ANNUAL INFORMATION FORM

PERPETUAL
ENERGY

For the year ended
December 31, 2016

March 14, 2017

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APPENDICES

CORPORATE STRUCTURE

Perpetual Energy Inc. ("Perpetual", the "Corporation" or the "Company") is a Canadian corporation headquartered in Calgary, Alberta. Perpetual is engaged in the exploration, development and marketing of oil and natural gas based energy in Alberta, Canada. The Company operates a diversified asset portfolio that includes liquids-rich gas in the Alberta Deep Basin, conventional heavy oil producing properties, shallow gas and undeveloped bitumen resource properties.

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 then 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.

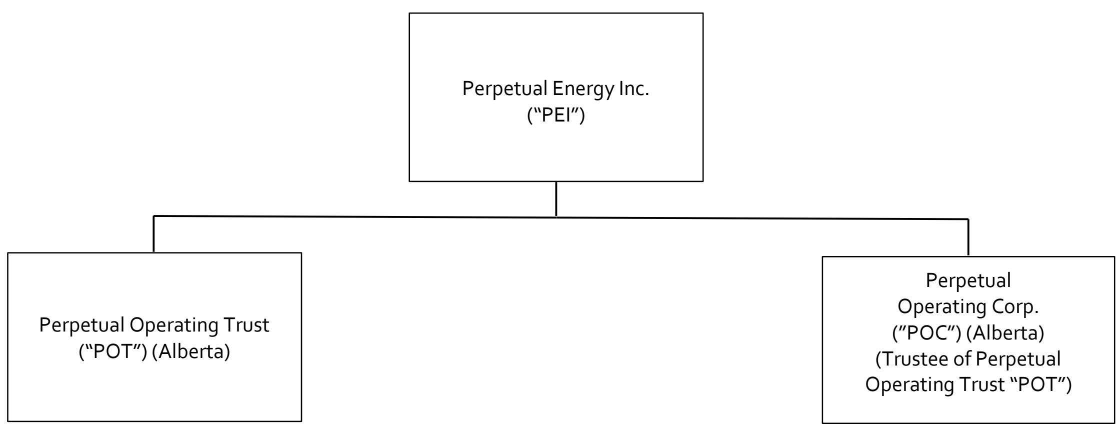
Perpetual's head office and registered office is located at Suite 3200, 605 – 5th Avenue S.W., Calgary, Alberta, T2P 3H5.

Employees

At December 31, 2016, Perpetual had 62 permanent employees and six part time hourly consultants located in its Calgary office and 15 permanent employees and eight 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 is described below.

Recent Developments

On January 23, 2017, Perpetual exchanged approximately $8.4 million aggregate principal amount of its 8.75% senior notes due March 15, 2018 (the "**2018 Senior Notes**") and approximately $9.0 million aggregate principal amount of its 8.75% senior notes due July 23, 2019 (the "**2019 Senior Notes**") for $17.4 million aggregate principal amount 8.75% senior notes due January 23, 2022 (the "**2022 Senior Notes**") collectively (the "**8.75% Senior Notes**").

On February 9, 2017, the Company made a partial repayment and refinanced its financial arrangement secured by 840,619 of the Company's shares of Tourmaline Oil Corp. ("**TOU Shares**") maturing in March 2017. Perpetual sold TOU Shares for net proceeds of $5.7 million and reduced the loan amount outstanding to $18.9 million while extending the maturity to August 1, 2017. The number of TOU Shares pledged as collateral was increased to 891,645, with a floor price of $21.14 per share established.

On March 14, 2017, the Company completed a $45 million second lien senior secured term loan (the "**Second Lien Facility**") financing, a $9 million non-brokered equity private placement (the "**Equity Private Placement**") and increased and extended the Company's current bank lending arrangements to October 31, 2017, providing for a $14 million increase in total borrowing capacity under the credit facility to $20 million. These financing arrangements materially strengthen liquidity to support the execution of the Company's 2017 capital program and improve its debt maturity profile.

2016

In January 2016, Perpetual completed a rights offering which generated $25 million in gross proceeds. The Company used a portion of the proceeds to fund its very modest 2016 capital expenditure program which was reduced to only $14 million due to low oil and natural gas prices. Perpetual issued an aggregate of 665.4 million (33.3 million post-consolidation) Common Shares on completion of the rights offering. This, along with other recapitalization programs throughout 2015, 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 TOU Shares.

