



## **Annual Information Form**

**Year Ended December 31, 2009**

**April 29, 2010**

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## SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements contained in this annual information form, and in certain documents incorporated by reference into this annual information form, constitute forward-looking statements and forward-looking information (collectively referred to herein as “**forward-looking statements**”) within the meaning of applicable Canadian securities laws. Such forward-looking statements relate to future events or Triton’s future performance and are based on Triton’s current internal expectations, estimates, projections, assumptions and beliefs, including, among other things, assumptions with respect to production, future capital expenditures and cash flow. Readers are cautioned that the assumptions used in the preparation of such information may prove incorrect. All statements other than statements of historical fact may be forward-looking statements. Such forward-looking statements are often, but not always, identified by the use of words such as “seek”, “anticipate”, “budget”, “plan”, “continue”, “estimate”, “expect”, “forecast”, “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 that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. Triton believes 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, or incorporated by reference into, this annual information form should not be unduly relied upon. These forward-looking statements speak only as of the date of this annual information form.

In particular, this annual information form and the documents incorporated by reference contain forward-looking statements pertaining to the following:

- Triton’s future operating and financial results;
- the impact of the acquisitions on Triton’s operations, inventory and opportunities, financial condition, access to capital and overall strategy;
- development and drilling plans for Triton’s assets;
- land expiries;
- abandonment and reclamation costs;
- the performance characteristics of Triton’s oil and natural gas properties;
- anticipated finding and development costs and operating costs for Triton;
- the quantity of Triton’s existing oil and natural gas reserves;
- Triton’s oil and natural gas production levels;
- capital expenditure programs and the timing thereof;
- the source of funding for Triton’s activities;
- projections of market prices and costs;
- the tax horizon of Triton;
- supply of and demand for oil and natural gas;
- expectations regarding Triton’s ability to raise capital and to continually add to reserves through acquisitions, development and optimization;
- treatment under governmental regulatory regimes and tax, environmental and other laws; and
- the impact of the acquisitions on Triton.

The actual results, performance or achievements of Triton could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below under “Risk Factors” and elsewhere in this annual information form and in certain documents incorporated by reference into this annual information form, but are not limited to:

- volatility in market prices for oil and natural gas and foreign exchange rates;
- operational risks and liabilities inherent in oil and natural gas operations;
- uncertainties associated with estimating oil and natural gas reserves;
- competition for, among other things, capital, drilling equipment, acquisitions of reserves, undeveloped lands and skilled personnel;
- incorrect assessments of the value of acquisitions;
- geological, technical, drilling and processing problems;

- changes in general economic, market and business conditions;
- the accuracy of oil and gas reserves estimates and estimated production levels as they are affected by exploration and development drilling and estimated decline rates;
- the uncertainties in regard to the timing of Triton's exploration and development program;
- unforeseen difficulties in integrating any acquired assets into Triton's operations;
- fluctuations in the costs of borrowing;
- political or economic developments;
- ability to obtain regulatory approvals and to obtain and maintain all required permits and licenses;
- the occurrence of unexpected events;
- the results of litigation or regulatory proceedings that may be brought against Triton;
- changes in income tax laws or changes in tax laws and incentive programs relating to the oil and gas industry; and
- the other factors discussed under "Risk Factors".

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 resources and reserves described can be profitably produced in the future.

With respect to forward looking statements contained in this annual information form, Triton has made assumptions regarding, among other things: that commodity prices will be consistent with the current forecasts of its engineers; royalty regimes will not be subject to material modification; that the Corporation will be able to obtain skilled labour and other industry services at reasonable rates; the timing and amount of capital expenditures and implementation thereof will be consistent with the Corporation's expectations; that future exchange rates will not vary materially from current levels; the impact of increasing competition; that the conditions in general economic and financial markets will not vary materially; that the Corporation will be able to access capital on acceptable terms; that drilling and other equipment will be available on acceptable terms; that government regulations and laws will not change materially; that royalty rates will not change in any material respect; and that future operating costs will be consistent with the Corporation's expectations.

Triton 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 Triton's current and future operations and such information may not be appropriate for other purposes.

Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward looking statements contained in this annual information form are expressly qualified by this cautionary statement. Except as required by applicable securities laws, Triton undertakes no obligation to publicly update or revise any forward looking statements and readers should also carefully consider the matters discussed under the heading "Risk Factors" in this annual information form.

#### **NON-GAAP MEASURES**

Funds flow from operations and operating netbacks are not recognized measures under GAAP. Management believes that funds flow from operations and operating netbacks are useful supplemental measures as they demonstrate Triton's ability to generate the cash necessary to repay debt or fund future growth through capital investment. Readers are cautioned, however, that these measures should not be construed as an alternative to net income determined in accordance with GAAP as an indication of Triton's performance. Triton's method of calculating these measures may differ from other companies and accordingly they may not be comparable to measures used by other companies. For these purposes, Triton defines funds flow from operations as cash provided by operations before changes in non-cash operating working capital and defines operating netbacks as revenue less royalties and operating expenses.

## GLOSSARY

*In this Annual Information Form, unless the context otherwise requires, the following words and phrases shall have the meanings set forth below:*

"**971021 AB**" means 971021 Alberta Ltd., formerly Taylor Hill Resources Ltd., a corporation previously incorporated under the ABCA now amalgamated with Triton to form Triton Energy Corp.;

"**ABCA**" means the *Business Corporations Act* (Alberta) as amended from time to time;

"**Acquired Assets**" means certain oil and gas assets acquired by Triton pursuant to the Asset Acquisition;

"**Annual Information Form**" means this annual information form;

"**Asset Acquisition**" means the acquisition by Triton on February 22, 2010 of the Acquired Assets from the Asset Vendor;

"**Asset Vendor**" means, together, a general partnership formed under the laws of Alberta and an affiliated corporation serving as managing partner of such partnership;

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum;

"**Common Share**" or "**Common Shares**" means, respectively, one or more common shares in the capital of Triton;

"**Corporation**" or "**Triton**" means Triton Energy Corp., a corporation amalgamated under the ABCA;

"**CRA**" means Canada Revenue Agency;

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

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

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

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

Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

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

"**Exploratory well**" means a well that is not a development well, a service well or a stratigraphic test well;

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

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

"**GAAP**" means Canadian generally accepted accounting principles;

"**GLJ**" means GLJ Petroleum Consultants;

"**GLJ Report**" means report of GLJ dated April 20, 2010 evaluating the crude oil, natural gas liquids and natural gas reserves of the Corporation as at December 31, 2009;

"**Gross**" or "**gross**" means:

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

"**NAFTA**" means the North American Free Trade Agreement;

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

"**Natural gas**" as described in the COGE Handbook means a mixture of lighter hydrocarbons that exist either in the gaseous phase or in solution in crude oil in reservoirs but are gaseous at atmospheric conditions. Natural gas may contain sulphur or other non-hydrocarbon compounds;

"**Natural gas liquids**" or "**NGLs**" as described in the COGE Handbook means those hydrocarbon components that can be recovered from natural gas as liquids including, but not limited to, ethane, propane, butanes, pentanes plus, condensate and small quantities of non-hydrocarbons;

"**NEB**" means the National Energy Board;

"**Net**" or "**net**" means:

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

"**NRF**" means the New Royalty Framework of the province of Alberta government effective January 1, 2009;

"**OPEC**" means the Organization of Petroleum Exporting Countries;

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

"**Performance Warrants**" means warrants to subscribe for Common Shares issued pursuant to the Private Placement, with each whole warrant entitling the holder to acquire one Common Share at a price of \$0.17 per share until December 31, 2014, subject to certain vesting provisions;

"**Private Placement**" has the meaning ascribed thereto under the heading "General Development of the Business – Year Ended December 31, 2009";

"**Property**" includes:

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

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

"**Property acquisition costs**" means costs incurred to acquire a property (directly by purchase or lease, or indirectly by acquiring another corporate entity with an interest in the property), including:

- (a) costs of lease bonuses and options to purchase or lease a property;
- (b) the portion of the costs applicable to hydrocarbons when land including rights to hydrocarbons is purchased in fee; and
- (c) brokers' fees, recording and registration fees, legal costs and other costs incurred in acquiring properties;

"**Proved property**" means a property or part of a property to which reserves have been specifically attributed;

"**Securities Act**" means the *Securities Act* (Alberta), R.S.A. c.S-4, as amended from time to time, including the regulations promulgated thereunder;

"**Tax Act**" means the *Income Tax Act* (Canada) R.S.C. 1985, c.1 (5<sup>th</sup> Supp.), as amended from time to time, including the regulations promulgated thereunder;

"**Trading Price**" means the 20-day weighted average trading price of the Common Shares on the TSXV; and

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

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

Unless otherwise specified, information in this Annual Information Form is as at the end of the Corporation's most recently completed financial year, being December 31, 2009.

## **RESERVES DEFINITIONS**

The determination of oil and gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of proved, probable and possible reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery.

The estimation and classification of reserves requires the application of professional judgment combined with geological and engineering knowledge to assess whether or not specific reserves classification criteria have been satisfied. Knowledge of concepts including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods is required to properly use and apply reserves definitions, as set forth below.

"**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;

"**proved**" reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves;

"**probable**" reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves;

"**developed producing**" reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty;

"**developed non-producing**" reserves are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown; and

"**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.

Reserves 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 nonproducing. 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.

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

### CONVENTIONS

Certain terms used herein are defined in the "Glossary". Unless otherwise indicated, references herein to "\$" or "**dollars**" are to Canadian dollars. All financial information with respect to the Corporation has been presented in Canadian dollars in accordance with generally accepted accounting principles in Canada.

### ABBREVIATIONS

#### Crude Oil and Natural Gas Liquids

Bbls	barrels
Bbls/d	barrels per day
Mbbls	thousand barrels
Boe	barrels of oil equivalent of natural gas (on the basis of 6 Mcf of natural gas to 1 bbl of oil)
Boe/d	barrels of oil equivalent per day
Mboe	thousand Boe
NGLs	natural gas liquids
Mmbtu	million British thermal units
Mstb	thousand stock tank barrels
Sib	stock tank barrel

#### Natural Gas

Bcf	billion cubic feet
Mcf	thousand cubic feet
Mmcf	million cubic feet
Mcf/d	thousand cubic feet per day
Mmcf/d	million cubic feet per day
GJ	gigajoule

#### Other

AECO	The natural gas storage facility located at Suffield, Alberta
LSD	Legal site description
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

### NOTE REGARDING BARREL OF OIL EQUIVALENT

**Disclosure provided herein in respect of Boe may be misleading, particularly if used in isolation. The Boe conversion ratio of 6 Mcf of natural gas to 1 bbl of oil used throughout this document is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.**

### CONVERSION

<u>To Convert From</u>	<u>To</u>	<u>Multiply By</u>
Mcf	Cubic metres	28.174
Thousand cubic metres	Mcf	35.494
Bbls	Cubic metres ("m <sup>3</sup> ")	0.159
Cubic metres	Bbls	6.290
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometres	1.609
Kilometres	Miles	0.621
Acres	Hectares	0.405
Hectares	Acres	2.471

## THE CORPORATION

The Corporation was incorporated under the ABCA on February 4, 2004 under the name "Triton Energy Corp." The Corporation filed Articles of Amendment on September 28, 2004 to remove the private company provisions and share transfer restrictions. On April 28, 2005, the Corporation acquired 100% of the issued and outstanding shares of 971021 AB pursuant to a share purchase and sale agreement. Effective January 8, 2007, the Corporation amalgamated with 971021 AB by way of vertical short form amalgamation under the ABCA to form one corporation operating under the name Triton Energy Corp. The registered office of the Corporation is located at Suite 4300, 888 – 3<sup>rd</sup> Street S.W., Calgary, Alberta T2P 5C5 and its head office is located at Suite 600, 734 – 7th Avenue SW, Calgary, Alberta T2P 3P8.

The Corporation does not have any subsidiaries.

The Corporation's Common Shares trade on the TSXV under the symbol "TEZ".

### GENERAL DEVELOPMENT OF THE BUSINESS

The following is a summary of the significant events in the development of the Corporation for the periods shown.

#### **Year Ended December 31, 2007**

On March 13, 2007, the Corporation closed a bought deal private placement for total gross proceeds of \$4,999,999 by issuing 2,439,024 Common Shares on a "flow-through" basis under the Tax Act at \$2.05 per share.

On October 16, 2007, the Corporation closed a bought deal private placement for total gross proceeds of \$4,812,840 by issuing 6,944,500 Common Shares on a "flow-through" basis under the Tax Act at \$0.72 per share.

