Annual Information Form

Year Ended December 31, 2014

March 26, 2015

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SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements contained in 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 Waldron's future performance and are based on Waldron'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. Waldron 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 contains forward-looking statements pertaining to the following:

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

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

The actual results, performance or achievements of Waldron 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, including but not limited to:

- the ability of the Corporation to continue as a going concern;
- the ability of the Corporation to obtain capital and credit
- volatility in market prices for oil and natural gas and in 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;
- success of drilling and capital expenditures
- 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 Waldronõs exploration and development program;
- unforeseen difficulties in integrating any acquired assets into Waldronõs 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 Waldron;
- 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".

With respect to forward-looking statements contained in this Annual Information Form, Waldron has made assumptions regarding, among other things: that the Corporation will have sufficient liquidity and capital resources; commodity prices will be consistent with the current forecasts of its engineers; royalty regimes and rates 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 Corporationõs 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; and that future operating costs will be consistent with the Corporationõs expectations.

Waldron 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 Waldronõs 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, Waldron undertakes no obligation to publicly update or revise any forward-looking statements. 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 of the Corporation believes that funds flow from operations and operating netbacks are useful supplemental measures as they demonstrate Waldron'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 Waldron's performance. Waldron'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, Waldron defines "funds flow from operations" as cash provided by operations before changes in non-cash operating working capital, transaction and other costs and decommissioning expenditures and defines "operating netbacks" as revenue, net of any realized gains or losses on commodity price contracts, less royalties and operating and transportation expenses.

GLOSSARY

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

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

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

"**Board of Directors**" means board of directors of the Corporation;

"**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 Waldron;

"**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 defense, 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 March 5, 2015 evaluating the crude oil, natural gas liquids and natural gas reserves of the Corporation as at December 31, 2014;

"**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;

"IFRS" means International Financial Reporting Standards;

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

"**National Instrument 51-101**" or "**NI 51-101**" means National Instrument 51-101 ï 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 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;

"**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 (5th Supp.), as amended from time to time, including the regulations promulgated thereunder;

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

"**Waldron**" or the "**Corporation**" means Waldron Energy Corporation, a corporation amalgamated under the ABCA.

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, 2014.

On June 11, 2010, Waldron completed a ten (10) to one (1) share consolidation. All share, stock option, warrant and per share comparative numbers in this Annual Information Form have been adjusted to reflect the share consolidation.

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 GAAP.

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
Stb	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
GJ/d	Gigajoule per day

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. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6Mcf:1Bbl, utilizing a conversion on a 6Mcf:1Bbl basis may be misleading as an indication of value.

CONVERSION

To Convert From	To	Multiply By
Mcf	Cubic metres	28.174
Thousand cubic metres	Mcf	35.494
Bbls	Cubic metres ("**m^3**")	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 Alberta Ltd. pursuant to a share purchase and sale agreement. Effective January 8, 2007, the Corporation amalgamated with 971021 Alberta Ltd. by way of vertical short form amalgamation under the ABCA to form one corporation operating under the name Triton Energy Corp.

On December 31, 2009, the Corporation completed a recapitalization, which consisted of series of transactions involving: (i) a non-brokered private placement of Common Shares and units comprising warrants and Common Shares for aggregate proceeds of $10.25 million, (ii) the acquisition of certain undeveloped land and drill-ready completion prospects, and (iii) the appointment of a new Board of Directors and management team.

Effective June 9 and 11, 2010 respectively, the Corporation amended its articles to change its name from "Triton Energy Corp." to "Waldron Energy Corporation", and to consolidate its Common Shares on the basis of ten (10) pre-consolidation shares for one (1) post-consolidation share.

The registered office of the Corporation is located at Suite 1600, 421 ï 7th Avenue S.W., Calgary, Alberta T2P 4K9 and its head office is located at Suite 600, 510 ï 5th Street S.W., Calgary, Alberta T2P 3S2.

The Corporation does not have any subsidiaries. The Corporation's Common Shares trade on the TSX under the symbol "WDN".

GENERAL DEVELOPMENT OF THE BUSINESS

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

2012

On July 25, 2012, the Corporation closed a private placement for total gross proceeds of $3.25 million by issuing 5,701,800 Common Shares on a "flow-through" basis under the Tax Act at a price of $0.57 per Common Share.

Operations

Operational highlights for the year ended December 31, 2012 included:

- The Corporation incurred $12.1 million in capital expenditures whereby $0.4 million was spent on land acquisitions, $0.2 million on geosciences and exploration activities, $10.1 million on drilling and completions, and $1.4 million on plant and facilities.

- The Corporation drilled 3.0 gross (3.0 net) Belly River wells and 2.0 gross (1.6 net) Crystal Glauconite wells.

- In December 2012, Waldron tied in Sullivan Lake 2-12-035-14W4 as a flowing Glauconite gas well.

- Production averaged 2,510 Boe/d for the year ended December 31, 2012.

- The Corporation exited 2012 with approximately 99,932 gross and 85,072 net acres of undeveloped land in Alberta.

2013

On July 31, 2013, the Corporation entered into an arrangement agreement (the "**Arrangement Agreement**") with Montana Exploration Corp. ("**Montana**") pursuant to which Montana would acquire all of the issued and outstanding Common Shares of Waldron.

On November 8, 2013, the Corporation closed a private placement for total gross proceeds of $1.5 million by issuing 3,333,333 Common Shares at a price of $0.45 per Common Share.

On December 30, 2013, the Corporation closed a private placement for total gross proceeds of $4.25 million by issuing 9,454,781 Common Shares on a "flow-through" basis under the Tax Act at a price of $0.45 per Common Share.

On December 31, 2013, the Corporation closed a private placement for total gross proceeds of $1.0 million by issuing 2,222,222 Common Shares at a price of $0.45 per Common Share.

Operations

Operational highlights for the year ended December 31, 2013 included:

- The Corporation incurred $3.8 million in capital expenditures whereby $0.3 million was spent on land acquisitions, $3.3 million on drilling and completions, and $0.1 million on plant and facilities.

- On a total proved basis, the Corporationõs one year F&D costs were approximately $8 per BOE, including changes in future development capital.

- The Corporation drilled 1.0 gross (1.0 net) Crystal Fahler well and completed certain workovers.

- Production averaged 1,903 Boe/d for the year ended December 31, 2013.

- The Corporation exited 2013 with approximately 84,372 gross and 70,627 net acres of undeveloped land in Alberta.

2014

On January 15, 2014, the Corporation closed a private placement for total gross proceeds of $1.0 million by issuing 2,222,223 Common Shares at a price of $0.45 per Common Share.

On February 19, 2014 Waldron announced the termination of the Arrangement Agreement entered into with Montana.

On February 28, 2014, Waldron closed a $6 million secured subordinated debenture financing that bears an interest rate of 9.5% per annum. The debenture had an original maturity date of February 28, 2015, which was revised to March 31, 2015 subsequent to December 31, 2014. The debenture is to be repaid in full upon maturity, subject to a further extension.

On June 18, 2014, Waldron closed the sale of a 3% gross overriding royalty on its existing land base for proceeds of $7 million. The royalty transaction also included an incremental 7% gross overriding royalty on two Ferrybank Falher wells that had yet to be drilled at the time of closing and includes a provision that $750,000 per well is to be returned to the royalty owner in the event the Ferrybank Falher wells are not drilled. During the twelve months ended December 31, 2014, the first of the two qualifying wells was drilled. The second well is to be drilled by April 18, 2015 in order to avoid the $750,000 payment. The Corporation is currently negotiating with the royalty owner regarding this commitment. The Corporation also has an option to purchase the GORR back for 15 months from the closing date at a price of 30% above the original proceeds on the royalty sale less any royalties paid under the agreement and less two thirds of any amounts returned as a result of any failure to drill the remaining Ferrybank well.