On March 24, 2016 shareholders voted in favour to consolidate the Common Shares on the basis of one (1) post-consolidation common share for every twenty (20) pre-consolidation Common Shares.

Several transactions in 2016 combined to materially reduce debt and focus the Company's operations. In March, a 37 section undeveloped oil sands lease portfolio was sold for $6.1 million, with the Company retaining a one percent gross over-riding royalty on future production. During the second quarter of 2016, $114.1 million of the 2018 Senior Notes and $100.3 million of the 2019 Senior Notes were exchanged for 4.4 million TOU Shares (the "**Security Swap**"). In May 2016 Perpetual completed the sale of its 30 percent partnership interest in Warwick Gas Storage LP ("**WGS LP**") for $20 million. The transaction included the disposition of Perpetual's share of WGS LP's approximately $8.3 million of debt net of working capital held by the partnership. In addition, Perpetual received a net dividend of $0.5 million at closing, for effective total value of approximately $23 million. The transaction included the gas storage reservoir and facility as well as 9,207 net acres of surrounding lands and associated wells and infrastructure with net production of 470 Mcf/d.

On October 1, 2016, the Company completed the strategic disposition of a large percentage of its high liability mature shallow gas properties in east central and northeast Alberta (the "**Shallow Gas Properties**") for nominal proceeds. The transaction included all of Perpetual's shallow gas assets and liabilities in eastern Alberta, specifically excluding heavy oil and natural gas assets in the Mannville and Panny areas and other bitumen leases in northeast Alberta. Pursuant to the transaction, Perpetual increased its Licensee Liability Management Ratings ("**LMR**") as defined by the Alberta Energy Regulator ("**AER**") to over 4.2 through the disposition of all of the liabilities associated with the Shallow Gas Properties and despite the loss of close to 35.5 MMcf/d of production, Perpetual's cash flow from operations was positively impacted. Furthermore, through gas marketing arrangements related to the transaction, the Company effectively retained full natural gas price upside exposure on the forecast base production from the Shallow Gas Properties should Alberta Energy Company ("**AECO**") natural gas prices exceed $2.81/GJ through August 2018, with no operating exposure or future capital spending commitments. For the same volumes and term, arrangements were made to provide the purchaser a floor price of $2.58/GJ. Included in the transaction was 82.1 Bcfe of proved plus probable working interest reserves based on the Company's third partv engineering report prepared by McDaniel and Associates Consultants Ltd. ("**McDaniel**") at year-end 2015, $128.0 million in discounted decommissioning obligations and 353,777 net acres of undeveloped lands not assigned reserves at year-end 2015. In September, the Company refinanced its TOU Share margin loan and in November an additional TOU Share margin loan was entered into. The Company also completed a private placement of 0.5 million flow-through Common Shares at a price of $2.15 per share for total gross cash proceeds of $1.1 million.

2015

In April 2015, Perpetual swapped its joint interest share in its West Edson asset in west central Alberta with Tourmaline in exchange for 6.75 million 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, 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 positioned Perpetual to capture the upside of the West Edson Property through ownership of the TOU Shares and also provided 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 the Company’s financial situation, augmenting its potential to optimize the shareholder value inherent in its existing diversified portfolio of assets. The TOU Shares also provided greater flexibility to capture and evaluate other new high impact opportunities and pursue strategic initiatives.

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 number and market price of TOU Shares.

In April 2015, Perpetual also completed the sale of certain fee simple lands in east central Alberta, and a working interest in related seismic data, for gross proceeds of $21 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 "**TOU Share Margin Loan**") with a counter-party which resulted in net proceeds of $18.2 million collateralized by one million TOU Shares, maturing on November 16, 2016. The proceeds were initially applied to reduce outstanding bank indebtedness. The TOU Share margin loan for the underlying amount of $21.3 million established a floor price for the TOU Shares pledged, preserving full exposure to increases in the price of the TOU Shares with downside price protection. The arrangement represented a collateralization of TOU 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 TOU Share margin loan. 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 percent royalty interest in the current developed producing reserves in the East Edson area (the "**Producing Royalty**") for cash proceeds of $50 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 percent 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 69percent from year-end 2013 to 105.2 MMboe.

