ANNUAL INFORMATION FORM

PERPETUAL
ENERGY

For the year ended
December 31, 2015

March 2, 2016

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APPENDICES

CORPORATE STRUCTURE

Perpetual Energy Inc. is an oil and natural gas exploration and production company headquartered in Calgary, Alberta. Any reference in this Annual Information Form to "Perpetual", the "Corporation" or the "Company" means Perpetual Energy Inc. The Corporation has been actively transitioning its asset base from primarily shallow gas to a diversified, resource-style platform for growth. Perpetual currently has liquids-rich natural gas assets in the deep basin of west central Alberta, shallow gas and heavy oil production in eastern Alberta oil sands leases in northern Alberta and an interest in a commercial natural gas storage facility.

Name, Address and Incorporation

Perpetual was incorporated under the *Business Corporations Act* (Alberta) (the "**ABCA**") under the name "Perpetual Energy Inc." on April 26, 2010 through the corporate conversion of Paramount Energy Trust. Perpetual amalgamated with its wholly-owned subsidiaries 1143046 Alberta Ltd., POT Acquisition Company Ltd., Profound Energy Inc. and Starboard Gas (W3) Ltd. on June 30, 2010 and continued as Perpetual Energy Inc.

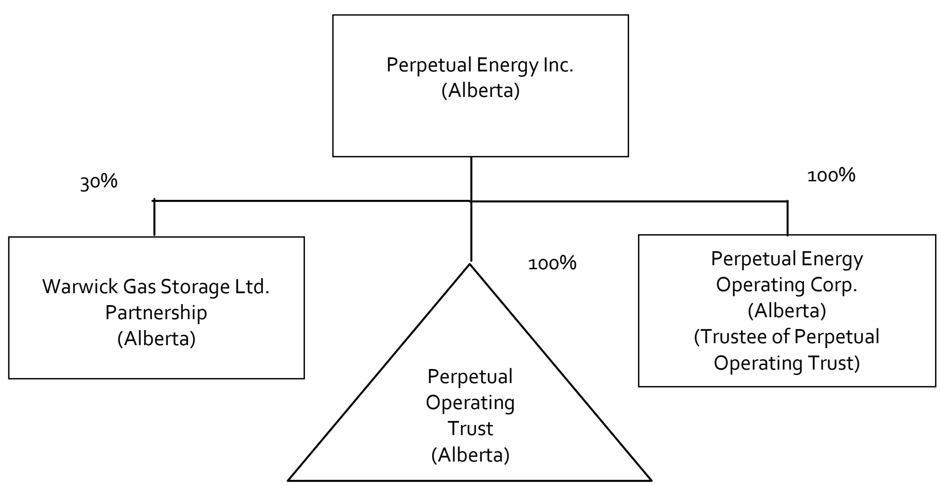
Perpetual's head office and registered office is located at Suite 3200, 605 – 5th Avenue S.W., Calgary, Alberta, T2P 3H5.

Employees

At December 31, 2015, Perpetual had 119 permanent employees and 9 consultants located in its Calgary office and 60 permanent employees and 22 hourly consultants in various field locations.

Inter-corporate Relationships

The following diagram illustrates the inter-corporate relationship between Perpetual and its material subsidiaries, the percentage of votes attached to all voting securities of the subsidiaries beneficially owned, or controlled or directed, directly or indirectly, by Perpetual and the jurisdiction of incorporation or formation of the subsidiaries.



GENERAL DEVELOPMENT OF THE BUSINESS

Three Year History

The general development of Perpetual's business over the last three completed financial years include events, such as acquisitions or dispositions, or conditions that have had an influence on that development, are described below.

Recent Developments

In January 2016, Perpetual closed a rights offering which generated $25 million in gross proceeds to the Company, which will be used to fund the Company's 2016 capital expenditure program. The Company issued an aggregate of 665.4 million common shares on completion of the rights offering. Closing the rights offering was part of a series of recapitalization transactions initiated in 2015 as a means to provide the Company with a stronger financial foundation and capital structure to operate within an uncertain commodity price and operating environment. The recapitalization transactions resulted in reduced indebtedness, provided additional liquidity for the Company's capital programs and allowed for the retention of core assets, including 6.5 million common shares of Tourmaline Oil Corp. ("**Tourmaline**").

Perpetual provided notice to its shareholders for its 2016 annual and special meeting, scheduled to be held on March 24, 2016, wherein the Company has proposed a share consolidation which, upon approval, will be completed on the basis of one (1) common share for up to every twenty (20) common shares issued and outstanding.

2015

In April 2015 Perpetual swapped its joint interest share in its West Edson asset in West Central with Tourmaline in exchange for 6.75 million TOU common shares ("**TOU Shares**") having a then current market value of approximately $258.7 million based on the closing price of the TOU Shares on the Toronto Stock Exchange on April 1, 2015. The transaction included all joint interest lands Perpetual held with Tourmaline in West Edson, together with the associated wells and infrastructure (the "**West Edson Property**").

Based on the Company's third party engineering report prepared by McDaniel and Associates Consultants Ltd., as at December 31, 2014, the disposition included 7.2 MMboe of recognized proved and probable developed natural gas and natural gas liquids reserves as well as 16.8 MMboe of proved and probable undeveloped reserves. Also included in the transaction were 9,600 net acres of undeveloped lands not currently assigned reserves at year-end 2014. Perpetual's production from the West Edson Property was approximately 5,750 boe/d.

The transaction positions Perpetual to capture the upside of the West Edson Property through ownership of the TOU Shares and also provides Perpetual shareholders with the value creation potential inherent in Tourmaline's extensive land and drilling opportunity inventory and strong balance sheet in this period of low commodity prices. It also materially strengthened Perpetual's financial situation, augmenting the Company's potential to optimize the shareholder value inherent in its existing diversified portfolio of assets. The TOU Shares also provide greater flexibility to capture and evaluate other new high impact opportunities and pursue strategic initiatives.

Furthermore, the increased liquidity of the TOU Shares relative to the West Edson Property positions Perpetual to manage downside risks associated with the current uncertain and volatile commodity price environment. Considering the TOU Shares as an offset to outstanding debt, this transaction drives material positive progress on one of the Company's 2015 strategic priorities, to reduce debt and manage downside risk, bolstering Perpetual's financial flexibility and optionality to manage its future credit facility and senior note obligations.

In conjunction with the closing of the swap of the West Edson property for TOU Shares in April 2015, Perpetual's lenders completed their semi-annual review and amended the Company's credit facility to include a revolving credit facility of $25 million and a term loan of $75 million. Collateral for the term loan was provided by a securities pledge agreement related to the TOU Shares and included a requirement to maintain a three-to-one value to loan ratio based on the market price of TOU Shares, and, as such, was reduced periodically throughout 2015 in response to reductions in the market price of TOU Shares.

In April 2015 Perpetual also closed the sale of certain fee simple lands in east central Alberta, and a working interest in related seismic data, for gross proceeds of $21.0 million. The disposition included 206,712 net acres (207,770 gross) of fee simple lands, approximately 163.1 Mboe of reserves (90 percent gas) associated with royalty interests, as well as the assignment of a 75 percent ownership interest in 1,013 square km of 3D proprietary seismic and 3,917 km of 2D proprietary seismic. Proceeds from the sale were initially applied against outstanding bank indebtedness.

In November 2015, the Company entered into a new financing arrangement (the "**New Financing Arrangement**") with a counterparty which resulted in net proceeds of $18.2 million collateralized by one million Tourmaline Shares. The proceeds were initially applied to reduce outstanding bank indebtedness. The New Financing Arrangement for the underlying amount of $21.3 million matures on November 16, 2016. The New Financing Arrangement provided Perpetual with additional liquidity and preserves its full exposure to increases in the price of the Tourmaline's Shares with downside price protection. The New Financing Arrangement represented a collateralization of Tourmaline Shares, not a sale, and Perpetual retained substantially all rights and privileges associated with the ownership of such shares.

In December 2015, the credit facility was amended to extend the maturities of the revolving credit facility and the term loan to October 31, 2016. Availability under the revolving credit facility was set at $20 million and availability under the term loan was set at $42 million with the reduction in the number of TOU Shares pledged as a result of the New Financing Arrangement. The term loan continues to require Perpetual to maintain a three-to-one value to loan ratio based on the market price of TOU Shares.

On December 31, 2015, Perpetual issued an aggregate of approximately 228.9 million common shares to the holders of the outstanding 7.00% Convertible Unsecured Debentures (the "**7.00% Debentures**") as repayment of the $34.9 million principal amount on maturity, pursuant to the terms of the 7.00% Debentures. All accrued and unpaid interest on the 7.00% Debentures was paid in cash at December 31, 2015.

2014

Perpetual accelerated the development of its west central liquid-rich natural gas during 2014 by maintaining focus on development activities in the Greater Edson area. Expansion of the West Edson gas processing facility was completed in the first half of 2014 and drilling operations filled the available processing capacity for the remainder of the year. In July 2014, Perpetual entered into the East Edson royalty disposition and farm-in agreements with an industry partner ("**East Edson JV**"). The arrangement included the disposition of a 50% royalty interest in the current developed producing reserves in the East Edson area (the "**Producing Royalty**") for cash proceeds of $50.0 million, less transaction costs and closing adjustments. Concurrent with the royalty disposition, Perpetual also entered into a farm-in agreement, whereby the partner contributed $70 million to an escrow account to fund the drilling, completion and tie-in of 13 horizontal wells in the Wilrich formation in exchange for a second royalty (the "**Drilling Royalty**") on new production from the East Edson property. The Drilling and Producing Royalties entitle the partner to receive, on a priority basis, a maximum of 5.6 MMcf/d of natural gas from the East Edson property plus oil and associated natural gas liquids ("**NGL**") from July 1, 2014 to December 31, 2022 and declining thereafter at 10% per year until the royalties terminate on December 31, 2034. As a result of Perpetual's 2014 capital initiatives, including the East Edson JV, proved plus probable reserves increased by 69% from year end 2013 to 105.2 MMboe.

Debt reduction and risk management was also a key strategic priority for Perpetual in 2014. A reduction in overall debt levels was achieved through the successful execution of several transactions including the East Edson JV, senior notes offering, monetization of future gas over bitumen ("**GOB**") royalty credits and non-core property dispositions.

In July 2014, Perpetual issued $125 million in senior unsecured notes which bear interest at 8.75% and mature in July 2019. Proceeds from the senior notes issuance were used to redeem all of Perpetual's $100 million outstanding 7.25% Convertible Unsecured Debentures on August 25, 2014 and $25 million of the outstanding 7.00% Debentures on December 31, 2014. By issuing the senior notes and redeeming outstanding convertible debentures with near term maturity dates, the Company extended the term for the majority of its long-term debt beyond 2018.

Perpetual closed two transactions in 2014 which effectively monetized the majority of its future GOB royalty credits associated with certain shut-in properties in northeast Alberta for net proceeds of $21.3 million. In exchange for the proceeds, Perpetual makes monthly payments to the purchaser which are based on the gas over bitumen formula set out in the Alberta Gas Royalty Regulations.

Property dispositions, net of acquisitions, of $70.4 million in 2014 included net proceeds of $47.0 million under the East Edson JV on the disposition of an overriding royalty interest; $21.4 million on the disposition of non-core Mannville heavy oil assets and $3.0 million received on the sale of undeveloped land. Offsetting property dispositions were acquisitions of $1.0 million, primarily related to additional land purchases in the Greater Edson area.

2013

Perpetual continued its asset base transformation and commodity diversification strategy throughout 2013. Exploration and development activities were focused on the Company's Mannville heavy oil property in eastern Alberta and liquids-rich natural gas property in the greater Edson area of west central Alberta. Expansion of the West Edson gas processing facility and construction of a refrigeration plant and a sales gas pipeline were undertaken in 2013 in order to accommodate the Company's growing production base while increasing overall netbacks from the core Edson property.

In the second quarter of 2013, Perpetual exercised its option and acquired an additional 20% interest in Warwick Gas Storage LP ("**WGS LP**"), a gas storage facility operated and managed by the Company, thereby increasing its equity ownership to 30%. An AER application for reservoir delta pressuring was approved to expand the working gas capacity of the gas storage facility to 21 Bcf.

Debt reduction continued to be a strategic priority in 2013, with proceeds of $79.0 million generated from non-core asset dispositions, primarily from the disposition of the Company's non-producing Elmworth Montney acreage.

Significant Acquisitions

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

DESCRIPTION OF THE BUSINESS

General

Perpetual is engaged in finding, developing, producing and marketing natural gas, natural gas liquids ("**NGL**"), oil and bitumen, and creating value through opportunities associated with these activities. Perpetual's business primarily consists of operations in Alberta focused on:

1) exploring and developing the Corporation's natural gas and NGL resource growth opportunities in the deep basin in west central Alberta;
2) the exploration for and extraction of heavy oil in eastern Alberta;
3) the development and production of shallow natural gas from mature producing regions in eastern Alberta where the Corporation has an established gathering and processing infrastructure;
4) bitumen opportunities in northeast Alberta; and
5) interest in a commercial gas storage business through the operation and 30% ownership in a gas storage facility at Warwick in east central Alberta.

Business Plan

Perpetual's business plan is based upon an entrepreneurial approach to value creation through finding, developing, producing, and marketing oil and gas based energy. The Company is focused on growing production, reserves, cash flow and value through exploration and development, the application of innovative technologies and acquisitions. The Company actively manages its strong and diversified portfolio of assets to crystallize value, capitalize on opportunities and manage risks through commodity price cycles.

In recent years through its purposeful transition from a shallow-gas focused distributing energy trust to a diversified, growth-oriented, exploration and production corporation, the foundations of Perpetual's strategy have been refined. Four pillars define Perpetual's strategy as the organization is built to grow, prosper and last.

1) Build a diversified portfolio of material, repeatable high return, resource-style assets for short-term and long-term growth and value:
    - optimize the legacy shallow gas asset base;
    - capture material positions in potential growth strategies through grass roots exploration and acquisitions and evaluate through risk-managed investment;
    - exploit and expand profitable, proven assets with prudent investment; and
    - maintain a diversified asset and opportunity portfolio by commodity, geography, risk-profile and development timeline.

2) Establish excellence in chosen priorities:
    - safety is job one;
    - value technical, operational, execution and leadership excellence;
    - maximize profits through a low-cost culture; and
    - be accountable for results.

3) Maintain a healthy balance sheet:
    - disciplined spending while balancing priorities;
    - maintain levers for optionality;
    - actively manage the portfolio to optimize value; and
    - position to be robust through commodity cycles.

4) Manage risk and capitalize on commodity price cycles:
    - assess technical, operational, execution and transactional risks and invest appropriately to balance risk and reward;
    - employ and actively manage market-based commodity price risk management strategies; and
    - capture counter-cyclical opportunities.

Over the past several years, Perpetual has prioritized repositioning its asset base and reducing debt while balancing the other pillars of its value-driven strategy. Three asset-related strategies have been employed.

1) Cash Flow Diversification:
    - exploration and development of conventional heavy oil opportunities, geographically synergistic with base operations;
    - exploration and development of resource-style, liquids-rich gas in the Alberta deep basin; and
    - pursuit of creative energy business opportunities leveraging assets and expertise, such as development of the commercial natural gas storage business at Warwick.

2) Asset Base Transformation for Long-Term Diversification and Growth:
   - new venture activities to capture and assess resource-style gas, liquids-rich gas and oil opportunities with risk-managed investment; and
   - bitumen resource definition, evaluation and extraction activities.

3) Base Asset Optimization:
   - maximize the value of base shallow gas assets by minimizing costs and maximizing revenue and maintaining exposure to low cost production and reserve addition opportunities through uphole recompletions and low exposure, concentric exploration of undeveloped shallow gas land base;
   - making accretive acquisitions to complement and enhance the value of the shallow gas opportunity inventory; and
   - directing excess cash flows to fund the diversification and growth strategies.

Perpetual has actively managed its transforming asset base, divesting of assets in all three of the above strategies as appropriate to manage risk, improve the balance sheet and optimize the overall value of its portfolio.

The Corporation has had significant success in repositioning its asset base to enhance and diversify its production, reserves and prospect inventory and add high impact, growth-oriented, resource-style opportunities to its asset portfolio, despite diminished funds flows related to low natural gas prices over this period. Diversifying growth opportunities to invest in profitably today include development programs in west central Alberta which include executing its planned development program in East Edson pursuant to the East Edson JV and horizontal development utilizing multi-stage fracture technology for liquids-rich gas in the West Edson area. In light of significant oil price weakness, horizontal development of heavy oil at Mannville in east central Alberta has been deferred until oil prices recover with limited capital directed to secondary recovery methods.

Longer term opportunities that have been captured, where resource is being assessed and technologies are being evaluated, include tight gas development potential in the shallow Viking and Colorado shale and other horizons in east central Alberta, several bitumen prospects in northeast Alberta and other oil and liquids-rich resource plays in the Alberta deep basin. At the same time, Perpetual remains exposed to significant value upside in its legacy shallow gas asset base related to a potential natural gas price recovery.

Debt reduction has been a strategic focus for Perpetual over the past years, achieved through the successful execution of transactions including the East Edson JV, monetization of future gas over bitumen royalty credits, disposition of fee simple lands and other non-core property dispositions. Considering the TOU Shares as an offset to outstanding debt bolsters the Corporation's financial flexibility and optionality to manage future financial obligations.

With projected low commodity prices in 2016, Perpetual will prioritize liquidity management and preservation of its balance sheet through reduced spending and a focus on reducing costs and maximizing efficiencies in administration and operations. Perpetual is focused on four key strategic priorities for 2016:

1) reduce debt and restore cash flow;
2) grow value and scope of Greater Edson liquids-rich gas;
3) maximize value potential of Eastern Alberta assets; and
4) advance high impact opportunities.

Operations

Perpetual continues to make progress in transitioning from its legacy asset base of conventional shallow natural gas assets in eastern Alberta and is largely focused on low cost, resource-style, liquids-rich gas in the West Central Alberta deep basin. In 2015, production from West Central Alberta deep basin assets accounted for 47% of production up from less than 5% prior to 2011. Perpetual's capital activities for 2016 will be very limited with drilling and completion activities restricted to the East Edson area. Development of conventional heavy oil in Mannville will be deferred until there are indicators that oil prices will improve. Perpetual also has established several long-term high impact opportunities that will be advanced technically with modest investment. These include exposure to shallow shale gas in eastern Alberta, bitumen opportunities in northeast Alberta and other exploration initiatives in the deep basin in West Central Alberta.

The following is a description of Perpetual's important oil and natural gas properties at December 31, 2015. Production stated is the Corporation's working interest share of production volumes and, unless otherwise noted, is average production for 2015. The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties due to the effects of aggregation. Unless otherwise specified, gross acres, net acres and well count information are as at December 31, 2015.

West Central Deep Basin

In the West Central area, core operations have been established in the greater Edson area where the company owns and operates both vertical, multi-zone commingled wells and horizontal wells producing liquids-rich gas from the Wilrich formation. Major facilities include one operated gas plant including liquids recovery facilities, one compressor station, a 15.5 km sales pipeline, an extensive gathering system and a 15% non-operated position in a sales gas plant. A small portion of the area's sour production is processed through a third-party deep cut plant.

On April 1, 2015, Perpetual swapped its joint interest share in the West Edson Property in West Central in exchange for 6.75 million TOU common shares having a then current market value of approximately $256.5 million based on the closing price of the TOU Shares on the Toronto Stock Exchange on March 12, 2015. Prior to the swap, Perpetual drilled three (1.5 net) natural gas wells in West Edson in 2015, which were included in the asset swap. Production from the West Edson Property was approximately 5,750 bbls/d at the time of the swap and represented 1,265 boe/d of Perpetual's average production in 2015.

East Edson

The East Edson area is located west of Edmonton, Alberta and is comprised of 53,405 net acres (62% undeveloped) with an average 97.9% working interest in 52 gross (50.9 net) producing natural gas wells and an average 78.1% working interest in 4 gross (3.1 net) producing oil wells. This area represented approximately 41% of production from Perpetual's assets for the year 2015. The Company operates the majority of this area which produced 8,021 boe/d in 2015, including 43.8 MMcf/d of natural gas and 724 bbl/d of crude oil and NGL. Pursuant to the East Edson JV, the Company pays, on a priority basis, a gross overriding royalty to an industry partner to a maximum of 5.6 MMcf/d of natural gas plus oil and associated NGL on a monthly basis beginning July 1, 2014 to December 31, 2022, declining thereafter at 10% per year until December 31, 2034.

In 2015, Perpetual drilled, completed, equipped and tied-in three (3.0 net) wells and completed a 3D seismic survey covering a portion of the East Edson JV lands that was initiated in 2014. Construction of a new East Edson gas plant was also completed in 2015 with the plant successfully brought online on July 15, 2015. The plant immediately demonstrated the operational ability to exceed the initial design capacity of 30 MMcf/d with high flowing pressures from the start-up of new wells. Completion of the East Edson gas plant satisfied one of Perpetual's commitments under the East Edson JV. In mid-September, the first expansion was completed with the installation of an additional compression unit, which increased total plant capacity to 45 MMcf/d.

Pursuant to the East Edson JV, Perpetual committed to spend $30 million to drill, complete and tie-in approximately five wells prior to December 31, 2015, substantially following the spending of the $70 million farm-in commitment by the partner. The majority of the partner's $70 million commitment and a portion of Perpetual's first $30 million commitment were spent by the end of 2014, with the balance being fully spent by the end of the first quarter of 2015. Finally, Perpetual also committed to invest an additional $30 million to drill, complete and tie-in approximately six additional wells prior to December 31, 2022.

Prior to the construction of the new facility, nearly 100% of Perpetual's sweet gas production was processed through a 100% Company owned and operated compressor and then passed on to be processed through a third party operated plant in which Perpetual has a 15% ownership interest. Volumes above current plant capacity continue to flow through this arrangement. Sour volumes of approximately 2 MMcf/d continue to be processed through the third party deep cut facility.

West Central Other

Other non-core assets in the West Central area are comprised of 51,698 net acres (74% undeveloped) with an average 59% working interest in 10 gross (5.9 net) producing oil and natural gas wells. West Central Other areas produced 28 boe/d in 2015.

In early 2014, Perpetual entered into a farm-out agreement on 6,240 acres of Duvernay rights in the Waskahigan area. The farmee drilled a horizontal well into the Duvernay which was completed during the fourth quarter of 2014 and completed a 10 day production test in Mach 2015, after significant delays due to transportation restrictions in the area, production from this well was again started in late 2015. During the well's first two months of free flowing production, it produced an average of 250 bbl/d condensate and 270 Mcf/d of natural gas (net 100 boe/d). With the earning terms fulfilled, Perpetual retains a 35% working interest in 3,840 gross acres and 100% working interest in the remaining 2,400 acres.

Over the last two years, Perpetual has been accumulating a land position in a new exploration area in the Alberta deep basin through acquisitions and Crown land sales. To date, Perpetual has an interest in 35,200 gross acres (17,440 net) of undeveloped land in the Columbia area with a partner. One (0.5 net) well was drilled in 2013 which is currently on production at low rates and remains under evaluation. These lands are prospective in multiple horizons and provide a new potential growth area for the Corporation.

Mannville Conventional Heavy Oil

The Mannville heavy oil property is located east of Edmonton, Alberta and stratigraphically overlaps a portion of the Eastern Alberta South shallow gas area. The recognized pools comprise 1,119 net acres of developed land. Perpetual has an additional 10,240 net acres of petroleum and natural gas rights prospective for oil within the Mannville area. Perpetual has an average 94.1% working interest in 74 gross (69.7 net) producing oil wells. Perpetual operates this area which produced 1,560 bbl/d of heavy crude oil in 2015, representing 8% of the Company's 2015 average production.