On July 30, 2014, the Corporation closed a private placement for total gross proceeds of $1.8 million by issuing 5,459,545 Common Shares on a "flow-through" basis under the Tax Act at a price of $0.33 per Common Share.

On December 2, 2014, the Corporation announced that it had engaged Cormark Securities Inc. as its exclusive financial advisor to assist the Corporation in order to pursue the sale of a material portion of the assets of the Corporation, either in one transaction or in a combination of transactions; a merger or other business combination; the outright sale of the Corporation; or some combination thereof (the "**Disposition process**"). As at the date hereof, the Disposition process is still ongoing.

Operations

Operational highlights for the year ended December 31, 2014 included:

- Excluding a total of $7.4 million in proceeds from the sale of a gross overriding royalty and other asset dispositions, the Corporation incurred $11.0 million in capital expenditures whereby $0.6 million was spent on land acquisitions, $9.2 million on drilling and completions, and $1.1 million on plant and facilities.

- The Corporation drilled 3.0 gross (3.0 net) wells and completed certain workovers.

- Production averaged 1,498 Boe/d for the year ended December 31, 2014. The Corporation estimates that production would have averaged approximately 1,618 Boe/d for the year ended December 31, 2014 excluding the estimated impacts of third party plant downtime and volume allocation adjustments relating to previous years which occurred in the year.

- The Corporation exited 2014 with approximately 83,728 gross and 70,252 net acres of undeveloped land in Alberta.

Significant Acquisitions

The Corporation did not complete any significant acquisition during or since the end of the most recently completed financial year for which disclosure is required under Part 8 of National Instrument 51-102 *Continuous Disclosure Obligations*.

DESCRIPTION OF THE BUSINESS AND OPERATIONS

General

Waldron 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

Pending the outcome of its announced Disposition process, the business plan of the Corporation is to focus on the deep basin of Alberta and to generate a repeatable inventory of liquids rich 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 exploration, development and exploitation program. Waldron also intends to operate with high working interests, and achieve operating efficiency by controlling infrastructure in its core areas.

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. In addition, there can be no assurance that the Corporation will have sufficient funds to implement its exploration and development strategy. See "Risk Factors".

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 Directorsô consideration of the qualitative aspects of the subject properties including risk profile, technical upside, reserve life and asset quality.

Environmental Matters

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. See "Risk Factors ï Environmental" and "Industry Conditions ï Environmental and Climate Change Regulation". Waldron undertakes continuing efforts to ensure compliance with applicable environmental laws and regulations and to ensure the safety of its employees, consultants and contractors and the general public in all areas where it conducts operations.

These efforts include the development and implementation of environmental, health and safety policies, procedures and manuals and the conduct of regular meetings and exercises. The Board of Directors reviews and monitors the environmental policies and activities of the Corporation on behalf of the Board of Directors as well as the activities of the Corporation as they relate to health and safety. In that regard, the Corporation has adopted corporate emergency response plans for the areas in which it operates, as well as other environment, health and safety policies.

Pursuant to applicable environmental regulations, Waldron is required to abandon, retire and reclaim wells, well sites and facilities. As of December 31, 2014, Waldron has recorded an asset retirement obligation of $12.4 million in its financial statements in accordance with GAAP. The Corporation anticipates that the expenditures necessary to satisfy the asset retirement obligation will be incurred over a period of approximately thirty years. The Corporation has not established a separate reclamation fund for the purpose of funding estimated future environmental and reclamation obligations. Any reclamation or abandonment costs incurred in the ordinary course in a specific period will be funded out of cash flow from operations. There are significant uncertainties related to asset retirement obligations generally, and no assurance can be given as to the eventual timing of and costs of such costs, or their effect on the Corporation.

Other than asset retirement obligations, ordinary course operational expenditures necessary to ensure environmental compliance, and the cost of health, safety and environmental personnel and programs, the Corporation is not aware of any environmental protection requirements that will impact its capital expenditures, earnings or competitive position in a manner disproportionate to that of its peers in its areas of operations. Compliance with any existing or new environmental legislation or requirements may require significant expenditures by the Corporation. Given the evolving nature of such requirements, however, it is not possible at this time to predict the nature of future requirements or their impact on the Corporationøs business, financial condition, results of operations and prospects.

The Corporation believes that there is a general trend toward stricter standards in environmental and safety legislation and regulation. Waldron is committed to meeting its responsibilities to protect the environment and the safety of its workers in all areas where it conducts operations and will take such steps as required to ensure compliance with environmental and safety legislation. No assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

HUMAN RESOURCES

As at the date hereof, the Corporation had 9 full time employees (3 officers and 6 other technical staff) and 3 part time consultants. See "Directors and Officers of the Corporation".

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 March 5, 2015. The effective date of the Statement is December 31, 2014 and the preparation date of the Statement is February 11, 2015.

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, 2014 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, 2014
FORECAST PRICES AND COSTS

RESERVES SUMMARY [1]

	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS[2]		NATURAL GAS LIQUIDS		TOTAL OIL EQUIVALENT[3]	
RESERVES CATEGORY	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (Mmcf)	Net (Mmcf)	Gross (Mbbl)	Net (Mbbl)	Gross (Mboe)	Net (Mboe)
Proved										
Producing	231	196	10	9	12,790	10,944	782	551	**3,155**	2,580
Developed Non-Producing	40	38	0	0	1,236	1,040	44	30	**290**	241
Undeveloped	0	0	0	0	2,438	2,164	318	256	**724**	617
TOTAL PROVED	271	234	10	9	16,464	14,148	1,144	837	**4,169**	3,438
PROBABLE	498	404	3	2	17,958	15,451	1,022	752	**4,515**	3,734
TOTAL PROVED PLUS PROBABLE	769	638	12	12	34,422	29,599	2,166	1,589	**8,684**	7,172

Notes:

(1) Columns may not add due to rounding.

(2) Natural gas volumes include solution gas volumes associated with the Corporationȏs light and medium crude oil reserves.
(3) Natural gas is converted to Boes at a ratio of six thousand standard cubic feet to one barrel of oil.

NET PRESENT VALUES OF FUTURE NET REVENUE[(1)(2)(3)]

RESERVES CATEGORY	BEFORE INCOME TAXES DISCOUNTED AT (%/year) 0 (M$)	5 (M$)	**10 (M$)**	15 (M$)	20 (M$)	AFTER INCOME TAXES DISCOUNTED AT (%/year) 0 (M$)	5 (M$)	10 (M$)	15 (M$)	20 (M$)
Proved Producing	46,537	33,812	**26,741**	22,223	19,074	46,537	33,812	26,741	22,223	19,074
Developed Non-Producing	2,241	1,796	**1,453**	1,185	972	2,241	1,796	1,453	1,185	972
Undeveloped	7,437	4,558	**2,891**	1,860	1,186	7,437	4,558	2,891	1,860	1,186
TOTAL PROVED	56,215	40,166	**31,086**	25,267	21,232	56,215	40,166	31,086	25,267	21,232
PROBABLE	58,504	30,773	**17,413**	10,027	5,597	49,253	26,773	15,471	9,009	5,031
TOTAL PROVED PLUS PROBABLE	114,719	70,938	**48,498**	35,294	26,829	105,467	66,938	46,556	34,276	26,263

Notes:

(1) Utilizes GLJ's price forecast as of January 1, 2015 as detailed below.
(2) Values are net of downhole abandonment liabilities for reserves wells. Non-reserve well and facility abandonment, surface reclamation and salvage values are not included.
(3) Columns may not add due to rounding.