Debt reduction and risk management were also key strategic priorities 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 offerings, monetization of future gas over bitumen ("**GOB**") royalty credits and non-core property dispositions.

In July 2014, Perpetual issued $125 million 2019 Senior Notes. Proceeds from the senior notes issuance were used to redeem all of Perpetual's $100 million outstanding 7.25% Convertible Unsecured Debentures (the "**7.25% 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 2017.

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 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 million received on the sale of undeveloped land. Offsetting property dispositions were acquisitions of one million, primarily related to additional land purchases in the Greater Edson area.

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.

DESCRIPTION OF THE BUSINESS

General

Perpetual is engaged in finding, developing, producing and marketing natural gas, 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 for and developing 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) bitumen opportunities in northeast Alberta; and
4) the development and production of shallow natural gas in eastern Alberta where the Corporation has overlapping heavy oil operations and future bitumen development prospects.

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 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:
    - 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;
    - pursue dispositions to 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 assets by minimizing costs and maximizing revenue;
   - 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 opportunity inventory; and
   - crystallizing value through dispositions.

Perpetual has actively transformed its 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 the past several years. Growth opportunities to invest in profitably today include the planned development program in East Edson in west central Alberta. Additionally, waterflood implementation and horizontal development of heavy oil at Mannville in East Central is being actively advanced.

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.

Strengthening the balance sheet 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, the sale of Warwick Gas Storage, the disposition of the Shallow Gas Properties, and the Security Swap for TOU Shares. Considering the TOU Shares as an offset to outstanding debt bolsters the Corporation's financial flexibility and optionality to manage future financial obligations.

Success in advancing the Company's strategic priorities has established a foundation for strong growth in production and funds flow in 2017. Perpetual's top four strategic priorities for 2017 include:

1) optimize balance sheet for growth;
2) grow value of Greater Edson liquids-rich gas;
3) optimize value potential of Eastern Alberta assets; and
4) advance high impact opportunities.

Operations

Perpetual has substantially completed the transformation of its operations from its legacy assets of conventional shallow natural gas in eastern Alberta to predominantly low operating cost, resource-style, liquids-rich gas in the West Central Alberta Deep Basin and cold heavy oil production in eastern Alberta with the disposition of the Shallow Gas Properties which closed October 1, 2016. In the fourth quarter of 2016, production from the West Central Alberta Deep Basin assets accounted for 79.4 percent of production up from 53.2 percent for full year 2016, 47 percent in 2015 and less than five percent prior to 2011. Due to low commodity prices, Perpetual's capital activities for 2016 were very limited, with drilling and completion activities restricted to one (1.0 net) well in the first quarter of 2016 in the East Edson area and waterflood activity during the third quarter in the Mannville area. Capital spending began ramping up in December 2016 as commodity prices recovered, with a drilling rig deployed in both the Edson and Mannville areas.

Capital activity in 2017 is focused on drilling to fill infrastructure at East Edson with the drill, complete and tie-in of up to 12 wells planned. Expansion of the Mannville portfolio is also targeted, with the drilling of two exploratory heavy oil prospects as well as additional waterflood optimization, and the testing of two shallow shale gas plays. Perpetual has also established several long-term high impact opportunities that will be advanced technically with modest investment; these include exposure to 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, 2016. Production stated is the Corporation's working interest share of production volumes and, unless otherwise noted, is average production for 2016. The estimates of reserves and future net revenue for individual properties are as evaluated by McDaniel at year-end 2016 and 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, 2016

West Central Deep Basin

In the West Central District, 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 percent working interest in a non-operated gas plant.

East Edson

The East Edson area is located west of Edmonton, Alberta in the Alberta Deep Basin and is comprised of 51,804 net acres (61 percent undeveloped) with an average 97.9 percent working interest in 51 gross (49.9 net) producing natural gas wells and an average 78.1 percent working interest in four gross (3.1 net) producing oil wells. This area represented approximately 53.2 percent of production from Perpetual's assets for the year 2016. The Company operates the majority of this area which produced 7,392 boe/d in 2016, including 40.8 MMcf/d of natural gas and 591.5 bbl/d of crude oil and NGL. Gas and NGL production is primarily from horizontal wells targeting the Wilrich formation.

Pursuant to the East Edson JV, the Company pays, on a priority basis, a gross overriding royalty to an industry partner up 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 ten percent per year until December 31, 2034.

