President, COO and a director of Devlan Exploration Inc. from December 1995 to July 2005.
Henry Hamm [1][2][3][4] Grande Prairie, Alberta	Lead Director (January 25, 2010)	Mr. Hamm owns and operates a number of private companies in the Grande Prairie region including Prudential Lands Corporation, a land development company formed in 1995 and Dirham Homes Inc., a home building company formed in 1976. Mr. Hamm also owns and operates Prudential Energy Services Inc., an oil and gas service company.
Brendan Carrigy Nanoose Bay, British Columbia	Director (March 23, 2009)	Mr. Carrigy was the Vice-President, Exploration of the Corporation from July, 2009 to August, 2011 and Executive Vice President from August, 2011 to March, 2012.. Mr. Carrigy was Vice-President, Exploration for Cyries Energy Inc. from inception in July 2004 to July 2007. Prior thereto, Mr. Carrigy was Exploration Manager of Cequel Energy Inc. from January 2002 to July 2004.
Kevin Andrus[4] Centennial, Colorado	Director (June 21, 2013)	Mr. Andrus is the Portfolio Manager of Energy Investments with GMT Capital Corp., a private investment company based in Atlanta, Georgia. A graduate of the Masters of Business Administration program from Regis University, Mr. Andrus is also a Chartered Financial Analyst charter holder who has spent the past two decades with various investment management companies.
Gail Hannon Calgary, Alberta	Chief Financial Officer (July 2, 2009)	Ms. Hannon has been the Chief Financial Officer of the Corporation since July 2, 2009. Ms. Hannon was the Controller with Artek Exploration Ltd. From March 2006 to May 2009. Prior thereto, Ms. Hannon was the Controller with White Fire Energy Ltd. From April 2005 to February 2006 and prior thereto was Accounting Manager/Controller with Lightning Energy Inc. from June 2002 to March 2005.

Name and Municipality of Residence	Position Held and Date Appointed	Principal Occupation
Trevor Murray Calgary, Alberta	Vice-President, Land (July 22, 2008)	Mr. Murray has been the Vice-President, Land of the Corporation since July 22, 2008. Mr. Murray was the Senior Landman of Iteration Energy Ltd. from January 2008 to May 2008. Prior thereto, Mr. Murray was employed at Cyries Energy Inc. as Senior Landman from August 2006 to January 2008. Prior thereto, Mr. Murray was the Negotiating Mineral Landman for PrimeWest Energy Trust from September 2004 to August 2006. Prior thereto, Mr. Murray was the Area Landman at Calpine Canada Ltd. from August 2001 to September 2004.
Clayton Thatcher Calgary, Alberta	Vice-President, Exploration (August 11, 2011)	Mr. Thatcher has been the Vice President, Exploration of the Corporation since August 11, 2011. Mr. Thatcher was the Vice President, Geophysics of the Corporation from March 2011 to August 2011 and Geophysicist from June 2010 to March 2011. Prior thereto, Mr. Thatcher was Geophysicist at Cenovus Energy and EnCana Corporation.

Notes:

(1) Member of the Audit Committee. Each member of Audit Committee is considered independent and financially literate.
(2) Member of the Reserves Committee.
(3) Member of the Corporate Governance and Compensation Committee.
(4) Member of the Nominating Committee

As at December 31, 2013, the directors and officers of the Corporation, and their associates and affiliates, as a group, whether, beneficial, direct or indirect, own 7.1 million Common Shares, representing approximately 8.7% of the Common Shares then outstanding and approximately 8.7% of the Common Shares outstanding as at the Effective Date.

The directors listed above will hold office until the next annual meeting of the Corporation or until their successors are elected or appointed.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

Corporate Cease Trade Orders or Bankruptcies

No director, officer or shareholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation, within 10 years before the date hereof, has been, a director or executive officer of any corporation that, while that person was acting in that capacity:

1. was the subject of a cease trade or similar order, or an order that denied the relevant corporation access to any exemption under securities legislation, for a period of more than 30 consecutive days;

2. was subject to an event that resulted, after the director or executive officer ceased to be a director or executive officer, in the corporation being the subject of a cease trade or similar order or an order that denied the relevant corporation access to any exemption under securities legislation, for a period of more than 30 consecutive days; or

3. within a year of that person ceasing to act in such 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.

Personal Bankruptcies:

No director, officer or shareholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation has within 10 years before the date hereof, become 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 the assets of such person.