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2014
FORECAST PRICES AND COSTS

RESERVES CATEGORY	REVENUE (M$)	ROYALTIES (M$)	OPERATING COSTS (M$)	CAPITAL DEVELOPMENT COSTS (M$)	ABANDONMENT COSTS (M$)	FUTURE NET REVENUE BEFORE INCOME TAXES (M$)	INCOME TAXES (M$)	FUTURE NET REVENUE AFTER INCOME TAXES (M$)
Proved Reserves	161,009	27,069	66,018	8,285	3,423	56,215	-	56,215
Proved Plus Probable Reserves	365,909	61,913	135,680	48,910	4,687	114,719	9,252	105,467

FUTURE NET REVENUE
BY PRODUCTION GROUP
AS OF DECEMBER 31, 2014
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)	3,584	$11.89/boe
	Heavy Oil (including solution gas and other by-products)	142	$9.54/boe
	Natural Gas (including by-products but excluding solution gas from oil wells)	27,348	$1.48/Mcfe
	Coal Bed Methane	12	$0.05/Mcfe
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	9,347	$10.63/boe
	Heavy Oil (including solution gas and other by-products)	201	$11.10/boe
	Natural Gas (including by-products but excluding solution gas from oil wells)	38,626	$1.04/Mcfe
	Coal Bed Methane	323	$0.52/Mcfe

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.

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, 2014, as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
FORECAST PRICES AND COSTS

	OIL								
Year	WTI Cushing Oklahoma ($US/Bbl)	Edmonton Oil Price 40° API ($Cdn/Bbl)	Bow River 25° API Hardisty ($Cdn/Bbl)	Alberta AECO Average Gas Price ($Cdn/MMBtu)	Pentanes Plus Edmonton ($Cdn/Bbl)	Butane Price Edmonton ($Cdn/Bbl)	Propane Price Edmonton ($Cdn/Bbl)	Inflation Rates[1] %/Year	Exchange Rate[2] ($US/$Cdn)
Forecast									
2015	62.50	64.71	55.00	3.31	69.24	52.91	19.63	2.0	0.85
2016	75.00	80.00	68.00	3.77	85.60	60.80	32.00	2.0	0.875
2017	80.00	85.71	72.86	4.02	91.71	65.14	38.57	2.0	0.875
2018	85.00	91.43	77.71	4.27	97.83	69.49	41.14	2.0	0.875
2019	90.00	97.14	82.57	4.53	103.94	73.83	43.71	2.0	0.875
2020	95.00	102.86	87.43	4.78	110.06	78.17	46.29	2.0	0.875
2021	98.54	106.18	90.26	5.03	113.62	80.70	47.78	2.0	0.875
2022	100.51	108.31	92.06	5.28	115.89	82.31	48.74	2.0	0.875
2023	102.52	110.47	93.90	5.53	118.20	83.96	49.71	2.0	0.875
2024	104.57	112.67	95.77	5.71	120.56	85.63	50.70	2.0	0.875
2025+	Escalated oil, gas and product prices at approximately 2% per year thereafter							2.0	0.875

Notes:

(1) Inflation rates for forecasting prices and costs.

(2) Exchange rates used to generate the benchmark reference prices in this table.

(3) Weighted average historical price realized by Waldron for the year ended December 31, 2014 was $4.82/Mcf AECO for natural gas. Approximately 73% of Waldron's production for the year ended December 31, 2014 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 reserves well downhole 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 ï Provincial Royalties and Incentives ï Alberta".

Reconciliation of Changes in Reserves and Future Gross Revenue

The following sets out the reconciliation of Waldron'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

	LIGHT AND MEDIUM OIL			HEAVY OIL		
FACTORS	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)
December 31, 2013	303	521	823	-	-	-
Extensions	-	-	-	-	-	-
Infill Drilling	-	-	-	-	-	-
Improved Recovery	-	-	-	-	-	-
Technical Revisions	31	(15)	16	12	3	14
Acquisitions	-	-	-	-	-	-
Dispositions	(2)	(9)	(10)	-	-	-
Economic Factors	(4)	1	(3)	-	-	-
Production	(56)	-	(56)	(2)	-	(2)
December 31, 2014	271	498	769	10	3	12

	NATURAL GAS LIQUIDS			ASSOCIATED AND NON-ASSOCIATED GAS AND COAL BED METHANE		
FACTORS	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Proved (Mmcf)	Gross Probable (Mmcf)	Gross Proved Plus Probable (Mmcf)
December 31, 2013	1,340	1,120	2,460	19,668	23,141	42,810
Extensions	264	216	480	2,077	1,962	4,040
Infill Drilling	88	114	202	640	831	1,471
Improved Recovery	-	-	-	-	-	-
Technical Revisions	(395)	(215)	(610)	(1,490)	(3,548)	(5,038)
Acquisitions	-	-	-	-	-	-
Dispositions	(1)	(8)	(8)	(6)	(59)	(65)
Economic Factors	(58)	(206)	(264)	(1,982)	(4,370)	(6,352)
Production	(93)	-	(93)	(2,443)	-	(2,443)
December 31, 2014	1,144	1,022	2,166	16,464	17,958	34,422

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 Waldron's assets for the years ended December 31, 2014, 2013 and 2012 and, in the aggregate, before that time based on forecast prices and costs.

Proved Undeveloped Reserves

Year	Light and Medium Oil (Mbbl)		Natural Gas (MMcf)		NGLs (Mbbl)	
	First Attributed	Total at Year End	First Attributed	Total at Year End	First Attributed	Total at Year End
Prior thereto	120	120	6,675	6,675	390	390
2012	-	-	1,280	4,814	104	268
2013	11	11	43	3,864	1	349
2014	-	-	2,438	2,438	318	318

Probable Undeveloped Reserves

Year	Light and Medium Oil (Mbbl)		Natural Gas (MMcf)		NGLs (Mbbl)	
	First Attributed	Total at Year End	First Attributed	Total at Year End	First Attributed	Total at Year End
Prior thereto	165	165	16,947	16,947	676	676
2012	142	264	1,765	17,537	34	672
2013	131	399	46	17,206	4	759
2014	-	367	2,710	13,528	320	762

In general, once proved and/or probable undeveloped reserves are identified, they are scheduled into Waldron'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 of capital or an inability to continue as a going concern;
- 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) availability of capital; (ii) historical production in the area compared with production rates from analogous producing areas; (iii) initial production rates; (iv) production decline rates; (v) ultimate recovery of reserves; (vi) success of future development activities; (vii) marketability of production; (viii) effects of government regulations; and (ix) 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
2015	2,096	3,696
2016	3,107	12,554
2017	429	11,361
2018	2,653	20,853
2019	0	0
Thereafter	0	446
Total Undiscounted	8,285	48,910

The future development costs are capital expenditures required in the future for Waldron to convert proved undeveloped reserves and probable reserves to proved developed producing reserves. The undiscounted development costs are $8.3 million for proved reserves and $48.9 million for proved plus probable reserves (in each case based on forecast prices and costs).

On an ongoing basis, Waldron will use internally generated cash flow from operations, debt, funds from dispositions, if any, 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 Waldron's principal oil and gas properties as at December 31, 2014. Unless otherwise stated, all production volumes in this section represent Waldron's gross interest.

Ferrybank

Ferrybank is located in west central Alberta about 60 kilometres northeast of Red Deer. Waldron has a 76.0% operated working interest in 60.0 sections of land in the area. At Ferrybank, sweet gas is produced from the upper and lower Mannville Formations at drill depths of 1,600 to 1,800 meters. The Mannville zones are deep basin sweet gas charged system with up to 70 bbls/Mmcf of natural gas liquids (including ethane). The oil targets at Ferrybank are in the Belly River and Ellerslie Formations. The drill depths are approximately 1,000 meters for the Belly River oil and 1,700 meters for the Ellerslie oil. Waldron owns its own gathering system as well as an oil battery. Natural gas is tied into a third party gathering system which transports Waldronōs natural gas to the nearby Keyera Rimbey gas plant for processing. Waldron had 17,968 (15,732 net) acres of undeveloped land at Ferrybank.