Perpetual fulfilled its commitment to spend $30 million to drill, complete and tie-in approximately five wells and construct a new gas processing facility prior to December 31, 2015 as part of the joint venture arrangement, substantially following the spending of the $70 million farm-in commitment by the partner. Perpetual also committed to invest an additional $30 million to drill, complete and tie-in approximately six additional wells prior to December 31, 2022. This final commitment is forecast to be fulfilled prior to the end of the first quarter 2017.

Production is processed through both a new 100 percent owned and operated 45 MMcf/d shallow cut gas processing facility which was constructed and came on stream in 2015 in conjunction with the East Edson JV, as well as through a third party operated facility at Rosevear in which Perpetual owns a 15 percent working interest. An extensive gathering system as well as a 100 percent Company owned and operated compressor station integrates operations across the field and optimize throughput. Volumes are currently processed primarily to the new operated facility with production above current plant capacity flowing through the non-operated plant. Sour volumes of approximately one MMcf/d were historically processed through a third party deep cut facility, but are now sweetened in field and processed alongside the sweet gas.

In 2016, Perpetual drilled one gross (1.0 net) well in the first quarter, with completion and equipping operations in the third quarter, and drilled one gross (1.0 net) well in the fourth quarter with completion and equipping activity substantially in January of 2017. The drilling rig is continuing operations and is projected to have drilled five gross (5.0 net) additional wells drilled by the end of the first quarter of 2017. There is adequate working interest capacity in the Company’s infrastructure to manage the forecast volumes. A modest investment of less than $5 million is required to further expand the capacity of the 100 percent owned and operated plant from 45 to 60 MMcf/d and is anticipated in 2018.

West Central Other

Other non-core assets in the West Central area are comprised of 54,454 net acres (84 percent undeveloped) with an average 62.8 percent working interest in nine gross (5.7 net) producing oil and natural gas wells. West Central Other areas produced 28 boe/d in 2016.

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. After significant delays substantially due to transportation restrictions in the area, continuous production from this well was 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 percent working interest in 3,840 gross acres and 100 percent working interest in the remaining 2,400 acres.

Over the last two years, Perpetual has been accumulating a material land position in a new exploration area in the Alberta Deep Basin through acquisitions and Crown land sales. At year-end 2016, Perpetual had an interest in 41,760 gross acres (22,949 net) of primary undeveloped land in the Columbia area with a partner. Perpetual has since purchased the partner‘s working interest and increased ownership through additional Crown land sales during the first quarter of 2017 to a total of 38,564 net acres of undeveloped lands. These lands are prospective in multiple horizons and provide a new potential growth area for the Corporation.

Eastern Alberta

In October 2016 Perpetual closed the disposition of the Shallow Gas Properties. The transaction included most of Perpetual’s shallow gas assets and liabilities in eastern Alberta, along with their related production of approximately 35.5 MMcfe/d, 82.1 Bcfe of proved plus probable working interest reserves and $128.0 million in discounted decommissioning obligations. Specifically excluded in the transaction were the heavy oil and natural gas assets in the Mannville and Panny areas and other bitumen leases in northeast Alberta. The total retained Eastern Alberta assets include 231,942 net acres (34 percent undeveloped).

Perpetual's focus in the Mannville area of Eastern Alberta 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, 13 pools have been discovered and placed on production. Certain assets were sold in 2014 leaving six Lloyd formation pools, one Sparky pool and one Basal Quartz pool with continued development and waterflood optimization in progress. Perpetual has an average 94.9 percent working interest in 166 gross (157.6 net) producing wells, 65.7 net oil wells and 91.9 net gas wells. Perpetual operates this area which produced 987.0 bbl/d of heavy crude representing 93.3 percent of the Company's 2016 average production.

The collapse of oil prices in 2014 resulted in deferral of oil well drilling through 2015 and early 2016. In 2016 Perpetual focused on waterflood expansion and invested capital to convert two wells to water injectors and construct the related pipelines and facilities. The combination of the partial recovery of Western Texas Intermediate ("**WTI**"), the decline in the Canadian dollar, the reduction in heavy oil differentials and reduced costs for drilling and related services has now provided enough recovery to wellhead prices and economics that conventional heavy oil drilling has regained its competitiveness. Perpetual deployed a rig to the Mannville area in late December of 2016 for the first time in over two years. The current first quarter 2017 capital program is designed to de-risk two new exploratory pools with three gross (2.67 net wells) and one gross (0.67 net) infill well targeting banked oil from waterflood operations. .