Perpetual's focus in the Mannville area has been on the exploration and development of cretaceous-aged conventional heavy oil pools geographically synergistic with the Corporation's shallow gas assets. Through Perpetual's extensive database of 2D and 3D seismic and low exposure exploration drilling, seven Lloyd formation pools, five Sparky pools and one Basal Quartz pool have been discovered and delineated with development in progress. In 2015 Perpetual focused on waterflood expansion and invested capital to convert three wells to waterflood injection and construct the related pipelines and facilities. In light of low oil prices, all heavy oil drilling has been deferred until oil prices recover, with limited capital allocated toward advancing the Mannville waterflood in 2016.

Eastern Alberta Shallow Gas

Perpetual's ownership in its legacy shallow gas assets provides upside exposure and development opportunity should natural gas prices improve in the long-term. Capital expenditures on shallow gas properties in both the North area and South area have been limited over the past several years as the Company has been focused on its commodity diversification strategy.

North

The North area comprises Perpetual's legacy shallow gas assets, located in northeast Alberta, where access is generally winter-only. It includes 1,309,570 net acres (44% undeveloped) with an average 71.2% working interest in 573 producing natural gas wellbores and four producing oil wells, with 642 gross (459 net) producing natural gas zones. The majority of natural gas production from the area is Company operated and processed through Company owned facilities and associated gathering and processing infrastructure. This area represented approximately 27% of production from Perpetual's assets for the year, with production of 5,224 boe/d in 2015 including 31.3 MMcf/d of natural gas and 7 bbl/d of oil and NGLs. At December 31, 2015 a total of 20 Bcf of shut in gas over bitumen reserves were removed from the 2015 year-end evaluation.

South

The South area is generally comprised of conventional shallow gas assets, located east of Edmonton, Alberta and includes 603,842 net acres (17% undeveloped) with an average 81.0% working interest in 486 producing wellbores, with 556 gross (456.3 net) producing natural gas zones. The majority of operations and production from this area is Company operated. The South area represented approximately 16% of production from Perpetual's assets for the year, with production of 3,242 boe/d in 2015 comprised of 19.3 MMcf/d of natural gas.

Perpetual also has an interest in a Viking/Colorado shale shallow unconventional dry gas play in east central Alberta. With low natural gas prices over the last three years, the Company has allocated limited capital spending to the technical and economic delineation of this vast resource. Based on prior year's activities, and monitoring of competitor activity, an eight well pilot project targeting horizontal development of the Colorado and potentially the Viking formations has been designed for execution with the goal to confirm well orientation, fracture techniques and type curves assumptions to assess the expected economic returns for future recovery of this material natural gas resource. No undeveloped reserves are currently assigned to the Viking/Colorado formation.

Warwick Gas Storage

The Warwick Gas Storage facility is located east of Edmonton, Alberta and is comprised of a 45 Bcf depleted gas pool with an estimated 21 Bcf of working gas capacity at the end of 2015. Perpetual developed the Warwick Gas Storage facility in 2010 as a grass roots development project where a depleted gas pool was converted for commercial gas storage operations. In 2012, the Company sold 90% of its interest in the Warwick Gas Storage business, while retaining an option to buy back up to an additional 30% ownership interest at the same price as the initial sale plus working capital and other adjustments. After the sale, Perpetual began accounting for its interest in WGS LP as an equity investment. In 2013, Perpetual exercised its option and bought back an additional 20% interest bringing its total ownership in WGS LP to 30% as of April 2013. Perpetual operates the gas storage facility under a management service agreement.

There are 14 horizontal wells and one vertical well that are injector and/or producers in the Warwick Gas Storage reservoir. Additionally, included in the gas storage facility are one standing well, one vertical producing well and four observation wells. During 2013, WGS LP implemented delta pressuring which increased the reservoir pressure and increased working gas capacity.

Bitumen

Perpetual has positioned itself with 277,739 net acres (98.0% undeveloped) of oil sands leases geographically synergistic with seven of its shallow gas operating areas in northeast Alberta including Panny, Liege, Marten Hills, Ells, Wabasca and Hoole as well as a small project area on the Peace River Arch. The bitumen resource potential on these leases will likely be developed over the long-term using a variety of recovery techniques, ranging from near cold production technologies to in-situ thermal techniques such as SAGD technology.

In 2013 Perpetual received funding approval through the Alberta government's Innovative Energy Technology Program **("IETP")** for the Company's Low-Pressure Electro-Thermally Assisted Drive **("LEAD")** pilot project to develop bitumen in the Bluesky reservoir in the Panny area of northeast Alberta. Total capital and operating costs for the initial pilot project are estimated at $18.2 million. Approved funding through IETP is 30% of eligible costs to a maximum of $5.5 million. The first phase of LEAD, consisting of a single well cyclic heating pilot has full regulatory approval, and was initiated in 2015. Perpetual drilled two (2.0 net) observation wells, installed a downhole electrical coil heater and related instrumentation on an existing horizontal well and completed construction of a bitumen battery in 2015. First heat in the ground commenced in mid-October 2015 with positive preliminary results from the first heating phase assessed through detailed data monitoring in the near proximity wells. First production is expected in the first quarter of 2016.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

March 2, 2016

The reserves data set forth below is based upon the figures contained in the report of McDaniel Associates and Consultants Ltd. ("McDaniel") dated effective December 31, 2015, with a preparation date of February 9, 2016 (the "McDaniel Report") evaluating or reviewing substantially all of Perpetual's crude oil, NGL and natural gas reserves.

Disclosure of Reserves Data

McDaniel evaluated 97% of the total proved plus probable future net revenue discounted at 10%. McDaniel evaluated in the McDaniel Report 80% of the assigned total proved plus probable reserves and reviewed the internal evaluation completed by Perpetual on the remaining portion, which primarily included certain natural gas assets in eastern Alberta. McDaniel prepared their reserve report using their own technical assumptions and interpretations, methodologies and pricing and cost assumptions. Due to rounding, certain columns set forth below in this section may not add.

The McDaniel Report has been prepared in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook ("**COGE Handbook**") and the reserve definitions contained in NI 51-101 and the COGE Handbook. Additional information not required by NI 51-101 has been presented to provide continuity and additional information which Perpetual believes is important to readers of this Annual Information Form. McDaniel was engaged to provide evaluations of proved and proved and probable reserves and no attempt was made to evaluate possible reserves.

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

The Report on Reserves Data by McDaniel in Form 51-101F2 is attached as Appendix B to this Annual Information Form and the Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3 is attached as Appendix A to this Annual Information Form.

There are numerous uncertainties inherent in estimating quantities of crude oil, NGL and natural gas reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth in this Annual Information Form are estimates only. In general, estimates of economically recoverable oil, NGL and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as geological, geophysical, and engineering assessment of hydrocarbons in place on company lands, historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and natural 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 crude oil, NGL 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.

The information relating to the Corporation's crude oil, NGL and natural gas reserves contains forward-looking statements relating to anticipated production, future net revenues, forecast capital expenditures, future development plans and costs related thereto, forecast operating costs, anticipated production and abandonment and reclamation costs. See "**Forward-Looking Information and Statements**" and "**Risk Factors – Reserves Estimates**".

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. Actual reserves and value may be greater than or less than the estimates provided in this Statement of Reserves and Other Oil and Gas Information.

SUMMARY OF RESERVES
TOTAL RESERVES
as at December 31, 2015
FORECAST PRICES AND COSTS

Reserves Categories	Light and Medium Crude Oil Gross[1] (Mbbl)	Light and Medium Crude Oil Net[2] (Mbbl)	Heavy Oil Gross[1] (Mbbl)	Heavy Oil Net[2] (Mbbl)	Conventional Natural Gas Gross[1] (MMcf)	Conventional Natural Gas Net[2] (MMcf)	Natural Gas Liquids Gross[1] (Mbbl)	Natural Gas Liquids Net[2] (Mbbl)	Oil Equivalent Gross[1] (Mboe)	Oil Equivalent Net[2] (Mboe)
Proved Producing	60	53	1,227	1,124	94,819	77,314	550	247	17,641	14,310
Proved Non Producing	-	-	53	47	9,375	8,562	5	4	1,621	1,477
Proved Undeveloped	10	10	355	299	138,410	107,594	1,688	879	25,122	19,121
Total Proved	70	63	1,636	1,471	242,604	193,469	2,243	1,129	44,383	34,908
Total Probable	33	26	1,081	936	179,188	163,297	2,428	1,897	33,407	30,076
Proved and Probable	103	89	2,716	2,407	421,792	356,766	4,671	3,026	77,790	64,984

1) "**Gross**" refers to working interest reserves before royalty deductions.
2) "**Net**" refers to company interest volumes after royalties.

NET PRESENT VALUE OF FUTURE NET REVENUE
BEFORE TAX
as at December 31, 2015
FORECAST PRICES AND COSTS ($ millions)

Reserves Categories	Before Income Taxes Discounted at (%) 0%	5%	10%	15%	20%	Unit Value Before Income Tax Discounted At 10%/Year ($/boe)
Proved Producing	$ 49	$ 58	$ 60	$ 60	$ 58	$4.19
Proved Non Producing	7	6	5	5	4	$3.69
Proved Undeveloped	158	101	63	37	20	$3.30
Total Proved	214	165	128	102	82	$3.68
Total Probable	526	321	210	147	108	$6.99
Proved and Probable	$739	$486	$339	$249	$190	$5.21

NET PRESENT VALUE OF FUTURE NET REVENUE
AFTER TAX
as at December 31, 2015
FORECAST PRICES AND COSTS ($ millions)

Reserves Categories	After Income Taxes Discounted at (%)[(1)(2)] 0%	5%	10%	15%	20%	Unit Value After Income Tax Discounted At 10%/Year ($/boe)
Proved Producing	$ 49	$ 58	$ 60	$ 60	$ 58	$4.19
Proved Non Producing	7	6	5	5	4	$3.69
Proved Undeveloped	158	101	63	37	20	$3.30
Total Proved	214	165	128	102	82	$3.68
Total Probable	480	300	200	142	106	$6.66
Proved and Probable	$693	$465	$329	$243	$188	$5.06

1) The after tax net present value of the Corporation's oil and gas properties reflects the tax burden on the properties on a stand-alone basis and utilizes the Corporation's tax pools.
2) The after tax net present value of the Corporation's oil and gas does not consider the corporate tax situation or tax planning. It does not provide an estimate of the value at the level of the Corporation, which may be significantly different. The Corporation's financial statements and the management's discussion and analysis should be consulted for information at the level of the Corporation.

FUTURE NET REVENUE
TOTAL RESERVES (UNDISCOUNTED)
as at December 31, 2015
FORECAST PRICES AND COSTS ($ millions)

Reserves Categories	Revenue	Royalties	Gas over bitumen Royalty Adjustments	Operating Costs	Development Costs	Abandonment and Reclamation Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes (1)(2)
Proved Reserves	1,200	(271)	5	(418)	(249)	(54)	214	0	214
Proved and Probable Reserves	2,318	(385)	5	(669)	(459)	(72)	739	(46)	693

1) The after tax net present value of the Corporation's oil and gas properties reflects the tax burden on the properties on a stand-alone basis and utilizes the Corporation's tax pools.

2) The after tax net present value of the Corporation's oil and gas does not consider the corporate tax situation, or tax planning. It does not provide an estimate of the value at the level of the Corporation, which may be significantly different. The Corporation's financial statements and the management's discussion and analysis should be consulted for information at the level of the Corporation.

FUTURE NET REVENUE
TOTAL RESERVES
by production group
as at December 31, 2015

Reserve Categories	Production Group	Future Net Revenue Before Income Taxes (discounted at 10%/year) ($ millions)	Unit Value ($/Mcfe) ($/boe)
Proved Reserves	Conventional Natural Gas (including by-products but excluding solution gas and by-products from oil wells)	102	0.53/Mcfe
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by products)	2	52.84/boe
Proved Reserves	Heavy Oil (including solution gas and other by products)	25	16.76/boe
Proved Reserves – Total		128	3.68/boe
Proved and Probable Reserves	Conventional Natural Gas (including by-products but excluding solution gas and by-products from oil wells)	291	0.82/Mcfe
Proved and Probably Reserves	Light and Medium Crude Oil (including solution gas and other by products)	2	52.57/boe
Proved and Probable Reserves	Heavy Oil (including solution gas and other by products)	45	18.86/boe
Proved and Probable Reserves – Total		339	5.21/boe

Forecast Prices and Costs

Pricing Assumptions (Forecast Prices and Costs)

SUMMARY OF PRICING ASSUMPTIONS
AS AT DECEMBER 31, 2015
FORECAST PRICES AND COSTS

Year	West Texas Intermediate Crude Oil ($US/bbl)	Edmonton Light Crude Oil ($Cdn/bbl)	Alberta Heavy Crude Oil ($Cdn/bbl)	Natural Gas at AECO ($Cdn/MMbtu)	Foreign Exchange ($US/$Cdn)[1]
2016	45.00	56.60	40.50	2.70	0.730
2017	53.60	66.40	47.50	3.20	0.750
2018	62.40	72.80	52.10	3.55	0.800
2019	69.00	80.90	57.80	3.85	0.800
2020	73.10	83.20	59.50	3.95	0.825
2021	77.30	88.20	63.10	4.20	0.825
2022	81.60	93.30	66.70	4.45	0.825
2023	86.20	98.70	70.60	4.70	0.825
2024	87.90	100.70	72.00	4.80	0.825
2025	89.60	102.60	73.40	4.90	0.825
2026	91.40	104.70	74.90	5.00	0.825
2027	93.30	106.90	76.40	5.10	0.825
2028	95.10	108.90	77.90	5.20	0.825
2029	97.00	111.10	79.40	5.30	0.825
2030	99.00	113.40	81.10	5.40	0.825

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

For comparison purposes, the Corporation realized a weighted average gas price for the year ended December 31, 2015 of $3.01/Mcf, including $0.14/Mcf of realized hedging gains for natural gas. The weighted average AECO daily gas index price for the same 12 month period was $2.55/GJ. Perpetual's realized oil price averaged $52.48/bbl including $11.21/bbl of realized hedging gains relative to the benchmarks. The Corporation realized an average NGL price of $33.72/bbl in 2015. The West Texas Intermediate benchmark price for 2015 was $US48.79/bbl.

RECONCILIATION OF GROSS RESERVES
TOTAL RESERVES[(1)]
FORECAST PRICES AND COSTS

	Gross Proved						Gross Probable						Gross Proved + Probable					
Factors	Light & Medium Oil Mbbl	Heavy Oil	Oil Mbbl	Conventional Natural Gas MMcf	Liquids Mbbl	Oil Equivalent Mboe	Light & Medium Oil Mbbl	Heavy Oil Mbbl	Oil Mbbl	Conventional Natural Gas MMcf	Liquids Mbbl	Oil Equivalent Mboe	Light & Medium Oil Mbbl	Heavy Oil Mbbl	Oil Mbbl	Conventional Natural Gas MMcf	Liquids Mbbl	Oil Equivalent Mboe
December 31, 2014[(2)]	92	2,165	2,257	308,369	2,836	56,488	67	1,471	1,539	268,316	2,444	48,702	159	3,637	3,795	576,685	5,280	105,190
Extensions & Improved Recoveries	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Technical Revisions	(8)	103	96	58,837	61	9,962	(34)	(313)	(347)	(25,528)	174	(4,428)	(42)	(210)	(252)	33,309	234	5,534
Acquisitions	-	-	-	-	-	-	-	-	-	8,435	173	1,579	-	-	-	8,435	173	1,579
Dispositions	-	-	-	(71,981)	(383)	(12,380)	-	-	-	(65,694)	(346)	(11,295)	-	-	-	(137,676)	(729)	(23,675)
Production	(13)	(571)	(584)	(37,833)	(259)	(7,148)	-	-	-	-	-	-	(13)	(571)	(584)	(37,833)	(259)	(7,148)
Economic Factors	(1)	(62)	(63)	(14,787)	(12)	(2,540)	-	(77)	(77)	(6,341)	(17)	(1,151)	(1)	(139)	(140)	(21,128)	(30)	(3,691)
December 31, 2015	70	1,636	1,706	242,604	2,243	44,383	33	1,081	1,114	179,188	2,428	33,407	103	2,716	2,820	421,792	4,671	77,790

1) Includes reserves from zones not affected by GOB issue and reserves shut-in pursuant to Alberta Energy and Utilities Board ("**AEUB**") decisions and orders. See "**Risk Factors – Gas Over Bitumen Matters**".

2) The opening balance on December 31, 2014 includes all of Perpetual's reserves, including reserves that were shut-in or identified for shut-in as a result of the GOB issue. As at December 31, 2014 all reserves shut-in as a result of the GOB issue were categorized as probable reserves. At December 31, 2015 all reserves shut-in as a result of the GOB issue were removed from the 2015 year-end evaluation.

Additional Information Relating to Reserves Data

Proved Undeveloped Reserves

The following table discloses, for each product type, the volumes of proved undeveloped reserves that were first attributed in each of the most recent three financial years and, in the aggregate, before that time.

	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Conventional Natural Gas (MMcf)		NGLs (Mbbl)	
Year	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**
Prior thereto	-	-	463	686	20,597	49,844	763	1,866
2013	-	-	347	537	23,034	54,217	395	1,071
2014	14	14	287	387	95,501	178,500	1,258	2,271
2015	-	10	-	355	-	138,410	-	1,688

The Corporation has a large inventory of proved undeveloped reserves, the majority of which are associated with its liquids-rich Wilrich gas program in West Central Alberta. These reserves are booked as per the COGE Handbook to company land immediately adjacent to existing producing wells. McDaniel has forecast the development of these proved undeveloped reserves over the next five years as part of larger drilling programs subject to commodity prices. The Corporation uses many factors to determine its annual budgets and all projects, whether booked as undeveloped reserves or unbooked and residing in Perpetual's prospect inventory, compete based on these factors with funds balanced to maximize returns from capital investments as well as drive strategic initiatives.

Probable Undeveloped Reserves

The following table discloses, for each product type, the volumes of probable undeveloped reserves that were first attributed in each of the most recent three financial years and, in the aggregate, before that time.

	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Conventional Natural Gas (MMcf)		NGLs (Mbbl)	
Year	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**
Prior thereto	-	-	964	1,116	44,465	118,236	1,429	2,519
2013	-	-	245	637	25,595	61,582	461	1,374
2014	4	4	267	378	142,304	178,829	1,750	2,166
2015	-	4	-	358	-	130,588	-	2,251

The Corporation has a large inventory of probable undeveloped reserves, the majority of which are associated with its liquids-rich Wilrich gas program in West Central Alberta. These reserves are booked as per the COGE handbook to company lands. McDaniel has forecast the development of these probable undeveloped reserves over the next nine years as part of larger drilling programs subject to commodity prices. As stated above, the Corporation uses many factors to determine its annual budgets and all projects, whether booked as probable undeveloped reserves or unbooked and residing in Perpetual's prospect inventory, compete based on these factors with funds balanced to maximize returns from capital investment as well as drive strategic initiatives.

Significant Factors or Uncertainties

In addition to the abandonment cost estimates provided by McDaniel inclusive in their reserve assessment, Perpetual compiles annually a detailed internal estimate of the Corporation's total future asset retirement obligation based on net ownership interest in all wells, facilities and pipelines, including estimated costs to abandon the wells, facilities and pipelines and reclaim the sites, and the estimated timing of the costs to be incurred in future periods. Pursuant to this evaluation, the estimated cost of future asset retirement obligations related to Perpetual's proved and probable reserves and other liabilities, net of the estimated salvage value of facilities and equipment and discounted at 8%, is $41.0 million as at December 31, 2015.

The McDaniel Report includes an undiscounted amount of $71.5 million, including $51.9 million related to developed reserves and $19.6 million for undeveloped reserves, with respect to expected future well abandonment costs related specifically to proved and probable reserves and such amount is included in the values captioned "**Total Proved and Probable Reserves**" in the NPV of Reserves tables (see "**FUTURE NET REVENUE**").

The following table presents the estimated future asset retirement obligations and estimated net salvage values at various discount rates:

Abandonment and Reclamation Costs

($ millions, net to Perpetual)	**Undiscounted**	**Discounted at 5%**	**8%**	**10%**
Total estimated future abandonment and reclamation costs[(1)]	179.2	108.0	71.0	54.0
Salvage value	(90.3)	(45.0)	(30.0)	(24.0)
Abandonment and reclamation costs, net of salvage	88.9	63.0	41.0	30.0
Well abandonment costs for developed reserves included in McDaniel Report	(51.9)	(26.5)	(18.2)	(14.3)
Estimate of additional future abandonment and reclamation costs, net of salvage[(2)]	37.0	36.5	22.8	15.7

1) Estimated internally in accordance with NI 51-101.
2) Future abandonment and reclamation costs not included in the McDaniel Report, net of salvage value.

The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserves estimates contained herein are based on current production forecasts, prices and economic conditions.

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

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

Future Development Costs

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

FUTURE DEVELOPMENT COSTS
FORECAST PRICES AND COSTS ($ millions)

Year	**Proved Reserves**		**Proved and Probable Reserves**	
Discount Rate	0%	10%	0%	10%
2016	36.4	34.8	36.5	34.9
2017	55.0	47.9	56.4	49.3
2018	63.5	49.9	66.6	52.4
2019	48.0	34.4	52.3	37.6
2020	46.1	29.9	46.5	30.2
Thereafter	0.1	0.1	200.3	105.0
Total	249.1	197.0	458.7	309.3

The Corporation expects to fund future development costs from internally-generated funds flow, debt or equity financing through the capital markets and the Corporation does not expect such costs to make development of any properties uneconomic.

The McDaniel Report estimates that future capital costs of $458.7 million will be required over the life of the Corporation's proved and probable reserves for the drilling, completion, equipping and tie-in of 11 conventional horizontal Mannville heavy oil wells and 87 horizontal gas wells targeting the Wilrich. Future capital costs also include recompletion of 2 oil wells and 205 gas wells included in Perpetual's proved and probable reserves. As the Corporation continues to invest capital to bring on additional production, development of the undeveloped reserves will be undertaken over the next several years.

OTHER OIL AND GAS INFORMATION

Oil and Gas Properties

A description of Perpetual's important oil and natural gas properties as at December 31, 2015 is included as part of "**Description of the Business – Operations**".

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, 2015.

	Producing Gas Wells		Producing Oil Wells		Non Producing Gas Wells(3)(4)		Non Producing Oil Wells(3)(4)	
Property	**Gross(1)**	**Net(2)**	**Gross(1)**	**Net(2)**	**Gross(1)**	**Net(2)**	**Gross(1)**	**Net(2)**
Eastern Alberta Shallow Gas								
North	573	406.6	4	4.0	1,022	838.9	5	3.8
South	486	393.6	4	0.6	575	493.0	14	8.2
	1,059	800.2	8	4.6	1,597	1,331.9	19	12.1
Mannville Heavy Oil	0	0	74	69.7	0	0	17	16.0
West Central Deep Basin								
East Edson	53	51.9	4	3.1	5	5.0	0	0.0
West Central Other	8	4.5	2	1.5	36	26.6	2	1.1
Western District Subtotal	61	56.4	6	4.6	41	31.6	2	1.1
Total	1,120	856.5	88	78.9	1,638	1,363.5	38	29.2

1) "**Gross**" refers to the number of wells, respectively, in which a working interest is held by the Corporation. In addition the Corporation held royalty interests in 267 producing wells at December 31, 2015.
2) "**Net**" refers to the aggregate of the numbers obtained by multiplying each gross well by the percentage working interest therein.
3) "**Non-Producing**" refers to wells which are not currently producing either due to lack of facilities, markets or regulatory approval. This includes 79 gross (57.0 net) wells shut-in as a result of GOB regulatory rulings.
4) Allowance for the abandonment costs associated with the wellbores was made in the McDaniel Report. There are 53 gross (39.0 net) wells that are classified as service wells not included in the gross/net well count.