Ricinus

Ricinus is located in west central Alberta about 80 kilometres west of Red Deer. Waldron has 77.2% operated working interest in 88.5 sections of land in the area. The main target at Ricinus is sweet gas in the Ellerslie and Glauconitic Formations at drill depths of 3,000 to 3,500 meters. The Ellerslie and Glauconitic zones are a deep basin sweet gas charged system with up to 40 bbls/Mmcf of natural gas liquids. Waldron owns its own gathering system in north Strachan which transports Waldronĉs natural gas to the nearby Keyera Strachan gas plant for processing through Waldronĉs own gathering system. In south Ricinus, gas is transported to the Apache Ricinus gas plant for processing. Waldron had 60,960 (50,248 net) acres of undeveloped land at Ricinus.

Newton

Newton is located in west central Alberta about 60 kilometres northwest of Edmonton. Waldron has 80.0% operated working interest in four sections of Crown land in the area. Newton produces sweet gas from the Ellerslie and the Sparky Mannville Formations at drill depths under 1,200 meters. Waldron owns its own gathering system, which is tied into a third party gathering system and transports Waldronĉs natural gas to the nearby Altagas Manola plant for processing. Waldron has no undeveloped land at Newton.

Sullivan Lake

Sullivan Lake is located in east central Alberta approximately 150 kilometres northeast of Calgary. Waldron has an average 97.2% operated working interest in 12 sections of land in the area. The Corporation produces sweet gas from the Lower Cretaceous Viking Formation and sweet gas and light oil in the Mannville 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 is tied into Penn West and Apache gathering systems. Waldron has 3,680 (3,680 net) acres of undeveloped land at Sullivan Lake.

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, 2014:

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing[1]		Producing		Non-Producing[1]	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	**55.0**	**52.7**	**42.0**	**39.2**	**70**	**49.0**	**38.0**	**33.1**

Note:

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

Properties with No Attributed Reserves

At December 31, 2014, the Corporation had 83,728 gross (70,252 net) acres of undeveloped land holdings in the Province of Alberta. The Corporation expects that rights of up to 40,288 net acres of its undeveloped land holdings will expire by December 31, 2015. Waldron is considering whether or not to drill or submit an application to continue, sell, swap or farm-out selected portions of the above acreage.

Significant Factors or Uncertainties Relevant to Properties with No Attributed Reserves

See *"Additional Information Relating to Reserves Data – Significant Factors or Uncertainties"* above.

Forward Contracts and Marketing

Our crude oil and natural gas production is currently sold directly to credit-worthy counterparties, with the exception of small quantities of non-operated properties which are marketed by the operator.

We periodically hedge the price on a portion of our crude oil and natural gas production. During 2014, the prices received for crude oil was decreased by $4.79 per barrel of sales oil and the prices received for natural gas was decreased by $0.23 per Mcf of sales gas as we entered into the following commodity price contracts:

Period	Commodity	Type of Contract	Quantity Contracted	Contract price ($CAD)
Jan 1, 2014 - Dec 31, 2014	Crude Oil	Swap	175 bbls/d	Edmonton Par $90.15/bbl
Jan 1, 2014 - Dec 31, 2014	Natural gas	Swap	2,600 Mcf/d	AECO $4.15/Mcf

Conversion factor: 1 Mcf = 1.116 GJ

Additional Information Concerning Abandonment Costs

Waldron 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 currently has 174.0 net wells for which it expects to incur abandonment costs.

Estimated costs of reserve well downhole 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 $3.4 million undiscounted ($1.7 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 surface reclamation or salvage value was included in these costs. The total proved plus probable abandonment costs are $4.7 million (undiscounted) and $1.7 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)
2015	440
2016	87
2017	134
Thereafter	2,762
Total Undiscounted	3,423
Total Discounted @ 10%	1,666

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

Year	Abandonment Costs (Undiscounted)
2015	402
2016	31
2017	120
Thereafter	4,134
Total Undiscounted	4,687
Total Discounted @ 10%	1,686

Tax Horizon

Based on the Corporationôs available tax pools, expected capital expenditures and forecast net income for 2015, the Corporation does not anticipate paying current income taxes in 2015. Depending on levels of production, commodity prices, acquisitions and capital expenditures, Waldron could begin paying current income taxes in 2016 or beyond.

Capital Expenditures

The following table summarizes capital expenditures related to the Corporation's activities for the year ended December 31, 2014:

Capital Expenditures	$000s
Property acquisition costs:	
Proved properties	$ -
Undeveloped properties	-
Exploration costs	4,567
Development costs	6,407
Total	$ 10,974

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, 2014:

	Exploration		Development	
	Gross	Net	Gross	Net
Light and Medium Oil	1.0	1.0	-	-
Heavy Oil	-	-	-	-
Natural Gas	1.0	1.0	1.0	1.0
Service	-	-	-	-
Dry	-	-	-	-
Total:	2.0	2.0	1.0	1.0

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, 2015 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":

Total Proved

	Light and Medium Oil *(Bbls/d)*	Heavy Oil *(Bbls/d)*	Natural Gas *(Mcf/d)*	Natural Gas Liquids *(Bbls/d)*	Boe *(Boe/d)*
Ferrybank	114	4	2,482	266	798
Ricinus	5	-	2,543	90	519
Other Properties	36	-	1,275	-	248
Total Proved	**155**	**4**	**6,300**	**356**	**1,565**

Total Proved Plus Probable

	Light and Medium Oil *(Bbls/d)*	Heavy Oil *(Bbls/d)*	Natural Gas *(Mcf/d)*	Natural Gas Liquids *(Bbls/d)*	Boe *(Boe/d)*
Ferrybank	146	4	2,523	270	841
Ricinus	5	-	2,586	92	527
Other Properties	33	-	1,324	-	254
Total Proved plus Probable	**185**	**4**	**6,433**	**362**	**1,623**

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			
	2014			
	Dec. 31	Sept. 30	June 30	Mar. 31
Average Daily Production[(1)]				
Light and Medium Crude Oil (Bbls/d)	173	181	133	143
Heavy Oil (Bbls/d)	-	-	-	-
Gas (Mcf/d)	5,786	6,875	6,215	7,544
NGLs (Bbls/d)	180	218	271	287
Combined (Boe/d)	1,317	1,545	1,440	1,687
Average Price Received[(2)]				
Light and Medium Crude Oil ($/Bbl)	$86.40	$86.02	$84.01	$84.27
Heavy Oil ($/Bbls)	-	-	-	-
Gas ($/Mcf)	$4.03	$4.16	$4.60	$5.41
NGLs ($/Bbls)	$26.63	$57.64	$51.50	$74.25
Combined ($/Boe)	$32.69	$36.73	$37.31	$43.96
Royalties Paid				
Light and Medium Crude Oil ($/Bbls)	$11.16	$15.30	$11.85	($0.70)
Heavy Oil ($/Bbls)	-	-	-	-
Gas ($/Mcf)	($0.51)	$0.22	$0.99	$0.18
NGLs ($/Bbls)	$9.60	$16.80	$16.81	$23.65
Combined ($/Boe)	$0.54	$5.14	$8.53	$4.77
Operating & Transportation Expenses ($/Boe)				
Light and Medium Crude Oil ($/Bbls)	$29.77	$25.14	$26.89	$27.75
Heavy Oil ($/Bbls)	-	-	-	-
Gas ($/Mcf)	$3.28	$3.07	$2.95	$2.73
NGLs ($/Bbls)	$14.11	$15.38	$16.78	$13.40
Combined ($/Boe)	$20.24	$18.78	$18.38	$16.84
Netback Received ($/Boe)[(3)]				
Light and Medium Crude Oil ($/Bbls)	$45.47	$45.58	$45.27	$57.22
Heavy Oil ($/Bbls)	-	-	-	-
Gas ($/Mcf)	$1.26	$0.87	$0.66	$2.50
NGLs ($/Bbls)	$2.92	$25.46	$17.91	$37.20
Combined ($/Boe)	$11.91	$12.81	$10.40	$22.35

Notes:

(1) Before deduction of royalties.
(2) Including realized gains and losses from commodity price contracts
(3) 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, 2014:

	Light and Medium Crude Oil (Bbls/d)	Heavy Oil (Bbls/d)	Gas (Mcf/d)	NGLS (Bbls/d)	Boe (Boe/d)
Ferrybank	131	-	2,615	157	724
Ricinus	1	-	2,649	79	522
Other	26	-	1,341	3	252
Total Alberta	158	-	6,605	239	1,498

The Corporation's production for the year ended December 31, 2014 was 11% light and medium crude oil, 16% natural gas liquids and 73% natural gas.