Perpetual also has an interest in the Viking/Colorado shallow unconventional dry gas play in east central Alberta. The play is prospective in the Mannville area and retention of this asset provides continued exposure. 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, however, did commence a project to further evaluate the play in late 2016 with the drilling of 2 (2.0 net) wells. Drilling losses in a shallower horizon caused drilling difficulties that resulted in the abandonment of one of the wells, however it was successfully re-drilled in the first quarter of 2017. Completion and testing operations are ongoing. No undeveloped reserves are currently assigned to the Viking/Colorado resource play.

Bitumen

Perpetual maintained 192,416 net acres (98 percent undeveloped) of oil sands leases at year-end 2016 which are geographically synergistic with several of its legacy shallow gas operating areas in northeast Alberta. In 2016, 23,883 net acres at Marten Hills were sold (subject to a retained one percent Gross over-riding royalty) for $6.1 million. In 2016, the Company surrendered 59,520 net acres where the development potential was viewed to be limited. Thesale and surrenders further provided over $100,000 per year inlease rental savings. The remaining acres are focused in Panny, Liege, Ells, and 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 $8.5 million. Approved funding through IETP is 30 percent of eligible costs through year-end 2016 and the Company is expected to recover $2.5 million through the program. The first phase of LEAD, consisting of a single well cyclic heat stimulation ("**CHS**") pilot has full regulatory approval, and was initiated in 2015. Perpetual drilled two (2.0 net) observation wells, installed a downhole electrical 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. Four cycles of heating and production were conducted from start up through to the end of 2016. The single well CHS phase of the pilot is expected to wind up during the first quarter of 2017 with economic scoping and planning for the next phase underway.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

February 7, 2017

The reserves data set forth below is based upon the figures contained in the report of McDaniel dated effective December 31, 2016, with a preparation date of February 7, 2017 (the "McDaniel Report") evaluating substantially all of Perpetual's crude oil, NGL and natural gas reserves.

Disclosure of Reserves Data

McDaniel evaluated in the McDaniel Report, 100%, of the assigned total proved plus probable reserves. 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, 2016
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	26	24	1,218	1,134	37,555	22,080	486	112	7,989	4,951
Proved Non Producing	-	-	120	109	2,122	1,819	23	14	496	427
Proved Undeveloped	11	10	335	286	146,778	117,757	1,802	1,171	26,611	21,093
Total Proved	37	35	1,672	1,530	186,455	141,656	2,311	1,297	35,096	26,471
Total Probable	9	8	832	743	140,292	124,715	1,963	1,576	26,186	23,112
Proved and Probable	46	43	2,504	2,272	326,747	266,370	4,274	2,873	61,283	49,583

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, 2016
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	$ 78	$ 75	$ 72	$ 68	$ 64	$14.52
Proved Non Producing	5	4	3	3	2	$7.92
Proved Undeveloped	278	191	136	99	74	$6.43
Total Proved	361	271	211	170	141	$7.97
Total Probable	451	266	170	117	85	$7.35
Proved and Probable	$812	$536	$381	$287	$226	$7.68

NET PRESENT VALUE OF FUTURE NET REVENUE
AFTER TAX
as at December 31, 2016
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	$ 78	$ 75	$ 72	$ 68	$ 64	$14.52
Proved Non Producing	5	4	3	3	2	$7.92
Proved Undeveloped	278	191	136	99	74	$6.43
Total Proved	361	271	211	170	141	$7.97
Total Probable	451	266	170	117	85	$7.35
Proved and Probable	$812	$536	$381	$287	$226	$7.68

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, 2016
FORECAST PRICES AND COSTS ($ millions)

Reserves Categories	Revenue	Royalties	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	1,010	(247)	(184)	(193)	(25)	361	0	361
Proved and Probable Reserves	1,864	(346)	(304)	(368)	(35)	812	0	812