<u>Penalties or Sanctions:</u>

No director, officer or shareholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation has been subject to:

1. any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or

2. 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 directors and officers of the Corporation and its subsidiaries are associated with other reporting issuers or other corporations which may give rise to conflicts of interest. In accordance with corporate laws, directors who have a material interest or any person who is a party to a material contract or a proposed material contract with the Corporation are required, subject to certain exceptions, to disclose that interest and generally abstain from voting on any resolution to approve the contract. In addition, the directors are required to act honestly and in good faith with a view to the best interests of the Corporation. Some of the directors of the Corporation have either other employment or other business or time restrictions placed on them and accordingly, these directors of the Corporation will only be able to devote part of their time to the affairs of the Corporation. In particular, certain of the directors and officers are involved in managerial and/or director positions with other oil and gas companies whose operations may, from time to time, provide financing to, or make equity investments in, competitors of the Corporation. Conflicts, if any, will be subject to the procedures and remedies available under the ABCA. The ABCA provides that in the event that a director has an interest in a contract or proposed contract or agreement, the director shall disclose his interest in such contract or agreement and shall refrain from voting on any matter in respect of such contract or agreement unless otherwise provided by the ABCA.

AUDIT COMMITTEE

Audit Committee Charter

The Corporation's Audit Committee Charter is attached hereto as Schedule "C".

Audit Committee Composition

As at the date hereof, the Audit Committee is comprised of the following members:

Dennis Nerland	Independent(1)	Financially literate(1)
Bradley Porter	Independent(1)	Financially literate(1)
Henry Hamm	Independent(1)	Financially literate(1)

Note:
(1) As defined by National Instrument 52-110 ("**NI 52-110**").

Relevant Education and Experience

Dennis Nerland

Mr. Nerland has been a partner with the law firm Shea Nerland Calnan since 1990 practicing primarily in the areas of tax and trust law. Mr. Nerland is a current and past director of a number of private and public companies listed on the TSXV and the Toronto Stock Exchange and is currently a trustee of a number of private investment trusts. Mr. Nerland has a Bachelor of Laws degree from the University of Calgary, a Master of Arts degree (Economics) from Carleton University and a Bachelor of Science degree (Economics and Mathematics) from the University of Calgary. He is a member of the Law Society of Alberta. Mr. Nerland received the ICD.D designation in 2011 and successfully completed the Rotman Financial Literary Program in 2012.

Bradley Porter

Mr. Porter was the Chief Operating Officer, Executive Vice-President, Operations of DeeThree Ltd., one of the predecessors of the Corporation, from January 24, 2007 to March 23, 2009 and a director of DeeThree Ltd. since January 24, 2007. Mr. Porter was Executive Vice President, COO and a Director of Dual Exploration Inc. from July 2005 to December 2006. Prior thereto, Mr. Porter was Executive Vice President, COO and a Director of Devlan Exploration Inc. from December 1995 to July 2005.

Henry Hamm

Mr. Hamm owns and operates a number of private companies in the Grande Prairie region including Prudential Lands Corporation, a land development company formed in 1995 and Dirham Homes Inc., a home building company formed in 1976.

Audit Committee Oversight

At no time since the commencement of the Corporation's financial year ended December 31, 2013, was a recommendation of the Committee to nominate or compensate an external auditor not adopted by the Board of Directors.

Reliance on Certain Exemptions

At no time since the commencement of the Corporation's financial year ended December 31, 2013, has the Corporation relied on any exemption from NI 52-110.

Pre-Approval Policies and Procedures

The Audit Committee has not adopted specific policies and procedures for the engagement of non-audit services other than the general requirements under the heading "External Auditors" of the Audit Committee Charter which states that the Audit Committee must pre-approve any non-audit services to the Corporation and the fees for those services.

External Auditor Service Fees

The aggregate fees billed by the Corporation's external auditors in each of the three fiscal years noted below for audit and other fees are as follows:

Financial Year Ending	Audit Fees ($)(1)	Audit Related Fees ($)(2)	Tax Fees ($) (3)	All Other Fees ($)(4)
2013	251,500	--	10,655	--
2012	219,500	--	6,210	--
2011	283,700	--	5,025	--

Notes:

(1) "Audit Fees" include fees necessary to perform the annual audit and quarterly reviews of our financial statements. Audit Fees include fees for review of tax provisions and for accounting consultations on matters reflected in the financial statements. Audit Fees also include audit or other attest services required by legislation or regulation, such as comfort letters, consents, reviews of securities filings and statutory audits.

(2) "Audit-Related Fees" for assurance and related services that are reasonably related to the performance of the audit or review of the Corporation's financial statements and are not reported as audit fees. The services provided in this category include due diligence

assistance, accounting consultations on proposed transactions, and consultation on International Financial Reporting Standards conversion.