For the twelve months ended December 31, 2014, approximately 54% of the Corporation's gross revenue was derived from natural gas production and the remaining 46% of the Corporation's gross revenue was derived from natural gas liquids, light and medium oil production.

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. As at the date hereof, there were 62,726,715 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

Waldron 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 Waldron, 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 TSX under the trading symbol "WDN". The following table sets forth the price range and trading volume of the Common Shares as reported by the TSX for the periods indicated.

Period	High	Low	Volume
2014			
January	0.35	0.31	284,100
February	0.35	0.26	492,500
March	0.36	0.30	1,259,300
April	0.35	0.32	992,800
May	0.34	0.28	2,342,400
June	0.32	0.28	1,926,900
July	0.32	0.28	1,075,000
August	0.28	0.26	1,859,700
September	0.30	0.25	1,972,500
October	0.28	0.23	431,800
November	0.26	0.16	866,500
December	0.17	0.10	1,252,100
2015			
January	0.10	0.05	1,241,000
February	0.07	0.04	1,031,100
March 1 - 26	0.05	0.03	494,300

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 securities of the Corporation, which are outstanding and were issued during the most recently completed fiscal year but not listed or quoted on a marketplace, as at December 31, 2014.

Date of Issuance	**Securities**	**Number of Securities**	**Price per Security**
March 14, 2014	Stock Options	1,620,000	$0.33
May 1, 2014	Stock Options	100,000	$0.33

ESCROWED SECURITIES

As at the date hereof, no Common Shares are subject to escrow.

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 as of the date of this Annual Information Form are as follows:

Name and Municipality of Residence	Position Held
Ernie Sapieha (2) Calgary, Alberta, Canada	President and Chief Executive Officer and a Director (Since December 31, 2009)
Donald F. Archibald (1)(2)(3) Calgary, Alberta, Canada	Chairman and Director (Since December 31, 2009)
David R. J. Lefebvre (1)(2)(3) Calgary, Alberta, Canada	Director (Since December 31, 2009)
John E. Zahary (1)(2)(3) Calgary, Alberta, Canada	Director (Since December 31, 2009)
Murray J. Stodalka (4) Calgary, Alberta, Canada	Chief Operating Officer (Since March 14, 2014)
Jeffrey A. Kearl Calgary, Alberta, Canada	Vice President, Finance and Chief Financial Officer (Since January 9, 2013)

Notes:

(1) Member of the Audit Committee.
(2) Member of the Reserves Committee.
(3) Member of the Compensation and Governance Committee.
(4) Mr. Stodalka was appointed Chief Executive Officer on March 14, 2014; prior thereto, he served as Executive Vice President, Engineering and Operations since December 31, 2009.
(5) The Corporation does not have an Executive Committee.

As at the date hereof, the directors, officers and management of the Corporation as a group own or control, directly or indirectly, 6,375,344 Common Shares or 10.2% 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. Sapieha, Stodalka, and Kearl devote their full time and attention to the business and affairs of the Corporation. The other directors of the Corporation 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. Sapieha, C.A. – President, Chief Executive Officer and a Director

Mr. Sapieha is a Chartered Accountant and has extensive experience as an executive and director in the oil and gas industry. Mr. Sapieha was the founder of Compton Petroleum Corporation ("**Compton**") and acted as President & CEO of Compton until December 2008. He is a Past Governor of the Canadian Association of Petroleum Producers and Director of the YMCA. Mr. Sapieha is a member of the Canadian Institute of Chartered Accountants.

Murray J. Stodalka, P.Eng. – Chief Operating Officer

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.

Jeffrey A. Kearl, C.A. – Vice President, Finance and Chief Financial Officer

Mr. Kearl joined Waldron in October 2012 as Controller and was appointed Vice-President, Finance and Chief Financial Officer in January 2013. He is a Chartered Accountant and holds a Bachelor of Commerce degree with an accounting concentration from the University of Calgary (2004) and is a member of the Canadian Institute of Chartered Accountants. Previously, Mr. Kearl was at Fairborne Energy Ltd as Manager, Financial Reporting from July 2009 to October 2012 and prior to that he was at Axia NetMedia Corporation from September 2007 ï July 2009 where he was a key member of the business development group, providing accounting and business modeling support to various corporate initiatives.

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 serves as a director of a number on a number of boards for both private and public 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.

David R. J. Lefebvre – Director

Mr. Lefebvre has been a partner of Gowling Lafleur Henderson LLP since February 2011, practising corporate, securities and mergers and acquisitions law. Prior thereto, he was a partner of Stikeman Elliott LLP. 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 companies.

John E. Zahary – Director

Mr. Zahary is a Professional Engineer and corporate director. He is currently the President & CEO of Altex Energy. Prior to his role at Altex, Mr. Zahary was President & CEO of Sunshine Oilsands Ltd. from December 2011 until December 2013. Prior to his role at Sunshine Oilsands Ltd., Mr. Zahary was President & CEO of Harvest Operations Corp. and a predecessor company from April 2004 to January 2012. 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 a Past Governor of the Canadian Association of Petroleum Producers, a past Director and 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 the Corporation's 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.

AUDIT COMMITTEE

Audit Committee's Mandate

A copy of the audit committeeǿs mandate and terms of reference is attached to this Annual Information Form as Schedule "C".

Composition of the Audit Committee

The members of the audit committee are Donald F. Archibald, David R.J. Lefebvre and John E. Zahary. Each member of the audit committee is financially literate. Other than Mr. Lefebvre, each member of the audit committee is independent. The Corporation relies on the exemption from the independence requirement set forth in Section -- of National Instrument 52 - 110 in connection with Mr. Lefebvre's appointment to the audit committee.

A member of the audit committee is independent if the member has no direct or indirect material relationship with the Corporation. A material relationship means a relationship which could, in the view of the Board of Directors, reasonably interfere with the exercise of a memberǿs independent judgment.

A member of the audit committee is considered financially literate if he or she has the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of the issues that can reasonably be expected to be raised by the Corporation.

Relevant Education and Experience

The following sets out the education and experience of each director relevant to the performance of his duties as a member of the audit committee.