Acreage Information

The following table sets out Perpetual's developed and undeveloped land holdings as at December 31, 2015. Except as previously identified in the East Edson JV, the Corporation does not have any material work commitments on any of Perpetual's properties.

	Developed Acres		Undeveloped Acres(3)	
Property	**Gross(1)**	**Net(2)**	**Gross(1)**	**Net(2)**
West Central Deep Basin				
Edson	26,720	20,371	44,640	33,034
West Edson	480	-	160	-
West Central Other	41,759	13,413	69,803	38,285
	68,959	33,784	114,603	71,319
Eastern Alberta Shallow Gas				
North	1,064,899	731,145	810,829	578,425
South	765,861	504,237	125,508	99,605
	1,830,760	1,235,682	936,337	678,030
Mannville Heavy Oil(4)	1,119	1,119	-	-
Bitumen	5,760	5,440	276,523	272,299
Total	1,906,598	1,276,025	1,327,463	1,021,648

1) "**Gross**" means the total number of acres in which the Corporation has an interest in respect of Perpetual's current assets.
2) "**Net**" means the aggregate of the numbers obtained by multiplying each gross acre by the actual percentage interest therein.
3) "**Undeveloped Acres**" refers to land where there are not any existing wells within the rights associated with those lands.
4) Undeveloped acreage in the South includes lands prospective for Mannville Heavy Oil.

During 2016, 36,592 net acres are set to expire. A total of 100,620 net acres expired in 2015. The Corporation intends to assess all expiring lands and, where appropriate, seek continuation through mapping, development activity or, in the case of higher risk areas, farm outs, where third parties provide exploration funding in exchange for an earned working interest.

Production Estimates

The following table sets out the volume of Perpetual's future production estimated by McDaniel on a proved and probable basis for the year ended December 31, 2016, which is reflected in the estimate of future net revenue disclosed in the tables.

2016 McDaniel Forecast Production[1]	Light and Medium Crude Oil (bbl/d)	Heavy Oil (bbl/d)	Conventional Natural Gas (MMcf/d)	Natural Gas Liquids (bbl/d)
Proved	55	987	89.4	729
Probable	8	101	6.6	47
Total Proved and Probable	63	1,088	96.0	776

1) Working interest before royalty deductions plus royalty interest share.

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:

	2015 Quarter Ended			
Production	**Dec 31**	**Sept 30**	**June 30**	**Mar 31**
Average Daily Conventional Natural Gas Production (MMcf/d)	105.1	105.5	86.0	120.4
Average Daily Light and Medium Oil Production (bbl/d)	1,278	1,426	1,766	2,045
Average Daily NGL Production	866	741	522	713
Total (boe/d)	19,661	19,758	16,621	22,819
Average Realized Price ($/boe)	18.48	18.27	24.20	21.33
Royalties ($/boe)	(1.81)	(2.57)	(1.96)	(2.66)
Operating Costs ($/boe)	(6.92)	(8.29)	(10.44)	(10.59)
Transportation Costs ($/boe)	(1.61)	(1.55)	(1.64)	(1.87)
Operating Netback ($/boe)	8.14	5.86	10.16	6.21

The following table indicates Perpetual's average daily production from each of the Corporation's core areas for the year ended December 31, 2015:

Property	Average Annual Daily Production (boe/d)
West Central Deep Basin	
Edson	8,049
West Edson	1,265
	9,314
Eastern Alberta Shallow Gas	
North	5,224
South	3,242
	8,466
Mannville Heavy Oil	1,926
Total	19,706

Capital Expenditures

The following table summarizes capital expenditures related to Perpetual's activities for the year ended December 31, 2015:

($ thousands)	2015	2014
Exploration and development	75,433	115,813
Geological and geophysical costs[1]	1,526	644
Acquisitions	241	998
Dispositions	(23,954)	(71,349)
Other	910	614
Total	54,156	46,720

1) Geological and geophysical expenditures and dry hole costs are expensed directly in the Corporation's statement of income.

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, 2015:

Exploratory Wells	**Gross**	**Net**
Light and Medium Crude Oil	-	-
Heavy Oil	-	-
Conventional Natural Gas	-	-
Evaluation (Oil Sands)	-	-
Total	-	-
Success Rate (%)	-	-
Development Wells		
Light and Medium Crude Oil	-	-
Heavy Oil	-	-
Conventional Natural Gas	6.0	4.5
Evaluation and Service Wells	2.0	2.0
Total	8.0	6.5
Success Rate (%)	100%	100%
Total Exploration & Development	**8.0**	**6.5**

COMMODITY PRICE RISK MANAGEMENT

Perpetual's commodity price risk management strategy is focused on using both physical and financial derivatives to provide increased certainty in funds flow by mitigating the effect of commodity price volatility, to lock in economics on capital programs and acquisitions, and to take advantage of perceived anomalies in commodity markets. Perpetual also utilizes foreign exchange swaps and physical or financial swaps related to the differential between natural gas prices at the AECO and New York Mercantile Exchange ("**NYMEX**") trading hubs and oil basis differentials between WTI and WCS in order to mitigate the effects of fluctuations in foreign exchange rates and basis differentials on the Corporation's realized commodity prices.

Natural Gas

Perpetual has in place natural gas financial contracts on an estimated 70 percent of forecasted natural gas production for 2016. The following tables provide a summary of derivative natural gas contracts outstanding at March 2, 2016. Subsequent to December 31, 2015, Perpetual realized gains of $1.6 million on crystallizations of 60,000 mmbtu per day of 2017 NYMEX to AECO basis differential contracts.

The following table provides a summary of physical natural gas sales arrangements at AECO. Settlements on these physical sales contracts are recognized in oil and natural gas revenue.

Term	Volumes sold (bought) at AECO (GJ/d)	Average price ($CAD/GJ)[1]	Market prices ($CAD/GJ)[2]	Type of contract
January 2016	(5,000)	2.15	2.20	Physical
January 2016	15,000	2.19	2.20	Physical
February 2016	20,000	2.19	2.23	Physical
March 2016	20,000	2.02	1.58	Physical

1) Average price calculated using weighted average price for net open contracts.
2) Market prices are based on settled AECO Monthly Index prices.

The Corporation had entered into financial natural gas sales arrangements at AECO as follows:

Term	Volumes sold (bought) at AECO (GJ/d)	Average price ($CAD/GJ)[1]	Market prices ($CAD/GJ)[2]	Type of contract
January 2016	(10,000)	2.15	2.20	Financial
January 2016	95,249	2.03	2.20	Financial
February 2016	47,500	2.22	2.23	Financial
March 2016	(47,500)	2.13	1.58	Financial
March 2016	94,500	2.12	1.58	Financial
April 2016 – December 2016	32,500	2.32	1.59	Financial

1) Average price calculated using weighted average price for net open contracts.
2) Market prices for January to March are based on settled AECO Monthly Index prices. Market prices for subsequent months are based on forward AECO prices as of market close on March 2, 2016.

The Corporation had entered into financial natural gas sales arrangements at NYMEX as follows:

Term	Volumes sold (bought) at NYMEX (MMBTU/d)	Average price ($USD/MMBTU)(1)	Market prices ($USD/MMBTU)(2)	Type of contract
February 2016	(5,000)	2.26	2.19	Financial
February 2016	35,000	2.25	2.19	Financial
March 2016	30,000	2.15	1.71	Financial
April 2016 – December 2016	35,000	2.35	2.04	Financial
January 2017 – December 2017	10,000	2.77	2.63	Financial

1) Average price calculated using weighted average price for net open contracts.
2) Market prices for January to March are based on settled NYMEX prices. Market prices for subsequent months are based on forward NYMEX prices as of market close on March 2, 2016.

The following table provides a summary of basis differential contracts between AECO and NYMEX trading:

Term	Volumes (MMBTU/d)	AECO-NYMEX differential ($USD/MMBTU)	Market prices ($USD/MMBTU)(1)	Type of contract
February 2016	30,000	(0.74)	(0.51)	Financial
March 2016	30,000	(0.74)	(0.47)	Financial
April 2016 – December 2016	35,000	(0.73)	(0.79)	Financial
January 2017 – December 2017	50,000	(0.70)	(0.70)	Financial

1) Market prices are based on forward AECO-NYMEX differential prices as of market close on March 2, 2016.

Crude Oil

The Corporation had entered into financial oil sales arrangements in $USD as follows:

Term	Volumes (bbl/d)	Floor price ($USD/bbl)	Ceiling price ($USD/bbl)	Market prices ($USD/bbl)(1)	Type of contract
January 2016 – December 2016	500	45.00	52.10	37.50	Financial
January 2016 – December 2016	500	42.00	50.70	37.50	Financial
January 2017 – December 2017	250	44.50	49.55	42.70	Financial

1) Market prices are based on forward WTI oil prices as of market close on March 2, 2016.

The following table provides a summary of basis differential contracts between WTI and WCS trading:

Term	Volumes (bbl/d)	WTI-WCS differential ($USD/bbl)(1)	Market prices ($USD/bbl)(2)	Type of contract
January 2016 – December 2016	500	(13.68)	(13.00)	Financial

1) Average price calculated using weighted average price for net open contracts; contracts settle at WTI index less a fixed basis amount.
2) Market prices are based on forward WTI-WCS differential prices as of market close on March 2, 2016.

Foreign Exchange

The Corporation has the following U.S. dollar forward sales arrangement:

Term	Notional $USD/month	Exchange rate ceiling ($CAD/$USD)	Market prices ($CAD/$USD)(1)	Type of contract
January 2016 – March 2018	3,500,000	1.25	1.34	Financial

1) Market prices are based on forward $CAD/$USD exchange rates as of market close on March 2, 2016.

If the average monthly exchange rate is above than the strike rate the Corporation pays $USD3,500,000 multiplied by the difference between the average monthly exchange rate and the strike rate. If the average monthly exchange rate is below than the strike rate the Corporation receives $USD3,500,000 multiplied by the difference between the average monthly exchange rate and the strike rate.

The Corporation has the following U.S. dollar forward sales arrangement:

Term	Notional $USD/month	Boosted notional [(1)] $USD / month	Strike rate ($CAD / $USD)	Market prices ($CAD/$USD)[(2)]	Type of contract
March 2016 – February 2018	1,000,000	3,000,000	1.25	1.34	Financial

1) If the spot rate at expiry of each contract month is below the strike rate Perpetual pays $USD3,000,000 multiplied by the difference between the spot rate at expiry and the strike rate.
2) Market prices are based on forward $CAD/$USD exchange rates as of market close on March 2, 2016.

If the spot rate at expiry of each contract month is above the strike rate the Corporation receives $USD1,000,000 multiplied by the difference between the spot rate at expiry and the strike rate. Cumulative receipts on this contract are limited to a total of $0.8 million.

DESCRIPTION OF CAPITAL STRUCTURE

The authorized share capital of Perpetual consists of an unlimited number of Common Shares and an unlimited number of preferred shares. As at the date hereof, there are 1,047,655,726 Common Share and no preferred shares issued and outstanding. Each Common Share entitles the holder thereof to receive notice of and to attend all meetings of shareholders of Perpetual and to one vote per share at such meetings (other than meetings of another class of shares of Perpetual). The Common Shares entitle the holders thereof to receive dividends as and when declared by the board of directors of Perpetual on the Common Shares as a class, subject to prior satisfaction of all preferential rights to dividends attached to all shares of other classes of shares of Perpetual ranking in priority to the Common Shares in respect of dividends. Holders of Common Shares will be entitled in the event of any liquidation, dissolution or winding-up of Perpetual, whether voluntary or involuntary, or any other distribution of the assets of Perpetual among its shareholders for the purposes of winding-up its affairs, and subject to prior satisfaction of all preferential rights to return of capital on dissolution attached to all shares of other classes of shares of Perpetual ranking in priority to the Common Shares in respect of return of capital on dissolution, to share rateably, together with the holders of shares of any other class of shares of Perpetual ranking equally with the Common Shares in respect of return of capital, in such assets of Perpetual as are available for distribution.

The preferred shares may be issuable in one or more series, each series to consist of such number of shares as may, before the issuance thereof, be determined by the board of directors of Perpetual. The board of directors may from time to time fix, before issuance, the designation, rights, privileges, restrictions and conditions attaching to each series of preferred shares including, without limiting the generality of the foregoing, the amount, if any, specified as being payable preferentially to such series on a distribution, the extent, if any, of further participation on a distribution, voting rights, if any, and dividend rights (including whether such dividends be preferential, or cumulative or non-cumulative), if any.

The holders of each series of preferred shares are entitled to receive any dividends declared by the board of directors of Perpetual in priority to the Common Shares and to be paid rateably with holders of each other series of preferred shares, and are entitled to participate in any distribution of the assets of Perpetual upon the liquidation, dissolution, bankruptcy or winding-up of Perpetual or other distribution of its assets among its shareholders for the purpose of winding-up its affairs in priority to the holders of the Common Shares and to share rateably in the distribution with holders of each other series of preferred shares.

Constraints

There are currently no constraints imposed on the ownership of securities of the Corporation to ensure that Perpetual has a required level of Canadian ownership.

Ratings

The following information relating to Perpetual's credit ratings is provided as it relates to the Company's financing costs and liquidity. Credit ratings affect Perpetual's ability to obtain short-term and long-term financing and the cost of such financing. A negative change in ratings outlook or any downgrade in current credit ratings by the ratings agencies could adversely affect the cost of borrowing and/or access to sources of liquidity and capital. Perpetual believes that its credit ratings will allow the Company to continue to have access to the capital markets, as and when needed, at a reasonable cost of funds.

Other than as set forth below, Perpetual has not asked for and received a stability rating, or to the knowledge of Perpetual, has received any other kind of rating, including, a provisional rating, from one or more approved rating organizations for securities of Perpetual that are outstanding and which continue in effect.

The Company's two series of outstanding 8.75% Senior Notes have both currently been assigned ratings of CCC+ by Standard and Poor's Rating Services, a division of McGraw-Hill Companies (Canada) Corporation ("**S&P**") and Caa1 by Moody's Investors Service, Inc. ("**Moody's**").

S&P and Moody's provide credit ratings of debt securities for commercial entities. A credit rating generally provides an indication of the risk that the borrower will not fulfill its full obligations in a timely manner with respect to both interest and principal commitments.

S&P's credit ratings are on a long-term debt rating scale that ranges from AAA to D, which represents the range from highest to lowest quality of such securities rated. S&P has assigned Perpetual a corporate credit rating of B-, stable outlook and a credit rating of CCC+ on the 8.75%

Senior Notes. An obligation rated "CCC" is currently vulnerable and dependant on favourable business, financial and economic conditions to meet financial commitments. Adverse business, financial, or economic conditions will likely impair the obligor's capacity or willingness to meet its financial commitment on the obligation. The ratings from AA to CCC may be modified by the addition of a plus (+) or a minus (-) sign to show relative standing within the major rating categories. In addition, S&P may add a rating outlook of "positive", "negative" or "stable" which assesses the potential direction of a long-term credit rating over the intermediate term (typically six months to two years).

Moody's credit ratings are on a long-term debt rating scale that ranges from AAA to C, which represents the range from highest to lowest quality of such securities rated. Moody's has assigned Perpetual a corporate family rating of Caa1, negative outlook, and a credit rating of Caa1, negative outlook on the Notes. According to the Moody's rating system, securities rated "Caa" are judged to be of poor standing and are subject to very high credit risk. Moody's appends numerical modifiers 1, 2 and 3 to each generic rating classification from AA through C. The modifier 1 indicates that the security ranks in the higher end of its generic rating category, the modifier 2 indicates a mid-range ranking and the modifier 3 indicates a ranking in the lower end of its generic rating category. In addition, Moody's may add a rating outlook of "positive", "negative" or "stable", which assess the likely direction of an issuer's rating over the medium term.

Credit ratings are intended to provide investors with an independent measure of credit quality of an issue of securities. Credit ratings are not recommendations to purchase, hold or sell securities and do not address the market price or suitability of a specific security for a particular investor. There is no assurance that any rating will remain in effect for any given period of time or that any rating will not be revised or withdrawn entirely by a rating agency in the future if, in its judgment, circumstances so warrant. A rating can be revised, suspended or withdrawn at any time by the rating agency. Potential investors should consult the rating agency should they require more information with respect to the interpretation and implications of the foregoing ratings. A revision or withdrawal of a credit rating could have a material adverse effect on the pricing and liquidity of the Notes in the secondary market.

MARKET FOR SECURITIES

Trading Price and Volume

The outstanding Common Shares are listed and posted for trading on the TMX under the trading symbols "PMT". The following tables set forth the closing price range and trading volume of the Common Shares as reported by the TMX for the periods indicated:

Common Shares

	Price Range		
	High ($)	**Low ($)**	**Volume**
2015			
January	1.11	0.87	1,179,495
February	1.28	0.97	1,449,457
March	1.25	0.96	2,141,878
April	1.22	0.95	3,613,011
May	1.13	0.93	1,538,032
June	1.00	0.88	1,766,961
July	0.98	0.80	1,402,806
August	0.87	0.50	1,360,731
September	0.80	0.63	1,116,300
October	0.80	0.64	957,792
November	0.69	0.19	4,532,404
December	0.24	0.045	23,779,661

Prior Sales

Other than Share Options, Restricted Rights, and Performance Rights to acquire Common Shares and the two series of 8.75% Senior Notes, there is no class of securities of Perpetual that is outstanding and not listed or quoted on a marketplace.

Set forth below are the grant dates, number granted and exercise prices at which Share Options, Restricted and Performance Rights were issued during the most recently completed financial year by Perpetual.

Date of Grant	Type of Award	Number of Awards Granted	Exercise Price
January 13, 2015	Restricted Rights	18,000	0.01
February 2, 2015	Restricted Rights	7,000	0.01
March 25, 2015	Restricted Rights	6,000	0.01
April 20, 2015	Restricted Rights	1,425,500	0.01
May 13, 2015	Restricted Rights	8,500	0.01

Date of Grant	Type of Award	Number of Awards Granted	Exercise Price
May 22, 2015	Restricted Rights	896,000	0.01
June 17, 2015	Restricted Rights	20,000	0.01
July 14, 2015	Restricted Rights	5,000	0.01
August 19, 2015	Share Options	2,150,000	0.69
August 19, 2015	Restricted Rights	27,500	0.01
August 20, 2015	Restricted Rights	23,500	0.01
August 24, 2015	Restricted Rights	8,500	0.01
August 26, 2015	Restricted Rights	16,500	0.01
August 31, 2015	Restricted Rights	10,000	0.01
September 2, 2015	Restricted Rights	32,000	0.01
September 4, 2015	Restricted Rights	70,500	0.01
September 9, 2015	Restricted Rights	16,500	0.01
October 1, 2015	Restricted Rights	45,500	0.01
October 7, 2015	Restricted Rights	42,500	0.01
November 12, 2015	Restricted Rights	47,500	0.01

DIVIDENDS

On October 19, 2011, the Corporation announced that future dividend payments would be suspended until further notice. Reinstatement of a dividend in the future will be evaluated at such time as Perpetual's balance sheet has regained strength and commodity prices and costs support a sustainable model where excess free funds flow, over and above capital investments, is once again being generated for distribution to Shareholders. Reinstatement of a dividend will be subject to review by the board of directors of the Corporation taking into account the prevailing circumstances at the relevant time. See "**Risk Factors**".

The credit facilities and the terms of the Notes contain provisions which restrict the ability of the Corporation to pay dividends to Shareholders in the event of the occurrence of certain events of default, and Section 43 of the ABCA also imposes certain restrictions on the ability of a corporation to pay dividends.

ESCROWED SECURITIES AND SECURITIES SUBJECT TO CONTRACTUAL RESTRICTION ON TRANSFER

To the knowledge of the Corporation, none of Perpetual's securities are held in escrow or subject to a contractual restriction on transfer.

DIRECTORS AND OFFICERS

Name, Occupation and Security Holding. The names, province or state, and country of residence, positions and offices held with the Corporation, and principal occupation of the directors and executive officers of the Corporation are set out below and, in the case of directors, the period each has served as a director of the Corporation. Karen A. Genoway, a current director, is retiring from the Board and will not be standing for re-election at the annual and special meeting scheduled to be held on March 24, 2016.

Name and Province and Country of Residence	Position held with the Corporation and Period Served as a Director	Principal Occupations During the Past Five Years
Clayton H. Riddell(5) Alberta, Canada	Chairman of the Board and Director since June 28, 2002	Mr. Riddell is the Executive Chairman of Paramount Resources Ltd. and has been a director of Paramount since 1978. Until May 2015 he was also the CEO and up until June 2002 he was also the President. He is the Chairman of the Board of Trilogy Energy Corp. and a director of Tourmaline Oil Corp., both of which are public oil and gas exploration and production companies. Mr. Riddell graduated from the University of Manitoba with a Bachelor of Science (Honours) degree in Geology and is currently a member of the Association of Professional Engineers and Geoscientists of Alberta, the Canadian Society of Petroleum Geologists, and the American Association of Petroleum Geologists. He received the J.C. Sproule Memorial Plaque from the Canadian

Name and Province and Country of Residence	Position held with the Corporation and Period Served as a Director	Principal Occupations During the Past Five Years
		Institute of Mining (1994), the Stanley Slipper Gold Medal from the Canadian Society of Petroleum Geologists (1999), an Honorary Doctor of Science degree from the University of Manitoba (2004), an Honorary Doctor of Laws degree from Carleton University (2014) and an Outstanding Explorer award from the American Association of Petroleum Geologists (2004). In 2006, Mr. Riddell was inducted into the Calgary Business Hall of Fame and in 2008 he was made an Officer of the Order of Canada. Mr. Riddell received the Fraser Institute's T. Patrick Boyle Founder's Award in 2012.
Susan L. Riddell Rose(4)(5) Alberta, Canada	President, Chief Executive Officer and Director since June 28, 2002	Ms. Riddell Rose is President and Chief Executive Officer of Perpetual Energy Inc. through the corporate conversion of Paramount Energy Trust. Ms. Riddell Rose graduated from Queen's University, Kingston, Ontario with a Bachelor of Science in Geological Engineering (1986) and has close to 30 years of experience in the Canadian oil and natural gas industry. She began her career as a geological engineer with Shell Canada. From 1990 until 2002 Sue was employed by Paramount Resources Ltd. in various capacities culminating in the position of Corporate Operating Officer. She has been a director of Paramount Resources Ltd. since 2000. Ms. Riddell is also on the board of directors of Newalta Inc. and Brookfield Office Properties. She is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta, the Canadian Society of Petroleum Geologists, the American Association of Petroleum Geologists and is a Governor of the Canadian Association of Petroleum Producers.
Karen A. Genoway(2)(3)(5)(6) Alberta, Canada	Director since June 28, 2002	Ms. Genoway is a professional landman with over 30 years experience in the oil and natural gas industry. She retired as Vice President, Land with Rimfire Energy Inc., a private company, at the end of 2015. Prior to that she was the Vice President, Land with Onyx. Ms. Genoway was with the Enerplus Group of Companies where she held the positions of Senior Vice President (1997 to 2000), Vice President Land (1989 to 1997) and Land Manager (1987 to 1989). Ms. Genoway is an active member of The Canadian Association of Petroleum Land Administration, the PADA Society, as well as The Canadian Association of Petroleum Landmen, an organization in which she served as a director and received her certification as a Professional Landman, P. Land. Ms. Genoway is a graduate of the ICD Corporate Governance College, Directors Education Program and received her accreditation, Institute-Certified Director, ICD.D, in April 2006.
Randall E. Johnson(1)(3)(5)(6) Alberta, Canada	Director since June 20, 2006	Mr. Johnson has been an independent businessman since 2005. Prior to that he was Managing Director of the Bank of Montreal's Corporate Banking group from 1996 to 2005, having been with the Bank of Montreal since 1984. Mr. Johnson has served on the Board of Directors of two publicly traded companies, Atlas Energy Ltd. and Dual Exploration Inc. and one privately held oil and gas company, Magellan Resources Ltd. Mr. Johnson received a B.Sc. in Mathematics in 1980, and an MBA in 1982 from Brigham Young University.
Robert A. Maitland(1)(3)(5)(6) Alberta, Canada	Director since February 7, 2008	Mr. Maitland has over 30 years of senior business experience, primarily in the oil and gas industry. He received a Bachelor of Commerce degree in 1975 from the University of Calgary, received his Chartered Accountant designation in 1977 and his ICD.D designation from the Institute of Corporate Directors in 2005. Since 2007, he has been a financial consultant. Previous to 2007, he has been the Vice President and Chief Financial Officer of Fairquest Energy Ltd., Fairborne Energy Ltd., Canadian Midstream Services Limited, Shiningbank Energy Income Fund, Post Energy Ltd. and Summit Resources Ltd. Mr. Maitland currently sits on the board of Rock Energy Inc., Altura Energy Inc. and one other private company.
Geoffrey C. Merritt(1)(2)(4)(5)(6) Alberta, Canada	Director since June 17, 2010	Mr. Merritt has over 35 years of experience in the upstream oil and gas sector. He was the founder of Masters Energy Inc., a public exploration and production company, incorporated in 2003. From 1998 to 2003, Mr. Merritt was the President and CEO of Sunfire Energy. Prior to 1998, he was the Vice President and General Manager of the oil and gas division of Pembina Corporation. Mr. Merritt received a B.Sc. in Chemical Engineering from the University of Alberta in 1978 and is a graduate of the Harvard Business School.