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, 2016

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)		1.24/Mcfe
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by products)		59.75/boe
Proved Reserves	Heavy Oil (including solution gas and other by products)		23.03/boe
Proved Reserves – Total			7.97/boe
Proved and Probable Reserves	Conventional Natural Gas (including by-products but excluding solution gas and by-products from oil wells)		1.23/Mcfe
Proved and Probable Reserves	Light and Medium Crude Oil (including solution gas and other by products)		57.39/boe
Proved and Probable Reserves	Heavy Oil (including solution gas and other by products)		23.14/boe
Proved and Probable Reserves – Total			7.68/boe

Forecast Prices and Costs

Pricing Assumptions (Forecast Prices and Costs)

SUMMARY OF PRICING ASSUMPTIONS
AS AT DECEMBER 31, 2016
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)
2017	55.00	69.80	46.50	3.40	0.750
2018	58.70	72.70	50.50	3.15	0.775
2019	62.40	75.50	54.00	3.30	0.800
2020	69.00	81.10	58.00	3.60	0.825
2021	75.80	86.60	61.90	3.90	0.850
2022	77.30	88.30	63.10	3.95	0.850
2023	78.80	90.00	64.40	4.10	0.850
2024	80.40	91.80	65.60	4.25	0.850
2025	82.00	93.70	67.00	4.30	0.850
2026	83.70	95.60	68.40	4.40	0.850
2027	85.30	97.40	69.60	4.50	0.850
2028	87.00	99.40	71.10	4.60	0.850
2029	88.80	101.40	72.50	4.65	0.850
2030	90.60	103.50	74.00	4.75	0.850
2031	92.40	105.50	75.40	4.85	0.850

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, 2016 of $2.42/Mcf, including $0.23/Mcf of realized hedging gains for natural gas. The weighted average AECO daily gas index price for the same 12 month period was $2.05/GJ. Perpetual's realized oil price averaged $37.60/bbl including $2.67/bbl of realized hedging gains relative to the benchmarks. The Corporation realized an average NGL price of $35.45/bbl in 2016. The West Texas Intermediate benchmark price for 2016 was $US43.32/bbl.

RECONCILIATION OF COMPANY GROSS RESERVES
BY PRINCIPAL PRODUCT TYPE
FORECAST PRICES AND COSTS

	Light and Medium Oil			Heavy Oil			Oil		
Factors	**Gross Proved (Mbbl)**	**Gross Probable (Mbbl)**	**Gross Proved Plus Probable (Mbbl)**	**Gross Proved (Mbbl)**	**Gross Probable (Mbbl)**	**Gross Proved Plus Probable (Mbbl)**	**Gross Proved (Mbbl)**	**Gross Probable (Mbbl)**	**Gross Proved Plus Probable (Mbbl)**
December 31, 2015	**70**	**33**	**103**	**1,636**	**1,081**	**2,716**	**1,706**	**1,114**	**2,820**
Extensions & Improved Recoveries	-	-	-	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-
Technical Revisions	(26)	(24)	(50)	415	(247)	169	390	(271)	119
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	(8)	(2)	(10)	(8)	(2)	(10)
Production	(7)	-	(7)	(371)	-	(371)	(378)	-	(378)
December 31, 2016	**37**	**9**	**46**	**1,672**	**832**	**2,504**	**1,709**	**841**	**2,550**

RECONCILIATION OF COMPANY GROSS RESERVES
BY PRINCIPAL PRODUCT TYPE
FORECAST PRICES AND COSTS

	Conventional Natural Gas			Liquids			Total BOE		
Factors	**Gross Proved (MMcf)**	**Gross Probable (MMcf)**	**Gross Proved Plus Probable (MMcf)**	**Gross Proved (Mbbl)**	**Gross Probable (Mbbl)**	**Gross Proved Plus Probable (Mbbl)**	**Gross Proved (Mbbl)**	**Gross Probable (Mbbl)**	**Gross Proved Plus Probable (Mbbl)**
December 31, 2015	**242,604**	**179,188**	**421,792**	**2,243**	**2,428**	**4,671**	**44,383**	**33,407**	**77,790**
Extensions & Improved Recoveries	-	-	-	-	-	-	-	-	-
Discoveries	31	(3)	28	-	-	-	5	(1)	5
Technical Revisions	21,746	(5,437)	16,309	324	(453)	(129)	4,338	(1,630)	2,708
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	(50,758)	(33,456)	(82,214)	(31)	(12)	(43)	(8,499)	(5,590)	(14,089)
Production	(27,169)	-	(27,169)	(224)	-	(224)	(5,131)	-	(5,131)
December 31, 2016	**186,455**	**140,292**	**326,747**	**2,311**	**1,963**	**4,274**	**35,096**	**26,186**	**61,283**