Operational highlights for the year ended December 31, 2007 included:

- The Corporation incurred \$17.5 million in capital expenditures whereby \$1.2 million was spent on land acquisitions, \$3.2 million on geosciences and exploration activities, \$8.9 million on drilling and completions and \$4.2 million on plant and facilities.
- The Corporation drilled 19 (15.3 net) wells.
- Production averaged 629 Boe/d for the year ended December 31, 2007.
- The Corporation exited 2007 with approximately 62,900 gross and 59,400 net acres of undeveloped land in Alberta.

#### **Year Ended December 31, 2008**

On April 23, 2008, the Corporation announced the appointments of Mr. Robert Pinckston and Mr. Frank Raffin to the positions of Manager, Exploration and Manager, Geophysics respectively. On May 9, 2008, the Corporation announced the appointment of Mr. Stephan D. Irish to the position of Vice President, Land. In conjunction with the appointments, the Corporation closed a non-brokered private placement to Messrs. Pinckston, Raffin and Irish for total gross proceeds of \$540,000 by issuing a total of 900,000 units at a price of \$0.60 per unit, each unit consisting of 900,000 Common Shares and 900,000 Common Share purchase warrants, each warrant entitling the holder to purchase one Common Share for a period of three years at \$0.60 per share in the first year, \$0.70 per share in the second year, and \$0.80 per share in the final year.

On July 2, 2008, the Corporation closed the sale of 100% of its interests in three non-operated producing wells and associated land in the Falher area to an arm's length party for net proceeds of \$1.0 million effective July 1, 2008. The proceeds from the sale have been allocated to Triton's ongoing exploration and development program.

Effective October 7, 2008, the Corporation received regulatory approval to commence a normal course issuer bid ("NCIB") to purchase for cancellation, from time to time, as the Corporation considers it advisable, up to a maximum of 3,192,000 Common Shares commencing October 9, 2008. In accordance with regulatory requirements, the maximum number of Common Shares approved for repurchase and cancellation under the NCIB represents approximately 10% of the public float of the Common Shares outstanding as of the date of the approval of the NCIB. Purchases of Common Shares are to be made on the open market through the facilities of the TSXV at a price consistent with the market pricing rules of the TSXV.

In November 2008, the Alberta Government announced changes to the NRF whereby in some cases, wells drilled after January 1, 2009 would be eligible for transitional royalty rates. Due to the fact that these changes were not announced until November 2008, this announcement had very little impact on the Corporation's planned 2008/2009 drilling program.

On November 20, 2008, the Corporation closed the sale of 100% of its interests in three producing wells and associated land in the Inland area to an arm's length party for net proceeds of \$3.13 million effective October 1, 2008. The proceeds from the sale have been allocated to Triton's ongoing exploration and development program.

Effective December 19, 2008, Triton closed a bought deal private placement for total gross proceeds of \$2,916,188 by issuing 7,856,500 Common Shares on a "flow-through basis" under the Tax Act at a price of \$0.375 per share.

Operational highlights for the year ended December 31, 2008 included:

- The Corporation incurred \$15.2 million in capital expenditures whereby \$1.5 million was spent on land acquisitions, \$2.9 million on geosciences and exploration activities, \$7.9 million on drilling and completions and \$2.9 million on plant and facilities.
- The Corporation drilled 9 (net) wells.
- The Corporation pooled and equalized in one (0.5 net) multi-zone petroleum and natural gas well.
- Production averaged 814 Boe/d for the year ended December 31, 2008.
- The Corporation exited 2008 with approximately 54,320 gross and 50,250 net acres of undeveloped land in Alberta.

### **Year Ended December 31, 2009**

On October 9, 2009, the Corporation's NCIB expired. During the course of the NCIB, the Corporation purchased and cancelled 2,967,944 Common Shares at an average price of \$0.23 per share.

On December 15, 2009, the Corporation announced, and on December 31, 2009 the Corporation completed a series of transactions involving: (i) a non-brokered private placement of Units and Common Shares for aggregate proceeds of \$10.25 million (the "**Private Placement**"), (ii) the acquisition of the undeveloped lands and drill-ready recompletion prospects of Waldron Energy Corporation ("**Waldron**") as more particularly described under "*Waldron Acquisition*" (the "**Waldron Acquisition**"), and (iii) the appointment of a new board of directors (the "**Board of Directors**") and management team (collectively, the "**Recapitalization**"). The definitive agreement entered into by Triton in connection with the Recapitalization also provided for a rights offering (the "**Rights Offering**") to holders of Common Shares.

#### ***Non-brokered Private Placement***

Triton issued an aggregate of 22,225,053 Common Shares at a price of \$0.13 per Common Share and 28,312,800 units ("**Units**") at a price of \$0.26 per Unit. Each Unit consists of one Common Share, one Common Share issued on a flow-through basis pursuant to the Tax Act and two Performance Warrants. Each Performance Warrant entitles the holder to purchase one Common Share at a price of \$0.17 for a period of 5 years from the date of issuance. The

Performance Warrants vest and become exercisable as to one-third upon the Trading Price equalling or exceeding \$0.24, an additional one-third upon the Trading Price equalling or exceeding \$0.36 and a final one-third upon the Trading Price equalling or exceeding \$0.42.

### ***Waldron Acquisition***

Triton also acquired from Waldron its undeveloped land and drill ready and re-completion prospects in Alberta for an aggregate purchase price of \$1.98 million. Such lands include a number of drill ready prospects and re-completions targeting deep basin liquids rich tight natural gas. In consideration thereof, Triton issued 15,200,000 units (“**Waldron Units**”) at a price of \$0.13 per Waldron Unit. Each Waldron Unit consists of one Common Share and one Common Share purchase warrant, which has substantially the same terms as the Performance Warrants.

### ***Asset Acquisition***

On December 31, 2009 the Corporation acquired two gross (1.5 net) sections of land with approximately 40 boepd of production located in the Ricinus area of west central Alberta for cash consideration of \$1,000,000.

### ***Rights Offering***

As part of the Recapitalization, Triton initiated the Rights Offering by way of a rights offering circular dated January 13, 2010. The Rights Offering allowed holders of Common Shares of Triton, as at January 27, 2010 (the “**Record Date**”), to be issued one right (a “**Right**”) for each Common Share held. Each four full Rights entitled the holder to purchase one Common Share at the exercise price of \$0.13 per share, being equal to the price of the Common Shares issued under the Private Placement. Subscribers for Common Shares or Units pursuant to the Private Placement and recipients of the Waldron Units were not entitled to participate in the Rights Offering with respect to any such securities and agreed not to exercise, sell or convey any Rights issuable to them by virtue of their ownership of such securities. The Rights expired at 4:00 p.m. (Calgary time) on February 18, 2010. 10,430,487 Common Shares were issued pursuant to the Rights Offering.

### ***Operations***

Operational highlights for the year ended December 31, 2009 included:

- The Corporation incurred \$7.7 million in capital expenditures whereby \$0.3 million was spent on land acquisitions, \$1.3 million on geosciences and exploration activities, \$4.4 million on drilling and completions, \$0.7 million on plant and facilities and \$1.0 million on an asset acquisition.
- The Corporation drilled and abandoned 4 gross (3.1 net) wells.
- Production averaged 867 Boe/d for the year ended December 31, 2009.
- The Corporation exited 2009 with approximately 41,756 gross and 39,103 net acres of undeveloped land in Alberta.

### **Recent Developments**

On January 20, 2010 Triton entered into an agreement in respect of the Asset Acquisition with the Asset Vendor to purchase the Acquired Assets from the Asset Vendor with an effective date of November 1, 2009 (the “**Asset Acquisition Agreement**”). The base purchase price for the Acquired Assets pursuant to the Asset Acquisition Agreement was \$45,000,000 before closing adjustments and interest, payable in cash. The Asset Acquisition closed on February 22, 2010. A copy of the Asset Acquisition Agreement has been filed by Triton on SEDAR and may be viewed under Triton’s profile at [www.sedar.com](http://www.sedar.com).

The Acquired Assets include assets with net production of approximately 1,126 Boe/d of liquids rich natural gas (65%) and light oil (35%) and 37 net sections of undeveloped land. The Acquired Assets are located in the Crystal

and Ferrybank areas of West Central Alberta. The Asset Acquisition increased Triton's exposure to the liquids rich natural gas Glauconite formation on the Hoadley trend, an area where industry players have experienced considerable success with horizontal drilling and are expected to provide Triton with multiple Ellerslie and Belly River light oil drilling locations. In addition, the Acquired Assets are generally characterized by high working interests (averaging approximately 70%), operatorship, two dimensional and three dimensional seismic coverage and control of infrastructure, all attributes that are expected to provide Triton with significant exposure to the benefits and upside of these properties. The Acquired Assets also include gathering and processing infrastructure capable of accommodating future production additions.

On February 22, 2010, the Corporation closed a bought deal pursuant to a short form prospectus for total gross proceeds of \$25,000,800 by issuing 104,170,000 Common Shares at a price of \$0.24 per Common Share.

On March 31, 2010, the Corporation closed a bought deal private placement for total gross proceeds of \$7,502,000 by issuing 34,100,000 Common Shares on a "flow-through" basis under the Tax Act at a price of \$0.22 per Common Share.

## **DESCRIPTION OF THE BUSINESS**

### **General**

Triton is an Alberta-based petroleum and natural gas exploration and production company engaged in the acquisition of, exploration for, and development and production of petroleum and natural gas in strategically located areas currently within the province of Alberta.

### **Exploration and Development Strategy**

Following the Recapitalization, the business plan of the Corporation is to focus on the deep basin of Alberta and to generate a repeatable inventory of liquids rich tight natural gas drilling prospects in central Alberta, complemented by light oil prospects. In order to achieve this plan, the Corporation intends to concentrate on the internal generation of prospects and strategic acquisitions followed by an aggressive exploration, development and exploitation program. Triton also intends to be a dominant player in its core areas, operate with high working interests, and achieve operating efficiency by controlling infrastructure.

Although the Corporation intends to follow this strategy, the Corporation is largely opportunity driven and will focus its expenditures in areas that provide the greatest economic return to the Corporation, recognizing that all drilling involves substantial risk and that a high degree of competition exists for prospects. No assurance can be given that drilling will prove successful in establishing commercially recoverable reserves. See "Risk Factors".

Triton's 2010 capital expenditure budget achieves a balance between low to medium risk opportunities and high impact exploration concepts funded through cash flow and available credit facilities in its west central Alberta core area. The Corporation's presently budgeted opportunities for 2010 include high impact Ellerslie liquids rich natural gas; horizontal Glauconite liquids rich natural gas on the Hoadley trend; Belly River, Ellerslie and Viking oil; and the acquisition of undeveloped acreage and seismic. It is expected that the 2010 budget will be reviewed and updated at the start of the third quarter to account for the results of budgeted operations to the end of the second quarter.

The Board of Directors has approved a 2010 capital budget of \$20.5 million which includes:

- drilling 9 net wells: two Ellerslie well deepening in Ricinus; one Ellerslie vertical drill well in Ricinus; two Glauconite horizontal drill wells in Crystal; one vertical and two horizontal Belly River oil drill wells in Crystal; and one commitment well in Sullivan Lake;
- oil well optimization and work over activity in the Crystal and Ferrybank areas; and
- the acquisition of land and seismic in Triton's core area of Strachan/Ricinus.

Production at the end of March 2010 was approximately 2,000 - 2,200 boe/d (75% natural gas; 25% oil & liquids).

The Board of Directors may, in its discretion, approve asset or corporate acquisitions or investments that do not conform to the foregoing description based upon the Board of Directors' consideration of the qualitative aspects of the subject properties including risk profile, technical upside, reserve life and asset quality.

#### **STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION**

The statement of reserves data and other oil and gas information set forth below (the "**Statement**") is dated April 20, 2010. The effective date of the Statement is December 31, 2009 and the preparation date of the Statement is April 8, 2010.

#### **Disclosure of Reserves Data and Other Information**

The reserves data set forth below (the "**Reserves Data**") is based upon an evaluation by GLJ with an effective date of December 31, 2009 contained in the GLJ Report. The Reserves Data summarizes the crude oil, natural gas liquids and natural gas reserves of the Corporation and the net present values of future net revenue for these reserves using forecast prices and costs. The GLJ Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101. Additional information not required by NI 51-101 has been presented to provide continuity and additional information which the Corporation believes is important to the readers of this information. The Corporation engaged GLJ to provide an evaluation of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

All of the Corporation's reserves are in Canada and, specifically, in the province of Alberta.