Name and Province and Country of Residence	Position held with the Corporation and Period Served as a Director	Principal Occupations During the Past Five Years
Donald J. Nelson(2)(4)(5)(6) Alberta, Canada	Director since June 28, 2002	Mr. Nelson has over 40 years of experience in the oil and gas industry, and is the President of Fairway Resources Inc., a private oil and gas consulting services firm. Mr. Nelson was with Summit Resources Limited from 1996 to 2002, until its acquisition by Paramount Resources Ltd., where he held the position of Vice President, Operations from 1996 to 1998 and President and Chief Executive Officer from 1998 to 2002. Mr. Nelson is a director of Keyera Corp., a publicly traded issuer and also sits on the boards of a number of private oil and gas companies. He is a professional engineer and is an active member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta and of the Society of Petroleum Engineers.
Howard R. Ward(3)(4)(5)(6) Alberta, Canada	Director since June 28, 2002	Prior to his retirement in February 2014, Mr. Ward had been a partner with International Energy Counsel LLP, a law firm, since December 2002. Prior thereto, Mr. Ward was counsel with the law firm McCarthy Tétrault LLP from June 2002 to December 2002. Prior to that, he was counsel with Donahue and Partners LLP and, for more than 22 years, partner with Burstall Ward (now Burstall Winger Zammit LLP), Barristers and Solicitors. He had been a member of the Law Society of Alberta since 1975. He also has served as a director of the following publicly traded entities: Blue Sky Resources Ltd. (July 1999 to July 2000); Cabre Exploration Ltd. (June 1981 to December 2000); Jet Energy Corp. (August 1995 to November 1999); and Tuscany Resources Ltd. (October 1997 to October 2001).
Jeffrey R. Green Alberta, Canada	Vice President, Corporate and Engineering Services	Mr. Green has close to 30 years of experience in the Canadian oil and natural gas industry. His previous industry experience includes Vice President of Production Operations & Administration, Manager, Acquisitions and Divestitures with Paramount Energy Trust and Exploitation Manager and Production Manager at Anadarko Canada Corp. Mr. Green has held additional technical and supervisory positions in other organizations including Norcen and Union Pacific Resources.
Gary C. Jackson Alberta, Canada	Vice President, Land, Acquisitions & Divestitures	Mr. Jackson has over 35 years of experience in the Canadian oil and natural gas industry. He was Vice President, Land of Summit Resources Limited from 2000 to 2002. His career has included the position of Manager of Acquisitions and Divestitures, Joint Venture Midstream and Land Services at Petro-Canada Oil and Gas as well as various positions related to land and contracts with Amerada Hess Canada and Placer Cego Petroleum.
Marcello M. Rapini Alberta, Canada	Vice President, Marketing	Mr. Rapini joined Perpetual Energy Inc. in December 2005 and has close to 30 years of gas marketing and trading experience in the natural gas industry. His previous positions include Vice President of Trade at Sempra Energy Trading, Senior Trader at Mirant Energy Marketing Ltd. and Senior Trader at Duke Energy Marketing.
Cameron R. Sebastian Alberta, Canada	Vice President, Finance and Chief Financial Officer	Mr. Sebastian has close to 30 years of experience in the North American energy industry. He was Vice President, Finance of Summit Resources Ltd. from 2000 to 2002 and the company's Controller from 1994 to 1997. Prior thereto he was Vice President, Finance of Pursuit Resources Corp. and Controller of Coho Energy Inc. in Dallas, Texas.
Vicki L. Benoit Alberta, Canada	Vice President, Production Operations	Ms. Benoit has over 26 years of oil and gas experience leading operations, production and asset teams for Devon Energy Corp., Southward Energy Corp., Starboard Energy Ltd. and consulting in an engineering capacity for various energy companies including Resolute Energy Corp., Omers Energy and Viking Energy Corp.
Linda L. McKean Alberta, Canada	Vice President, Exploitation	Ms. McKean has close to 30 years of experience in the Canadian oil and natural gas industry. Ms. McKean has been with Perpetual and the predecessor Paramount Energy Trust since 2004 in the positions of Eastern District Manager and consulting engineer. Her previous industry technical experience includes reservoir engineering positions at Berkley Petroleum and Anadarko Canada Corp, and 10 years at Shell Canada working as a development geologist and as a reservoir engineer.

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

5) The terms of office of all directors of the Company will expire on the date of the next annual shareholders' meeting.
6) Ms. Genoway, Mr. Johnson, Mr. Maitland, Mr. Nelson, Mr. Merritt and Mr. Ward are independent, non-employee directors.

The directors and officers of Perpetual, as a group, beneficially own or control or direct, directly or indirectly an aggregate of 512,826,452 voting securities as of March 2, 2016 representing approximately 48.95% of the outstanding Common Shares.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

Cease Trade Orders

To the knowledge of the Corporation, except as described below, no director or executive officer of the Corporation (nor any personal holding company of any of such persons) is, as of the date of this Annual Information Form, or was within 10 years before the date of this Annual Information Form, a director, chief executive officer or chief financial officer of any company (including the Corporation), that: (a) was subject to a cease trade order (including a management cease trade order), an order similar to a cease trade order or an order that denied the relevant company access to any exemption under securities legislation, in each case that was in effect for a period of more than 30 consecutive days (collectively, an "**Order**"), that was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer; or (b) was subject to an Order that was issued after the director or executive 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.

Mr. Riddell is a director and executive officer of Paramount Resources Ltd. ("**Paramount**") and Ms. Riddell Rose is a director and was an officer of Paramount from May 1998 to June 2002. From 1992 to 2008, Paramount was the general partner of T.T.Y. Paramount Partnership No. 5 ("**TTY**"), a limited partnership, which was an unlisted reporting issuer in certain provinces of Canada. TTY was established in 1980 to conduct oil and gas exploration and development but had not carried on active operations since 1984 and had only nominal assets. A cease trade order against TTY was issued by the Autorité des marches financiers in 1999 for failing to file the June 30, 1998 interim financial statements in Québec. The cease trade order was revoked on April 9, 2008. TTY was dissolved on July 21, 2008.

Bankruptcies

To the knowledge of the Corporation, no director or executive officer of the Corporation (nor any personal holding company of any of such persons), or shareholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation: (a) is, as of the date of this Annual Information Form, or has been within the 10 years before the date of this Annual Information Form, a director or executive officer of any company (including the Corporation) that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; or (b) has, within the 10 years before the date of this Annual Information Form, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, executive officer or shareholder.

Mr. Robert Maitland was a director of GasFrac Energy Services Inc. ("**GasFrac**") from April 2008 until GasFrac's annual meeting held on May 27, 2014, at which time he did not stand for re-election to the GasFrac board of directors. GasFrac obtained court approval on January 28, 2015 under the *Companies' Creditors Arrangement Act* (Canada) in respect of a forbearance agreement between GasFrac and its major creditor until March 18, 2015. Substantially all of GasFrac's assets were sold under a court ordered process approving the wind up of GasFrac on March 16, 2015.

Penalties or Sanctions

To the knowledge of the Corporation, no director or executive officer of the Corporation (nor any personal holding company of any of such persons), or shareholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation, 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 that would likely be considered important to a reasonable investor in making an investment decision.

Conflicts of Interest

Certain officers and directors of the Corporation are also officers and/or directors of other entities engaged in the oil and gas business generally. As a result, situations may arise where the interest of such directors and officers conflict with their interests as directors and officers of other companies. The resolution of such conflicts is governed by applicable corporate laws, which require that directors act honestly, in good faith and with a view to the best interests of the Corporation. Conflicts, if any, will be handled in a manner consistent with the procedures and remedies set forth in 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 INFORMATION

Audit Committee Charter

The mandate and responsibilities of Perpetual's audit committee (the "**Audit Committee**") are set out in the Audit Committee Charter which is part of the Corporation's Corporate Governance Directors' Manual. The Audit Committee Charter is set out in Appendix "C" to this Annual Information Form.

Audit Committee

The Audit Committee reviews and recommends to the Board the approval of the annual and interim financial statements, the associated management's discussion and analysis and related financial disclosure to the public and regulatory authorities. It is responsible for the engagement of Perpetual's external auditors, upon approval by Shareholders, including fees paid for the annual audit and interim financial reviews, and pre-approves non-audit services. The Audit Committee communicates directly with the auditors and reviews programs and policies regarding the effectiveness of internal controls over the Corporation's accounting and financial reporting systems. It also reviews insurance coverage and directors' and officers' liability insurance. The Audit Committee must liaise with the Reserves Committee on matters relating to reserves valuations which impact Perpetual's financial statements.

Composition of the Audit Committee

The Audit Committee consists of three members: Robert A. Maitland, Geoffrey C. Merritt and Randall E. Johnson. Mr. Maitland is Chair of the Audit Committee. Each of the members of the Audit Committee is independent and financially literate in accordance with the meanings set out in National Instrument 52-110 Audit Committees.

Relevant Education and Experience

Robert A. Maitland

Mr. Maitland is a Chartered Accountant. He has completed the Institute of Corporate Directors - Director Education Program and has received his accreditation as Institute-Certified Director, ICD.D. He has over 30 years of senior business experience, primarily in the oil and gas industry and has been the Vice President and Chief Financial Officer of Summit Resources Ltd., Omega Hydrocarbons Ltd., Shiningbank Energy Income Fund, Post Energy Ltd., Pan East Petroleum Corp., Fairborne Energy Ltd. and Fairquest Energy Ltd. He presently serves on the board of directors of Rock Energy Inc. (a publicly traded oil and gas company) and one other private company.

Randall E. Johnson

Mr. Johnson graduated with a Bachelor of Science degree in Mathematics (1980) and a Masters of Business Administration degree (1982) from Brigham Young University in Provo, Utah. His 22 year career in Corporate Banking commenced with CIBC in 1982 in Calgary. In 1984, he moved to Bank of Montreal's Corporate Banking group where he worked as an Associate from 1984 to 1987, Account Manager from 1987 to 1990, Director from 1990 to 1996, and then as Managing Director from 1996 to 2005. After retiring from Bank of Montreal in January 2005, Mr. Johnson joined the Board of Directors of three publicly traded oil and gas companies: Atlas Energy Ltd. (May 2005 to December 2006), Dual Exploration Inc. (June 2005 to November 2006), and Perpetual (June 2006 to present). During 2005 and 2006, Mr. Johnson was a part-time faculty member of the Bissett School of Business at Mount Royal University.

Geoffrey C. Merritt

Geoff Merritt has over 30 years of experience in the upstream oil and gas sector. He was the founder and Chief Executive Officer of Masters Energy Inc., a public exploration and production company, incorporated in 2003 and acquired by Zargon Oil & Gas Ltd. in April 2009. From 1998 to 2003, Mr. Merritt was the President and CEO of Sunfire Energy, a public exploration and production company. Prior to 1998, Geoff was the Vice President and General Manager of the oil and gas division of Pembina Corporation. Mr. Merritt is on the board of Zargon Oil and Gas Ltd. Mr. Merritt received a B.Sc. in Chemical Engineering from the University of Alberta in 1978 and is a graduate of the Harvard Business School.

Pre-Approval of Policies and Procedures

Perpetual has adopted policies and procedures with respect to the pre-approval of audit and permitted non-audit services to be provided by KPMG LLP. The Audit Committee establishes a budget for the provision of a specified list of audit and permitted non-audit services that the audit committee believes to be typical, recurring or otherwise likely to be provided by KPMG LLP. The budget generally covers the period between the adoption of the budget and the next meeting of the Audit Committee, but at the option of the Audit Committee it may cover a longer or shorter period. The list of services is sufficiently detailed as to the particular services to be provided to ensure that (i) the Audit Committee knows precisely what services it is being asked to pre-approve and (ii) it is not necessary for any member of management to make a judgment as to whether a proposed service fits within the pre-approved services.

The Audit Committee must pre-approve the provision of permitted services by KPMG LLP which are not otherwise pre-approved by the Audit Committee, including the fees and terms of the proposed services. Prohibited services may not be pre-approved by the Audit Committee.

External Auditor Service Fees

Audit Fees

The aggregate fees billed by Perpetual's external auditor in each of the last two fiscal years for audit services were $530,000 in 2015 and $535,000 in 2014, which includes fees related to offering documents and the Corporation's year-end audit and quarterly reviews.

Audit-Related Fees

The aggregate fees billed in each of the last two fiscal years for assurance related services by Perpetual's external auditor that are reasonably related to the performance of the audit or review of the financial statements that are not reported under Audit Fees above were nil in 2015 and nil in 2014.

Tax Fees

The aggregate fees billed in each of the last two fiscal years for professional services rendered by Perpetual's external auditor for tax compliance, tax advice and tax planning were nil in 2015 and nil in 2014.

All Other Fees

The aggregate fees billed in the 2015 fiscal year by Perpetual's external auditor for services other than those services reported above were nil. For the 2014 fiscal year those fees totalled nil.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

Legal Proceedings

There are no legal proceedings Perpetual is or was a party to, or that any of its property is or was the subject of, during Perpetual's financial year, nor are any such legal proceedings known to Perpetual to be contemplated, that involves a claim for damages, exclusive of interest and costs, exceeding 10% of the current assets of Perpetual.

Regulatory Actions

There are no:

1) penalties or sanctions imposed against Perpetual by a court relating to securities legislation or by a securities regulatory authority during Perpetual's financial year;
2) other penalties or sanctions imposed by a court or regulatory body against Perpetual that would likely be considered important to a reasonable investor in making an investment decision; and
3) settlement agreements Perpetual entered into before a court relating to securities legislation or with a securities regulatory authority during Perpetual's financial year.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There is no material interest, direct or indirect, of any: (a) director or executive officer of Perpetual; (b) person or company that beneficially owns, or controls or directs, directly or indirectly, more than 10% of any class or series of Perpetual's voting securities; and (c) associate or affiliate of any of the persons or companies referred to in (a) or (b) above in any transaction within the three most recently completed financial years or during the current financial year that has materially affected or is reasonably expected to materially affect Perpetual.

TRANSFER AGENT AND REGISTRAR

Computershare Trust Company of Canada at its offices in Calgary, Alberta and Toronto, Ontario acts as the transfer agent and registrar for the Common Shares.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, the Corporation has not entered into any material contracts within the most recently completed financial year, or before the most recently completed financial year which are still in effect.

INTERESTS OF EXPERTS

Names of Experts

The only persons or companies who are named as having prepared or certified a report, valuation, statement or opinion described or included in a filing, or referred to in a filing, made under National Instrument 51-102 by the Corporation during, or relating to, the Corporation's most recently completed financial year, and whose profession or business gives authority to the report, valuation, statement or opinion made by the person or company, are KPMG LLP, the Corporation's independent auditors, and McDaniel, the Corporation's independent reserve evaluators.

Interests of Experts

To the Corporation's knowledge, no registered or beneficial interests, direct or indirect, in any securities or other property of the Corporation or of one of the Corporation's associates or affiliates (i) were held by the McDaniel or by the "designated professionals" (as defined in Form 51-102F2) of McDaniel, when McDaniel prepared its reports, valuations, statements or opinions referred to herein as having been prepared by McDaniel, (ii) were received by McDaniel or the designated professionals of McDaniel after McDaniel prepared the reports, valuations, statements or opinions in question, or (iii) is to be received by McDaniel or the designated professionals of McDaniel.

Neither McDaniel nor any director, officer or employee of McDaniel 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.

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

OTHER BUSINESS INFORMATION

Specialized Skill and Knowledge

Perpetual employs individuals with various professional skills in the course of pursuing its business plan. These professional skills include, but are not limited to, geology, geophysics, engineering, marketing, finance and business skills. Drawing on significant experience in the oil and gas business, Perpetual believes its management team has a demonstrated track record of bringing together all of the key components to a successful exploration and production company: strong technical and leadership skills; operational and capital project execution expertise; an entrepreneurial spirit that allows Perpetual to effectively identify, evaluate and execute on value added initiatives; expertise in planning and financial controls; ability to execute on business development opportunities; and capital markets expertise.

Competitive Conditions

The oil and natural gas industry is intensely competitive and Perpetual competes with a substantial number of other entities, many of which have greater technical, operational and/or financial resources. With the maturing nature of the Western Canadian Sedimentary Basin, the access to new prospects is becoming more competitive and complex.

Perpetual attempts to enhance its competitive position by operating in areas where it believes its technical personnel are able to reduce some of the risks associated with exploration, production and marketing because the Company has established core competencies in these areas of operation. Management believes that Perpetual will be able to explore for and develop new production and reserves with the objective of increasing its funds flow and reserve base. See "**Risk Factors – Competition**".

Commodity Price Cycles

The Company's operational results and financial condition are dependent on commodity prices, specifically the prices of oil, natural gas, NGL and seasonal natural gas price spreads. Commodity prices have fluctuated widely during recent years and are determined by supply and demand factors including general economic conditions, weather, environmental regulations and policies, geopolitical risks, oil and gas resource extraction technologies, oil fields equipment and services, local and regional access to markets, refining capacity, as well as operating results and conditions in other oil and natural gas producing regions. See "**Risk Factors – Seasonality**".

Environmental Protection

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation. Compliance with such legislation may require significant expenditures or result in operational restrictions. 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, all of which might have a significant negative impact on earnings and overall competitiveness of the Corporation. For a description of the financial and operational effects of environmental protection requirements on the capital expenditures, earnings and competitive position of Perpetual, see "**Industry Conditions – Environmental Regulation**" and "**Risk Factors – Environmental**".

Reorganizations

Other than disclosed under "**General Development of the Business**", Perpetual has not completed any material reorganization within the three most recently completed financial years or during the current financial year. No material reorganization is currently proposed for the current financial year. See "**General Development of the Business**".

Environmental, Health and Safety Policies

The Corporation supports environmental protection and worker health and safety through the implementation and communication of the Corporation's environmental management and health and safety policies, practices and procedures. Committees focused on environment, health and safety ("**EH&S**") issues are established in the Corporation's operations which are designed to drive continuous improvement in policies and programs which target accountability for EH&S by the Corporation and its employees. Practices for continuous improvement of EH&S performance management includes providing employees with job orientation, training, instruction and supervision to build competency, skill and accountability in conducting daily activities in a healthy, environmentally responsible and safe manner.

The Corporation develops emergency response practices, procedures and readiness plans in conjunction with local authorities, emergency services and the communities in which it operates in order to effectively respond to an environmental or safety incident should it arise. The effectiveness of these plans is evaluated on a regular basis to ensure preparedness for emergency situations. Environmental and risk assessments are undertaken for new projects, or when acquiring new properties or facilities in order to identify, assess and minimize environmental risks, loss and operational exposures. The Corporation conducts audits of operations to measure compliance with internal and industry standards, and for continuous improvement in practices and procedures. Documentation is maintained to support internal accountability and measure operational performance against recognized industry indicators to assist in achieving the objectives of the described policies and programs.

Perpetual's culture of safety has been acknowledged through the results of an independent audit for the Certificate of Recognition ("**COR**") program under the Alberta governments "Partnership in Injury Reduction" initiative. In 2015 Perpetual conducted an internal maintenance audit. This audit allows the Corporation to maintain its COR accreditation which demonstrates the Corporation has exceeded the Alberta Employment and Immigration Workplace Partnerships standard, an accomplishment shared amongst a select few in the oil and gas industry. As part of the COR accreditation an external auditor is required to audit the Corporation every three years.

The Corporation also faces environmental, health and safety risks in the normal course of its operations due to the handling and storage of hazardous substances. The Corporation's environmental and health and safety management systems are designed to manage such risks in the Corporation's business and allow action to be taken to control the risk of environmental, health or safety impacts from such operations. A key aspect of these systems is the conducting of internal and external inspection and audits of worksites and offices. See "**Risk Factors – Environmental**".

INDUSTRY CONDITIONS

Companies operating in the oil and natural gas industry are subject to extensive regulation and control of operations (including land tenure, exploration, development, production, refining and upgrading, transportation, and marketing) as a result of legislation enacted by various levels of government with respect to the pricing and taxation of oil and natural gas through agreements among the governments of Canada, Alberta, British Columbia, and Saskatchewan all of which should be carefully considered by investors in the oil and gas industry. 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 in western Canada.

Pricing and Marketing

Oil

In Canada, the producers of oil are entitled to negotiate sales contracts directly with oil purchasers, which results in the market determining the price of oil. Worldwide supply and demand factors primarily determine oil prices; however, prices are also influenced by regional market and transportation issues. The specific price depends in part on oil quality, prices of competing fuels, distance to market, availability of transportation, value of refined products, the supply/demand balance and contractual terms of sale. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National Energy Board of Canada (the "**NEB**"). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB. The NEB is currently undergoing a consultation process to update the regulations governing the issuance of export licences. The updating process is necessary to meet the criteria set out in the federal *Jobs, Growth and Long-term Prosperity Act* (Canada) (the "**Prosperity Act**") which received Royal Assent on June 29, 2012. In this transitory period, the NEB has issued, and is currently following an "Interim Memorandum of Guidance concerning Oil and Gas Export Applications and Gas Import Applications" under Part VI of the *National Energy Board Act* (Canada).