(3) "Tax Fees" include fees for all tax services other than those included in "Audit Fees" and "Audit-Related Fees". This category includes fees for tax compliance, tax planning and tax advice.

(4) "All Other Fees" include all other non-audit services.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

There are no legal proceedings material to the Corporation to which the Corporation is a party or of which any of its property is the subject matter, and there are no such proceedings known to the Corporation to be contemplated.

There are no penalties or sanctions imposed against the Corporation by a court relating to securities legislation or by a securities regulatory authority during legal proceedings material to the Corporation to which the Corporation is a party or of which any of its property is the subject matter, and there are no such proceedings known to the Corporation to be contemplated during the financial year ended December 31, 2013.

INTERESTS OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Other than set forth herein or an SEDAR, there are no material interests, direct or indirect, of any informed person of the Corporation, any proposed directors of the Corporation or any associates or affiliates of such persons, in any material transaction or in any proposed material transaction which has materially affected or would materially affect the Corporation or any of its subsidiaries other than as described below.

AUDITOR, TRANSFER AGENT AND REGISTRAR

The auditors of the Corporation are KPMG LLP, Chartered Accountants, 2700, 250 - 5th Ave. SW, Calgary, AB, T2P 4B9.

Olympia Trust Corporation of Canada is the transfer agent and registrar for the Common Shares at its principal office in Calgary, Alberta.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, the Corporation 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 and would be required to be filed under NI 51-102.

INTERESTS OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a statement, report or valuation described or included in a filing, or referred to in a filing, made under NI 51-102 by the Corporation during, or related to, the Corporation's most recently completed financial year other than Sproule, the Corporation's independent engineering evaluators and KPMG LLP, the Corporation's auditors.

As at the date of hereof, the principal reserve evaluators of Sproule, as a group, beneficially own, directly or indirectly, less than 1% of the outstanding Common Shares.

KPMG LLP are the auditors of the Corporation and have confirmed that they are independent with respect to the Corporation within the meaning of the relevant rules and related interpretations prescribed by the relevant bodies in Canada and any applicable legislation or regulations.

Daniel Kenney, the Corporate Secretary of the Corporation, is a lawyer at Davis LLP, which law firm provides legal services to the Corporation. As of the date hereof, the associates and partners of Davis LLP, as a group, beneficially own, directly or indirectly, less than 1% of the outstanding Common Shares.

ADDITIONAL INFORMATION

Additional information relating to the Corporation may be found on SEDAR at www.SEDAR.com.

Additional information including directors' and officers' remuneration and indebtedness, principal holders of the Corporation's securities, options to purchase securities, audit committee information and interests of insiders in material transactions, if applicable, is contained in the 2012 Information Circular.

Additional information is provided in the Corporation's comparative financial statements and management's discussion and analysis for the year ended December 31, 2013, which are available on SEDAR. Additional information is provided in the Corporation's comparative financial statements and management's discussion and analysis for the year ended December 31, 2013.

SCHEDULE A

FORM 51 -101F2
REPORT OF RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR

Form 51-101F2

Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor

Report on Reserves Data

To the Board of Directors of DeeThree Exploration Ltd. (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2013. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2013, estimated using forecast prices and costs.

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

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

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

Executed as to our report referred to above:

Sproule Associates Limited
Calgary, Alberta
March 6, 2014

Original Signed by Geoff W. Beatson, P.Eng.

Geoff W. Beatson, P.Eng.
Senior Engineering Advisor and Partner

Original Signed by Attila A. Szabo, P.Eng.
on behalf of Richard A. Brekke, P.Eng.

Richard A. Brekke, P.Eng.
Manager, Engineering and Partner

Original Signed by Steven G. Robson, P.Geo.

Steven G. Robson, P.Geo.
Petroleum Geologist

Original Signed by Ian K. Kirkland, P.Geol.

Ian K. Kirkland, P.Geol.
Senior Petroleum Geologist and Partner

SCHEDULE B

REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE (FORM 51-10F3)

Terms to which a meaning is ascribed in National Instrument 51-101 have the same meaning herein.

Management of DeeThree Exploration Ltd. (the "**Corporation**") are responsible for the preparation and disclosure of information with respect to the Corporation's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2013, estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated and reviewed the Corporation's reserves data. The report of the independent qualified reserves evaluator will be filed with securities regulatory authorities concurrently with this report.