The Report of Management and Directors on Oil and Gas Disclosure and the Report on Reserves Data by the Independent Qualified Reserves Evaluator are attached as Schedules "A" and "B" hereto, respectively.

**It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserve estimates of the Corporation's crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquid reserves may be greater than or less than the estimates provided herein.**

**Reserves Data (Forecast Prices and Costs)**

SUMMARY OF OIL AND GAS RESERVES  
AND NET PRESENT VALUES OF FUTURE NET REVENUE  
AS OF DECEMBER 31, 2009  
FORECAST PRICES AND COSTS

RESERVES CATEGORY	RESERVES SUMMARY <sup>(1)</sup>									
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS <sup>(2)</sup>		NATURAL GAS LIQUIDS		TOTAL OIL EQUIVALENT <sup>(3)</sup>	
	Gross (Mbbbl)	Net (Mbbbl)	Gross (Mbbbl)	Net (Mbbbl)	Gross (Mmcf)	Net (Mmcf)	Gross (Mbbbl)	Net (Mbbbl)	Gross (Mboe)	Net (Mboe)
Proved										
Producing	34	27	0	0	4,616	3,719	25	17	829	664
Developed										
Non-Producing	4	3	0	0	1,228	932	19	12	228	170
Undeveloped	0	0	0	0	623	468	2	1	106	79
TOTAL PROVED	38	30	0	0	6,467	5,119	46	29	1,162	913
PROBABLE	22	17	0	0	4,332	3,492	24	16	769	615
TOTAL PROVED PLUS PROBABLE	61	48	0	0	10,799	8,611	70	45	1,931	1,528

Notes:

- (1) Numbers in this table are subject to round off error.
- (2) Natural gas volumes include solution gas volumes associated with the Corporation's light and medium crude oil reserves.
- (3) Natural gas is converted Boes at a ratio of six thousand standard cubic feet to one barrel of oil.

RESERVES CATEGORY	NET PRESENT VALUES OF FUTURE NET REVENUE <sup>(1)(2)(3)</sup>									
	BEFORE INCOME TAXES DISCOUNTED AT (%/year)					AFTER INCOME TAXES DISCOUNTED AT (%/year)				
	0 (M\$)	5 (M\$)	10 (M\$)	15 (M\$)	20 (M\$)	0 (M\$)	5 (M\$)	10 (M\$)	15 (M\$)	20 (M\$)
Proved										
Producing	17,762	15,642	14,091	12,891	11,925	17,762	15,642	14,091	12,891	11,925
Developed										
Non-Producing	3,680	3,038	2,539	2,146	1,830	3,680	3,038	2,539	2,146	1,830
Undeveloped	1,156	897	702	552	436	974	753	586	459	360
TOTAL PROVED	22,598	19,577	17,332	15,589	14,191	22,416	19,432	17,217	15,495	14,114
PROBABLE	16,175	12,015	9,329	7,467	6,113	12,590	9,234	7,109	5,656	4,609
TOTAL PROVED PLUS PROBABLE	38,773	31,591	26,662	23,056	20,304	35,006	28,666	24,326	21,151	18,724

Notes:

- (1) Utilizes GLJ's price forecast as of December 31, 2009 as detailed below.
- (2) Values are net of abandonment liabilities.
- (3) Columns may not add due to rounding.

TOTAL FUTURE NET REVENUE  
(UNDISCOUNTED)  
AS OF DECEMBER 31, 2009  
FORECAST PRICES AND COSTS

RESERVES CATEGORY	REVENUE (M\$)	ROYALTIES (M\$)	OPERATING COSTS (M\$)	DEVELOPMENT COSTS (M\$)	WELL ABANDONMENT COSTS (M\$)	FUTURE NET REVENUE BEFORE INCOME TAXES (M\$)	INCOME TAXES (M\$)	FUTURE NET REVENUE AFTER INCOME TAXES (M\$)
Proved Reserves	51,125	9,797	15,595	2,553	583	22,598	182	22,416
Proved Plus Probable Reserves	88,859	16,238	28,283	4,830	736	38,773	3,767	35,006

FUTURE NET REVENUE  
BY PRODUCTION GROUP  
AS OF DECEMBER 31, 2009  
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) (M\$)	UNIT VALUE BEFORE INCOME TAX DISCOUNTED AT 10%/year
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	760	\$31.92/Bbl
	Natural Gas (including by-products but excluding solution gas from oil wells)	16,573	\$3.11/Mcf
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	1,095	\$29.57/Bbl
	Natural Gas (including by-products but excluding solution gas from oil wells)	25,566	\$2.86/Mcf

**Notes to Reserves Data Tables:**

- Columns may not add due to rounding.
- The crude oil, natural gas liquids and natural gas reserve estimates presented in the GLJ Report are based on the definitions and guidelines contained in NI 51-101 and the COGE Handbook. A summary of those definitions are set forth below.

*Reserve Categories*

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:

- analysis of drilling, geological, geophysical and engineering data;
- the use of established technology; and
- specified economic conditions, specifically the forecast prices and costs.

Reserves are classified according to the degree of certainty associated with the estimates:

- (a) **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.
- (b) **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.

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

Each of the reserve categories (proved and probable) may be divided into developed and undeveloped categories:

- (a) **Developed reserves** are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.
  - (i) **Developed producing reserves** are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.
  - (ii) **Developed non-producing reserves** are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.
- (b) **Undeveloped reserves** are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) 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 subdivide 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.

#### *Levels of Certainty for Reported Reserves*

The qualitative certainty levels referred to in the definitions above are applicable to individual reserve entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserve estimates are prepared). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

- (a) at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and
- (b) at least a 50 percent probability that the quantities actually recovered will equal or exceed the estimated proved plus probable reserves.

A qualitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

Additional clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in the COGE Handbook.

### 3. Forecast Costs and Price Assumptions

The forecast cost and price assumptions assume increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. Crude oil and natural gas benchmark reference pricing, inflation and exchange rates utilized by GLJ in the GLJ Report were GLJ's forecasts, as at December 31, 2009, as follows:

#### SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS FORECAST PRICES AND COSTS

Year	OIL			Alberta AECO Average Gas Price (\$Cdn/Mcf)	Pentanes Plus Edmonton (\$Cdn/Bbl)	Butane Price Edmonton (\$Cdn/Bbl)	Propane Price Edmonton (\$Cdn/Bbl)	Inflation Rates <sup>(1)</sup> %/Year	Exchange Rate <sup>(2)</sup> (\$US/\$Cdn)
	WTI Cushing Oklahoma (\$US/Bbl)	Edmonton Oil Price 40° API (\$Cdn/Bbl)	Bow River 25° API Hardisty (\$Cdn/Bbl)						
Forecast									
2010	\$80.00	\$83.26	\$71.61	\$5.96	\$84.93	\$64.11	\$52.46	2.0%	0.95
2011	\$83.00	\$86.42	\$72.59	\$6.79	\$88.15	\$66.54	\$54.45	2.0%	0.95
2012	\$86.00	\$89.58	\$73.45	\$6.89	\$91.37	\$68.98	\$56.43	2.0%	0.95
2013	\$89.00	\$92.74	\$74.19	\$6.95	\$94.59	\$71.41	\$58.42	2.0%	0.95
2014	\$92.00	\$95.90	\$76.72	\$7.05	\$97.82	\$73.84	\$60.42	2.0%	0.95
2015	\$93.84	\$97.84	\$78.27	\$7.16	\$99.79	\$75.33	\$61.64	2.0%	0.95
2016	\$95.72	\$99.81	\$79.85	\$7.42	\$101.81	\$76.85	\$62.88	2.0%	0.95
2017	\$97.64	\$101.83	\$81.46	\$7.95	\$103.86	\$78.41	\$64.15	2.0%	0.95
2018	\$99.59	\$103.88	\$83.11	\$8.52	\$105.96	\$79.99	\$65.45	2.0%	0.95
2019	\$101.58	\$105.98	\$84.78	\$8.69	\$108.10	\$81.60	\$66.77	2.0%	0.95
2020+	Escalated oil, gas and product prices at approximately 2% per year thereafter							2.0%	0.95

#### Notes:

- (1) Inflation rates for forecasting prices and costs. Cost inflation for 2011 forecast at 2%.
- (2) Exchange rates used to generate the benchmark reference prices in this table.
- (3) Weighted average historical price realized by Triton for the year ended December 31, 2009 was \$4.12/Mcf AECO for natural gas. Substantially all of Triton's production for the year ended December 31, 2009 was natural gas.
- (4) Estimated future abandonment costs related to a working interest have been taken into account by GLJ in determining reserves that should be attributed to a property and in determining the aggregate future net revenue therefrom, there was deducted the reasonable estimated future well abandonment costs. No allowance was made, however, for the abandonment of non reserves wells, the reclamation of wellsites or the abandonment and reclamation of any facilities.
- (5) The forecast price and cost assumptions assume the continuance of current laws and regulations.
- (6) The extent and character of all factual data supplied to GLJ were accepted by GLJ as represented. No field inspection was conducted.
- (7) The impact of the optional Transitional Royalty Rate ("TRR") (announced by the Alberta Government on November 19, 2008) was considered in forecasts of future drilling in Alberta and taken into account in the above calculations of future net revenue. In the calculation of future net revenue, the Corporation was assumed to opt for TRR on new wells where justified by a comparison of economics under TRR and the NRF. The effects of the short term incentive program announced by the Government of Alberta on March 3, 2009 were not included or considered in the calculation of reserves and future net revenue. See "Industry Conditions – Provincial Royalties and Incentives – Alberta".

**Reconciliation of Changes in Reserves and Future Gross Revenue**

The following sets out the reconciliation of Triton's gross reserves based on forecast prices and costs by principal product type:

RECONCILIATION OF COMPANY GROSS RESERVES BY PRINCIPAL PRODUCT TYPE FORECAST PRICES AND COSTS						
FACTORS	LIGHT AND MEDIUM OIL			ASSOCIATED AND NON- ASSOCIATED GAS		
	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Proved (Mmcf)	Gross Probable (Mmcf)	Gross Proved Plus Probable (Mmcf)
December 31, 2008	179	90	268			
Extensions	0	0	0	0	0	0
Improved Recovery	0	0	0	0	0	0
Technical Revisions	(129)	(67)	(196)	(829)	184	(645)
Discoveries	0	0	0	0	0	0
Acquisitions	0	0	0	562	186	748
Dispositions	0	0	0	0	0	0
Economic Factors	0	0	0	0	0	0
Production	(12)	0	(12)	(1,791)	0	(1,791)
December 31, 2009	38	22	61	6,467	4,332	10,799

Note:

- (1) The Corporation has no unconventional reserves.

**Additional Information Relating to Reserves Data****Undeveloped Reserves**

The following tables set forth the gross proved undeveloped reserves and the gross probable undeveloped reserves, each by product type, attributed to Triton's assets for the years ended December 31, 2009, 2008 and 2007 and, in the aggregate, before that time based on forecast prices and costs.

*Proved Undeveloped Reserves*

Year	Light and Medium Oil (Mbbbl)		Natural Gas (MMcf)		NGLs (Mbbbl)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
Prior thereto	0.0	0.0	0.0	0.0	0.0	0.0
2007	61.1	61.1	884.5	884.5	11.1	11.1
2008	0.0	0.0	0.0	871.8	0	0.0
2009	0.0	0.0	623.0	623.0	2.0	2.0

*Probable Undeveloped Reserves*

Year	Light and Medium Oil (Mbbbl)		Natural Gas (MMcf)		NGLs (Mbbbl)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
Prior thereto	0.0	0.0	0.0	0.0	0.0	0.0
2007	31.0	31.0	146.6	146.6	1.6	1.6
2008	0.0	0.0	0.0	136.0	0.0	1.6
2009	0.0	0.0	1,168	2,057	4.0	6.0

In general, once proved and/or probable undeveloped reserves are identified they are scheduled into Triton's development plans. The Corporation plans to develop its proved and probable undeveloped reserves within two years. A number of factors that could result in delayed or cancelled development are as follows:

- changing economic conditions (due to pricing, operating and capital expenditure fluctuations);
- changing technical conditions (production anomalies (such as water breakthrough, accelerated depletion));
- multi-zone developments (such as a prospective formation completion may be delayed until the initial completion is no longer economic);
- availability and allocation of capital based on other opportunities available to the Corporation in any given year;
- a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and
- surface access issues (landowners, weather conditions, regulatory approvals).