Natural Gas

Canada's natural gas market has been deregulated since 1985. Supply and demand determine the price of natural gas and price is calculated at the sale point, being the wellhead, the outlet of a gas processing plant, on a gas transmission system, at a storage facility, at the inlet to a utility system or at the point of receipt by the consumer. Accordingly, the price for natural gas is dependent upon such producer's own arrangements (whether long or short term contracts and the specific point of sale). As natural gas is also traded on trading platforms such as the Natural Gas Exchange, Intercontinental Exchange or the NYMEX in the United States, spot and future prices can also be influenced by supply and demand fundamentals on these platforms. 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 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 40 years) or for a larger quantity requires an exporter to obtain an export licence from the NEB.

The North American Free Trade Agreement

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the United States and Mexico came into force on January 1, 1994. In the context of energy resources, Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to the total supply of goods of the party maintaining the restriction as compared to the proportion prevailing in the most recent 36 month period; (ii) impose an export price higher than the domestic price (subject to an exception with respect to certain measures which only restrict the volume of exports); and (iii) disrupt normal channels of supply.

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

Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations that govern royalties, production rates and other matters. The royalty regime in a given province is a significant factor in the profitability of oil sands projects, crude oil, natural gas liquids, sulphur and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiation between the mineral freehold owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Royalties from production on Crown lands are determined by governmental regulation and are generally calculated as a percentage of the value of gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery and the type or quality of the petroleum product produced. Other royalties and royalty-like interests are carved out of the working interest owner's interest, from time to time, through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests, or net carried interests.

Occasionally the governments of the western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays or royalty tax credits and are generally introduced when commodity prices are low to encourage exploration and development activity by improving earnings and cash flow within the industry.

The federal government has signaled it will, *inter alia*, phase out subsidies for the oil and gas industry, which include only allowing the use of the Canadian Exploration Expenses tax deduction in cases of successful exploration, implementing more stringent reviews for pipelines, and establishing a pan-Canadian framework for combating climate change within 90 days of the 2015 Paris Climate Conference which concluded on December 12, 2015. These changes could affect earnings of companies operating in the oil and natural gas industry.

Alberta

On January 29, 2016, the Government of Alberta released and accepted the Royalty Review Advisory Panel's recommendations, which outlined the implementation of a "Modernized Royalty Framework" for Alberta (the "**MRF**"). The MRF will take effect on January 1, 2017. Wells drilled prior to January 1, 2017 will continue to be governed by the current "Alberta Royalty Framework" for a period of 10 years until January 1, 2027. The MRF is structured in three phases: (i) Pre-Payout, (ii) Mid-Life, and (iii) Mature. During the Pre-Payout phase, a fixed 5% royalty will apply until the well reaches payout. Well payout occurs when the cumulative revenue from a well is equal to the Drilling and Completion Cost Allowance (determined by a formula that approximates drilling and completion costs for wells based on depth, length and historical costs). The new royalty rate will be payable on gross revenue generated from all production streams (oil, gas, and natural gas liquids), eliminating the need to label a well as "oil" or "gas". Post-payout, the Mid-Life phase will apply a higher royalty rate than the Pre-Payout phase. While the metrics for calculating the Mid-Life phase royalty have yet to be released, the rate will be determined based on commodity prices and are intended, on average, to yield the same internal rate of return as under the current Alberta Royalty Framework. In the Mature phase, once a well reaches the tail end of its cycle and production falls below a Maturity Threshold, currently estimated to be 20 bbl/d for oil and 200 mcf/d for gas, the royalty rate will move to a sliding scale (based on volume and price) with a minimum royalty rate of 5%. The downward adjustment of the royalty rate in the Mature phase is intended to account for the higher per-unit fixed cost involved in operating an older well. Details of the MRF, including the applicable royalty rates and formulas, are scheduled to be released by March 31, 2016.

Oil sands projects are also subject to Alberta's royalty regime. The MRF does not change the oil sands royalty framework, however, the method and figures by which the royalties are calculated will be released to the public. Prior to payout of an oil sands project, the royalty is payable on gross revenues of an oil sands project. Gross revenue royalty rates range between 1% - 9% depending on the market price of oil, determined using the average monthly price, expressed in Canadian dollars, for WTI crude oil at Cushing, Oklahoma. Rates are 1% when the market price of oil is less than or equal to $55 per barrel and increase for every dollar of market price of oil increase to a maximum of 9% when oil is priced at $120 or higher. After payout, the royalty payable is the greater of the gross revenue royalty based on the gross revenue royalty rate of 1% - 9% and the net revenue royalty based on the net revenue royalty rate. Net revenue royalty rates start at 25% and increase for every dollar of market price of oil increase above $55 up to 40% when oil is priced at $120 or higher.

Currently, producers of oil and natural gas from Crown lands in Alberta are required to pay annual rental payments, at a rate of $3.50 per hectare, and make monthly royalty payments in respect of oil and natural gas produced.

Royalties, for wells drilled prior to January 1, 2017 are paid pursuant to "The New Royalty Framework" (implemented by the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*) and the "Alberta Royalty Framework" until January 1, 2027. Royalty rates for conventional oil are set by a single sliding rate formula, which is applied monthly and incorporates separate variables to account for production rates and market prices. The maximum royalty payable under the royalty regime is 40%. Royalty rates for natural gas under the royalty regime are similarly determined using a single sliding rate formula with the maximum royalty payable under the royalty regime set at 36%.

Producers of oil and natural gas from freehold lands in Alberta are required to pay freehold mineral tax. The freehold mineral tax is a tax levied by the Government of Alberta on the value of oil and natural gas production from non-Crown lands and is derived from the *Freehold Mineral Rights Tax Act* (Alberta). The freehold mineral tax is levied on an annual basis on calendar year production using a tax formula that takes into consideration, among other things, the amount of production, the hours of production, the value of each unit of production, the tax rate and the percentages that the owners hold in the title. The basic formula for the assessment of freehold mineral tax is: revenue less allocable costs equals net revenue divided by wellhead production equals the value based upon unit of production. If payors do not wish to file individual unit values, a default price is supplied by the Crown. On average, the tax levied is 4% of revenues reported from fee simple mineral title properties.

The Government of Alberta has from time to time implemented drilling credits, incentives or transitional royalty programs to encourage oil and gas development and new drilling. For example, the Innovative Energy Technologies Program (the "**IETP**") has the stated objectives of increasing recovery from oil and gas deposits, finding technical solutions to the gas over bitumen issue, improving the recovery of bitumen by in-situ and mining techniques and improving the recovery of natural gas from coal seams. The IETP provides royalty adjustments to specific pilot and demonstration projects that utilize new or innovative technologies to increase recovery from existing reserves.

In addition, the Government of Alberta has implemented certain initiatives intended to accelerate technological development and facilitate the development of unconventional resources (the "**Emerging Resource and Technologies Initiative**"). These initiatives apply to wells drilled before January 1, 2017, for a 10 year period, until January 1, 2027. Specifically:

- Coalbed methane wells will receive a maximum royalty rate of 5% for 36 producing months up to 750 MMcf of production, retroactive to wells that began producing on or after May 1, 2010;
- Shale gas wells will receive a maximum royalty rate of 5% for 36 producing months with no limitation on production volume, retroactive to wells that began producing on or after May 1, 2010;
- Horizontal gas wells will receive a maximum royalty rate of 5% for 18 producing months up to 500 MMcf of production, retroactive to wells that commenced drilling on or after May 1, 2010; and
- Horizontal oil wells and horizontal non-project oil sands wells will receive a maximum royalty rate of 5% with volume and production month limits set according to the depth of the well (including the horizontal distance), retroactive to wells that commenced drilling on or after May 1, 2010.

While the MRF eliminates the various royalty credits and incentives, outlined above, for wells drilled after December 31, 2016, the Government of Alberta has committed to creating cost allowance programs for both enhanced oil recovery schemes and higher risk experimental drilling. Details of these programs are scheduled to be released simultaneously with the finalization of the MRF, prior to March 31, 2016.

British Columbia

Producers of oil and natural gas from Crown lands in British Columbia are required to pay annual rental payments, and make monthly royalty payments in respect of oil and natural gas produced. The amount payable as a royalty in respect of oil depends on the type and vintage of the oil, the quantity of oil produced in a month and the value of that oil. Generally, oil is classified as either light or heavy and the vintage of oil is classified as either "old oil" which is produced from a pool discovered before October 31, 1975, "new oil" produced from a pool discovered between October 31, 1975 and June 1, 1998, and "third-tier oil" produced from a pool discovered after June 1, 1998 or through an enhanced oil recovery ("**EOR**") scheme. The royalty calculation takes into account the production of oil on a well-by-well basis, the specified royalty rate for a given vintage of oil, the average unit selling price of the oil and any applicable royalty exemptions. Royalty rates are reduced on low-productivity wells, reflecting the higher unit costs of extraction, and are the lowest for third-tier oil, reflecting the higher unit costs of both exploration and extraction.

The royalty payable in respect of natural gas produced on Crown lands is determined by a sliding scale formula based on a reference price, which is the greater of the average net price obtained by the producer and a prescribed minimum price. For non-conservation gas (not produced in association with oil), the royalty rate depends on the date of acquisition of the oil and natural gas tenure rights and the spud date of the well, and may also be impacted by the select price, a parameter used in the royalty rate formula to account for inflation. Royalty rates are fixed for certain classes of non-conservation gas when the reference price is below the select price. Conservation gas is subject to a lower royalty rate than non-conservation gas. Royalties on natural gas liquids are levied at a flat rate of 20% of sales volume.

Producers of oil and natural gas from freehold lands in British Columbia are required to pay monthly freehold production taxes. For oil, the level of the freehold production tax is based on the volume of monthly production. It is either a flat rate, or, beyond a certain production level, is determined using a sliding scale formula based on the production level. For natural gas, the freehold production tax is either a flat rate, or, at certain production levels, is determined using a sliding scale formula based on the reference price similar to that applied to natural gas production on Crown land, and depends on whether the natural gas is conservation gas or non-conservation gas. The production tax rate for freehold natural gas liquids is a flat rate of 12.25%.

As of January 1, 2017, all liquid natural gas ("**LNG**") facilities will be subject to a 3.5% income tax. This income tax is scheduled to increase to 5% in 2037. During the period in which net operating losses and capital investment are deducted, a tax rate of 1.5% will apply to the taxpayer's net income. Once the net operating losses and capital investment have been depleted, the full rate of 3.5% is payable. To encourage investment the Government of British Columbia will offer a corporate income tax credit to any LNG taxpayer based on the amount of LNG acquired for an LNG facility.

The Government of British Columbia maintains a number of targeted royalty programs for key resource areas intended to increase the competitiveness of British Columbia's low productivity natural gas wells. These include both royalty credit and royalty reduction programs, including the following:

- *Deep Well Royalty Credit Program* providing a royalty credit for natural gas wells defined in terms of a dollar amount applied against royalties, is well specific and applies to drilling and completion costs for vertical wells with a true vertical depth greater than 2,500 metres and horizontal wells with a true vertical depth greater than 1,900 metres (or 2,300 metres if spud before September 1, 2009) and if certain other criteria are met, is intended to reflect the higher drilling and completion costs. Effective April 1, 2014, there are two tiers to the Deep Well Royalty Credit Program, "tier one" and "tier two". The pre-existing Deep Well Royalty Credit Program, as described above, will comprise tier two of the program. Tier one of the Deep Well Royalty Credit Program applies to shallower horizontal wells with a true vertical depth less than or equal to 1,900 metres if spud after March 31, 2014. Currently all wells that qualify for the tier one royalty credits are subject to a minimum royalty of 6% while wells that qualify for the tier two royalty credits are subject to a minimum royalty of 3%. These minimum royalty amounts apply when the net royalty payable would otherwise be zero for a production month;
- *Deep Re-Entry Royalty Credit Program* providing a royalty credit for deep re-entry wells with a true vertical depth to the top of pay if the re-entry well event is greater than 2,300 metres and a re-entry date after November 30, 2003; or if the well was spud on or after January 1, 2009, with a true vertical depth to the completion point of the re-entry well event being greater than 2,300 metres;
- *Deep Discovery Royalty Credit Program* providing the lesser of a 3 year royalty holiday or 283,000,000 m^3 of royalty free gas for deep discovery wells with a true vertical depth greater than 4,000 metres whose surface locations are at least 20 kilometres away from the surface location of any well drilled into a recognized pool within the same formation;
- *Coalbed Gas Royalty Reduction and Credit Program* providing a royalty reduction for coalbed gas wells with average daily production less than 17,000 m^3 as well as a royalty credit for coalbed gas wells equal to $50,000 for wells drilled on Crown land and a tax credit equal to $30,000 for wells drilled on freehold land;
- *Marginal Royalty Reduction Program* providing a monthly royalty reduction for low productivity natural gas wells with an average daily rate of production less than 23 m^3 for every metre of marginal well depth in the first 12 months of production. To be eligible, wells must have been spudded after May 31, 1998 and the first month of marketable gas production must have occurred between June 2003 and August 2008. Once a well passes the initial eligibility test, a reduction is realized in each month that average daily production is less than 25,000 m^3;
- *Ultra-Marginal Royalty Reduction Program* providing royalty reductions for low productivity, shallow natural gas wells. Vertical wells must be less than 2,500 metres and horizontal wells less than 2,300 metres to be eligible. Production in the first 12 months ending after January 2007 must be less than 17 m^3 per metre of depth for exploratory wildcat wells and less than 11 m^3 per metre of depth for development wells and exploratory outpost wells. The well must have been spudded or re-entered after December 31, 2005. A reduction is realized in each month that average daily production is less than 60,000 m^3. Horizontal wells that are spud on or after April 1, 2014 are not eligible for the Ultra-Marginal Royalty Reduction Program due to the potential for overlap with shallower horizontal wells eligible for a royalty credit under the Deep Well Royalty Credit Program; and
- *Net Profit Royalty Reduction Program* providing reduced initial royalty rates to facilitate the development and commercialization of technically complex resources such as coalbed gas, tight gas, shale gas and enhanced-recovery projects, with higher royalty rates applied once capital costs have been recovered.

Oil produced from an oil well that is located on either Crown or freehold land and completed in a new pool discovered subsequent to June 30, 1974 may also be exempt from the payment of a royalty for the first 36 months of production or 11,450 m^3 of production, whichever comes first.

The Government of British Columbia also maintains an Infrastructure Royalty Credit Program that provides royalty credits for up to 50% of the cost of certain approved road construction or pipeline infrastructure projects intended to facilitate increased oil and gas exploration and production in under-developed areas and to extend the drilling season.

Saskatchewan

In Saskatchewan, taxes ("**Resource Surcharge**") and royalties are applicable to revenue generated by corporations focused on oil and gas operations.

A Resource Surcharge on the value of sales of oil, natural gas, potash, uranium and coal in Saskatchewan is levied under authority of *The Corporation Capital Tax Act*. For resource corporations, the Resource Surcharge rate is 3% of the value of sales of all potash, uranium and coal produced in Saskatchewan, and oil and natural gas produced from wells drilled in Saskatchewan prior to October 1, 2002. For oil and natural gas produced from wells drilled in Saskatchewan after September 30, 2002, the Resource Surcharge rate is 1.7% of the value of sales. The Resource Surcharge applies to resource trusts in addition to resource corporations.

The amount payable as a Crown royalty or a freehold production tax in respect of oil depends on the type and vintage of oil, the quantity of oil produced in a month, the value of the oil produced and specified adjustment factors determined monthly by the provincial government. For Crown royalty and freehold production tax purposes, conventional oil is divided into "types", being "heavy oil", "southwest designated oil" or "non-heavy oil other than southwest designated oil". The vintage of oil, being "fourth tier oil", "third tier oil", "new oil" and "old oil", depends on the finished drilling date of a well and is applied to each of the three crude oil types slightly differently. Heavy oil is classified as third tier oil (produced from a vertical well having a finished drilling date on or after January 1, 1994 and before October 1, 2002 or incremental oil from new or expanded waterflood projects with a commencement date on or after January 1, 1994 and before October 1, 2002), fourth tier oil (having a finished drilling date on or after October 1, 2002 or incremental oil from new or expanded waterflood projects with a commencement date on or after October 1, 2002) or new oil (conventional oil that is not classified as "third tier oil" or "fourth tier oil"). Southwest designated oil uses the same definition of fourth tier oil but third tier oil is defined as conventional oil produced from a vertical well having a finished drilling date on or after February 9, 1998 and before October 1, 2002 or incremental oil from new or expanded waterflood projects with a commencement date on or after February 9, 1998 and before October 1, 2002 and new oil is defined as conventional oil produced from a horizontal well having a finished drilling date on or after February 9, 1998 and before October 1, 2002. For non-heavy oil other than southwest designated oil, the same classification as heavy oil is used but new oil is defined as conventional oil produced from a vertical well completed after 1973 and having a finished drilling date prior to 1994, conventional oil produced from a horizontal well having a finished drilling date on or after April 1, 1991 and before October 1, 2002, or incremental oil from new or expanded waterflood projects with a commencement date on or after January 1, 1974 and before 1994 whereas old oil is defined as conventional oil not classified as third or fourth tier oil or new oil. Production tax rates for freehold production are determined by first determining the Crown royalty rate and then subtracting the "Production Tax Factor" ("**PTF**") applicable to that classification of oil. Currently the PTF is 6.9 for "old oil", 10.0 for "new oil" and "third tier oil" and 12.5 for "fourth tier oil". The minimum rate for freehold production tax is zero.

Base prices are used to establish lower limits in the price-sensitive royalty structure for conventional oil and apply at a reference well production rate of 100 m^3 for "old oil", "new oil" and "third tier oil", and 250 m^3 per month for "fourth tier oil". Where average wellhead prices are below the established base prices of $100 per m^3 for third and fourth tier oil and $50 per m^3 for new oil and old oil, base royalty rates are applied. Base royalty rates are 5% for all fourth tier oil, 10% for heavy oil that is third tier oil or new oil, 12.5% for southwest designated oil that is third tier oil or new oil, 15% for non-heavy oil other than southwest designated oil that is third tier or new oil, and 20% for old oil. Where average wellhead prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base oil price. Marginal royalty rates are 30% for all fourth tier oil, 25% for heavy oil that is third tier oil or new oil, 35% for southwest designated oil that is third tier oil or new oil, 35% for non-heavy oil other than southwest designated oil that is third tier or new oil, and 45% for old oil.

The amount payable as a Crown royalty or a freehold production tax in respect of natural gas production is determined by a sliding scale based on the monthly provincial average gas price published by the Government of Saskatchewan, the quantity produced in a given month, the type of natural gas, and the classification of the natural gas. Like conventional oil, natural gas may be classified as "non-associated gas" (gas produced from gas wells) or "associated gas" (gas produced from oil wells) and royalty rates are determined according to the finished drilling date of the respective well. Non-associated gas is classified as new gas (having a finished drilling date before February 9, 1998 with a first production date on or after October 1, 1976), third tier gas (having a finished drilling date on or after February 9, 1998 and before October 1, 2002), fourth tier gas (having a finished drilling date on or after October 1, 2002) and old gas (not classified as either third tier, fourth tier or new gas). A similar classification is used for associated gas except that the classification of old gas is not used, the definition of fourth tier gas also includes production from oil wells with a finished drilling date prior to October 1, 2002, where the individual oil well has a gas-oil production ratio in any month of at least 3,500 m^3 of gas for every m^3 of oil, and new gas is defined as oil produced from a well with a finished drilling date before February 9, 1998 that received special approval, prior to October 1, 2002, to produce oil and gas concurrently without gas-oil ratio penalties.

On December 9, 2010, the Government of Saskatchewan enacted the *Freehold Oil and Gas Production Tax Act, 2010* with the intention to facilitate the efficient payment of freehold production taxes by industry. Two new regulations with respect to this legislation are: (i) *The Freehold Oil and Gas Production Tax Regulations, 2012* which sets out the terms and conditions under which the taxes are calculated and paid; and (ii) *The Recovered Crude Oil Tax Regulations*, 2012 which sets out the terms and conditions under which taxes on recovered crude oil that was delivered from a crude oil recovery facility on or after March 1, 2012 are to be calculated and paid.

As with conventional oil production, base prices based on a well reference rate of 250 10^3 m^3/month are used to establish lower limits in the price-sensitive royalty structure for natural gas. Where average field-gate prices are below the established base prices of $1.35 per gigajoule for third and fourth tier gas and $0.95 per gigajoule for new gas and old gas, base royalty rates are applied. Base royalty rates are 5% for all fourth tier gas, 15% for third tier or new gas, and 20% for old gas. Where average wellhead prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base gas price. Marginal royalty rates are 30% for all fourth tier gas, 35% for third tier and new gas, and 45% for old gas**.** The current regulatory scheme provides for certain differences with respect to the administration of "fourth tier gas" which is associated gas.

The Government of Saskatchewan currently provides a number of targeted incentive programs. These include both royalty reduction and incentive volume programs, including the following:

- *Royalty/Tax Incentive Volumes for Vertical Oil Wells Drilled on or after October 1, 2002* providing reduced Crown royalty (a Crown royalty rate of the lesser of "fourth tier oil" Crown royalty rate and 2.5%) and freehold tax rates (a freehold production tax rate of 0%) on incentive volumes of 8,000 m^3 for deep development vertical oil wells, 4,000 m^3 for non-deep exploratory vertical oil wells and 16,000 m^3 for deep exploratory vertical oil wells (more than 1,700 metres or within certain formations) and after the incentive volume is produced, the oil produced will be subject to the "fourth tier" royalty tax rate;
- *Royalty/Tax Incentive Volumes for Exploratory Gas Wells Drilled on or after October 1, 2002* providing reduced Crown royalty (a Crown royalty rate of the lesser of "fourth tier oil" Crown *royalty* rate and 2.5%) and freehold tax rates (a freehold production tax rate of 0%) on incentive volumes of 25,000,000 m^3 for qualifying exploratory gas wells;
- *Royalty/Tax Incentive Volumes for Horizontal Oil Wells Drilled on or after October 1, 2002 providing* reduced Crown royalty (a Crown royalty rate of the lesser of "fourth tier oil" Crown royalty rate and 2.5%) and freehold tax rates (a freehold production tax rate of 0%) on incentive volumes of 6,000 m^3 for non-deep horizontal oil wells and 16,000 m^3 for deep horizontal oil wells (more than 1,700 metres total vertical depth or within certain formations) and after the incentive volume is produced, the oil produced will be subject to the "fourth tier" royalty tax rate;
- *Royalty/Tax Incentive Volumes for Horizontal Gas Wells drilled on or after June 1, 2010 and before April 1, 2013* providing for a classification of the well as a qualifying exploratory gas well and resulting in a reduced Crown royalty (a Crown royalty rate of the lesser of "fourth tier oil" Crown royalty rate and 2.5%) and freehold tax rates (a freehold production tax rate of 0%) on incentive volumes of 25,000,000 m^3 for horizontal gas wells and after the incentive volume is produced, the gas produced will be subject to the "fourth tier" royalty tax rate;
- *Royalty/Tax Regime for Incremental Oil Produced from New or Expanded Waterflood Projects* Implemented on or after October 1, 2002 whereby incremental production from approved waterflood projects is treated as fourth tier oil for the purposes of Crown royalty and freehold tax calculations;
- *Royalty/Tax Regime for Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing prior to April 1, 2005* providing lower Crown royalty and freehold tax determinations based in part on the profitability of EOR projects during and subsequent to the payout of the EOR operations;
- *Royalty/Tax Regime for Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing on or after April 1, 2005* providing a Crown royalty of 1% of gross revenues on EOR projects pre-payout and 20% of EOR operating income post-payout and a freehold production tax of 0% pre-payout and 8% post-payout on operating income from EOR projects; and
- *Royalty/Tax Regime for High Water-Cut Oil Wells* designed to extend the product lives and improve the recovery rates of high water-cut oil wells and granting "third tier oil" royalty/tax rates with a Saskatchewan Resource Credit of 2.5% for oil produced prior to April 2013 and 2.25% for oil produced on or after April 1, 2013 to incremental high water-cut oil production resulting from qualifying investments made to rejuvenate eligible oil wells and/or associated facilities.