Name and Place of Residence	Independent	Financially Literate	Relevant Education and Experience
Donald F. Archibald Calgary, Alberta	Yes	Yes	Mr. Archibald currently serves as a director on a number of private and public company boards. From July 2004 to March 2008, Mr. Archibald was the Chairman and Chief Executive Officer of Cyries Energy Inc. From January 2002 to July 2004, Mr. Archibald was the President and Chief Executive Officer of Cequel Energy Inc. From, 1995 to March 2001, Mr. Archibald was the President and Chief Executive Officer of Cypress Energy Inc. He has considerable public company experience and holds a Bachelor of Commerce degree and Masters of Business Administration degree.
John E. Zahary Calgary, Alberta	Yes	Yes	Mr. Zahary is a Professional Engineer and is currently the President & CEO of Altex Energy. Prior to his role at Altex Energy, Mr. Zahary was President & CEO of Sunshine Oilsands Ltd. from December 2011 until December 2013. Prior to his role at Sunshine Oilsands Ltd., Mr. Zahary was President & CEO of Harvest Operations Corp. and a predecessor company from April 2004 to January 2012. Prior thereto, he was President of Petrovera Resources. 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 a Past Governor of the Canadian Association of Petroleum Producers, a past Director and President of the Alberta Chamber of Resources, and Chairman of the Western Canada Rhodes Scholarship Selection Committee. Mr. Zahary holds a

Name and Place of Residence	Independent	Financially Literate	Relevant Education and Experience
			B.Sc. in Mechanical Engineering from the University of Calgary and a M.Phil. in Management from the University of Oxford.
David R. J. Lefebvre Calgary, Alberta	No[(1)]	Yes	Mr. Lefebvre has been a partner of Gowling Lafleur Henderson LLP since February 2011, practising corporate, securities and mergers and acquisitions law. Prior thereto, he was a partner of Stikeman Elliott LLP. Mr. Lefebvreǿs 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 companies.

Notes:

(1) Mr. Lefebvre is not independent for the purposes of National Instrument 52-110 ð Audit Committees. The Corporation relies on the exemption from the requirement that all members of an audit committee must be independent set out in Section 3.5 of such instrument.

Pre-Approval Policies and Procedures

The audit committee has adopted a policy to review and may pre-approve any non-audit services to be provided to the Corporation by the external auditors and consider the impact on the independence of such auditors. The committee may delegate to one or more independent members the authority to pre-approve non-audit services, provided that the member report to the committee at the next scheduled meeting such pre-approval and the members comply with such other procedures as may be established by the committee from time to time.

External Auditor Service Fees (By Category)

The audit committee has reviewed the nature and amount of non-audit services provided by KPMG LLP to the Corporation to ensure auditor independence. Fees incurred with KPMG LLP for the fiscal years ended December 31, 2014 and December 31, 2013 for audit and non-audit services are outlined in the following table.

Nature of Services	Fees Paid to Auditors in Year Ended December 31, 2014	Fees Paid to Auditors in Year Ended December 31, 2013
Audit Fees[(1)]	$176,425	$141,600
Audit-Related Fees[(2)]	Nil	$34,500
Tax Fees[(3)]	$17,430	$14,400
All Other Fees[(4)]	Nil	Nil
Total	$193,855	$190,500

Notes:

(1) "Audit Fees" include fees necessary to perform the annual audit and quarterly reviews of the Corporationǿs financial statements. Audit Fees include fees for review of tax provisions and for accounting consultations on matters reflected in the financial statements.

(2) "Audit-Related Fees" include services that are traditionally performed by the auditor. These audit-related services include employee benefit audits, due diligence assistance, accounting consultations on proposed transactions, internal control reviews and audit or attest services not required by legislation or regulation. Audit-Related Fees also include audit or other attest services required by legislation or regulation, such as comfort letters, consents, reviews of securities filings and statutory audits.

(3) "Tax Fees" include fees for all tax services other than those included in "Audit Fees" and "Audit-Related Fees". This category includes fees for tax compliance, tax planning and tax advice. Tax planning and tax advice includes assistance with tax audits and appeals, tax advice related to mergers and acquisitions, and requests for rulings or technical advice from tax authorities.

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

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 2014, or that any of its properties is or was the subject matter of in 2014, nor are there any such proceedings known to the Corporation to be contemplated.

During the year ended December 31, 2014, 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

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 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.

Liquidity Risks

The Corporation's current credit facilities and any replacement credit facilities may not provide sufficient liquidity. The amounts available under the Corporation's existing credit facilities may not be sufficient for future operations, or the Corporation may not be able to obtain additional financing on attractive economic terms, if at all. Repayment of all outstanding amounts under the Corporation's credit facilities may be demanded on relatively short notice. If this occurs, the Corporation may need to obtain alternate financing. Any failure to obtain suitable replacement financing may have a material adverse effect on the Corporation's business.

In particular, the Corporationös $6 million secured subordinated debt facility becomes due on March 31, 2015, extended from the original maturity date of February 28, 2015. Additionally, the Corporationös senior bank facility will undergo a borrowing base review on or before April 1, 2015 which may lead to further decreases to the facility amount. The maturity of the subordinated debt facility and the upcoming review of the senior bank debt facility give rise to material uncertainties that may cast significant doubt on the Corporationös ability to continue as a going concern if the facilities are not renewed, paid out, extended and/or refinanced. In advance of the revised maturity date of the subordinated debenture and the borrowing base review of the senior bank debt, the Corporation continues to work with its lenders to demonstrate a justifiable lending base and renegotiate lending terms. Additionally, the Corporation engaged a financial advisor in December 2014 to undertake a sales process whereby certain assets or the entire Corporation may be sold. The realization of proceeds from the sales process, if acceptable bids are successfully negotiated, gives rise to material uncertainties that may cast significant doubt on the Corporationös ability to continue as a going concern. As at the date hereof, the sales process is still ongoing. Subsequent to December 31, 2014, the subordinated debt lenderös waived the Corporationös default of the lender-defined debt to trailing cash flow ratio covenant as well as the lender-defined debt to equity covenant as at December 31, 2014.

While continuing open discussions with its lender, the Corporation will also evaluate other financing alternatives, if available on favourable terms, in order to retire the debt.

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.

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 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 has had and may continue to 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.

Borrowing

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

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 has reduced and may continue to 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.

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.

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

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.

Substantial Capital 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.

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 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 ability to execute its business strategy and on its business, financial condition, results of operations and prospects.

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.

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.

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 acquirerὂs 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 Waldronὂs 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 Waldron 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 Waldron. Any such instance may offset the return on and value of the securities of Waldron.

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.

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.

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.

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.

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.

Global Financial Crisis and Petroleum Supply

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 and 2010, causing a loss of confidence in the broader U.S. and global credit and financial markets. Although conditions have stabilized, these factors may negatively impact valuations of the Corporation and are expected to continue to impact the performance of the global economy going forward.

Petroleum prices are expected to remain volatile for the near future as a result of, among other things, market uncertainties over the supply and demand of these commodities due to the current state of the world economies, OPEC actions, supply and demand imbalances for petroleum products, political instability in the Middle East and elsewhere and the global credit and liquidity concerns.

Variations in Foreign Exchange Rates and Interest Rates

World oil and gas prices are quoted in United States dollars and the price received by Canadian producers is therefore affected by the Canadian/U.S. dollar exchange rate, which will fluctuate over time. Material increases in the value of the Canadian dollar will 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.

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 Waldron. An increase in royalty could reduce Waldronôs earnings and/or could make capital expenditures by Waldron uneconomic.

Regulatory and Tax

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.

The taxation laws and regulations, and the current administrative practices of the federal and provincial tax authorities, applicable with respect to the Corporationôs oil and gas activities, shares issued on a "flow-through" basis under the Tax Act and other matters may change or be construed in such a way as to have a material adverse effect on the Corporation and its shareholders. There is no guarantee that there will not be any differences of opinion with federal and provincial tax authorities with respect to the activities contemplated by the Corporation's exploration and development programs, the tax treatment of its flow-through shares and other matters. No guarantee can be given that Canadian tax laws will not be amended, that the amendments announced with respect to such laws will be adopted or that the current administrative practices of the tax authorities will not be modified. In addition, there is no guarantee that expected tax deductions will be accepted by Canada Revenue Agency, that the Corporation and shareholders will not be reassessed or that they will not be subject to penalties for any such reassessments or to interest payable on any additional taxes.

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. In addition, 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.

Climate Change

The Corporation's exploration and production facilities and other operations and activities emit greenhouse gases and require the Corporation to comply with Albertaôs 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 Corporationȇs business, financial condition, results of operations and prospects. The future implementation or modification of greenhouse gas emissions 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 ï Environmental and Climate Change Regulation".