The Reserves Committee of the board of directors of the Corporation has: (a) reviewed the Corporation'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, in the event of a proposal to change the independent qualified reserves evaluator, to inquire whether there had been disputes between the previous independent qualified reserves evaluator; and (c) reviewed the reserves data with management and the independent qualified reserves evaluator.

The Reserves Committee of the board of directors has reviewed the Corporation's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has, on the recommendation of the Reserves Committee, approved: (a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data 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 is based on judgements regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

"signed"	*"signed"*
Martin Cheyne, President, Chief Executive Officer and Director	Gail Hannon, Chief Financial Officer
"signed"	*"signed"*
Henry Hamm, Director	Brendan Carrigy, Director

March 24, 2014

SCHEDULE C
AUDIT COMMITTEE CHARTER

1. Role and Objective

The Audit Committee (the "**Committee**") is a committee of the Board of Directors of the Corporation to which the Board has delegated its responsibility for oversight of the nature and scope of the annual audit, management's reporting on internal accounting standards and practices, financial information and accounting systems and procedures, financial reporting and statements and recommending, for Board of Director approval, the audited financial reports and other mandatory disclosure releases containing financial information. The objectives of the Committee, with respect to the Corporation and its subsidiaries, are as follows:

- To assist Directors to meet their responsibilities in respect of the preparation and disclosure of the financial reports of the Corporation and related matters.
- Provide an open avenue of communication among the Corporation's auditors, financial and senior management and the Board of Directors.
- To ensure the external auditors' independence and review and appraise their performance.
- To increase the credibility and objectivity of financial reports.
- To strengthen the role of the outside directors by facilitating in depth discussions between directors on the Committee, management and external auditors.

2. Composition

The Committee shall be composed of at least three individuals appointed by the Board from amongst its members, all of which members will be independent (within the meaning of National Instrument 52-110 *Audit Committees*) unless the Board determines to rely on an exemption in NI 52-110. "Independent" generally means free from any business or other direct or indirect material relationship with the Corporation that could, in the view of the Board, reasonably interfere with the exercise of the member's independent judgment.

The Secretary to the Board shall act as Secretary of the Committee.

A quorum shall be a majority of the members of the Committee.

All of the members must be financially literate within the meaning of NI 52-110 unless the Board has determined to rely on an exemption in NI 52-110. Being "financially literate" means members have 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 issues that can reasonably be expected to be raised by the Corporation's financial statements.

3. Meetings

The Committee shall meet at least four times per year and/or as deemed appropriate by the Committee Chair. As part of its job to foster open communication, the Committee will meet at least annually with management and the external auditors in separate sessions.

Agendas, with input from management, shall be circulated to Committee members and relevant management personnel along with background information on a timely basis prior to the Committee meetings.

The minutes of the Committee meetings shall accurately record the decisions reached and shall be distributed to the Committee members with copies to the Board of Directors, the Chief Financial Officer or such other officer acting in that capacity, and the external auditor.

The Chief Executive Officer and the Chief Financial Officer or their designates shall be available to attend at all meetings of the Committee upon the invitation of the Committee.

The Controller, Treasurer and/or such other staff as appropriate to provide information to the Committee shall attend meetings upon invitation by the Committee.

4. Mandate and Responsibilities

To fulfill its responsibilities and duties, the Committee shall:

1 undertake annually a review of this mandate and make recommendations to the Corporate Governance and Compensation Committee as to proposed changes;

2 satisfy itself on behalf of the Board with respect to the Corporation's internal control systems, including, where applicable, relating to derivative instruments:

a) identifying, monitoring and mitigating business risks; and

b) ensuring compliance with legal and regulatory requirements;

3 review the Corporation's financial reports, MD&A, any annual earnings, interim earnings and press releases before the Corporation publicly discloses this information and any reports or other financial information (including quarterly financial reports), which are submitted to any governmental body, or to the public, including any certification, report, opinion, or review rendered by the external auditors; the process should include but not be limited to:

a) reviewing changes in accounting principles, or in their application, which may have a material impact on the current or future years' financial reports;

b) reviewing significant accruals, reserves or other estimates such as the ceiling test calculation;

c) reviewing accounting treatment of unusual or non-recurring transactions;

d) ascertaining compliance with covenants under loan agreements;

e) reviewing financial reporting relating to asset retirement obligations;

f) reviewing disclosure requirements for commitments and contingencies;

g) reviewing adjustments raised by the external auditors, whether or not included in the financial reports;

h) reviewing unresolved differences between management and the external auditors;

i) obtain explanations of significant variances with comparative reporting periods; and

j) determine through inquiry if there are any related party transactions and ensure the nature and extent of such transactions are properly disclosed;