On June 22, 2011, the Government of Saskatchewan released the Upstream Petroleum Industry Associated Gas Conservation Standards, which are designed to reduce emissions resulting from the flaring and venting of associated gas (the "**Associated Natural Gas Standards**"). The Associated Natural Gas Standards were jointly developed with industry and the implementation of such standards commenced on July 1, 2012 for new wells and facilities licensed on or after such date. The new standards apply to existing licensed wells and facilities on July 1, 2015.

Effective April 1, 2014, the Saskatchewan Ministry of the Economy streamlined fees related to licenses and applications in the oil and gas sector by eliminating 11 different licensing fees, which resulted in an aggregate of 20,000 fee transactions per year, and replacing them with a single annual levy based on a company's production and number of wells. While the fees have been streamlined, approvals to conduct the relevant activities are still required. These changes to the fee structure are part of ongoing work by the Government of Saskatchewan to streamline the licensing, regulation and monitoring processes in the oil and gas sector.

Land Tenure

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

Each of the provinces of Alberta, British Columbia, and Saskatchewan have implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or license. The Government of British Columbia expanded its policy of deep rights reversion for leases issued after March 29, 2007 to provide for the reversion of both shallow and deep formations that cannot be shown to be capable of production at the end of the primary term.

Alberta also has a policy of "shallow rights reversion" which provides for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for all leases and licenses issued after January 1, 2009 at the conclusion of the primary term of the lease or license.

Production and Operation Regulations

The oil and natural gas industry in Canada is highly regulated and subject to significant control by provincial regulators. Regulatory approval is required for, among other things, the drilling of oil and natural gas wells, construction and operation of facilities, the storage, injection and disposal of substances and the abandonment and reclamation of well-sites. In order to conduct oil and gas operations and remain in good standing with the applicable provincial regulator, we must comply with applicable legislation, regulations, orders, directives and other directions (all of which are subject to governmental oversight, review and revision, from time to time). Compliance with such legislation, regulations, orders, directives or other directions can be costly and a breach of the same may result in fines or other sanctions.

Environmental Regulation

The oil and natural gas industry is currently subject to regulation pursuant to a variety of provincial and federal environmental legislation, all of which is subject to governmental review and revision from time to time. Such legislation provides for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain oil and gas industry operations, such as sulphur dioxide and nitrous oxide. In addition, such legislation sets out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability and the imposition of material fines and penalties.

Federal

Pursuant to the *Prosperity Act*, the Government of Canada amended or repealed several pieces of federal environmental legislation and in addition, created a new federal environment assessment regime that came in to force on July 6, 2012. The changes to the environmental legislation under the *Prosperity Act* are intended to provide for more efficient and timely environmental assessments of projects that previously had been subject to overlapping legislative jurisdiction.

Alberta

The Alberta Energy Regulator (the "**AER**") is the single regulator responsible for all energy development in Alberta. The AER ensures the safe, efficient, orderly, and environmentally responsible development of hydrocarbon resources including allocating and conserving water resources, managing public lands, and protecting the environment. The AER's responsibilities exclude the functions of the Alberta Utilities Commission and the Surface Rights Board, as well as Alberta Energy's responsibility for mineral tenure. The objective behind a single regulator is an enhanced regulatory regime that is efficient, attractive to business and investors, and effective in supporting public safety, environmental management and resource conservation while respecting the rights of landowners.

The Government of Alberta relies on regional planning to accomplish its responsible resource development goals. The following frameworks, plans and policies form the basis of Alberta's Integrated Resource Management System ("**IRMS**"). The IRMS method to natural resource management sets out to engage and consult with stakeholders and the public. While the AER is the primary regulator for energy development, several governmental departments and agencies may be involved in land use issues, including Alberta Environment and Parks, Alberta Energy, the AER, the Alberta Environmental Monitoring, Evaluation and Reporting Agency, the Policy Management Office, the Aboriginal Consultation Office, and the Land Use Secretariat.

In December 2008, the Government of Alberta released a new land use policy for surface land in Alberta, the Alberta Land Use Framework (the "**ALUF**"). The ALUF sets out an approach to manage public and private land use and natural resource development in a manner that is consistent with the long-term economic, environmental and social goals of the province. It calls for the development of seven region-specific land use plans in order to manage the combined impacts of existing and future land use within a specific region and the incorporation of a cumulative effects management approach into such plans.

Proclaimed in force in Alberta on October 1, 2009, the *Alberta Land Stewardship Act* (the "**ALSA**") provides the legislative authority for the Government of Alberta to implement the policies contained in the ALUF. Regional plans established under the ALSA are deemed to be legislative instruments equivalent to regulations and will be binding on the Government of Alberta and provincial regulators, including those governing the oil and gas industry. In the event of a conflict or inconsistency between a regional plan and another regulation, regulatory instrument or statutory consent, the regional plan will prevail. Further, the ALSA requires local governments, provincial departments, agencies and administrative bodies or tribunals to review their regulatory instruments and make any appropriate changes to ensure that they comply with an adopted regional plan. The ALSA also contemplates the amendment or extinguishment of previously issued statutory consents such as regulatory permits, licenses, registrations, approvals and authorizations for the purpose of achieving or maintaining an objective or policy resulting from the implementation of a regional plan. Among the measures to support the goals of the regional plans contained in the ALSA are conservation easements, which can be granted for the protection, conservation and enhancement of land; and conservation directives, which are explicit declarations contained in a regional plan to set aside specified lands in order to protect, conserve, manage and enhance the environment.

On August 22, 2012, the Government of Alberta approved the Lower Athabasca Regional Plan ("**LARP**") which came into force on September 1, 2012. The LARP is the first of seven regional plans developed under the ALUF. LARP covers a region in the northeastern corner of Alberta that is approximately 93,212 square kilometres in size. The region includes a substantial portion of the Athabasca oil sands area, which contains approximately 82% of the province's oil sands resources and much of the Cold Lake oil sands area.

LARP establishes six new conservation areas and nine new provincial recreation areas. In conservation and provincial recreation areas, conventional oil and gas companies with pre-existing tenure may continue to operate. Any new petroleum and gas tenure issued in conservation and provincial recreation areas will include a restriction that prohibits surface access. In contrast, oil sands companies' tenure has been (or will be) cancelled in conservation areas and no new oil sands tenure will be issued. While new oil sands tenure will be issued in provincial recreation areas, new and existing oil sands tenure will prohibit surface access.

In July 2014, the Government of Alberta approved the South Saskatchewan Regional Plan ("**SSRP**") which came into force on September 1, 2014. The SSRP is the second regional plan developed under the ALUF. The SSRP covers approximately 83,764 square kilometres and includes 44% of the provincial population.

The SSRP creates four new and four expanded conservation areas, and two new and six expanded provincial parks and recreational areas. Similar to LARP, the SSRP will honour existing petroleum and natural gas tenure in conservation and provincial recreational areas. However, any new petroleum and natural gas tenures sold in conservation areas, provincial parks, and recreational areas will prohibit surface access. However, oil and gas companies must minimize impacts of activities on the natural landscape, historic resources, wildlife, fish and vegetation when exploring, developing and extracting the resources. Freehold mineral rights will not be subject to this restriction.

British Columbia

In British Columbia, the *Oil and Gas Activities Act* (the "**OGAA**") impacts conventional oil and gas producers, shale gas producers and other operators of oil and gas facilities in the province. Under the OGAA, the British Columbia Oil and Gas Commission (the "**Commission**") has broad powers, particularly with respect to compliance and enforcement and the setting of technical safety and operational standards for oil and gas activities. The *Environmental Protection and Management Regulation* establishes the government's environmental objectives for water, riparian habitats, wildlife and wildlife habitat, old-growth forests and cultural heritage resources. The OGAA requires the Commission to consider these environmental objectives in deciding whether or not to authorize an oil and gas activity. In addition, although not an exclusively environmental statute, the *Petroleum and Natural Gas Act*, in conjunction with the OGAA, requires proponents to obtain various approvals before undertaking exploration or production work, such as geophysical licences, geophysical exploration project approvals, permits for the exclusive right to do geological work and geophysical exploration work, and well, test hole and water-source well authorizations. Such approvals are given subject to environmental considerations and licences and project approvals can be suspended or cancelled for failure to comply with this legislation or its regulations.

Saskatchewan

In May 2011, the Government of Saskatchewan passed changes to *The Oil and Gas Conservation Act* ("**SKOGCA**"), the act governing the regulation of resource development operations in the province. Although the associated Bill received Royal Assent on May 18, 2011, it was not proclaimed into force until April 1, 2012, in conjunction with the release of *The Oil and Gas Conservation Regulations, 2012* ("**OGCR**") and *The Petroleum Registry and Electronic Documents Regulations* ("**Registry Regulations**"). The aim of the amendments to the SKOGCA, and the associated regulations, is to provide resource companies investing in Saskatchewan's energy and resource industries with the best support services and business and regulatory systems available. With the enactment of the Registry Regulations and the OGCR, the Government of Saskatchewan has implemented a number of operational aspects, including the increased demand for record-keeping, increased testing requirements for injection wells and increased investigation and enforcement powers; and, procedural aspects including those related to Saskatchewan's participation as partner in the Petroleum Registry of Alberta.

Liability Management Rating Programs

Alberta

In Alberta, the AER implements 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.

Made effective in three phases, from May 1, 2013 to August 1, 2015, the AER implemented important changes to the AB LLR Program (the "**Changes**") that resulted in a significant increase in the number of oil and gas companies in Alberta that are required to post security. The Changes affect the deemed parameters and costs used in the formula that calculates the ratio of deemed liabilities to deemed assets under the AB LLR Program, increasing a licensee's deemed liabilities and rendering the industry average netback factor more sensitive to asset value fluctuations. The Changes stem from concern that the previous regime significantly underestimated the environmental liabilities of licensees.

The AER implemented 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 is 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*. The list of current wells subject to the IWCP is available on the AER's Digital Data Submission system.

British Columbia

In British Columbia, the Commission implements the Liability Management Rating ("**LMR**") Program, designed to manage public liability exposure related to oil and gas activities by ensuring that permit holders carry the financial risks and regulatory responsibility of their operations through to regulatory closure. Under the LMR Program, the Commission determines the required security deposits for permit holders under the OGAA. The LMR is the ratio of a permit holder's deemed assets to deemed liabilities. Permit holders whose deemed liabilities exceed deemed assets will be considered high risk and reviewed for a security deposit. Permit holders who fail to submit the required security deposit within the allotted timeframe may be in non-compliance with the OGAA.

Saskatchewan

In Saskatchewan, the Ministry of Economy implements the Licensee Liability Rating Program (the "**SK LLR Program**"). The SK LLR Program is designed to assess and manage the financial risk that a licensee's well and facility abandonment and reclamation liabilities pose to an orphan fund (the "**Oil and Gas Orphan Fund**") established under the SKOGCA. The Oil and Gas Orphan Fund is responsible for carrying out the abandonment and reclamation of wells and facilities contained within the SK LLR Program when a licensee or WIP is defunct or missing. The SK LLR Program requires a licensee whose deemed liabilities exceed its deemed assets to post a security deposit. The ratio of deemed liabilities to deemed assets is assessed once each month for all licensees of oil, gas and service wells and upstream oil and gas facilities.

Climate Change Regulation

Federal

Climate change regulation at both the federal and provincial level has the potential to significantly affect the regulatory environment of the oil and natural gas industry in Canada. Such regulations, surveyed below, impose certain costs and risks on the industry.

The Government of Canada is a signatory to the *United Nations Framework Convention on Climate Change* (the "**UNFCCC**") and a participant to the Copenhagen Accord (a non-binding agreement created by the UNFCCC which represents a broad political consensus and reinforces commitments to reducing greenhouse gas ("**GHG**") emissions). On January 29, 2010, Canada inscribed in the Copenhagen Accord its 2020 economy-wide target of a 17% reduction of GHG emissions from 2005 levels. This target is aligned with the United States target. In a report dated October 2013, the federal government stated that this target represents a significant challenge in light of strong economic growth (Canada's economy is projected to be approximately 31% larger in 2020 compared to 2005 levels).

On April 26, 2007, the Government of Canada released "Turning the Corner: An Action Plan to Reduce Greenhouse Gases and Air Pollution" (the "**Action Plan**") which set forth a plan for regulations to address both GHGs and air pollution. An update to the Action Plan, "Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions" was released on March 10, 2008 (the "**Updated Action Plan**"). The Updated Action Plan outlines emissions intensity-based targets, for application to regulated sectors on a facility-specific basis, sector-wide basis or company-by-company basis. Although the intention was for draft regulations aimed at implementing the Updated Action Plan to become binding on January 1, 2010, the only regulations being implemented are in the transportation and electricity sectors. The federal government indicates that it is taking a sector-by-sector regulatory approach to reducing GHG emissions and is working on regulations for other sectors. Representatives of the Government of Canada have indicated that the proposals contained in the Updated Action Plan will be modified to ensure consistency with the direction ultimately taken by the United States with respect to GHG emissions regulation. 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 GHG emissions.

On December 12, 2015, the UNFCCC adopted the Paris Agreement, to which Canada is a participant. The Paris Agreement mandates that all countries must work together to limit global temperature rise resulting from GHG emissions to a goal of less than 2° Celsius and to pursue efforts to limit below 1.5° Celsius, through implementing successive nationally determined contributions. Technical details remain unreleased, but the Government of Canada is expected to announce a plan within 90 days of the Paris Agreement, which will significantly increase Canada's GHG emission reduction targets.

Alberta

As part of its efforts to reduce GHG emissions, Alberta introduced legislation to address GHG emissions: the *Climate Change and Emissions Management Act* (the "**CCEMA**") enacted on December 4, 2003 and amended through the *Climate Change and Emissions Management Amendment Act*, which received royal assent on November 4, 2008. The accompanying regulations include the *Specified Gas Emitters Regulation* ("**SGER**"), which imposes GHG limits, and the *Specified Gas Reporting Regulation*, which imposes GHG emissions reporting requirements. Alberta is the first jurisdiction in North America to impose regulations requiring large facilities in various sectors to reduce their GHG emissions. The SGER applies to facilities emitting more than 100,000 tonnes of GHGs in 2003 or any subsequent year ("**Regulated Emitters**"), and requires reductions in GHG emissions intensity (e.g. the quantity of GHG emissions per unit of production) from emissions intensity baselines established in accordance with the SGER.

On June 25, 2015, the Government of Alberta renewed the SGER for a period of two years with significant amendments while Alberta's newly formed Climate Advisory Panel conducted a comprehensive review of the province's climate change policy. In 2015, Regulated Emitters are required to reduce their emissions intensity by 2% from their baseline in the fourth year of commercial operation, 4% of their baseline in the fifth year, 6% of their baseline in the sixth year, 8% of their baseline in the seventh year, 10% of their baseline in the eighth year, and 12% of their baseline in the ninth or subsequent years. These reduction targets will increase, meaning that Regulated Emitters in their ninth or subsequent years of commercial operation must reduce their emissions intensity from their baseline by 15% in 2016 and 20% in 2017.

Regulated Emitters can meet their emissions intensity targets through a combination of the following: (1) producing its products with lower carbon inputs, (2) purchasing emissions offset credits from non-regulated emitters (generated through activities that result in emissions reductions in accordance with established protocols), (3) purchasing emissions performance credits from other Regulated Emitters that earned credits through the reduction of their emissions below the 100,000 tonne threshold, (4) cogeneration compliance adjustments, and (5) by contributing to the Climate Change and Emissions Management Fund (the "**Fund**"). Contributions to the Fund are made at a rate of $15 per tonne of GHG emissions, increasing to a rate of $20 per tonne of GHG emissions in 2016 and $30 per tonne of GHG emissions in 2017. Proceeds from the Fund are directed at testing and implementing new technologies for greening energy production.

On November 22, 2015, as a result of the Climate Advisory Panel's Climate Leadership report, the Government of Alberta announced its Climate Leadership Plan which proposes to introduce a carbon tax on all emitters. An economy-wide levy $30 per tonne of GHG emissions will be phased in, starting in January 2017 at $20 per tonne, and increasing to $30 per tonne in January 2018. An oil sands specific approach was proposed to replace the $30 per tonne of GHG emissions to further reduce emissions and promote carbon competitiveness rather than rewarding past intensity levels. A 100 megatonne per year limit for GHG emissions was proposed for oil sands operations, which currently emit roughly 70 megatonnes per year. This cap exempts new upgrading and cogeneration facilities, which are allocated a separate 10 megatonne limit. The existing SGER will be replaced for large industrial facilities with a Carbon Competitiveness Regulation ("**CCR**"), in which sector specific output-based carbon allocations will be used to ensure competitiveness.

Alberta is also the first jurisdiction in North America to direct dedicated funding to implement carbon capture and storage technology across industrial sectors. Alberta has committed $1.24 billion over 15 years to fund two large-scale carbon capture and storage projects that will begin commercializing the technology on the scale needed to be successful. On December 2, 2010, the Government of Alberta passed the *Carbon Capture and Storage Statutes Amendment Act, 2010*. It deemed the pore space underlying all land in Alberta to be, and to have always been, the property of the Crown and provided for the assumption of long-term liability for carbon sequestration projects by the Crown, subject to the satisfaction of certain conditions.

British Columbia

In February 2008, the Government of British Columbia announced a revenue-neutral carbon tax that took effect July 1, 2008. The tax is consumption-based and applied at the time of retail sale or consumption of virtually all fossil fuels purchased or used in British Columbia. The current tax level is $30 per tonne of GHG emissions. The final scheduled increase took effect on July 1, 2012. There is no plan for further rate increases or expansions at this time. In order to make the tax revenue-neutral, the Government of British Columbia has implemented tax credits and reductions in order to offset the tax revenues that the Government of British Columbia would otherwise receive from the tax.

In the 2012 Budget, the Government of British Columbia announced that it would undertake a comprehensive review of the carbon tax and its impact on British Columbians. The review covered all aspects of the carbon tax, including revenue neutrality, and considered the impact on the competitiveness of British Columbia businesses such as those in the agriculture sector, and in particular, British Columbia's food producers. After the review, the Government of British Columbia confirmed that it will keep its revenue-neutral carbon tax; the current carbon tax rates and tax base will be maintained and revenues will continue to be returned through tax reductions.

On April 3, 2008, the Government of British Columbia introduced the *Greenhouse Gas Reduction (Cap and Trade) Act* (the "**Cap and Trade Act**"), which received royal assent on May 29, 2008 and partially came into force by regulation of the Lieutenant Governor in Council. It sets a province-wide target of a 33% reduction in the 2007 level of GHG emissions by 2020 and an 80% reduction by 2050. Unlike the emissions intensity approach taken by the federal government and the Alberta government, the Cap and Trade Act establishes an absolute cap on GHG emissions. The *Reporting Regulation*, implemented under the authority of the Cap and Trade Act, sets out the requirements for the reporting of the GHG emissions from facilities in British Columbia emitting 10,000 tonnes or more of carbon dioxide equivalent emissions per year beginning on January 1, 2010. Those reporting operations with emissions of 25,000 tonnes or greater are required to have emissions reports verified by a third party. Recent amendments to the Cap and Trade Act repealed past requirements on public-sector organizations, including Crown corporations, to be carbon neutral by 2010, and they are now only required to produce annual carbon reduction plans and reports. Additional regulations that will further enable the Government of British Columbia to implement a cap and trade system are currently under development.

Saskatchewan

On May 11, 2009, the Government of Saskatchewan announced *The Management and Reduction of Greenhouse Gases Act* (the "**MRGGA**") to regulate GHG emissions in the province. The MRGGA received Royal Assent on May 20, 2010 and will come into force on proclamation. The MRGGA establishes a framework for achieving the provincial target of a 20% reduction in GHG emissions from 2006 levels by 2020. Although the MRGGA and related regulations have yet to be proclaimed in force, draft versions indicate that the government of Saskatchewan will permit the use of pre-certified investment credits, early action credits and emissions offsets in compliance, similar to the federal climate change initiatives. It remains unclear whether the scheme implemented by the MRGGA will be based on emissions intensity or an absolute cap on emissions.

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. The risks set out below are not an exhaustive list and should not be taken as a complete summary or description of all the risks associated with the Corporation's business and the oil and natural gas business generally.

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, the Corporation's existing reserves, and the production from them, will decline over time as the Corporation produces from such reserves. A future increase in the Corporation's reserves will depend on both the ability of the Corporation to explore and develop its existing properties and its ability to select and acquire suitable producing properties or prospects. There is no assurance that the Corporation will be able continue to find satisfactory properties to acquire or participate in. Moreover, management of the Corporation may determine that current markets, terms of acquisition, participation or pricing conditions make potential acquisitions or participations uneconomic. There is also no assurance that the Corporation will discover or acquire further commercial quantities of oil and natural gas.

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

Drilling hazards, environmental damage and various field operating conditions could greatly increase the cost of operations and adversely affect the production from successful wells. Field operating conditions include, but are not limited to, delays in obtaining governmental approvals or consents, and shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, it is not possible to eliminate production delays and declines from normal field operating conditions, which can negatively affect revenue and cash flow levels to varying degrees.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including, but not limited to, fire, explosion, blowouts, cratering, sour gas releases, spills and other environmental hazards. These typical risks and hazards could result in substantial damage to oil and natural gas wells, production facilities, other property, the environment and personal injury. Particularly, 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.

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.

As is standard industry practice, the Corporation is not fully insured against all risks, nor are all risks insurable. Although the Corporation maintains liability insurance in an amount that it considers consistent with industry practice, liabilities associated with certain risks could exceed policy limits or not be covered. In either event the Corporation could incur significant costs.

Weakness in the Oil and Gas Industry

Recent market events and conditions, including global excess oil and natural gas supply, recent actions taken by the Organization of the Petroleum Exporting Countries ("OPEC"), slowing growth in China and other emerging economies, market volatility and disruptions in Asia, and sovereign debt levels in various countries, have caused significant weakness and volatility in commodity prices. These events and conditions have caused a significant decrease in the valuation of oil and gas companies and a decrease in confidence in the oil and gas industry. These difficulties have been exacerbated in Canada by the recent changes in government at a federal level and, in case of Alberta, the provincial level and the resultant uncertainty surrounding regulatory, tax and royalty changes that may be implemented by the new governments. In addition, the inability to get the necessary approvals to build pipelines and other facilities to provide better access to markets for the oil and gas industry in western Canada has led to additional uncertainty and reduced confidence in the oil and gas industry in western Canada. Lower commodity prices may also affect the volume and value of the Corporation's reserves especially as certain reserves become uneconomic. In addition, lower commodity prices have restricted, and are anticipated to continue to restrict, the Corporation's cash flow resulting in a reduced capital expenditure budget. As a result, the Corporation may not be able to replace its production with additional reserves and both the Corporation's production and reserves could be reduced on a year over year basis. Any decrease in value of the Corporation's reserves may reduce the borrowing base under its credit facilities, which, depending on the level of the Corporation's indebtedness, could result in the Corporation having to repay a portion of its indebtedness. Given the current market conditions and the lack of confidence in the Canadian oil and gas industry, the Corporation may have difficulty raising additional funds or if it is able to do so, it may be on unfavourable and highly dilutive terms. If these conditions persist, the Corporation's cash flow may not be sufficient to continue to fund its operations and to satisfy its obligations when due and the Corporation's ability to continue as a going concern and discharge its obligations will require additional equity or debt financing and/or proceeds from asset sales. There can be no assurance that such equity or debt financing will be available on terms that are satisfactory to the Corporation or at all. Similarly, there can be no assurance that the Corporation will be able to realize any or sufficient proceeds from asset sales to discharge its obligations and continue as a going concern.