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.

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, access to facilities, the approval of other participants, the selection of technology and risk management practices.

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.

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.

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.

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. Waldron cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on Waldronǿs business, financial condition, results of operations and cash flows.

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.

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.

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.

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.

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 ï Conflicts of Interest".

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 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^3/day) must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or 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

Interprovincial and international natural gas pipelines are regulated by the NEB and provide the opportunity for firm pipeline capacity. Interprovincial and international crude oil pipelines are also regulated by the NEB and operate on a common carrier basis. The NEB has allowed some crude oil pipelines to meet common carrier obligations by providing firm contract service. Depending upon the pipeline, there is therefore some apportionment risk (i.e. risk of pro-rationing capacity) relating to crude oil service that is not subject to firm contracts, which may affect the ability to produce and market production. This may be exacerbated by the inability of certain proposed pipeline projects to meet future export demand due to failures to obtain required approvals or otherwise to proceed.

The North American Free Trade Agreement

NAFTA, entered into by 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 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 current royalty rates for conventional oil are set by a single sliding rate formula which is applied monthly, with a maximum rate of up to 40%, and which rate caps once the price of conventional oil reaches $140 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 are set by a single sliding rate formula currently ranging from 5% to 36%, with a rate cap once the price of natural gas reaches $15/GJ. Oil sands projects are also 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.

The Government of Alberta has several royalty programs to encourage the development of oil and gas reserves. Examples of these include the New Well Royalty Rate, which applies to oil and natural gas, the Natural Gas Deep Drillings Program, the Deep Oil Exploration Well Program, the Horizontal Oil Royalty Rate, the Shale Gas New Well Program (which also applies to oil), and the Coalbed Methane (CBM) New Well Royalty Rate. Each of these programs provides reduced royalty rates for a certain period of time or volume of production. The Government of Alberta also has a drilling royalty credit for new conventional oil and natural gas wells, where 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, 2011, subject to certain maximum amounts.

The Government of Alberta also has a introduced 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.

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.

The Government of Alberta has a policy of both deeper rights reversion and shallow rights reversion. These policies are intended to maximize the development of currently undeveloped resources. Deeper rights reversions cause all rights below the deepest zone penetrated by a validating well to be returned to the Crown at the end of the primary term of the lease or license. This policy has been in effect for some time. More recently, on January 1, 2009, the shallow rights reversion policy was implemented, which causes 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, while 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, as of April 16, 2013, the Government indefinitely suspended implementation of shallow rights reversion on agreements issued prior to January 1, 2009.

Environmental and Climate Change Regulation

General

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.

The operations of the Corporation are, and will continue to be, affected in varying degrees by laws and regulations regarding environmental protection. The Corporation believes that it is in material compliance with applicable environmental laws and regulations. The Corporation expects to meet its responsibilities to protect the environment wherever it operates and anticipates making increased expenditures of both a capital and an expense nature as a result of the increasingly stringent laws relating to the protection of the environment, and will be taking such steps as are required to ensure compliance with applicable environmental legislation. It also believes that it is reasonably likely that the trend towards stricter standards in environmental legislation and regulation will continue. The Corporation is not currently able to quantify any increased expenditures to meet current or future environmental requirements, but does not anticipated that its competitive position will be adversely affected by environmental laws and regulations governing its oil and natural gas operations.

Alberta

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 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 51 million tonnes of actual reduction, due to changes in operations and investing on verified offset projects. In addition, certain companies contributed $503 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.

On December 2, 2010, the Government of Alberta passed the *Carbon Capture and Storage Statues Amendment Act, 2010*, which deemed the pore space underlying all land in Alberta to be, and to have always been, the property of the Crown and provided for the assumption of long-term liability for carbon sequestration projects by the Crown, subject to satisfaction of certain conditions.

Federal

In December 2002, the Government of Canada ratified the Kyoto Protocol. The Kyoto Protocol came into force on February 16, 2005 and committed Canada to reduce its greenhouse gas emissions levels to 6% below 1990 "business-as-usual" levels by 2012. The *Kyoto Protocol Implementation Act* came into force on June 22, 2007, with a 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 required 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 authorized the establishment of regulations respecting matters such as emissions limits, monitoring, trading and enforcement. However, in December 2011, Canada withdrew from the Kyoto Protocol. There were various reasons for this, including the requirement to purchase a significant number of international credits, and the fact that the United States was not covered by the Kyoto Protocol.

Subsequent to the Kyoto Protocol, government leaders and representatives from many countries have met to negotiate a new climate change regime to be a successor to the Kyoto Protocol. This has resulted in the development of the Copenhagen Accord, the Cancun Agreements and the Durban Platform. These agreements have launched a new process to produce a global climate change agreement by 2015 that will include binding commitments for all major emitters. In response to the Copenhagen Accord, the Government of Canada indicated that it will seek to achieve a 17% reduction in greenhouse gas emissions from 2005 levels by 2020, a reduction of 607 million tonnes per year. Canada will also continue to engage in United Nations Framework Convention on Climate Change (UNFCCC) negotiations to support the establishment of a fair and comprehensive global climate change regime that will effectively address global climate change, and will continue to work with international partners outside the formal United Nations negotiations.

As part of its climate change policies, the Government of Canadaǿs current Action on Climate Change has stated goals of reducing passenger vehicle emission, and reducing fuel consumption, by 50% of 2008 levels by 2025 have indicated that the proposals contained in the Updated Action Plan will be modified to ensure consistency with the direction ultimately taken by the United States with respect to greenhouse gas emissions regulation. In June 2012, the second US-Canada Clean Energy Dialogue Action Plan was released. The plan renewed efforts to enhance bilateral collaboration on the development of clean energy technologies to reduce greenhouse gas emissions.

Liability Management Rating Programs

Alberta

In Alberta, the AER administers the Licensee Liability Rating Program (the "**AB LLR Program**"). The AB LLR Program is a liability management program governing most conventional upstream oil and gas wells, facilities and pipelines. The ABOGCA establishes an orphan fund (the "**Orphan Fund**") to pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline included in the AB LLR Program if a licensee or working interest participant ("**WIP**") becomes defunct. The Orphan Fund is funded by licensees in the AB LLR Program through a levy administered by the AER. The AB LLR Program is designed to minimize the risk to the Orphan Fund posed by unfunded liability of licensees and prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines. The AB LLR Program requires a licensee whose deemed liabilities exceed its deemed assets to provide the AER with a security deposit. The ratio of deemed liabilities to deemed assets is assessed once each month and failure to post the required security deposit may result in the initiation of enforcement action by the AER.

On May 1, 2013, the AER began to implement a three year program of changes to the AB LLR Program which stem from concerns that the previous regime significantly underestimated the environmental liabilities of licensees. The current changes have already had an effect on oil and gas producers in Alberta as the May 1, 2013 changes resulted in a significant increase in the number of oil and gas companies in Alberta that are required to post security with the AER.

On July 4, 2014, the AER introduced the inactive well compliance program (the "**IWCP**") to address the growing inventory of inactive wells in Alberta and to increase the AER's surveillance and compliance efforts under *Directive 013: Suspension Requirements for Wells* ("**Directive 013**"). The IWCP applies to all inactive wells that are noncompliant with Directive 013 as of April 1, 2015. The objective is to bring all inactive noncompliant wells under the IWCP into compliance with the requirements of Directive 013 within 5 years. As of April 1, 2015, each licensee will be required to bring 20% of its inactive wells into compliance every year, either by reactivating or suspending the wells in accordance with Directive 013 or by abandoning them in accordance with *Directive 020: Well Abandonment*.

AUDITORS, REGISTRAR AND TRANSFER AGENT

The auditors of the Corporation are KPMG LLP, Chartered Accountants, 3100, 205 ï 5th Avenue S.W., Calgary, Alberta, T2P 4B9.