*Significant Factors or Uncertainties*

The process of evaluating reserves is inherently complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions and other factors and assumptions that may affect the reserve estimates and the present worth of the future net revenue therefrom. These factors and assumptions include, among others: (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 becomes 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 government 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 Corporation does not anticipate any unusually high development costs or operating costs, the need to build a major pipeline or other major facility before production of reserves can begin, or contractual obligations to produce and sell a significant portion of production at prices substantially below those which could be realized but for those contractual obligations.

### ***Future Development Costs***

The following table sets forth development costs deducted in the estimation of the Corporation's future net revenue attributable to the reserve categories noted below:

Year	Forecast Prices and Costs (M\$)	
	Proved Reserves	Proved Plus Probable Reserves
2010	0	1,155
2011	2,553	3,675
Thereafter	0	0
<b>Total Undiscounted</b>	<b>2,553</b>	<b>4,830</b>

The future development costs are capital expenditures required in the future for Triton to convert proved undeveloped reserves and probable reserves to proved developed producing reserves. The undiscounted development costs are \$2.53 million for proved reserves and \$4.83 million for proved plus probable reserves (in each case based on forecast prices and costs).

On an ongoing basis, Triton will use internally generated cash flow from operations, debt and new equity issues if available on favourable terms to finance its capital expenditure program. The cost of funding is not expected to have any effect on disclosed reserves or future net revenue nor make the development of a property uneconomic for the Corporation.

### **Other Oil and Gas Information**

#### ***Principal Properties***

The following is a description of Triton's principal oil and gas properties as at December 31, 2009. Unless otherwise stated, all production volumes in this section represent Triton's gross interest.

#### *Newton*

Newton is located in west central Alberta about 60 kilometres northwest of Edmonton. Triton has 100% operated working interest in 14 sections of Crown land in the area. The target at Newton is sweet gas in multiple Mannville sandstone formations at drill depths under 1,200 meters. The Corporation exited 2009 with approximately 2,637 Mcf/d of natural gas plus 11 bbl/d of natural gas liquids from four (4.0 net) operated natural gas wells at Newton. Triton owns its own gathering system, which is tied into a third party gathering system and transports Triton's natural gas to the nearby Altagas Manola plant for processing. Triton has 6,400 (6,400 net) acres of undeveloped land at Newton and has 3 (3 net) additional drilling locations identified by geological mapping and 2-D seismic.

#### *Sullivan Lake*

Sullivan Lake is located in east central Alberta approximately 150 kilometres northeast of Calgary. Triton has an average 99.5% operated working interest in 11.75 sections of land in the area including seven sections of Crown land and 4.75 sections of freehold land. The Corporation is targeting sweet gas in the Lower Cretaceous Viking formation and sweet gas and light oil in the Mannville sandstone formation at drill depths under 1,200 meters, as well as multiple shallow gas horizons in the Belly River formation at drill depths less than 450 meters. The

Corporation exited 2009 with approximately 1,669 Mcf/d of natural gas and 15 bbl/d of light oil from five (4.85 net) operated natural gas wells, which are tied into Penn West and Apache gathering systems and one net operated oil well. Triton has 4,320 (4,320 net) acres of undeveloped land at Sullivan Lake.

### *Ricinus*

Ricinus is located in west central Alberta about 80 kilometres west of Red Deer. Triton has 79.5% operated working interest in 6.5 sections of Crown land in the area. The target at Ricinus is sweet gas in the Ellerslie formation at drill depths of 3,200 to 3,500 meters. The Ellerslie zone is a deep basin sweet gas charges system with up to 37 bbls/Mmcf of natural gas liquids. On December 31, 2009, Triton acquired 5.5 gross and net undeveloped sections of Crown land including the drill ready prospects. Additionally, the Corporation acquired 2.0 (1.5 net) producing wells from an unrelated company. The Corporation exited 2009 with approximately 100 Mcf/d of natural gas from 1.3 net operated natural gas wells at Ricinus. Triton owns its own gathering system, which is tied into a third party gathering system and transports Triton's natural gas to the nearby Keyera Strachan gas plant for processing. Triton had 15,200 (6,330 net) acres of undeveloped land at Ricinus and plans to drill three (2.8 net) wells in the area in 2010.

### *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, 2009:

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing <sup>(1)</sup>	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	2	1.75	5	3.4	12	11	6	5.5

Note:

- (1) All non-producing oil and natural gas wells are located near existing infrastructure.

### *Properties with No Attributable Reserves*

At December 31, 2009, the Corporation had 41,756 gross (39,103 net) acres of undeveloped land holdings in the Province of Alberta. The Corporation expects that rights to 16,896 net acres of its undeveloped land holdings will expire by December 31, 2010. Triton is considering whether or not to drill or submit an application to continue, sell, swap or farm-out selected portions of the above acreage.

### *Forward Contracts and Marketing*

As of the date hereof, the Corporation does not have any forward contracts.

### *Additional Information Concerning Abandonment Costs*

Triton estimates well abandonment costs on an area by area basis using historical costs and supplemented by current industry costs and changes in regulatory requirements. If representative comparisons are not readily available, an estimate is prepared based on the various regulatory abandonment requirements. The Corporation has 24.0 net well events for which it expects to incur abandonment costs.

Estimated costs of abandonment were included in the GLJ Report as a deduction in determining future net revenue. The total estimated abandonment costs in respect of proved reserves using forecast prices is \$0.6 million undiscounted (\$0.3 million using a 10% discount rate). 100% of such amounts were deducted as abandonment costs in estimating future net revenue of the Corporation in respect of proved reserves as disclosed above. No allowance for salvage value was included in these costs. The total proved plus probable abandonment costs are \$0.7 million (undiscounted) and \$0.3 million (discounted at 10%).

The table below indicates the expected timing of well abandonment costs for the Corporation and sets forth abandonment costs deducted in the estimation of the Corporation's future net revenue:

*Forecast Prices and Costs (Total Proved) (\$000s)*

Year	Abandonment Costs (Undiscounted)
2010	0
2011	24
2012	31
Thereafter	528
Total Undiscounted	583
Total Discounted @ 10%	295

*Forecast Prices and Costs (Total Proved plus Probable) (\$000s)*

Year	Abandonment Costs (Undiscounted)
2010	0
2011	0
2012	24
Thereafter	712
Total Undiscounted	736
Total Discounted @ 10%	267

***Tax Horizon***

Based on the Corporation's available tax pools, expected capital expenditures and forecast net income for 2010, the Corporation does not anticipate paying current income taxes in 2010. Depending on levels of production, commodity prices, acquisitions and capital expenditures, Triton may begin paying current income taxes in 2011 or beyond.

***Capital Expenditures***

The following table summarizes capital expenditures related to the Corporation's activities for the year ended December 31, 2009:

Capital Expenditures	\$000s
Property acquisition costs:	
Proved properties	\$1,244
Undeveloped properties <sup>(1)</sup>	1,976
Exploration costs	5,726
Development costs	727
Total	\$9,673

Note:

- (1) Non-cash transaction. See "General Development of the Business – Year Ended December 31, 2009 - Waldron Acquisition."

**Exploration and Development Activities**

The following table sets forth the gross and net exploratory and development wells in which the Corporation participated during the year ended December 31, 2009:

	Exploration		Development	
	Gross	Net	Gross	Net
Light and Medium Oil	0	0	0	0
Heavy Oil	0	0	0	0
Natural Gas	0	0	0	0
Service	0	0	0	0
Dry	4.0	3.1	0	0
<b>Total:</b>	<b>4.0</b>	<b>3.1</b>	<b>0</b>	<b>0</b>

See "- Principal Properties" for a description of the Corporation's exploration and development plans.

**Production Estimates**

The following table sets out the volume of the Corporation's gross working interest production estimated for the year ended December 31, 2010 as evaluated by GLJ which is reflected in the estimate of future net revenue disclosed in the tables contained under "- Disclosure of Reserves Data and Other Information":

**Forecast Prices and Costs**

## Total Proved

	Light and Medium Oil (Bbls/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	Boe (Boe/d)
Newton	2	2,263	8	387
Sullivan	15	1,613	1	286
Ricinus	5	261	4	51
<b>Total Proved</b>	<b>22</b>	<b>4,137</b>	<b>13</b>	<b>724</b>

## Total Proved Plus Probable

	Light and Medium Oil (Bbls/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	Boe (Boe/d)
Newton	2	2,407	9	412
Sullivan	15	1,716	1	304
Ricinus	5	277	4	54
<b>Total Proved plus Probable</b>	<b>22</b>	<b>4,401</b>	<b>14</b>	<b>770</b>

**Production History**

The following tables summarize certain information in respect of production, product prices received, royalties paid, operating expenses and resulting netback for the periods indicated below:

	Quarter Ended			
	2009			
	Dec. 31	Sept. 30	June 30	Mar. 31
<b>Average Daily Production<sup>(1)</sup></b>				
Light and Medium Crude Oil (Bbls/d)	28	11	32	52
Heavy Oil (Bbls/d)	-	-	-	-
Gas (Mcf/d)	4,576	4,658	5,327	5,076
NGLs (Bbls/d)	14	28	19	12
Combined (Boe/d)	805	816	939	909
<b>Average Price Received</b>				
Light and Medium Crude Oil (\$/Bbl)	70.81	65.65	67.50	31.83
Heavy Oil (\$/Bbls)	-	-	-	-
Gas (\$/Mcf)	4.67	2.97	3.56	5.20
NGLs (\$/Bbls)	79.49	44.10	67.50	31.83
Combined (\$/Boe)	30.40	19.34	23.88	31.25
<b>Royalties Paid</b>				
Light and Medium Crude Oil (\$/Bbls)	13.18	20.55	5.18	8.19
Heavy Oil (\$/Bbls)	-	-	-	-
Gas (\$/Mcf)	0.53	0.35	0.63	1.07
NGLs (\$/Bbls)	16.52	10.36	6.64	17.64
Combined (\$/Boe)	3.76	2.63	3.86	6.69
<b>Operating &amp; Transportation Expenses (\$/Boe)</b>				
Light and Medium Crude Oil (\$/Bbls)	10.79	11.39	9.94	11.58
Heavy Oil (\$/Bbls)	-	-	-	-
Gas (\$/Mcf)	1.80	1.90	1.66	1.93
NGLs (\$/Bbls)	10.79	11.39	9.94	11.58
Combined (\$/Boe)	10.79	11.39	9.94	11.58
<b>Netback Received (\$/Boe)<sup>(2)</sup></b>				
Light and Medium Crude Oil (\$/Bbls)	46.84	33.71	52.37	12.05
Heavy Oil (\$/Bbls)	-	-	-	-
Gas (\$/Mcf)	2.34	0.72	1.28	2.19
NGLs (\$/Bbls)	52.19	22.35	50.91	2.61
Combined (\$/Boe)	15.86	5.32	10.08	12.98

**Notes:**

- (1) Before deduction of royalties.
- (2) Netbacks are calculated by subtracting royalties and operating and transportation costs from revenues.

The following table indicates the Corporation's average daily production from its important fields for the year ended December 31, 2009:

	Light and Medium Crude Oil (Bbls/d)	Heavy Oil (Bbls/d)	Gas (Mcf/d)	NGLS (Bbls/d)	Boe (Boe/d)
Newton	5	-	3,030	10	520
Sullivan	19	-	1,809	1	322
Ricinus	-	-	-	-	-
Other Alberta	7	-	90	3	25
Total Alberta	31	-	4,929	14	867

The Corporation's production for the year ended December 31, 2009 was 4% light and medium crude oil, 94% natural gas and 2% natural gas liquids.

For the twelve months ended December 31, 2009, approximately 94% of the Corporation's gross revenue was derived from natural gas production and the remaining 6% of the Corporation's gross revenue was derived from natural gas liquids, light and medium oil production.