4 review the financial reports and related information included in prospectuses, management discussion and analysis (MD&A), information circular-proxy statements and annual information forms (AIF), prior to Board approval;

5 with respect to the appointment of external auditors by the Board:

a) require the external auditors to report directly to the Committee;

b) review annually the performance of the external auditors who shall be ultimately accountable to the Board of Directors and the Committee as representatives of the shareholders of the Corporation;

c) obtain annually, a formal written statement of external auditors setting forth all relationships between the external auditors and the Corporation and confirming their independence from the Corporation;

d) review and discuss with the external auditors any disclosed relationships or services that may impact the objectivity and independence of the external auditors;

e) be directly responsible for overseeing the work of the external auditors engaged for the purpose of issuing an auditors' report or performing other audit, review or attest services for the Corporation, including the resolution of disagreements between management and the external auditor regarding financial reporting;

f) review management's recommendation for the appointment of external auditors and recommend to the Board appointment of external auditors and the compensation of the external auditors;

g) review the terms of engagement of the external auditors, including the appropriateness and reasonableness of the auditors' fees;

h) when there is to be a change in auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change; and

i) take, or recommend that the full Board of Directors take, appropriate action to oversee the independence of the external auditors;

j) at each meeting, consult with the external auditors, without the presence of management, about the quality of the Corporation's accounting principles, internal controls and the completeness and accuracy of the Corporation's financial reports;

6 review all public disclosure containing audited or unaudited financial information before release;

7 review financial reporting relating to risk exposure;

8 satisfy itself that adequate procedures are in place for the review of the Corporation's public disclosure of financial information from the Corporation's financial reports and periodically assess the adequacy of those procedures;

9 review and approve the Corporation's hiring policies regarding partners, employees and former partners and employees of the present and former external auditors of the Corporation;

10 review annually with the external auditors their plan for their audit and, upon completion of the audit, their reports upon the financial reports of the Corporation and its subsidiaries;

11 review and pre-approve all audit and audit-related services and the fees and other compensation related thereto, and any non-audit services, provided by the Corporation's external auditors and consider the impact on the independence of the auditors; The pre-approval requirement is waived with respect to the provision of non-audit services if:

a) the aggregate amount of all such non-audit services provided to the Corporation constitutes not more than five percent (5%) of the total amount of revenues paid by the Corporation to its external auditors during the fiscal year in which the non-audit services are provided;

b) such services were not recognized by the Corporation at the time of the engagement to be non-audit services; and

c) such services are promptly brought to the attention of the Committee by the Corporation and approved prior to the completion of the audit by the Committee or by one or more members of the Committee who are members of the Board of Directors to whom authority to grant such approvals has been delegated by the Committee;

provided the pre-approval of the non-audit services is presented to the Committee's first scheduled meeting following such approval, such authority may be delegated by the Committee to one or more independent members of the Committee;

12 review any other matters that the Audit Committee feels are important to its mandate or that the Board chooses to delegate to it;

13 with respect to the financial reporting process:

a) in consultation with the external auditors, review with management the integrity of the Corporation's financial reporting process, both internal and external;

b) consider the external auditors' judgments about the quality and appropriateness of the Corporation's accounting principles as applied in its financial reporting;

c) consider and approve, if appropriate, changes to the Corporation's auditing and accounting principles and practices as suggested by the external auditors and management;

d) review significant judgments made by management in the preparation of the financial reports and the view of the external auditors as to appropriateness of such judgments;

e) following completion of the annual audit, review separately with management and the external auditors any significant difficulties encountered during the course of the audit, including any restrictions on the scope of work or access to required information;

f) review any significant disagreement among management and the external auditors regarding financial reporting;

g) review with the external auditors and management the extent to which changes and improvements in financial or accounting practices have been implemented;

h) review the certification process;

i) establish procedures for the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal accounting controls, or auditing matters; and

j) establish procedures for the confidential, anonymous submission by employees of the Corporation of concerns regarding questionable accounting or auditing matters.

5. Authority

Following each meeting, in addition to a verbal report, the Committee will report to the Board by way of providing copies of the minutes of such Committee meeting at the next Board meeting after a meeting is held (these may still be in draft form).

Supporting schedules and information reviewed by the Committee shall be available for examination by any director.

The Committee shall have the authority to investigate any financial activity of the Corporation and to communicate directly with the internal and external auditors. All employees are to cooperate as requested by the Committee.

The Committee may retain, and set and pay the compensation for, persons having special expertise and/or obtain independent professional advice to assist in fulfilling its duties and responsibilities at the expense of the Corporation.