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	-	-	347	537	23,034	54,217	395	1,071
2014	-	14	287	387	95,501	178,500	1,258	2,271
2015	-	10	-	355	-	138,410	-	1,688
2016	**-**	**11**	**-**	**335**	**-**	**146,778**	**-**	**1,803**

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. In East Edson at year-end 2016, McDaniel has increased the proved undeveloped reserves per location based on better than previously forecasted performance of producing wells. This has resulted in fewer wells being required to maintain full facility and transportation capacity within the five year development plan time frame. 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	-	-	245	637	25,595	61,582	461	1,374
2014	-	4	267	378	142,304	178,829	1,750	2,166
2015	-	4	-	358	-	130,588	-	2,251
2016	**-**	**(11)**	**-**	**272**	**-**	**102,573**	**-**	**1,437**

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. In East Edson at year-end 2016, McDaniel has increased the probable undeveloped reserves per location based on better than previously forecasted performance of producing wells. This has resulted in fewer wells being required to maintain full facility and transportation capacity within the nine year development plan time frame. 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 $6.4 million as at December 31, 2016.

The McDaniel Report includes an undiscounted amount of $34.8 million, including $18.6 million related to developed reserves and $16.2 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

			Discounted at	
($ millions, net to Perpetual)	**Undiscounted**	**5%**	**8%**	**10%**
Total estimated future abandonment and reclamation costs(1)	37.9	22.8	14.9	11.3
Salvage value	(27.4)	(12.5)	(8.5)	(6.7)
Abandonment and reclamation costs, net of salvage	10.5	10.3	6.4	4.6
Well abandonment costs for developed reserves included in McDaniel Report	(18.6)	(7.8)	(5.0)	(3.8)
Estimate of additional future abandonment and reclamation costs, net of salvage(2)	(8.1)	2.5	1.4	0.8

1) Estimated internally for existing wells, pipelines and facilities.
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.

The current March 2017 LMR for Perpetual's two operating companies, PEI and POC, are 2.51 and 3.92 respectively. See "**Liability Management Rating Programs**".

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%
2017	42.7	41.0	42.9	41.1
2018	42.0	36.5	42.3	36.7
2019	39.3	31.0	41.5	32.8
2020	34.4	24.7	34.4	24.7
2021	34.8	22.8	34.8	22.8
Thereafter	0	0	171.7	87.3
Total	193.3	156.0	367.6	245.4

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 $365.4 million will be required over the life of the Corporation's proved and probable reserves for the drilling, completion, equipping and tie-in of eight conventional horizontal Mannville heavy oil wells and 76 horizontal gas wells targeting the Wilrich. Future capital costs also include recompletion of 27 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 systematically 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, 2016 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, 2016.

	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)**
West Central Deep Basin								
East Edson	51	49.9	4	3.1	3	3.0	0	0.0
West Central Other	8	5.2	1	0.5	36	26.7	5	4.1
West Central District	59	55.1	5	3.6	39	29.7	5	4.1
Eastern Alberta	96	91.9	70	65.7	187	172.8	33	29.8
Total	155	147.0	75	69.3	226	202.5	38	34.0

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 49 producing wells at December 31, 2016.
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 36 gross (30.5 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 20 gross (16.0 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, 2016. Except as previously identified in the East Edson JV, the Corporation does not have 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				
East Edson	27,200	20,370	40,800	31,434
West Central Other	31,679	8,823	77,483	45,631
West Central District	58,879	29,193	118,283	77,065
Eastern Alberta	205,294	153,008	92,141	78,934
Bitumen	5,760	3,520	215,083	188,896
Total	**269,933**	**185,721**	**425,507**	**344,895**

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.

During 2017, 41,367 net acres are set to expire. A total of 43,197 net acres expired in 2016. 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, 2017, which is reflected in the estimate of future net revenue disclosed in the tables.