### DIRECTORS AND OFFICERS OF THE CORPORATION

The name, municipality of residence, and position held with the Corporation of each of the directors and officers of the Corporation are as follows:

Name and Municipality of Residence	Position Held
Ernest G. Sapiuha <sup>(2)</sup> Calgary, Alberta	President and Chief Executive Officer and a Director (Since December 31, 2009)
Donald F. Archibald <sup>(1)(2)</sup> Calgary, Alberta	Director (Since December 31, 2009)
Thomas A. Budd <sup>(1)(2)(3)(4)</sup> Calgary, Alberta	Director (Since December 31, 2009)
David R. J. Lefebvre <sup>(2)(3)(4)</sup> Calgary, Alberta	Director (Since December 31, 2009)
John E. Zahary <sup>(1)(2)(3)(4)</sup> Calgary, Alberta	Director (Since December 31, 2009)
Murray J. Stodalka Calgary, Alberta	Executive Vice-President, Engineering and Operations
Dean J. Schultz Calgary, Alberta, Canada	Vice President, Finance and Chief Financial Officer
Byron Lissel Calgary, Alberta	Vice-President, Exploration
Nanna Eliuk Calgary, Alberta	Vice-President, Geophysics and Land

Notes:

- (1) Member of the Audit Committee.
- (2) Member of the Reserves Committee.
- (3) Member of the Compensation Committee.
- (4) Member of the Corporate Governance Committee.
- (5) The Corporation does not have an Executive Committee.

As at the date hereof, the directors and officers of the Corporation as a group own or control, directly or indirectly, 60,827,548 Common Shares or 21.3% of the issued and outstanding Common Shares.

The term of office of all directors will expire at the next annual meeting of the shareholders of the Corporation.

Messrs. Sapiiha, Stodalka, Schultz and Lissel and Ms. Eliuk devote their full time and attention to the business and affairs of the Corporation. The other directors of the Corporation will devote time and attention to the affairs of the Corporation as required.

Profiles of the Corporation's directors and senior officers and the particulars of their respective principal occupations during the last five years are set forth below.

***Ernest G. Sapiiha, C.A. – President, Chief Executive Officer and a Director***

Mr. Sapiiha has in excess of 25 years of executive experience in the oil and gas industry. Previously, Mr. Sapiiha was the founder of Compton Petroleum Corporation (“**Compton**”) and acted as President & CEO of Compton until January 2009.

***Murray J. Stodalka, P.Eng. – Executive Vice President, Engineering and Operations***

Mr. Stodalka is a professional engineer with over 25 years of engineering and operations experience in the oil and gas industry. Previously, Mr. Stodalka was VP Engineering and Operations at Compton from 1996 to March 2009.

***Dean J. Schultz, C.A. – Vice President, Finance and Chief Financial Officer***

Mr. Schultz has over 17 years of management and business experience and joined Triton in January 2005 as Vice-President, Finance and Chief Financial Officer. He is a Chartered Accountant and holds a B.Sc. degree in Mathematical Sciences from the University of Alberta (1993) and is a member of the Canadian Institute of Chartered Accountants. Previously, Mr. Schultz was at Collins Barrow Calgary LLP where he provided audit, assurance, accounting and compliance services for public and private corporations.

***Byron Lissel, P.Geol. –Vice President, Exploration***

Mr. Lissel is a professional geologist with over 25 years of experience in the oil and gas industry. Mr. Lissel was Compton’s original geologist and was responsible for the assembly of Compton’s Southern Alberta land base and the discovery of its Hooker resource play in 1996. Subsequent to Compton, Mr. Lissel held the position of VP Exploration at Pocaterra Resources, Tsunami Exploration and Stratosphere Energy.

***Nanna Eliuk, P.Geoph. –Vice President, Geophysics and Land***

Ms. Eliuk is a professional geophysicist with over 15 years of experience in the oil and gas industry. Ms. Eliuk spent five years at Compton as a Senior Geophysicist specializing in the deep basin of Alberta and prior thereto held senior positions at Hunt Oil and Husky Energy.

***Donald F. Archibald – Director***

Mr. Archibald is an independent businessman and brings an extensive wealth of knowledge and experience as a leader in the public oil and gas industry. Currently, Mr. Archibald is Chairman at Iteration Energy Ltd. and Cequence Energy Ltd., and serves as a director at Progress Energy Resources Corp., Ember Resources Inc., Sea NG Corp., Spartan Exploration Ltd. and several other private companies. Previously, Mr. Archibald held the position of Chairman & CEO at Cyries Energy Inc. from June 2004 to March 2008, President & CEO at Cequel Energy Inc. from January 2002 to June 2004 and Cypress Energy Inc. from April 1996 to March 2001.

***Thomas A. Budd – Director***

Mr. Budd is an independent investor and has many years of experience providing mergers and acquisitions and financial advice on a significant number of Canada’s oil & gas transactions. Most recently, Mr. Budd served as President and Vice Chairman, Head of Investment Banking at GMP Corp. and Griffiths McBurney Canada Corp.

from April 1996 until 2008. Prior thereto, Mr. Budd was a founding partner and director of an independent investment dealer in Calgary for six years. Prior to that, he held corporate finance positions with two national investment dealers for eight years.

***David R. J. Lefebvre – Director***

Mr. Lefebvre has been a partner of Stikeman Elliott LLP since September 2004, practising corporate, securities and mergers and acquisitions law. Mr. Lefebvre's focus has been on national and international mergers and acquisitions, capital markets, project financings, private equity and corporate governance. Mr. Lefebvre currently serves on the board of directors of a number of public and private companies.

***John E. Zahary – Director***

Mr. Zahary is a professional engineer and currently acts as President & CEO of Harvest Energy Trust since February 2006. Prior to his current role, Mr. Zahary was President & CEO of Viking Energy Trust from April 2004 to February 2006. Prior thereto, he was President of Petrovera Resources, a 46,000 boe/d oil and natural gas producer with assets in Saskatchewan and Alberta. Previously, Mr. Zahary held senior positions at PanCanadian Petroleum Limited, Canadian Oil Sands Trust, Gulf Canada Resources Ltd., Imperial Oil Limited and Texaco Canada Resources. Mr. Zahary is the Past Governor of the Canadian Association of Petroleum Producers, Director and Past President of the Alberta Chamber of Resources, and Chairman of the Western Canada Rhodes Scholarship Selection Committee. Mr. Zahary holds a B.Sc. in Mechanical Engineering from the University of Calgary and a M.Phil. in Management from the University of Oxford.

**Cease Trade Orders, Bankruptcies, Penalties or Sanctions**

To our knowledge, no director or officer of the Corporation: (i) is, or has been in the last 10 years, a director, Chief Executive Officer or Chief Financial Officer of an issuer that, while that person was acting in that capacity, (a) was the subject of a cease trade order or similar order or an order that denied the issuer access to any exemptions under securities legislation, for a period of more than 30 consecutive days (an "**order**"), (b) was subject to an order that was issued after the director or officer ceased to be a director, Chief Executive Officer or Chief Financial Officer and which resulted from an event that occurred while that person was acting in the capacity as director, Chief Executive Officer or Chief Financial Officer, or (c) within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; (ii) has, within the last 10 years, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangements or compromises with creditors, or had a receiver or receiver manager or trustee appointed to hold his assets; or (iii) has been subject to: (a) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority, or (b) any other penalties or sanctions imposed by a court or regulatory body.

**Conflicts of Interest**

There are potential conflicts of interest to which the directors and officers of the Corporation will be subject in connection with the operations of the Corporation. In particular, certain of the directors and officers of the Corporation are involved in managerial and/or director positions with other oil and gas companies whose operations may, from time to time, be in direct competition with those of the Corporation or with entities which may, from time to time, provide financing to, or make equity investments in, competitors of the Corporation. See "Directors and Officers 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.

## DESCRIPTION OF SHARE CAPITAL

The following is a summary of the rights, privileges, restrictions and conditions attaching to the Common Shares and the preferred shares of the Corporation. No preferred shares are presently issued and outstanding.

### Common Shares

The Corporation has an unlimited number of Common Shares authorized. At April 29, 2010, there were 286,204,777 Common Shares of the Corporation issued and outstanding. All Common Shares have been issued as fully paid and non-assessable. The holders of Common Shares are entitled to dividends if, as and when declared by the Board of Directors, to one vote per Common Share at any meeting of the shareholders of the Corporation and, upon liquidation, to receive all assets of the Corporation as are distributable to the holders of Common Shares.

### Preferred Shares

Triton is authorized to issue an unlimited number of preferred shares issuable in series, each series consisting of such number of shares and having such rights, privileges, restrictions and conditions as may be determined by the Board of Directors prior to the issuance thereof. With respect to the payment of dividends and the distribution of assets in the event of liquidation, dissolution or winding-up of Triton, whether voluntary or involuntary, the preferred shares are entitled to preference over the Common Shares and any other shares ranking junior to the preferred shares from time to time and may also be given such other preferences over the Common Shares and any other shares ranking junior to the preferred shares as may be determined at the time of creation of such series. At the date hereof, no series of preferred shares has been created.

## PRICE RANGE AND TRADING VOLUME OF THE COMMON SHARES

The outstanding Common Shares are currently traded on the TSXV under the trading symbol "TEZ". The following table sets forth the price range and trading volume of the Common Shares as reported by the TSXV for the periods indicated.

Period	High	Low	Volume
<u>2009</u>			
January	0.35	0.26	394,813
February	0.28	0.25	552,847
March	0.27	0.18	1,046,954
April	0.38	0.25	938,800
May	0.34	0.19	4,071,600
June	0.24	0.19	917,160
July	0.20	0.16	924,100
August	0.20	0.14	1,886,200
September	0.24	0.14	1,144,900
October	0.22	0.16	5,051,500
November	0.20	0.17	558,533
December	0.34	0.15	8,590,833
<u>2010</u>			
January	0.38	0.27	9,955,668
February	0.30	0.22	6,908,557
March	0.24	0.17	44,810,951
April 1 – 28	0.23	0.20	5,980,400

## DIVIDENDS

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

## PRIOR SALES

The following table summarizes the issuances of Common Shares or securities convertible into Common Shares in the financial year ended December 31, 2009.

Date of Issuance <sup>(3)</sup>	Securities	Number of Securities	Price per Security
March 13, 2009	Stock Options	3,125,000	n/a
December 31, 2009	Units <sup>(1)</sup>	28,312,800	\$0.26
December 31, 2009	Common Shares	22,225,053	\$0.13
December 31, 2009	Waldron Units <sup>(2)</sup>	15,200,000	\$0.13

Notes:

- (1) Each Unit consists of one Common Share, one Common Share issued on a flow-through basis and two Performance Warrants.
- (2) Each Waldron Unit consists of one Common Share and one Common Share purchase warrant, each such warrant having substantially the same terms as the Performance Warrants.
- (3) Since December 31, 2009, the Corporation has issued the following securities: 3,125,000 Common Shares at a price of \$0.21 per Common Share pursuant to the exercise of stock options on January 5, 2010; 10,430,487 Common Shares at a price of \$0.13 per Common Share pursuant to the Rights Offering on February 18, 2010; 104,170,000 Common Shares at a price of \$0.24 per Common Share on February 22, 2010 pursuant to a short form prospectus; and 34,100,000 "flow-through" Common Shares at a price of \$0.22 per Common Share on March 31, 2010.

## ESCROWED SECURITIES

As at April 29, 2010, the Common Shares and Performance Warrants of the Corporation that are subject to escrow are set out in the following table.

Designation of Class	Number of securities held in escrow	Percentage of class
Common Shares <sup>(1)</sup>	50,233,204	17.55
Warrants <sup>(1)(2)</sup>	50,233,204	69.94

Notes:

- (1) The Common Shares and Performance Warrants that are held in escrow comprised part of the Units issued pursuant to the Private Placement. Seventy-five percent (75%) of the Units issued to new officers, directors and employees of Triton and their associates and affiliates (as defined in the Securities Act) under the Private Placement and seventy-five percent (75%) of the Waldron Units are subject to contractual escrow, with Valiant Trust Company as the escrow agent. The escrowed securities will be released in successive six month intervals such that one third of the escrowed securities will be released six months after December 31, 2009, one third will be released 12 months after December 31, 2009 and the remaining one third will be released 18 months after December 31, 2009.
- (2) Includes warrants issued pursuant to the Units and the Waldron Units.

## HUMAN RESOURCES

As at December 31, 2009, the Corporation had 8 full time employees (5 officers and 3 other technical staff), and 5 part time consultants. See "Directors and Officers of the Corporation".

## **LEGAL PROCEEDINGS AND REGULATORY ACTIONS**

To the knowledge of the Corporation, there are no legal proceedings material to the Corporation to which the Corporation is a party, or was a party to in 2009, or that any of its properties is or was the subject matter of in 2009, nor are there any such proceedings known to the Corporation to be contemplated.

During the year ended December 31, 2009, there were: (i) no penalties or sanctions imposed against the Corporation or by a court relating to securities legislation or by a securities regulatory authority; (ii) no other penalties or sanctions imposed by a court or regulatory body against the Corporation that would likely be considered important to a reasonable investor in making an investment decision; and (iii) no settlement agreements the Corporation entered into with a court relating to a securities legislation or with a securities regulatory authority.