Prices, Markets and Marketing

Numerous factors beyond the Corporation's control do, and will continue to, affect the marketability and price of oil and natural gas acquired or discovered by the Corporation. 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 or contract for the delivery of crude oil by rail. Deliverability uncertainties related to the distance the Corporation's reserves are from pipelines, railway lines, processing and storage facilities, operational problems affecting pipelines, railway lines and facilities as well as government regulation relating to prices, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business may also affect the Corporation.

Prices for oil and natural gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors beyond the control of the Corporation. These factors include economic conditions in the United States, Canada, Europe, China and emerging markets, the actions of OPEC, governmental regulation, political stability in the Middle East, Northern Africa and elsewhere, the foreign supply and demand of oil and natural gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Prices for oil and natural gas are also subject to the availability of foreign markets and the Corporation's ability to access such markets. Oil prices are expected to remain volatile and may decline in the near future as a result of global excess supply due to the increased growth of shale oil production in the United States, the decline in global demand for exported crude oil commodities, and OPEC's recent decisions pertaining to the oil production of OPEC member countries, among other factors. A 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 because of lower prices, which could result in reduced production of oil or natural gas and a reduction in the volumes and the value of the Corporation's reserves. The Corporation might also elect not to produce from certain wells at lower prices.

All these factors could result in a material decrease in the Corporation's expected net production revenue and a reduction in its oil and natural gas acquisition, development and exploration activities. Any substantial and extended decline in the price of oil and natural gas would have an adverse effect on the Corporation's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Oil and natural gas prices are expected to remain volatile for the near future because of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies, OPEC actions, sanctions imposed on certain oil producing nations by other countries and ongoing credit and liquidity concerns. Volatile oil and natural gas prices make it difficult to estimate the value of producing properties for acquisitions and often cause disruption in the market for oil and natural 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.

See "*Weakness in the Oil and Gas Industry*".

Market Price of Common Shares

The trading price of securities of oil and natural gas issuers is subject to substantial volatility often based on factors related and unrelated to the financial performance or prospects of the issuers involved. Factors unrelated to the Corporation's performance could include macroeconomic developments nationally, within North America or globally, domestic and global commodity prices or current perceptions of the oil and gas market. Similarly, the market price of the common shares of the Corporation could be subject to significant fluctuations in response to variations in the Corporation's operating results, financial condition, liquidity and other internal factors. Accordingly, the price at which the common shares of the Corporation will trade cannot be accurately predicted.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The Corporation considers acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner and the Corporation's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Corporation. The integration of acquired businesses may require substantial management effort, time and resources diverting 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 may be periodically disposed of so 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, may realize less than their carrying value on the financial statements of the Corporation.

Operational Dependence

Other companies operate some of the assets in which the Corporation has an interest. 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 depends upon a number of factors that may be outside of the Corporation's control, including, but not limited to, the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

In addition, due to the current low and volatile commodity prices, many companies, including companies that may operate some of the assets in which the Corporation has an interest, may be in financial difficulty, which could impact their ability to fund and pursue capital expenditures, carry out their operations in a safe and effective manner and satisfy regulatory requirements with respect to abandonment and reclamation obligations. If companies that operate some of the assets in which the Corporation has an interest fail to satisfy regulatory requirements with respect to abandonment and reclamation obligations the Corporation may be required to satisfy such obligations and to seek recourse from such companies. To the extent that any of such companies go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in such assets being shut-in, the Corporation potentially becoming subject to additional liabilities relating to such assets and the Corporation having difficulty collecting revenue due from such operators. Any of these factors could materially adversely affect the Corporation's financial and operational results.

Reliance on Royalty Payers

The Corporation relies on other companies drilling and producing from lands in which the Corporation has a royalty interest. The Corporation has limited ability to exercise influence over the decision of other companies to drill and produce from lands in which the Corporation has a royalty interest. The Corporation's return on lands it which it has a royalty interest depends upon a number of factors that may be outside of the Corporation's control, including, but not limited to, the capital expenditure budgets and financial resources of the companies who have a working interest in such lands, the operator's ability to efficiently produce the resources from such lands and commodity prices.

In addition, due to the current low and volatile commodity prices, many companies, including companies that may have a working interest in the lands in which the Corporation has a royalty interest, may be in financial difficulty, which could affect their ability to fund and pursue capital expenditures on such lands. In addition, weak commodity prices might result in companies choosing to defer capital spending or shutting-in existing production. Any reduction in the drilling and production from lands in which the Corporation has a royalty interest will negatively affect the Corporation's cash flows and financial results.

Any financial difficulty of any companies who have assets in which the Corporation has a royalty interest may affect the Corporation's ability to collect royalty payments especially if such companies go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency.

Project Risks

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

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of storage capacity;
- the availability of, and the ability to acquire, water supplies needed for drilling and hydraulic fracturing, or the Corporation's ability to dispose of water used or removed from strata at a reasonable cost and in accordance with applicable environmental regulations;
- the supply of and demand for oil and natural gas;
- the availability of alternative fuel sources;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- transportation outages;
- currency fluctuations;
- regulatory changes;
- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, the Corporation could be unable to execute projects on time, on budget, or at all, and may be unable to market the oil and natural gas that it produces effectively.

Gathering and Processing Facilities, Pipeline Systems and Rail

The Corporation delivers its products through gathering and processing facilities and pipeline systems some of which it does not own and by rail. The amount of oil and natural gas that the Corporation can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities, pipeline systems and railway lines. The lack of availability of capacity in any of the gathering and processing facilities, pipeline systems and railway lines, and in particular the processing facilities, could result in the Corporation's inability to realize the full economic potential of its production or in a reduction of the price offered for the Corporation's production. The lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to produce and market oil and natural gas production. In addition, the pro-rationing of capacity on inter-provincial pipeline systems continues to affect the ability to export oil and natural gas. Unexpected shut downs or curtailment of capacity of pipelines for maintenance or integrity work or because of actions taken by regulators could also affect the Corporation's production, operations and financial results. Furthermore, producers are increasingly turning to rail as an alternative means of transportation. In recent years, the volume of crude oil shipped by rail in North America has increased dramatically. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities could harm the Corporation's business and, in turn, the Corporation's financial condition, results of operations and cash flows. The federal government has signaled that it plans to review the National Energy Board approval process for large projects. This may cause the timeframe for project approvals to increase for current and future applications.

Following major accidents in Lac-Megantic, Quebec and North Dakota, the Transportation Safety Board of Canada and the U.S. National Transportation Board have recommended additional regulations for railway tank cars carrying crude oil. In June 2015, as a result of these recommendations, the Government of Canada passed the Safe and Accountable Rail Act which increased insurance obligations on the shipment of crude oil by rail, imposed a per tonne levy of $1.65 on crude oil shipped by rail to compensate victims and for environmental cleanup in the event of a railway accident. In addition to this legislation, new regulations have implemented the TC-117 standard for all rail tank cars carrying flammable liquids which formalized the commitment to retrofit, and eventually phase out DOT-111 tank cars carrying crude oil. The increased regulation of rail transportation may reduce the ability of railway lines to alleviate pipeline capacity issues and add additional costs to the transportation of crude oil by rail.

A portion of the Corporation's production may, from time to time, be processed through facilities owned by third parties and over which the Corporation does not have control. From time to time these facilities may discontinue or decrease operations either as a result of normal servicing requirements or as a result of unexpected events. A discontinuation or decrease of operations could have a materially adverse effect on the Corporation's ability to process its production and deliver the same for sale.

Competition

The petroleum industry is competitive in all of its phases. The Corporation competes with numerous other entities 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, methods, and reliability of delivery and storage.

Cost of New Technologies

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

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 oil, natural gas and other liquid hydrocarbons. The Corporation cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on the Corporation's business, financial condition, results of operations and cash flows.

Regulatory

Various levels of governments impose extensive controls and regulations on oil and natural gas operations (including exploration, development, production, pricing, marketing and transportation). Governments may regulate or intervene with respect to exploration and production activities, prices, taxes, royalties and the exportation of oil and natural gas. Amendments to these controls and regulations may occur from time to time in response to economic or political conditions. See "**Industry Conditions**". The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for crude oil and natural gas and increase the Corporation's costs, either of which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In order to conduct oil and natural gas operations, the Corporation will require regulatory permits, licenses, registrations, approvals and authorizations from various governmental authorities. There can be no assurance that the Corporation will be able to obtain all of the permits, licenses, registrations, approvals and authorizations that may be required to conduct operations that it may wish to undertake. In addition to regulatory requirements pertaining to the production, marketing and sale of oil and natural gas mentioned above, the Corporation's business and financial condition could be influenced by federal legislation affecting, in particular, foreign investment, through legislation such as the *Competition Act* (Canada) and the *Investment Canada Act* (Canada).

Royalty Regimes

There can be no assurance that the federal government and the provincial governments of the western provinces will not adopt new royalty regimes or modify the existing royalty regimes which may have an impact on the economics of the Corporation's projects. An increase in royalties would reduce the Corporation's earnings and could make future capital investments, or the Corporation's operations, less economic. On January 29, 2016, the Government of Alberta adopted a new royalty regime which will take effect on January 1, 2017. Details of this new regime are scheduled to be finalized and released before March 31, 2016. See "*Industry Conditions – Royalties and Incentives*".

Hydraulic Fracturing

Hydraulic fracturing involves the injection of water, sand and small amounts of additives under pressure into rock formations to stimulate the production of oil and natural gas. Specifically, hydraulic fracturing enables the production of commercial quantities of oil and natural gas from reservoirs that were previously unproductive. Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to operational delays, increased operating costs, third party or governmental claims, and could increase the Corporation's costs of compliance and doing business as well as delay the development of oil and natural gas resources from shale formations, which are not commercial without the use of hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that the Corporation is ultimately able to produce from its reserves.

Due to recent seismic activity reported in the Fox Creek area of Alberta, the Alberta Energy Regulator has announced new seismic monitoring and reporting requirements for hydraulic fracturing operators in the Duvernay Zone in the Fox Creek area. These requirements include, among others, an assessment of the potential for seismicity prior to operations, the implementation of a response plan to address potential events, and the suspension of operations if a seismic event above a particular threshold occurs. The Alberta Energy Regulator continues to monitor seismic activity around the province and may extend these requirements to other areas of the province if necessary.

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 the spill, release or emission of various substances produced in association with certain oil and gas industry operations. In addition, such legislation sets out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites.

Compliance with environmental legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Corporation to incur costs to remedy such discharge. Although the Corporation believes that it will be in material compliance with current applicable environmental 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.

Liability Management

Alberta, Saskatchewan and British Columbia have developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder becomes defunct. These programs generally involve an assessment of the ratio of a licensee's deemed assets to deemed liabilities. If a licensee's deemed liabilities exceed its deemed assets, a security deposit is required. Changes of the ratio of the Corporation's deemed assets to deemed liabilities or changes to the requirements of liability management programs may result in significant increases to the security that must be posted. In addition, the liability management system may prevent or interfere with the Corporation's ability to acquire or dispose of assets as both the vendor and the purchaser of oil and gas assets must be in compliance with the liability management programs (both before and after the transfer of the assets) for the applicable regulatory agency to allow for the transfer of such assets. This is of particular concern to junior oil and gas companies as they may be disproportionately affected by price instability. See "*Industry Conditions – Liability Management Rating Programs*".

Climate Change

The Corporation's exploration and production facilities and other operations and activities emit greenhouse gases which may require the Corporation to comply with GHG emissions legislation at the provincial or federal level. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place. As a signatory to the *United Nations Framework Convention on Climate Change* (the "**UNFCCC**") and a participant to the Copenhagen Agreement (a non-binding agreement created by the UNFCCC), the Government of Canada announced on January 29, 2010 that it will seek a 17% reduction in GHG emissions from 2005 levels by 2020; however, these GHG emission reduction targets are not binding. Some of the Corporation's significant facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage GHG emissions. As a result of the UNFCCC adopting the Paris Agreement on December 12, 2015, to which Canada was a participant, the Government of Canada is expected to announce a plan to further reduce its GHG emission reduction targets by March 11, 2016. The direct or indirect costs of compliance with these regulations may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In addition, concerns about climate change have resulted in a number of environmental activists and members of the public opposing the continued exploitation and development of fossil fuels. Given the evolving nature of the debate related to climate change and the control of GHG and resulting requirements, it is not possible to predict the impact on the Corporation and its operations and financial condition. See "*Industry Conditions – Climate Change Regulation*".

Variations in Foreign Exchange Rates and Interest Rates

World oil and natural gas prices are quoted in United States dollars. The Canadian/United States dollar exchange rate, which fluctuates over time, consequently affects the price received by Canadian producers of oil and natural gas. Material increases in the value of the Canadian dollar relative to the United States dollar will negatively affect the Corporation's production revenues. Accordingly, exchange rates between Canada and the United States could affect the future value of the Corporation's reserves as determined by independent evaluators. Although a low value of the Canadian dollar relative to the United States dollar may positively affect the price the Corporation receives for its oil and natural gas production, it could also result in an increase in the price for certain goods used for the Corporation's operations, which may have a negative impact on the Corporation's financial results.

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, resulting in a reduced amount available to fund its exploration and development activities, and if applicable, the cash available for dividends and could negatively impact the market price of the common shares of the Corporation.

Substantial Capital Requirements

The Corporation anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. As future capital expenditures will be financed out of cash generated from operations, borrowings and possible future equity sales, the Corporation's ability to do so is dependent on, among other factors:

- the overall state of the capital markets;
- the Corporation's credit rating (if applicable);
- commodity prices;
- interest rates;
- royalty rates;
- tax burden due to current and future tax laws; and
- investor appetite for investments in the energy industry and the Corporation's securities in particular.

Further, if the Corporation's revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future drilling programs. The current conditions in the oil and gas industry have negatively impacted the ability of oil and gas companies to access additional financing. 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 Corporation may be required to seek additional equity financing on terms that are highly dilutive to existing shareholders. The inability of the Corporation to access sufficient capital for its operations could have a material adverse effect on the Corporation's business financial condition, results of operations and prospects.

Additional Funding Requirements

The Corporation's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times and from time to time, the Corporation may require additional financing in order to carry out its oil and natural gas acquisition, exploration and development activities. Failure to obtain 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. Due to the conditions in the oil and gas industry and/or global economic volatility, the Corporation may from time to time have restricted access to capital and increased borrowing costs. The current conditions in the oil and gas industry have negatively impacted the ability of oil and gas companies to access additional financing.

Continued depressed oil and natural gas prices have caused decreases, and may cause further decreases, in the Corporation's revenues from its reserves, which may affect the Corporation's ability to expend the necessary capital to replace its reserves or to maintain its production. To the extent that external sources of capital become limited, unavailable or available on onerous terms, the Corporation's ability to make capital investments and maintain existing assets may be impaired, and its assets, liabilities, business, financial condition and results of operations may be affected materially and adversely as a result. In addition, the future development of the Corporation's petroleum properties may require additional financing and there are no assurances that such financing will be available or, if available, will be available upon acceptable terms. Alternatively, any available financing may be highly dilutive to existing shareholders. Failure to obtain any financing necessary for the Corporation's capital expenditure plans may result in a delay in development or production on the Corporation's properties.

Credit Facility Arrangements

The Corporation currently has a credit facility and the amount authorized thereunder is dependent on the borrowing base determined by its lenders. The Corporation is required to comply with covenants under its credit facility which may, in certain cases, include certain financial ratio tests, which from time to time either affect the availability, or price, of additional funding and in the event that the Corporation does not comply with these covenants, the Corporation's access to capital could be restricted or repayment could be required. Events beyond the Corporation's control may contribute to the failure of the Corporation to comply with such covenants. A failure to comply with covenants could result in default under the Corporation's credit facility, which could result in the Corporation being required to repay amounts owing thereunder. The acceleration of the Corporation's indebtedness under one agreement may permit acceleration of indebtedness under other agreements that contain cross default or cross-acceleration provisions. In addition, the Corporation's credit facility may impose operating and financial restrictions on the Corporation that could include restrictions on, the payment of dividends, repurchase or making of other distributions with respect to the Corporation's securities, incurring of additional indebtedness, the provision of guarantees, the assumption of loans, making of capital expenditures, entering into of amalgamations, mergers, take-over bids or disposition of assets, among others.

The Corporation's lenders use the Corporation's reserves, commodity prices, applicable discount rate and other factors, to periodically determine the Corporation's borrowing base. Commodity prices continue to be depressed and have fallen dramatically since 2014. There remains a substantial amount of uncertainty as to when and if commodity prices will recover. Depressed commodity prices could reduce the Corporation's borrowing base, reducing the funds available to the Corporation under the credit facility. This could result in the requirement to repay a portion, or all, of the Corporation's indebtedness.

If the Corporation's lenders require repayment of all or portion of the amounts outstanding under its credit facilities for any reason, including for a default of a covenant or the reduction of a borrowing base, there is no certainty that the Corporation would be in a position to make such repayment. Even if the Corporation is able to obtain new financing in order to make any required repayment under its credit facilities, it may not be on commercially reasonable terms or terms that are acceptable to the Corporation. If the Corporation is unable to repay amounts owing under credit facilities, the lenders under the credit facility could proceed to foreclose or otherwise realize upon the collateral granted to them to secure the indebtedness.

Issuance of Debt

From time to time, the Corporation may enter into transactions to acquire assets or 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 debt financing that may not be available or, if available, may not be available on favourable terms. Neither the Corporation's articles nor its by-laws limit the amount of indebtedness that the Corporation may incur. The level of the Corporation's indebtedness from time to time could impair the Corporation's ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

Hedging

From time to time, the Corporation may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline. However, to the extent that the Corporation engages in price risk management activities to protect itself from commodity price declines, it may also be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to manage price risk. In addition, the Corporation's hedging arrangements may expose it to the risk of financial loss in certain circumstances, including instances in which:

- production falls short of the hedged volumes or prices fall significantly lower than projected;
- there is a widening of price-basis differentials between delivery points for production and the delivery point assumed in the hedge arrangement;
- the counterparties to the hedging arrangements or other price risk management contracts fail to perform under those arrangements; or
- a sudden unexpected event materially impacts oil and natural gas prices.

Similarly, from time to time the Corporation may enter into agreements to fix the exchange rate of Canadian to United States dollars or other currencies in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to other currencies. However, if the Canadian dollar declines in value compared to such fixed currencies, the Corporation will not benefit from the fluctuating exchange rate.

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.

Diluent Supply

Heavy oil and bitumen are characterized by high specific gravity or weight and high viscosity or resistance to flow. Diluent is required to facilitate the transportation of heavy oil and bitumen. A shortfall in the supply of diluent may cause its price to increase thereby increasing the cost to transport heavy oil and bitumen to market and correspondingly increasing the Corporation's overall operating cost, decreasing its net revenues and negatively impacting the overall profitability of its heavy oil and bitumen projects.

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. The actual interest of the Corporation in properties may accordingly vary from the Corporation's records. If a title defect does exist, it is possible that the Corporation may lose all or a portion of the properties to which the title defect relates, which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. There may be valid challenges to title or legislative changes, which affect the Corporation's title to the oil and natural gas properties the Corporation controls that could impair the Corporation's activities on them and result in a reduction of the revenue received by 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 reserve and associated cash flow information set forth in this document are estimates only. Generally, estimates of economically recoverable oil and natural gas reserves and the future net cash flows from such estimated reserves are based upon a number of variable factors and assumptions, such as:

- historical production from the properties;
- production rates;
- ultimate reserve recovery;
- timing and amount of capital expenditures;
- marketability of oil and natural gas;
- royalty rates; and
- 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 and such variations could be material.

The estimation of proved reserves that may be developed and produced in the future is 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. 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 natural 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 and 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, except as may be specifically stated, has not been updated and therefore does not reflect changes in the Corporation's reserves since that date.

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, certain 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.

Geopolitical Risks

Political events throughout the world that cause disruptions in the supply of oil continuously affect the marketability and price of oil and natural gas acquired or discovered by the Corporation. Conflicts, or conversely peaceful developments, arising outside of Canada have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and result in a reduction of the Corporation's net production revenue.

In addition, the Corporation's oil and natural gas properties, wells and facilities could be the subject of 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 does not have insurance to protect against the risk from terrorism.

Dilution

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

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.

Expiration of Licences and Leases

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

Dividends

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

Litigation

In the normal course of the Corporation's operations, it may become involved in, named as a party to, or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions, related to personal injuries, property damage, property tax, land rights, the environment and contract disputes. The outcome of outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to the Corporation and as a result, could have a material adverse effect on the Corporation's assets, liabilities, business, financial condition and results of operations.

Even if the Corporation prevails in any such legal proceeding, the proceedings could be costly and time-consuming and may divert the attention of management and key personnel from the Corporation's business operations, which could adversely affect its financial condition.

Intellectual Property Litigation

Due to the rapid development of oil and gas technology, in the normal course of the Corporation's operations, the Corporation may become involved in, named as a party to, or be the subject of, various legal proceedings in which it is alleged that the Corporation has infringed the intellectual property rights of others or commenced lawsuits against others who the Corporation believes are infringing upon its intellectual property rights. The Corporation's involvement in intellectual property litigation could result in significant expense, adversely affecting the development of its assets or intellectual property or diverting the efforts of its technical and management personnel, whether or not such litigation is resolved in the Corporation's favour. In the event of an adverse outcome as a defendant in any such litigation, the Corporation may, among other things, be required to: (a) pay substantial damages; cease the development, use, sale or importation of processes that infringe upon other patented intellectual property; (b) expend significant resources to develop or acquire non-infringing intellectual property; (c) discontinue processes incorporating infringing technology; or (d) obtain licences to the infringing intellectual property. However, the Corporation may not be successful in such development or acquisition or such licences may not be available on reasonable terms. Any such development, acquisition or licence could require the expenditure of substantial time and other resources and could have a material adverse effect on the Corporation's business and financial results.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights in 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.

Breach of Confidentiality

While discussing potential business relationships or other transactions with third parties, the Corporation may disclose confidential information relating to the business, operations or affairs of the Corporation. Although confidentiality agreements are signed by third parties prior to the disclosure of any confidential information, a breach could put the Corporation at competitive risk and may cause significant damage to its business. The harm to the Corporation's business from a breach of confidentiality cannot presently be quantified, but may be material and may not be compensable in damages. There is no assurance that, in the event of a breach of confidentiality, the Corporation will be able to obtain equitable remedies, such as injunctive relief, from a court of competent jurisdiction in a timely manner, if at all, in order to prevent or mitigate any damage to its business that such a breach of confidentiality may cause.

Income Taxes

The Corporation files all required income tax returns and believes that it is in full compliance with the provisions of the Tax Act and all other applicable provincial tax legislation. However, such returns are subject to reassessment by the applicable taxation authority. In the event of a successful reassessment of the Corporation, whether by re-characterization of exploration and development expenditures or otherwise, such reassessment may have an impact on current and future taxes payable.

Income tax laws relating to the oil and natural gas industry, such as the treatment of resource taxation or dividends, may in the future be changed or interpreted in a manner that adversely affects the Corporation. Furthermore, tax authorities having jurisdiction over the Corporation may disagree with how the Corporation calculates its income for tax purposes or could change administrative practices to the Corporation's detriment.