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

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

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. 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, 2014.

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

Management of Waldron Energy Corporation (the "**Company**") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2014, 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 26th day of March 2015.

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

(signed) "*Murray J. Stodalka*"
Murray J. Stodalka
Chief Operating Officer

(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 Waldron Energy Corporation (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2014. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2014, estimated using forecast prices and costs.

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

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

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

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, 2014, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator	Description and Preparation Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate – M$)			
			Audited	Evaluated	Reviewed	**Total**
GLJ Petroleum Consultants	Corporate Summary February 11, 2015	CANADA	-	48,498	-	**48,498**

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

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

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

EXECUTED as to our report referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, March 5, 2015

"Originally Signed by"

Bryan M. Joa, P. Eng. Vice-President
GLJ Petroleum Consultants

SCHEDULE "C"

AUDIT COMMITTEE MANDATE AND TERMS OF REFERENCE

Role and Objective

The Audit Committee (the "**Committee**") is a committee of the board of directors (the "**Board**") of Waldron Energy Corporation ("**Waldron**" or the "**Corporation**") to which the Board has delegated its responsibility for the oversight of the nature and scope of the annual audit, the oversight of managementôs reporting on internal accounting standards and practices, the review of financial information, accounting systems and procedures, financial reporting and financial statements and has charged the Committee with the responsibility of recommending, for approval of the Board, the audited financial statements, interim financial statements and other mandatory disclosure releases containing financial information.

The primary objectives of the Committee are as follows:

1. To assist directors in meeting their responsibilities (especially for accountability) in respect of the preparation and disclosure of the financial statements of Waldron and related matters;

2. To provide better communication between directors and external auditors;

3. To enhance the external auditorôs independence;

4. To increase the credibility and objectivity of financial reports; and

5. To strengthen the role of the outside directors by facilitating in depth discussions between directors on the Committee, management and external auditors.

Membership of Committee

1. The Committee will be comprised of at least three (3) directors of Waldron or such greater number as the Board may determine from time to time and all members of the Committee shall be "independent" (as such term is used in National Instrument 52-110 ð Audit Committees ("**NI 52-110**") unless the Board determines that the exemption contained in NI 52-110 is available and determines to rely thereon.

2. The Board of Directors may from time to time designate one of the members of the Committee to be the Chair of the Committee.

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

Mandate and Responsibilities of Committee

It is the responsibility of the Committee to:

1. Oversee the work of the external auditors, including the resolution of any disagreements between management and the external auditors regarding financial reporting.

2. Satisfy itself on behalf of the Board with respect to Waldronôs internal control systems:

   - identifying, monitoring and mitigating business risks; and

   - ensuring compliance with legal, ethical and regulatory requirements.

3. Review the annual and interim financial statements of Waldron and related managementôs discussion and analysis ("**MD&A**") prior to their submission to the Board for approval. The process should include but not be limited to:

   - reviewing changes in accounting principles and policies, or in their application, which may have a material impact on the current or future yearsô financial statements;
   - reviewing significant accruals, reserves or other estimates such as the ceiling test calculation;
   - reviewing accounting treatment of unusual or non-recurring transactions;
   - ascertaining compliance with covenants under loan agreements;
   - reviewing disclosure requirements for commitments and contingencies;
   - reviewing adjustments raised by the external auditors, whether or not included in the financial statements;
   - reviewing unresolved differences between management and the external auditors; and
   - obtain explanations of significant variances with comparative reporting periods.

4. Review the financial statements, prospectuses, MD&A, annual information forms ("**AIF**") and all public disclosure containing audited or unaudited financial information (including, without limitation, annual and interim press releases and any other press releases disclosing earnings or financial results) before release and prior to Board approval. The Committee must be satisfied that adequate procedures are in place for the review of Waldronôs disclosure of all other financial information and will periodically assess the accuracy of those procedures.

5. With respect to the appointment of external auditors by the Board:

   - recommend to the Board the external auditors to be nominated;
   - recommend to the Board the terms of engagement of the external auditor, including the compensation of the auditors and a confirmation that the external auditors will report directly to the Committee;
   - on an annual basis, review and discuss with the external auditors all significant relationships such auditors have with the Corporation to determine the auditorsô independence;
   - when there is to be a change in auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change; and
   - review and pre-approve any non-audit services to be provided to Waldron or its subsidiaries by the external auditors and consider the impact on the independence of such auditors. The Committee may delegate to one or more independent members the authority to preð approve nonð audit services, provided that the member(s) report to the Committee at the next scheduled meeting such preð approval and the member(s) comply with such other procedures as may be established by the Committee from time to time.

6. Review with external auditors (and internal auditor if one is appointed by Waldron) their assessment of the internal controls of Waldron, their written reports containing recommendations for improvement, and managementôs response and follow-up to any identified weaknesses. The Committee will also review

annually with the external auditors their plan for their audit and, upon completion of the audit, their reports upon the financial statements of Waldron and its subsidiaries.

7. Review risk management policies and procedures of Waldron (i.e. hedging, litigation and insurance).

8. Establish a procedure for:

- the receipt, retention and treatment of complaints received by Waldron regarding accounting, internal accounting controls or auditing matters; and

- the confidential, anonymous submission by employees of Waldron of concerns regarding questionable accounting or auditing matters.

9. Review and approve Waldronõs hiring policies regarding partners and employees and former partners and employees of the present and former external auditors of Waldron.

10. The Committee has authority to communicate directly with the internal auditors (if any) and the external auditors of the Corporation. The Committee will also have the authority to investigate any financial activity of Waldron. All employees of Waldron are to cooperate as requested by the Committee.

11. The Committee may also retain persons having special expertise and/or obtain independent professional advice to assist in filling their responsibilities at such compensation as established by the Committee and at the expense of Waldron without any further approval of the Board.

Meetings and Administrative Matters

1. At all meetings of the Committee every question shall be decided by a majority of the votes cast. In case of an equality of votes, the Chairman of the meeting shall be entitled to a second or casting vote.

2. The Chair will preside at all meetings of the Committee, unless the Chair is not present, in which case the members of the Committee that are present will designate from among such members the Chair for purposes of the meeting.

3. A quorum for meetings of the Committee will be a majority of its members, and the rules for calling, holding, conducting and adjourning meetings of the Committee will be the same as those governing the Board unless otherwise determined by the Committee or the Board.

4. Meetings of the Committee should be scheduled to take place at least four times per year. Minutes of all meetings of the Committee will be taken. The CFO will attend meetings of the Committee, unless otherwise excused from all or part of any such meeting by the Chairman.

5. The Committee will meet with the external auditor at least once per year (in connection with the preparation of the year-end financial statements) and at such other times as the external auditor and the Committee consider appropriate.

6. Agendas, approved by the Chair, will be circulated to Committee members along with background information on a timely basis prior to the Committee meetings.

7. The Committee may invite such officers, directors and employees of the Corporation as it sees fit from time to time to attend at meetings of the Committee and assist in the discussion and consideration of the matters being considered by the Committee.

8. Minutes of the Committee will be recorded and maintained and circulated to directors who are not members of the Committee or otherwise made available at a subsequent meeting of the Board.

9. The Committee may retain persons having special expertise and may obtain independent professional advice to assist in fulfilling its responsibilities at the expense of the Corporation.

10. Any members of the Committee may be removed or replaced at any time by the Board and will cease to be a member of the Committee as soon as such member ceases to be a director. The Board may fill vacancies on the Committee by appointment from among its members. If and whenever a vacancy exists on the Committee, the remaining members may exercise all its powers so long as a quorum remains. Subject to the foregoing, following appointment as a member of the Committee, each member will hold such office until the Committee is reconstituted.

11. Any issues arising from these meetings that bear on the relationship between the Board and management should be communicated to the Chairman of the Board by the Committee Chair.