## **INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS**

Other than as described above under “General Development of the Business – Year Ended December 31, 2009 – Non-brokered Private Placement” and “- Waldron Acquisition”, there were no material interests, direct or indirect, of directors or officers of the Corporation, of any shareholder who beneficially owns, directly or indirectly, or exercises control or direction over more than 10% of the outstanding Common Shares, or any other Informed Person (as defined in National Instrument 51-102 – Continuous Disclosure Obligations) or any known associate or affiliate of such persons, in any transaction within the three most recently completed financial years or during the current financial that has materially affected or would materially affect the Corporation.

## **MATERIAL CONTRACTS**

The Corporation has not entered into any material contracts within the most recently completed financial year, or before the most recently completed financial year which are still in effect.

## **RISK FACTORS**

**Investors should carefully consider the risk factors set out below and consider all other information contained herein and in the Corporation's other public filings before making an investment decision.**

### **New Management Group**

As part of the Recapitalization, the management team of Triton and the Board of Directors were reconstituted. The successful operation of Triton’s business will depend upon the abilities, expertise, judgment, discretion, integrity and good faith of the new management team, employees and Board of Directors. The new management team is currently assessing the assets and operations of Triton, including its existing land base, facilities, reserves, prospects and personnel. The new management team at Triton may determine that assumptions, assessments, decisions or strategies adopted by Triton’s prior management are no longer applicable or appropriate and will not be continued, endorsed or followed. In such event, Triton may reassess the plans for or importance assigned to certain assets or prospects and announce a realignment of historical corporate priorities. Such reassessment and realignment may result in changes to the value attributed to such assets or prospects, or potentially, the disposition of such assets or properties, which individually or in the aggregate may be material.

### **Reserves Replacement**

Triton’s future oil and natural gas reserves, production, and cash flows to be derived therefrom are highly dependent on Triton successfully acquiring or discovering new reserves. Without the continual addition of new reserves, any existing reserves Triton may have at any particular time and the production therefrom will decline over time as such existing reserves are exploited. A future increase in Triton’s reserves will depend not only on Triton’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 Triton’s future exploration and development efforts will result in the discovery and development of additional commercial accumulations of oil and natural gas.

### **Delays in Business Operations**

In addition to the usual delays in payments by purchasers of oil and natural gas to Triton or to the operator, and the delays by operators in remitting payment to Triton, 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 Triton in a given period and expose Triton to additional third party credit risks.

### **Exploration, Development and Production Risks**

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

Future oil and natural gas exploration may involve unprofitable efforts, not only from dry wells, but also from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, cratering, sour gas releases and spills, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or personal injury. In particular, the Corporation may explore for and produce sour natural gas in certain areas. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to the Corporation. 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 that it considers 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. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

## **Global Financial Crisis**

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions, have caused significant volatility to commodity prices. These conditions worsened in 2008 and continued in 2009, causing a loss of confidence in the broader U.S. and global credit and financial markets and resulting in the collapse of, and government intervention in, major banks, financial institutions and insurers and creating a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. Although conditions improved in the latter portions of 2009, these factors have negatively impacted company valuations and will impact the performance of the global economy going forward.

Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and demand of these commodities due to the current state of the world economies, OPEC actions and the ongoing global credit and liquidity concerns.

## **Prices, Markets and Marketing**

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

## **Accounting**

Triton is engaged in the exploration for and production of oil and natural gas in Canada. Triton will follow the full cost method of accounting for oil and gas operations whereby all costs related to the acquisition of, exploration for and development of oil and gas reserves are capitalized into a single Canadian cost centre. Such costs include leasehold acquisition costs, geological and geophysical costs, lease rentals on non-producing properties, drilling both productive and non-productive wells, plant and equipment costs, asset retirement costs and related overhead. Government incentives are credited to the cost of the oil and gas properties at the time the expenditures are incurred. Proceeds from the disposal of properties are applied as a reduction of the cost of the remaining assets with no gain or loss recognized, unless such a sale would result in a change of more than 20% in the depletion rate.

All costs of acquisition, exploration and development of oil and gas reserves, associated tangible plant and equipment costs and estimated costs of future development of proven undeveloped reserves are depleted and depreciated by the unit of production method based on estimated proven reserves (before deduction of royalties) as determined by independent engineers. Costs of unproved properties and seismic costs on undeveloped land are initially excluded from oil and gas properties for the purpose of calculating depletion. When proved reserves are assigned or the property is considered to be impaired, the cost of the property or the amount of the impairment is added to costs subject to depletion. For purposes of the calculation, natural gas reserves and production will be converted to equivalent volumes of petroleum based upon relative energy content.

Triton assesses the carrying value of property, plant and equipment for impairment (the "ceiling test"). The ceiling test is calculated by comparing the carrying value of property, plant and equipment to the sum of undiscounted cash flows expected to result from the future production of proved reserves and the lower of cost and market value of unproved properties. Cash flows will be based on third party quoted forward prices, adjusted for quality and transportation. Should the ceiling test result in an excess of carrying value, an impairment loss will be recognized to the extent that the carrying value of property, plant and equipment exceeds the estimated net present value of proved and probable reserves, and the sale of unproved properties.

### **Adoption of International Financial Reporting Standards**

Effective January 1, 2011, Triton will be required to adopt of the International Financial Reporting Standards ("IFRS") which may result in materially different reported financial results and may require amendments to its credit agreements to reflect the changes in accounting principles. As of the date of this AIF, Triton has not yet determined its accounting policies under IFRS and is unable to quantify the impact IFRS will have on its financial statements. Triton has the option to adopt IFRS standards prior to January 1, 2011 and is evaluating whether or not to adopt early.

### **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 acquirer's own assessments. Both of these assessments include a series of assumptions regarding such factors as 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 Triton'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 Triton 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 Triton. Any such instance may offset the return on and value of the securities of Triton.

### **Alternatives to and Changing Demand for Petroleum Products**

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

### **Changes in Legislation**

The return on an investment in securities of Triton 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 Triton or Triton's shareholders, as a result of their holding and disposing of the securities of Triton.

### **Changes to Royalty Regime**

There can be no assurance that the Government of Alberta or the Canadian federal government will not adopt a new royalty regime or modify the methodology of royalty calculations which could increase the royalties paid by Triton. An increase in royalty could reduce Triton's earnings and/or could make capital expenditures by Triton uneconomic.

### **Income Taxes**

Triton will file all required income tax returns and expects to be in full compliance with the provisions of the Tax Act 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 Triton, whether by re-characterization of exploration and development expenditures or otherwise, such reassessment may have an impact on current and future taxes payable.

## **Borrowing**

Triton's lenders have been or may be provided with security over substantially all of the assets of Triton. If Triton becomes unable to pay its debt service charges or otherwise commits an event of default, such as bankruptcy, these lenders may foreclose on or sell Triton's properties. The proceeds of such sale would be applied to satisfy amounts owed to Triton's lenders and other creditors and only the remainder, if any, would be available to Triton or to its shareholders upon liquidation.

The prices of oil and natural gas prices may be volatile and subject to fluctuation. Any material decline in prices could result in a reduction of the Corporation's net production revenue. The economics of producing from some wells may change as a result of lower prices, which could result in reduced production of oil or gas and a reduction in the volumes of the Corporation's reserves. The Corporation might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in the Corporation's expected net production revenue and a reduction in its oil and gas acquisition, development and exploration activities. Prices for oil and gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond the control of the Corporation. These factors include economic conditions in the United States and Canada, the actions of the Organization of Petroleum Exporting Countries ("OPEC"), governmental regulation, political stability in the Middle-East and elsewhere, the foreign supply of oil and gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Any substantial and extended decline in the price of oil and gas would have an adverse effect on the Corporation's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies, OPEC actions and the ongoing credit and liquidity concerns. Volatile oil and gas prices make it difficult to estimate the value of producing properties for acquisition and often cause disruption in the market for oil and gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

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

## **Project Risks**

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

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of storage capacity;
- the supply of and demand for oil and natural gas;
- the availability of alternative fuel sources;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- changes in regulations;
- the availability and productivity of skilled labour; and

- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

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

### **Regulatory**

Oil and natural gas operations (exploration, production, pricing, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government, which may be amended from time to time. See "Industry Conditions". Governments may regulate or intervene with respect to price, taxes, royalties and the exportation of oil and natural gas. Such regulations may be changed from time to time in response to economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for natural gas and crude oil and increase the Corporation's costs, any of which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In order to conduct oil and gas operations, the Corporation will require licenses from various governmental authorities. There can be no assurance that the Corporation will be able to obtain all of the licenses and permits that may be required to conduct operations that it may wish to undertake.

### **Environmental**

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Corporation to incur costs to remedy such discharge. Although the Corporation believes that it will be in material compliance with current applicable environmental regulations, no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. There has been much public debate with respect to Canada's ability to meet these targets and the government's strategy or alternative strategies with respect to climate change and the control of greenhouse gases. Implementation of strategies for reducing greenhouse gases whether to meet the limits required by the Kyoto Protocol or as otherwise determined, could have a material impact on the nature of oil and natural gas operations, including those of the Corporation. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact on the Corporation and its operations and financial condition. See "Industry Conditions – Environmental Regulation".

### **Operational Dependence**

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

### **Substantial Capital Requirements**

The Corporation anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. If the Corporation's revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future drilling programs. In addition, uncertain levels of near term industry activity coupled with the present global credit crisis exposes the Corporation to additional access to capital risk. 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 business financial condition, results of operations and prospects.

### **Reserve Estimates**

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids reserves and the future cash flows attributed to such reserves. The reserves and associated cash flow information set forth herein are estimates only. In general, estimates of economically recoverable oil and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserves recovery, timing and amount of capital expenditures, marketability of oil and gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times, may vary. The Corporation's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material.

Estimates of proved reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Recovery factors and drainage areas were estimated by experience and analogy to similar producing pools. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history and production practices will result in variations in the estimated reserves and such variations could be material.

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

Actual production and cash flows derived from the Corporation's oil and gas reserves will vary from the estimates contained in the reserve evaluation, and such variations could be material. The reserve evaluation is based in part on the assumed success of activities the Corporation intends to undertake in future years. The reserves and estimated cash flows to be derived therefrom contained in the reserve evaluation will be reduced to the extent that such activities do not achieve the level of success assumed in the reserve evaluation. The reserve evaluation is effective as of a specific effective date and has not been updated and thus does not reflect changes in the Corporation's reserves since that date.

### **Additional Funding Requirements**

The Corporation's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times. From time to time, the Corporation may require additional financing in order to carry out its oil and gas acquisition, exploration and development activities. Failure to obtain such 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. If the Corporation's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect the Corporation's ability to expend the necessary capital to replace its reserves or to

maintain its production. If the Corporation's cash flow from operations is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or, if available, on terms acceptable to the Corporation. Continued uncertainty in domestic and international credit markets could materially affect the Corporation's ability to access sufficient capital for its capital expenditures and acquisitions, and as a result, may have a material adverse effect on the Corporation's ability to execute its business strategy and on its business, financial condition, results of operations and prospects.

### **Third Party Credit Risk**

The Corporation 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 may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in the Corporation's ongoing capital program, potentially delaying the program and the results of such program until the Corporation finds a suitable alternative partner.

### **Climate Change**

Canada is a signatory to the United Nations Framework Convention on Climate Change and has ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nationwide emissions of carbon dioxide, methane, nitrous oxide and other so-called "greenhouse gases". Recently, representatives from approximately 170 countries met in Copenhagen, Denmark to attempt to negotiate a successor to the Kyoto Protocol. The result of such meeting was the Copenhagen Accord, a non-binding political consensus, rather than a binding international treaty such as the Kyoto Protocol. The Corporation's exploration and production facilities and other operations and activities emit greenhouse gases and require the Corporation to comply with Alberta's greenhouse gas emissions legislation contained in the *Climate Change and Emissions Management Act* and *Specified Gas Emitters Regulation*. The Corporation will also be required to comply with the regulatory scheme for greenhouse gas emissions ultimately adopted by the federal government, which are now expected to be consistent with regulatory scheme for greenhouse gas emissions adopted by the United States. The direct or indirect costs of these regulations may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospectus. The future implementation or modification of greenhouse gas emissions, whether to meet the limits required by the Kyoto Protocol, the Copenhagen Accord or as otherwise determined, could have a material impact on the nature of oil and gas operations, including those of the Corporation. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact on the Corporation and its operations and financial condition. See "Industry Conditions – Environmental Regulation".