Seasonality

The level of activity in the Canadian oil and natural 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. In addition, certain oil and natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding decreases in the demand for the goods and services of the Corporation. The exploration for and the development of oil and natural gas reserves is dependent on access to areas where drilling is to be conducted. Seasonal weather variation, including "freeze-up" and "break-up", affect access in certain circumstances.

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 addition, the Corporation may be exposed to third party credit risk from operators of properties in which the Corporation has a working or royalty interest. 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 affect 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. To the extent that any of such third parties go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in the Corporation being unable to collect all or portion of any money owing from such parties. Any of these factors could materially adversely affect the Corporation's financial and operational results.

Conflicts of Interest

Certain directors or officers of the Corporation may also be directors or officers of other oil and natural gas companies and as such may, in certain circumstances, have a conflict of interest. Conflicts of interest, if any, will be subject to and governed by procedures prescribed by the ABCA which require a director of officer of a corporation who is a party to, or is a director or an officer of, or has a material interest in any person who is a party to, a material contract or proposed material contract with the Corporation to disclose his or her interest and, in the case of directors, to refrain from voting on any matter in respect of such contract unless otherwise permitted under the ABCA. See "**Directors and Officers – Conflicts of Interest**".

Reliance on Key Personnel

The Corporation's success depends in large measure on certain key personnel. The loss of the services of such key personnel may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The Corporation does not have any key person insurance in effect for the Corporation. The contributions of the existing management team to the immediate and near term operations of the Corporation are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that the Corporation will be able to continue to attract and retain all personnel necessary for the development and operation of its business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the management of the Corporation.

Expansion into New Activities

The operations and expertise of the Corporation's management are currently focused primarily on oil and gas production, exploration and development in the Western Canada Sedimentary Basin. In the future the Corporation may acquire or move into new industry related activities or new geographical areas, may acquire different energy related assets, and as a result may face unexpected risks or alternatively, significantly increase the Corporation's exposure to one or more existing risk factors, which may in turn result in the Corporation's future operational and financial conditions being adversely affected.

Forward-Looking Information May Prove Inaccurate

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

Share Price Volatility

The market price for Common Shares may be volatile and subject to wide fluctuations in response to numerous factors, many of which are beyond the Corporation's control, including the following: (i) actual or anticipated fluctuations in the Corporation's quarterly results of operations; (ii) actual or anticipated changes in oil and natural gas prices; (iii) recommendations by securities research analysts; (iv) changes in the economic performance or market valuations of other companies that investors deem comparable to the Corporation; (v) addition or departure of the Corporation's executive officers and other key personnel; (vi) sales or perceived sales of additional Common Shares; (vii) significant acquisitions or business combinations, strategic partnerships, joint ventures or capital commitments by or involving the Corporation or its competitors; and (viii) news reports relating to trends, concerns, technological or competitive developments, regulatory changes and other related issues in the Corporation's industry or target markets.

Financial markets have experienced significant price and volume fluctuations in the last several years that have particularly affected the market prices of equity securities of companies and that have, in many cases, been unrelated to the operating performance, underlying asset values or prospects of such companies. Accordingly, the market price of the Common Shares may decline even if the Corporation's operating results, underlying asset values or prospects have not changed. Additionally, these factors, as well as other related factors, may cause decreases in asset values that are deemed to be other than temporary, which may result in impairment losses. As well, certain institutional investors may base their investment decisions on consideration of the Corporation's environmental, governance and social practices and performance against such institutions' respective investment guidelines and criteria, and failure to meet such criteria may result in a limited or no investment in the Common Shares by those institutions, which could adversely affect the trading price of the Common Shares. There can be no assurance that continuing fluctuations in the price and volume of publicly traded equity securities will not occur. If such increased levels of volatility and market turmoil continue, the Corporation's operations could be adversely impacted and the trading price of the Common Shares may be adversely affected.

Future Acquisition Activities May Have Adverse Effects

The acquisition of oil and natural gas companies and assets is subject to substantial risks, including the failure to identify material problems during due diligence, the risk of over-paying for assets and the inability to arrange financing for an acquisition as may be required or desired. Further, the integration and consolidation of acquisitions requires substantial human, financial and other resources and, ultimately, the Corporation's acquisitions may not be successfully integrated. There can be no assurances that any future acquisitions will perform as expected or that the returns from such acquisitions will support the indebtedness incurred to acquire them or the capital expenditures needed to develop them.

Internal Controls

Effective internal controls are necessary for the Corporation to provide reliable financial reports and to help prevent fraud. Although the Corporation undertakes a number of procedures in order to help ensure the reliability of its financial reports, including those imposed on it under Canadian securities laws, the Corporation cannot be certain that such measures will ensure that the Corporation will maintain adequate control over financial processes and reporting. Failure to implement required new or improved controls, or difficulties encountered in their implementation, could harm the Corporation's results of operations or cause it to fail to meet its reporting obligations. If the Corporation or its independent auditors discover a material weakness, the disclosure of that fact, even if quickly remedied, could reduce the market's confidence in the Corporation's consolidated financial statements and adversely affect the trading price of the Common Shares. Other than as disclosed in this document, the company has not disclosed any material weaknesses in its internal controls in the past two years.

Additional Risks

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

CONVENTIONS

Certain other terms used but not defined herein are defined in National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* ("**NI 51-101**") and in the Canadian Oil and Gas Evaluation Handbook Volume I (the "**COGE Handbook**"). 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, 2015. All dollar amounts herein are in Canadian dollars, unless otherwise stated. Words importing the singular also include the plural, and *vice versa*, and words importing one gender include all genders.

ABBREVIATIONS

Natural Gas		**Oil and Liquids**	
Mcf	thousand cubic feet	bbl	barrels
Mcfe	thousand cubic feet equivalent	Mbbl	thousand barrels
MMcf	million cubic feet	MMbbl	million barrels
MMcfe	million cubic feet equivalent	bbl/d	barrels per day
Bcf	billion cubic feet	m^3	cubic metres
Bcfe	billion cubic feet equivalent	boe	barrel of oil equivalent
Mcf/d	thousand cubic feet per day	Mboe	thousand barrels of oil equivalent
MMcf/d	million cubic feet per day	MMboe	million barrels of oil equivalent
Mcfe/d	thousand cubic feet equivalent per day	boe/d	barrels of oil equivalent per day
m^3	cubic metres		
MMbtu	million British Thermal Units		
GJ	Gigajoule		

The Corporation reports production and reserves in either Mcf equivalent (Mcfe) or barrels of oil equivalent (boe). Mcfe and boe may be misleading, particularly if used in isolation. In accordance with NI 51-101, an Mcfe and boe conversion ratio for crude oil and natural gas of 1 bbl: 6 Mcf has been used, which is based on an energy equivalency conversion method primarily applicable at the burner tip and does not necessarily 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 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

CONVERSIONS

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

To Convert From	To	Multiply By
Mcf	cubic metres	28.174
cubic metres	cubic feet	35.494
bbl	cubic metres	0.159
cubic metres	bbl	6.293
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.471
gigajoules	MMbtu	0.950

FORWARD-LOOKING INFORMATION AND STATEMENTS

Certain information and statements contained in this Annual Information Form constitute forward-looking information and statements within the meaning of applicable securities laws. This information and these statements relate to future events or to Perpetual's future performance. All statements other than statements of historical fact may be forward-looking statements. The use of any of the words "anticipate", "continue", "estimate", "expect", "forecast", "may", "will", "project", "should", "believe", "outlook", "guidance", "objective", "plans", "intends", "targeting", "could", "potential", "outlook", "strategy" and any similar expressions are intended to identify forward-looking information and statements.

In particular, but without limiting the foregoing, this Annual Information Form contains forward-looking information and statements pertaining to the following:

- the quantity and recoverability of the Corporation's reserves;
- the timing and amount of future production;
- future commodity prices as well as supply and demand for natural gas and oil;
- the existence, operations and strategy of the Corporation's commodity price risk management program;
- the approximate amount of forward sales and hedging to be employed, and the value of financial forward natural gas contracts;
- funds flow sensitivities to commodity price, production, foreign exchange and interest rate changes;
- operating, general and administrative, and other expenses;
- amount of future abandonment and reclamation costs, decommissioning and environmental obligations;
- the use of exploration and development activity, prudent asset management, and acquisitions to sustain, replace or add to reserves and production or expand the Corporation's asset base;
- the Corporation's acquisition strategy and the existence of acquisition opportunities, the criteria to be considered in connection therewith and the benefits to be derived therefrom;
- the Corporation's s divestiture strategy;
- the Corporation's commodity diversification and asset base transformation strategy;
- the Corporation's business plan;
- future growth in the Corporation's funds flow;
- the Corporation's ability to benefit from the combination of growth opportunities and the ability to grow through the capital markets;
- expected book value and related tax value of the Corporation's assets and prospect inventory and estimates of net asset value;
- ability to fund exploration and development;
- expectations regarding the Corporation's access to capital to fund its acquisition, exploration and development activities;
- deferred income tax and its effect on funds flow;
- intentions with respect to preservation of tax pools and taxes payable by the Corporation;
- funding of and anticipated results from capital expenditure programs;
- renewal of and borrowing costs associated with the credit facility;
- future debt levels, financial capacity, liquidity and capital resources;
- future contractual commitments;
- drilling, completion, facilities and construction plans;
- future drilling, workovers and recompletions estimated in Perpetual's prospect inventory;
- the impact of Canadian federal and provincial governmental regulation on the Corporation relative to other issuers;
- Crown royalty rates;
- working gas capacity and other operating and marketing parameters related to WGS LP;
- the Corporation's treatment under governmental regulatory regimes;
- business strategies and plans of management, including future changes in the structure of business operations; and
- reliance on third parties in the industry to develop and expand the Corporation's assets and operations.

The forward-looking information and statements contained in this Annual Information Form reflect several material factors and expectations and assumptions of the Corporation including, without limitation, that Perpetual will conduct its operations in a manner consistent with its expectations and, where applicable, consistent with past practice; the general continuance of current or, where applicable, assumed industry conditions; the continuance of existing, and in certain circumstances, the implementation of proposed tax, royalty and regulatory regimes; the ability of Perpetual to obtain equipment, services, and supplies in a timely manner to carry out its activities; the accuracy of the estimates of Perpetual's reserve volumes; the timely receipt of required regulatory approvals; certain commodity price and other cost assumptions; the ability to secure adequate product transportation; the continued availability of adequate debt and/or equity financing and funds flow to fund the Corporation's capital and operating requirements as needed; and the extent of Perpetual's liabilities.

Perpetual believes the material factors, expectations and assumptions reflected in the forward-looking information and statements are reasonable but no assurance can be given that these factors, expectations and assumptions will prove to be correct. The forward-looking information and statements included in this Annual Information Form are not guarantees of future performance and should not be unduly relied upon. Such information and 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 information or statements including, without limitation:

- volatility in market prices for oil, natural gas, NGL, power and other products;
- supply and demand regarding Perpetual's products;

- risks inherent in Perpetual's operations, such as production declines, unexpected results, geological, technical, or drilling and process problems;
- unanticipated operating events that can reduce production or cause production to be shut-in or delayed, including plant upsets, transportation bottlenecks and market disruptions;
- unanticipated well or facility operating performance that impacts storage operations or working gas capacity;
- changes in exploration or development plans by Perpetual or by third party operators of Perpetual's properties;
- reliance on industry partners;
- uncertainties or inaccuracies associated with estimating reserves and resource volumes;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands, skilled personnel, equipment for drilling, completions, facilities and pipeline construction and maintenance;
- increased service and operational costs;
- incorrect assessments of the value of acquisitions;
- increased debt levels or debt service requirements;
- industry conditions including fluctuations in the price of natural gas and related commodities;
- royalties payable in respect of Perpetual's production;
- governmental regulation of the oil and gas industry, including environmental regulation;
- fluctuation in foreign exchange or interest rates;
- the need to obtain required approvals from regulatory authorities;
- changes in laws applicable to the Corporation, royalty rates, or other regulatory matters;
- general economic conditions in Canada, the United States and globally;
- stock market volatility and market valuations;
- limited, unfavourable, or a lack of access to capital markets; and
- certain other risks detailed from time to time in Perpetual's public disclosure documents including, without limitation, those risks and contingencies described above and under **"Risk Factors**" in this Annual Information Form. The foregoing list of risk factors should not be considered exhaustive.

The forward-looking information and statements contained in this Annual Information Form speak only as of the date of this Annual Information Form, and none of the Corporation or its subsidiaries assumes any obligation to publicly update or revise them to reflect new events or circumstances, unless expressly required to do so by applicable securities laws.

ADDITIONAL INFORMATION

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

Additional information, including directors' and officers' remuneration and indebtedness, principal holders of the Corporation's securities and securities authorized for issuance under equity compensation plans is contained in the Corporation's information circular for the Corporation's most recent annual meeting of security holders that involved the election of directors.

Additional financial information is contained in the Corporation's financial statements and the related management's discussion and analysis for the Corporation's most recently completed financial year.

APPENDIX A

REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE IN ACCORDANCE WITH FORM 51-101F3

Management of Perpetual Energy Inc. (the "**Corporation**") is responsible for the preparation and disclosure of information with respect to the Corporation's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data.

McDaniel & Associates Consultants Ltd., an independent qualified reserves evaluator, has evaluated the Corporation's reserves data. The report of the independent qualified reserves evaluator is presented below.

The Reserves Committee of the board of directors of the Corporation has

(a) reviewed the Corporation's procedures for providing information to the independent qualified reserves evaluator;

(b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and

(c) reviewed the reserves data with management and the independent qualified reserves evaluator.

The Reserves Committee of the board of directors has reviewed the Corporation's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The Board of Directors has, on the recommendation of the Reserves Committee, approved

(a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information;

(b) the filing of Form 51-102F2 which is the report of the independent qualified reserves evaluator on the reserves data, contingent resources data, or prospective resources 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.

DATED as of this 2nd day of March, 2016.

"*Susan L. Riddell Rose*"
Susan L. Riddell Rose
President and Chief Executive Officer

"*Cameron R. Sebastian*"
Cameron R. Sebastian
Vice President, Finance and Chief Financial Officer

"*Robert A. Maitland*"
Robert A. Maitland
Director

"*Donald J. Nelson*"
Donald J. Nelson
Director, Chairman of the Reserves Committee

APPENDIX B

**REPORT ON RESERVES DATA BY MCDANIEL & ASSOCIATES CONSULTANTS LTD.
IN ACCORDANCE WITH FORM 51-101F2
MCDANIEL & ASSOCIATES CONSULTANTS LTD.**

Attention: The Board of Directors of Perpetual Energy Inc.

Re: **Form 51-101F2
Report on Reserves Data by an Independent Qualified Reserves Evaluator
of Perpetual Energy Inc. (the "Company")**

To the Board of Directors of Perpetual Energy Inc. (the "**Company**"):

1. We have evaluated and reviewed the Company's reserves data as at December 31, 2015. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2015 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 and review.
3. We carried out our evaluation and review in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "**COGE Handbook**") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).
4. Those standards require that we plan and perform an evaluation and review to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation and review also includes assessing whether the reserves data are in accordance with principles and definitions in the COGE Handbook.
5. The following table shows the net present value of future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated and reviewed using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated for the year ended December 31, 2015, and identifies the respective portions thereof that we have evaluated, reviewed and reported on to the Company's Management:

			Net Present Value of Future Net Revenue $M (before income taxes, 10% discount rate)			
Independent Qualified Reserves Evaluator	**Effective Date of Evaluation Report**	**Location of Reserves**	**Audited**	**Evaluated**	**Reviewed**	**Total**
McDaniel & Associates Consultants Ltd.	December 31, 2015	Canada	-	329,823	8,821	338,644

6. In our opinion, the reserves data respectively evaluated and reviewed 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.
7. We have no responsibility to update our report referred to in paragraph 5 for events and circumstances occurring after the effective date of our report.
8. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

MCDANIEL & ASSOCIATES CONSULTANTS LTD.

"signed by P. A. Welch"
P. A. Welch, P. Eng.
President & Managing Director

Calgary, Alberta
February 9, 2016

APPENDIX C

AUDIT COMMITTEE

The Audit Committee:

- must review and, if appropriate, recommend to the Board the approval of the financial statements, MD&A and annual and interim earnings press releases prior to this information being publicly disclosed;
- must annually review this written charter (setting out the Audit Committee's mandate and responsibilities) and recommend any changes to the Compensation and Corporate Governance Committee;
- supply for the purposes of this Manual, in consultation with corporate counsel, a list of the laws, rules and regulations that pertain to the operation of the Audit Committee;
- must recommend to the Board the nomination, appointment, retention and compensation of external auditors ("**Auditors**");
- must oversee the work of Auditors, which oversight may include approval of the Auditor's audit plan, planning report, annual engagement letter, or services related thereto, subject to ratification by the Board
- must review and approve all non-audit services provided by the Auditors prior to the performance of those services;
- communicates directly with the Auditors who must report directly to the Audit Committee;
- must be satisfied that adequate procedures are in place for the review of PEI's public disclosure of financial information extracted or derived from the financial statements, and must periodically assess the adequacies of those procedures;
- must establish procedures for the receipt, retention and treatment of complaints regarding accounting, internal accounting controls, or auditing matters, and for the confidential, anonymous submission by employees of concerns regarding questionable accounting or auditing matters;
- must review and approve PEI's hiring policies regarding former and existing partners and employees of past or present Auditors;
- reviews programs and policies regarding the maintenance and effectiveness of disclosure controls and internal controls over the Corporation's accounting and financial reporting systems;
- reviews insurance coverage and Directors' and Officers' liability insurance; and,
- liaises with the reserves committee ("**Reserves Committee**") on matters relating to reserves valuations which impact the financial statements of PEI.

Purpose

The Audit Committee's purpose is to provide assistance to the Board in fulfilling its legal, regulatory and fiduciary obligations with respect to financial accounting, internal control processes, continuous public disclosure, the independent audit function, non-audit services provided by Auditors and such other related matters as may be delegated by the Board of Directors.

Composition, Procedures and Organization

The Audit Committee will be comprised of three or more Directors as determined from time to time by resolution of the Board.

Each member of the Audit Committee must be independent as defined in NI 52-110 and as such must be free from any material relationship that may interfere with the exercise of his or her independent judgment as a member of the Audit Committee.

Consistent with the appointment of other Board committees, the members of the Audit Committee will be appointed by the Board at the first meeting of the Board following each AGM or at such other time as may be determined by the Board.

The Committee will designate the Chairman of the Audit Committee by majority vote. The presence in person or by telephone of a majority of the Audit Committee's members constitutes a quorum for any meeting.

All actions of the Audit Committee will require a vote of the majority of its members present at a meeting of such committee at which a quorum is present.

All members of the Audit Committee must be financially literate at the time of their appointment or have become financially literate within a reasonable period of time after such appointment. NI 52-110 sets out that an individual is "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 PEI's financial statements.

Accountability and Reporting

The Audit Committee is accountable to the Board. The Audit Committee must provide the Board with a summary of all meetings and its recommendations together with a copy of the minutes of each such meeting. If applicable, the Chairman will provide oral reports as requested.

All information reviewed and discussed by the Audit Committee at any meeting must be retained and made available for examination by the Board. The Audit Committee will review its mandate annually, and will forward to the Compensation and Corporate Governance Committee any recommended alterations to that mandate.

Meetings

The Committee will meet with such frequency and at such intervals as it determines is necessary to carry out its duties and responsibilities.

The Audit Committee will meet to review and recommend for approval to the Board of Directors the interim and year-end financial statements and MD&A; related financial public disclosure and regulatory filings including the Annual Information Form, Management Information Circular; other continuous disclosure documentation ("**Continuous Disclosure Documents**") as described in NI 52-101 (which is incorporated herein by reference); and to report to the Board on same. In addition to regularly scheduled quarterly meetings, the Audit Committee may meet on other occasions with the Auditors in order to be advised of current practices in the industry and to discuss and review other matters including the annual work plans, processes and procedures. The Audit Committee must meet at least quarterly with the Auditors in the absence of PEI's management and Officers and employees to discuss any matters that the Committee or a committee member believes should be discussed privately.

The Chairman of the Audit Committee will appoint a Director, Officer or employee of PEI to act as secretary for the purposes of recording the minutes of each meeting.

Responsibilities

The Audit Committee must:

- review and approve the Audit Committee Mandate annually;
- review and recommend to the Board the appointment, termination and retention of, and the compensation to be paid to, the Auditors;
- evaluate the performance of the Auditors;
- review and consider the Auditors' audit plan and annual engagement letter including the proposed fees and the proposed work plan;
- consider and make recommendations to the Board or otherwise pre-approve, all non-audit services provided by the Auditors to PEI or its subsidiaries;
- oversee the work and the performance of the Auditors, review the independence of the Auditors and report to the Board on these matters;
- review the annual and quarterly financial statements, MD&A and financial press releases, Annual Information Form, Management Information Circular and other related Continuous Disclosure Documents as appropriate, prior to their public disclosure;
- review the Auditors' report on the annual audited financial statements and the Auditor's review letters on interim financial statements;
- provide oral or written reports to the Board when necessary;
- resolve disagreements between management and the Auditors regarding financial reporting;
- receive periodic certificates and reports from management with respect to compliance with financial, regulatory, taxation and continuous disclosure requirements, and satisfy itself (a) that adequate procedures are in place to ensure timely and full public disclosure of Continuous Disclosure Documents; and, (b) that a system of internal controls over financial reporting has been implemented and is being maintained, in accordance with both the Disclosure Policy and the Management Responsibility For Internal Control Policy; and additionally, must consider whether any identified deficiencies in internal controls are significant or are material weaknesses;
- meet with the Auditors, without management being present, at each time the interim and financial statements are being considered, to ensure that no management restrictions have been placed on the scope of the Auditors' work and to discuss the working relationship between the Auditors and management and other matters that the Audit Committee or the Auditors may wish to raise;
- review and monitor the implementation and adequacy of disclosure policies;
- review insurance coverage including Directors' and Officers' liability insurance;
- be notified in writing within three business days of any fraud, litigation or regulatory investigation which, in the opinion of the Corporation's management, is material. Confirmation of receipt of such notification by each member of the Audit Committee will additionally be required. Any fraud, material litigation or regulatory investigation not reported as outlined above will be reported quarterly to the Board of Directors at the March, May, August, and November meetings immediately following the discovery of such occurrence;
- review and monitor the implementation and adequacy of hedging policies and controls, with reference to the Corporation's Hedging and Risk Management Policy, which is attached to this Manual in Section 7;
- review compliance with applicable laws, regulations and policies;
- be advised of and review the results of any internal audits of PEI and report on same to the Board;
- establish procedures for:
  (a) the receipt, retention and treatment of complaints received by PEI regarding accounting, internal accounting controls, or auditing matters; and

(b) the confidential, anonymous submission by employees of the issuer of concerns regarding questionable accounting or auditing matters; (together with (a), a "**Whistleblower Process**")

- ensure that PEI management regularly advises employees of the existence of a Whistleblower Process;
- receive regular reports respecting complaints made under the Whistleblower Process;
- inform the Auditors of whether the Audit Committee has knowledge of any actual, suspected or alleged fraud affecting PEI, including complaints regarding financial reporting and confidential submissions by employees;
- review and validate PEI management's annual review of fraud risk assessment;
- review and approve PEI's hiring policies regarding partners, employees and former partners and employees of the present and former Auditor of the issuer; and
- monitor the selection and application of proper accounting principles and practices and to review the status of all relevant financial and related fiduciary aspects of PEI.