### **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 effected by the Canadian/U.S. dollar exchange rate, 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 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 Common Shares.

### **Management of Growth**

The Corporation may be subject to growth-related risks including capacity constraints and pressure on its internal systems and controls. The ability of the Corporation to manage growth effectively will require it to continue to implement and improve its operational and financial systems and to expand, train and manage its employee base. The inability of the Corporation to deal with this growth may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

### **Availability of Drilling Equipment and Access**

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment (typically leased from third parties) in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to the Corporation and may delay exploration and development activities.

### **Failure to Realize Anticipated Benefits of Acquisitions and Dispositions**

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

### **Competition**

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

### **Issuance of Debt**

From time to time the Corporation may enter into transactions to acquire assets or the shares of other organizations. These transactions may be financed in whole or in part with debt, which may increase the Corporation's debt levels above industry standards for oil and natural gas companies of similar size. Depending on future exploration and development plans, the Corporation may require additional equity and/or debt financing that may not be available or, if available, may not be available on favourable terms. Neither the Corporation's articles nor its by-laws limit the amount of indebtedness that the Corporation may incur. The level of the Corporation's indebtedness from time to time, could impair the Corporation's ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

### **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 and the Corporation may nevertheless be obligated to pay royalties on such higher prices, even though not received by it, after giving effect to such agreements. 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 will not benefit from the fluctuating exchange rate.

### **Title to Assets**

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat the Corporation's claim which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

### **Insurance**

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

### **Geo-Political Risks**

The marketability and price of oil and natural gas that may be acquired or discovered by the Corporation is and will continue to be affected by political events throughout the world that cause disruptions in the supply of oil. Conflicts, or conversely peaceful developments, arising in the Middle-East, and other areas of the world, have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and therefore result in a reduction of the Corporation's net production revenue.

In addition, the Corporation's oil and natural gas properties, wells and facilities could be subject to a terrorist attack. If any of the Corporation's properties, wells or facilities are the subject of terrorist attack, it may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The Corporation will not have insurance to protect against the risk from terrorism.

### **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.

### **Expiration of Licences and Leases**

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

**Dividends**

The Corporation has not paid any dividends on its outstanding shares. Payment of dividends in the future will be dependent on, among other things, the cash flow, results of operations and financial condition of the Corporation, the need for funds to finance ongoing operations and other considerations as the Board of Directors considers relevant.

**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 properties and assets; however, if a claim arose and was successful such claim may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

**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.

**Conflicts of Interest**

Certain directors of the Corporation are also directors of other oil and gas companies and as such may, in certain circumstances, have a conflict of interest requiring them to abstain from certain decisions. Conflicts, if any, will be subject to the procedures and remedies of the ABCA. See "Directors and Officers – Conflicts of Interest".

**Reliance on Key Personnel**

The Corporation's success depends in large measure on certain key personnel. The loss of the services of such key personnel may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The Corporation does not have any key person insurance in effect for the Corporation. The contributions of the existing management team to the immediate and near term 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, discretion, integrity and good faith of the management of the Corporation.

**INDUSTRY CONDITIONS**

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

## **Pricing and Marketing - Oil and Natural Gas**

The producers of oil are entitled to negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Oil prices are primarily based on worldwide supply and demand. The specific price depends in part on oil quality, prices of competing fuels, distance to the markets, the value of refined products, the supply/demand balance and other contractual terms. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National Energy Board of Canada (the "NEB"). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB and the issuance of such licence requires a public hearing and the approval of the Governor in Council.

The price of natural gas is determined by negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m<sup>3</sup>/day) must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or a larger quantity requires an exporter to obtain an export licence from the NEB and the issuance of such licence requires a public hearing and the approval of the Governor in Council.

The Government of Alberta also regulates the volume of natural gas that may be removed from the province for consumption elsewhere based on such factors as reserve availability, transportation arrangements and market considerations.

## **Pipeline Capacity**

Although pipeline expansions are ongoing, the lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to produce and to market natural gas production. 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.

## **The North American Free Trade Agreement**

NAFTA among the governments of Canada, United States of America, and Mexico became effective on January 1, 1994. NAFTA carries forward most of the material energy terms that are contained in the Canada United States Free Trade Agreement. In the context of energy resources, Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to domestic use (based upon the proportion prevailing in the most recent 36 month period); (ii) impose an export price higher than the domestic price subject to an exception with respect to certain voluntary measures which only restrict the volume of exports; and (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum or maximum export or import price requirements, provided, in the case of export price requirements, any prohibition in any circumstances in which any other form of quantitative restriction is prohibited, and in the case of import-price requirements, such requirements do not apply with respect to enforcement of countervailing and anti-dumping orders and undertakings.

NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector by 2010 and prohibits discriminatory border restrictions and export taxes. NAFTA also contemplates clearer disciplines on regulators to ensure fair implementation of any regulatory changes and to minimize disruption of contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, which is important for Canadian natural gas exports.

## Provincial Royalties and Incentives

### *General*

In addition to federal regulation, each province has legislation and regulations which govern land tenure, royalties, production rates, environmental protection and other matters. The royalty regime is a significant factor in the profitability of crude oil, natural gas liquids, sulphur and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiation between the mineral freehold owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery and the type or quality of the petroleum product produced. Other royalties and royalty-like interests are, 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.

Occasionally the governments of the western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays and tax credits, and are generally introduced when commodity prices are low. The programs are designed to encourage exploration and development activity by improving earnings and cash flow within the industry. Royalty holidays and reductions would reduce the amount of Crown royalties paid by oil and gas producers to the provincial governments and would increase the net income and funds from operations of such producers. However, the trend in recent years has been for provincial governments to eliminate, amend or allow such incentive programs to expire without renewal, and consequently few such incentive programs are currently operative.

### *Alberta*

In Alberta, companies are granted the right to explore, produce and develop petroleum and natural gas resources in exchange for royalties, bonus bid payments and rents. On October 25, 2007, the Government of Alberta released a report entitled "The New Royalty Framework" containing the Alberta Government's proposals for Alberta's new royalty regime, which was followed by the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*, which was given Royal Assent on December 2, 2008. The NRF and the applicable new legislation became effective on January 1, 2009. The NRF established new royalty rates for conventional oil, natural gas and oil sands. The new royalty rates for conventional oil are set by a single sliding rate formula which is applied monthly and increases the old royalty from 30% to 35% applied to the old and new tiers, to up to 50% and with rate caps once the price of conventional oil reaches \$120 per barrel. The sliding rate formula includes in its calculation the price of oil and well production.

With respect to natural gas, and similar to the conventional oil framework, the royalties outlined in the NRF are set by a single sliding rate formula ranging from 5% to 50% with a rate cap once the price of natural gas reaches \$16.59/GJ. Prior to the NRF, the royalty reserved to the Crown in respect of natural gas production, subject to various incentives, was between 15% and 30%, in the case of new natural gas, and between 15% and 35%, in the case of old natural gas, depending upon a prescribed or corporate average reference price. In response to the drop in commodity prices experienced during the second half of 2008, the Government of Alberta announced on November 19, 2008, the introduction of a five year program of transitional royalty rates with the intent of promoting new drilling. Under this new program, companies drilling new natural gas or conventional oil deep wells (between 1,000 and 3,500 metres) will be given a one-time option, on a well by well basis, to adopt either the new transitional royalty rates or those outlined in the NRF. In order to qualify for this program wells must be drilled during the period starting on November 19, 2008 and ending on December 31, 2013. Following this period all new wells drilled will automatically be subject to the NRF.

Oil sands projects are now subject to the NRF, and regulated, among others, by the *Oil Sands Royalty Regulation, 2009*, *Oil Sands Allowed Costs (Ministerial) Regulation* and the *Bitumen Valuation Methodology (Ministerial) Regulation, 2009*, all approved by the Government of Alberta on December 10, 2008.

On April 10, 2008, the Government of Alberta introduced two new royalty programs that will encourage the development of deep oil and gas reserves, and these are: (a) a five-year oil program for exploration wells over 2,000 metres that will provide royalty adjustments to offset higher drilling costs and provide a greater incentive for producers to continue to pursue new, deeper oil plays (these oil wells will qualify for up to a \$1 million or 12 months of royalty offsets, whichever comes first); and (b) a five-year natural gas deep drilling program that will replace the existing program in order to encourage continued deep gas exploration for wells deeper than 2,500 metres (the program will create a sliding scale of royalty credit according to depth of up to \$3,750 per metre). These new programs are to be implemented along with the NRF.

Regulations made pursuant to the *Mines and Minerals Act* (Alberta) provided various incentives for exploring and developing oil reserves in Alberta. However, the Alberta Government announced in August of 2006 that four royalty programs were to be amended, a new program was to be introduced and the Alberta Royalty Tax Credit Program was to be eliminated, effective January 1, 2007. The programs affected by this announcement were: (i) Deep Gas Royalty Holiday; (ii) Low Productivity Well Royalty Reduction; (iii) Reactivated Well Royalty Exemption; and (iv) Horizontal Re-Entry Royalty Reduction. The program introduced was the Innovative Energy Technologies Program (the "IETP"), which has a stated objective of promoting the producers' investment in research, technology and innovation for the purposes of improving environmental performance while creating commercial value. The IETP provides royalty reductions which are presumed to reduce financial risk. Alberta Energy decides which projects qualify and the level of support that will be provided.

The NRF includes a policy of "shallow rights reversion". The Government of Alberta started to implement this policy on January 1, 2009, and its intent is to maximize the development of currently undeveloped resources that is consistent with the Government of Alberta's objective of maximizing recovery of known gas resources, while increasing royalty revenues. The policy's stated objective is for the mineral rights to shallow gas geological formations that are not being developed to revert back to the Alberta Government and be made available for resale, and in the event of non-productive shallow wells, to sever the rights from shallow zones and encourage increased production from up-hole zones. The shallow rights reversion policy affects all petroleum and natural gas agreements; however, the timing of the reversion will differ depending on whether the leases and licenses were acquired prior to January 1, 2009 or subsequent to January 1, 2009. Leases granted after January 1, 2009 will be subject to shallow rights reversion at the expiry of the primary term, and in the event of a licence the policy will apply at the expiry of the intermediate term. 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. The lease or licence holder can make a request to extend this period. The order in which these agreements will receive the reversion notice will depend on the vintage of their term, with the older leases and licenses receiving a reversion notice first. Leases or licences that were granted prior to January 1, 2009 but have not yet been continued will have a grace period until they are continued under section 15 of the *P&G Tenure Regulation* and be subject to deeper rights reversion prior to receiving a shallow rights reversion notice.

On March 3, 2009, the Government of Alberta announced a three-point incentive program to stimulate new and continued economic activity in Alberta which included a drilling royalty credit for new conventional oil and natural gas wells and a new well royalty incentive program. Under the drilling royalty credit program a \$200 per meter royalty credit will be available on new conventional oil and natural gas wells drilled between April 1, 2009 and March 31, 2010, subject to certain maximum amounts. The maximum credits available will be determined by the Corporation's production levels in 2008 and its drilling activity between April 1, 2009 and March 31, 2010. Based on Triton's 2008 production it will be entitled to a maximum credit of 50% of royalties payable in the period April 1, 2009 and March 31, 2010. The new well incentive program will apply to wells beginning production of conventional oil and natural gas between April 1, 2009 and March 31, 2010 and provides for a maximum 5% royalty rate for the first 12 months of production, up to a maximum of 50,000 barrels or 500 Mmcf of natural gas.

In addition to the foregoing, Alberta maintains a royalty reduction program for low productivity oil and oil sands wells, a royalty adjustment program for deep marginal gas wells and a royalty exemption for re-entry wells, among others.

## Land Tenure

Crude oil and natural gas located in the western provinces is owned predominantly by the respective provincial governments. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences and permits for varying terms from two years and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. Oil and natural gas located in such provinces can also be privately owned and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

## Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations. In addition, such legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage and the imposition of material fines and penalties.

Environmental legislation in Alberta has been consolidated into the *Environmental Protection and Enhancement Act* (Alberta) (the "**EPEA**"), which came into force on September 1, 1993, and the *Oil and Gas Conservation Act* (Alberta) (the "**OGCA**"). The EPEA and OGCA impose stricter environmental standards, require more stringent compliance, reporting and monitoring obligations, and significantly increased penalties. In 2006, the Alberta Government enacted regulations pursuant to the EPEA to specifically target sulphur oxide and nitrous oxide emissions from industrial operations including the oil and gas industry. In addition, the reduction emission guidelines outlined in the *Climate Change and Emissions Management Amendment Act* came into effect on July 1, 2007 ("**CCEMAA**"). Under this legislation, Alberta facilities emitting more than 100,000 tonnes of greenhouse gases a year must reduce their emissions intensity by 12%. Industries have three options to choose from in order to meet the reduction requirements outlined in this legislation, and these are: (i) by making improvement to operations that result in reductions; (ii) by purchasing emission credits from other sectors or facilities that have emissions below the 100,000 tonne threshold and are voluntarily reducing their emission; or (iii) by contributing to the Climate Change and Emissions Management Fund (the "**Fund**"). Industries can either choose one of these options or a combination thereof. Pursuant to CCEMAA and the *Specified Gas Emitters Regulation*, companies were obliged to reduce their emission intensity by 12% by March 31, 2008. Alberta industries have achieved 2.6 million tonnes of actual reduction, due to changes in operations and investing on verified offset projects. In addition, certain companies contributed \$40 million to the Fund. It is reasonably likely that the trend towards stricter standards in environmental legislation and regulation will continue.

On January 24, 2008, the Alberta Government announced a new climate change action plan that will cut Alberta's projected 400 million tonnes of emissions in half by 2050. This plan is based on three areas: (i) carbon capture and storage, which will be mandatory for *in situ* oil sand facilities that use heavy fuels for steam generation; (ii) energy conservation and efficiency; and (iii) greening production through increased investment in clean energy technology, including supporting research on new oil sands extraction processes, as well as the funding of projects that reduce the cost of separating carbon dioxide from other emissions supporting carbon capture and storage. In addition to this action plan, the Provincial Energy Strategy unveiled on December 11, 2008 is expected to, among other things, support the upgrading, refining and petrochemical clusters existing in the Province, market Alberta's energy internationally, review the emission targets and carbon charges applied to large facilities, and promote the innovation of energy technology by encouraging investment in research and development.

In December 2002, the Government of Canada ratified the Kyoto Protocol. The Kyoto Protocol calls for Canada to reduce its greenhouse gas emissions to 6% below 1990 "business-as-usual" levels between 2008 and 2012. The Kyoto Protocol came into force on February 16, 2005 and commits Canada to reduce its greenhouse gas emissions levels to 6% below 1990 "business-as-usual" levels by 2012.

In anticipation of the expiry of the Kyoto Protocol in 2012, government leaders and representatives from approximately 170 countries met in Copenhagen, Denmark from December 6 to 18, 2009 (the "**Copenhagen**

**Conference**") to attempt to negotiate a successor to the Kyoto Protocol. The primary result of the Copenhagen Conference was the Copenhagen Accord, which represents a broad political consensus rather than a binding international treaty like the Kyoto Protocol and has not been endorsed by all participating countries. The Copenhagen Accord reinforces the commitment to reducing greenhouse gas emissions contained in the Kyoto Protocol and promises funding to help developing countries mitigate and adapt to climate change. Although certain countries, including Canada, have committed to reducing their emissions individually or jointly by at least 80% by 2050, the Copenhagen Accord does not establish binding greenhouse gas emissions reduction targets. The Copenhagen Accord calls for a review and implementation of its stated goals by 2016.

In response to the Copenhagen Accord, the Government of Canada has recently indicated that it will seek to achieve a 17% reduction in greenhouse gas emissions from 2005 levels by 2020. This goal is similar to the goal expressed in previous policy documents, which are discussed below.

On February 14, 2007, the House of Commons passed Bill C-288, *An Act to ensure Canada meets its global climate change obligations under the Kyoto Protocol*. The resulting *Kyoto Protocol Implementation Act* came into force on June 22, 2007. Its stated purpose is to "ensure that Canada takes effective and timely action to meet its obligations under the Kyoto Protocol and help address the problem of global climate change." It requires the federal Minister of the Environment to, among other things, produce an annual climate change plan detailing the measures to be taken to ensure Canada meets its obligations under the Kyoto Protocol. It also authorizes the establishment of regulations respecting matters such as emissions limits, monitoring, trading and enforcement.

On April 26, 2007, the Government of Canada released "Turning the Corner: An Action Plan to Reduce Greenhouse Gases and Air Pollution" (the "**Action Plan**") which set forth a plan for regulations to address both greenhouse gases and air pollution. An update to the Action Plan, "Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions" was released on March 10, 2008 (the "**Updated Action Plan**"). Although draft regulations for the implementation of the Updated Action Plan were intended to be published in the fall of 2008 and become binding on January 1, 2010, no such regulations have been proposed to date. Further, representatives of the Government of Canada have recently indicated that the proposals contained in the Updated Action Plan will be modified to ensure consistency with the direction ultimately taken by the United States with respect to greenhouse gas emissions regulation. The approach of the United States is expected to include an absolute cap on emissions combined with allowances to be used for compliance that may be partially auctioned off to regulated entities. It is also unclear whether the approach adopted by the United States will provide for the payment into a technology fund as a compliance mechanism, as is currently permitted in Alberta and by the Updated Action Plan. As a result, many provisions of the Updated Action Plan, described below, are expected to be significantly modified.

The stated goal of the Updated Action Plan, as currently drafted, is to reduce greenhouse gas emissions to 20% below 2006 levels by 2020 and 60-70% by 2050. As noted above, the goal has now been modified by the Government of Canada. The Updated Action Plan outlines emissions intensity-based targets which will be applied to regulated sectors on either a facility-specific, sector-wide or company-by-company basis. Facility-specific targets applied to the upstream oil and gas, oil sands, petroleum refining and natural gas pipelines sectors. Unless a minimum regulatory threshold applies, all facilities within a regulated sector will be subject to the emissions intensity targets.

The Updated Action Plan makes a distinction between "Existing Facilities" and "New Facilities". For Existing Facilities, the Updated Action Plan requires an emissions intensity reduction of 18% below 2006 levels by 2010 followed by a continuous annual emissions intensity improvement of 2%. "New Facilities" are defined as facilities beginning operations in 2004 and include both greenfield facilities and major facility expansions that (i) result in a 25% or greater increase in a facility's physical capacity, or (ii) involve significant changes to the processes of the facility. New Facilities will be given a 3-year grace period during which no emissions intensity reductions will be required. Targets requiring an annual 2% emissions intensity reduction will begin to apply in the fourth year of commercial operation of a New Facility. Further, emissions intensity targets for New Facilities will be based on a cleaner fuel standard to encourage continuous emissions intensity reductions over time. The method of applying this cleaner fuel standard has not yet been determined. In addition, the Updated Action Plan indicates that targets for the adoption of carbon capture and storage ("**CCS**") technologies will be developed for oil sands in-situ facilities, 43 upgraders and coal-fired power generators that begin operations in 2012 or later. These targets will become operational in 2018, although the exact nature of the targets has not yet been determined.

Given the large number of small facilities within the upstream oil and gas and natural gas pipeline sectors, facilities within these sectors will only be subject to emissions intensity targets if they meet certain minimum emissions thresholds. That threshold will be (i) 50,000 tonnes of CO<sub>2</sub> equivalents per facility per year for natural gas pipelines; (ii) 3,000 tonnes of CO<sub>2</sub> equivalents per facility per year for the upstream oil and gas facility; and (iii) 10,000 boe/d/company. These regulatory thresholds are significantly lower than the regulatory threshold in force in Alberta, discussed below. In all other sectors govern by the Updated Action Plan, all facilities will be subject to regulation

Four separate compliance mechanisms are provided for in the Updated Action Plan in respect of the above targets: Technology Fund contributions, offset credits, clean development credits and credits for early action. Regulated entities will be able to use Technology Fund contributions to meet their emissions intensity targets. The contribution rate for Technology Fund contributions will increase over time, beginning at \$15 tonnes per CO<sub>2</sub> equivalent for the 2010-12 period, rising to \$20 in 2013, and thereafter increasing at the nominal rate of GDP growth. Maximum contribution limits will also decline from 70% in 2010 to 0% in 2018. Monies raised through contributions to the Technology Fund will be used to invest in technology to reduce greenhouse gas emissions. Alternatively, regulated entities may be able to receive credits for investing in large-scale and transformative projects at the same contribution rate and under similar requirements as described above.

The offset system is intended to encourage emissions reductions from activities outside of the regulated sphere, allowing non-regulated entities to participate in and benefit from emissions reduction activities. In order to generate offset credits, project proponents must propose and receive approval for emissions reduction activities that will be verified before offset credits will be issued to the project proponent. Those credits can then be sold to regulated entities for use in compliance or non-regulated purchasers that wish to either purchase the offset credits for cancellation or banking for future use or sale.

Under the Updated Action Plan, regulated entities will also be able to purchase credits created through the Clean Development Mechanism of the Kyoto Protocol which facilitates investment by developed nations in emissions-reduction projects in developing countries. The purchase of such Emissions Reduction Credits will be restricted to 10% of each firm's regulatory obligation, with the added restriction that credits generated through forest sink projects will not be available for use in complying with the Canadian regulations.

Finally, a one-time credit of up to 15 million tonnes worth of emissions credits will be awarded to regulated entities for emissions reduction activities undertaken between 1992 and 2006. These credits will be both tradable and bankable.

#### **AUDITORS, REGISTRAR AND TRANSFER AGENT**

The auditors of the Corporation are Collins Barrow Calgary LLP, Chartered Accountants, 1400, 777 – 8<sup>th</sup> Avenue S.W., Calgary, Alberta, T2P 3R5.

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

#### **INTEREST 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 National Instrument 51-102 by the Corporation during, or related to, the Corporation's most recently completed financial year other than GLJ, the independent reserve evaluator, and Collins Barrow Calgary LLP, the Corporation's auditors. None of the principals of GLJ had any registered or beneficial interests, direct or indirect, in any securities or other property of the Corporation or of the Corporation's associates or affiliates either at the time they prepared the statement, report or valuation prepared by it, at any time thereafter or to be received by them. Collins Barrow Calgary LLP is independent in accordance with the auditors' rules of professional conduct in Canada.

In addition, none of the aforementioned persons or companies, nor any director, officer or employee of any of the aforementioned persons or companies, is or is expected to be elected, appointed or employed as a director, officer or employee of the Corporation or of any associate or affiliate of the Corporation.

#### **ADDITIONAL INFORMATION**

Additional information relating to the Corporation can be found on SEDAR at [www.sedar.com](http://www.sedar.com). Additional information, including directors' and officers' remuneration and indebtedness, principal holders of Common Shares and securities authorized for issuance under equity compensation plans, is contained in the Corporation's information circular for the most recent annual meeting of shareholders that involved the election of directors. Additional financial information is provided for in our financial statements and management's discussion and analysis for the year ended December 31, 2009.

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

Management of Triton Energy Corp. (the "**Company**") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2009, estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated the Company's reserves data. The report of the independent qualified reserves evaluator is presented below.

The Reserves Committee of the board of directors of the Company has:

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

The Reserves Committee of the board of directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has approved:

- (a) the content and filing with securities regulatory authorities of the reserves data and other oil and gas information;
- (b) the filing of Form 51-102F2 which is the report of the independent qualified reserves evaluator on the reserves data; and
- (c) the content and filing of this report.

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that the reserves are categorized according to the probability of their recovery.

DATED as of this 29<sup>th</sup> day of April, 2010.

(signed) "*Ernest G. Sapieha*"  
Ernest G. Sapieha  
President and Chief Executive Officer

(signed) "*Murray J. Stodalka*"  
Murray J. Stodalka  
Executive Vice-President, Engineering and Operations

(signed) "*John E. Zahary*"  
John E. Zahary  
Director

(signed) "*Donald F. Archibald*"  
Donald F. Archibald  
Director

**SCHEDULE "B"**

**FORM 51-101F2  
REPORT ON RESERVES DATA BY  
INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR**

To the board of directors of Triton Energy Corp. (the "Company"):

1. We have prepared an evaluation of the Company's reserves data as at December 31, 2009. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2009, estimated using forecast prices and costs.
2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

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

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions in the COGE Handbook.
4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2009, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator	Description and Preparation Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate - \$M)			
			Audited	Evaluated	Reviewed	<b>Total</b>
GLJ Petroleum Consultants	April 8, 2010	CANADA	-	26,662	-	<b>26,662</b>

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook.
6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.
7. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

EXECUTED as to our report referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, April 20, 2010

*"Originally Signed by"*

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Neil I. Dell, P. Eng. Vice-President  
GLJ Petroleum Consultants