2017 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	19.2	864.9	53.0	639.7
Probable	0.8	49.3	3.9	45.2
Total Proved and Probable	**20.0**	**914.2**	**56.9**	**684.9**

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:

	2016 Quarter Ended			
Production	**Dec 31**	**Sept 30**	**June 30**	**Mar 31**
Average Daily Conventional Natural Gas Production (MMcf/d)	40.3	75.5	85.2	98.2
Average Daily Light and Medium Oil Production (bbl/d)	936	1,052	1,073	1,174
Average Daily NGL Production	467	476	682	836
Total (boe/d)	**8,118**	**14,123**	**15,959**	**18,378**
Average Realized Price ($/boe)	18.34	15.11	13.82	19.55
Royalties ($/boe)	(4.11)	(1.71)	(1.27)	(1.36)
Operating Costs ($/boe)	(2.15)	(7.36)	(6.53)	(8.59)
Transportation Costs ($/boe)	(1.30)	(1.80)	(1.46)	(1.49)
Operating Netback ($/boe)	**10.78**	**4.24**	**4.56**	**8.11**

The following table indicates Perpetual's average daily production from each of the Corporation's core areas for the year ended December 31, 2016:

Property	**Average Annual Daily Production (boe/d)**
West Central Deep Basin	
East Edson	7,391
West Central Other	61
West Central District	7,453
Eastern Alberta	6,675
Total	**14,128**

Capital Expenditures

The following table summarizes capital expenditures related to Perpetual's activities for the year ended December 31, 2016:

($ thousands)	**2016**	2015
Exploration and Development	**14,039**	75,431
Geological and Geophysical Costs[1]	**23**	1,526
Acquisitions	**12**	243
Dispositions	**(26,224)**	(23,953)
Other	**541**	910
Total	**(11,609)**	54,157

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

Exploration and Development Capital Expenditures

(*$ millions*)	**2016**	2015
West Central	**10,538**	67,501
Eastern Alberta	**3,501**	7,930
Total	**14,039**	75,431

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, 2016:

Exploratory Wells	**Gross**	**Net**
Light and Medium Crude Oil	0	0
Heavy Oil	0	0
Natural Gas[1]	1	1
Evaluation (Oil Sands)	0	0
Total	1	1
Success Rate (%)	0%	0%
Development Wells		
Light and Medium Crude Oil	0	0
Heavy Oil	0	0
Natural Gas	3	3
Evaluation and Service Wells	0	0
Total	3	3
Success Rate (%)	100%	100%
Total Exploration & Development	4	4

1) The exploratory well encountered drilling operational problems and was abandoned prior to reaching total depth due to drilling problems. The well was successfully re-drilled in 2017.

COMMODITY PRICE RISK MANAGEMENT

Perpetual’s commodity price risk management strategy is focused on managing downside risk and increasing certainty in cash flow from operating activities by mitigating the effect of commodity price volatility. Physical forward sales and financial derivatives are used to manage the balance sheet, 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 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 revenue.

Natural Gas

The following tables provide a summary of derivative natural gas contracts outstanding at March 14, 2017. Subsequent to December 31, 2016, Perpetual realized a gain of $4.9 million on crystallization of 30,000 GJ/d of 2017 basis contracts and 25,000 GJ/d of 2018 basis contracts.

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

Term	Sell/Buy	Volumes sold (bought) at AECO (GJ/d)	Average price ($CAD/GJ)(1)	Market prices ($CAD/GJ)(2)	Type of contract
March 2017	Sell	62,500	2.81	2.33	Physical
March 2017	Buy	37,500	2.45	2.33	Physical
April 2017	Sell	35,000	2.66	2.43	Physical
May 2017	Sell	30,000	2.93	2.38	Physical
June 2017 – October 2017	Sell	20,000	3.15	2.44	Physical
November 2017 – December 2017	Sell	32,500	3.07	2.77	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
April 2017	22,500	2.67	2.43	Financial
May 2017 – December 2017	7,500	3.15	2.51	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 14, 2017.

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
March 2017 – December 2017	250	50.00	61.50	49.37	Financial
March 2017 – December 2017	500	50.00	59.40	49.37	Financial

1) Market prices are based on forward WTI oil prices as of market close on March 14, 2017.

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
April 2017 – December 2017	500	(15.40)	(14.83)	Financial
April 2017 – December 2017	250	(14.85)	(14.83)	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 14, 2017.

Subsequent to December 31, 2016, Perpetual realized a loss of $0.9 million on crystallization of a 250 bbl/d calendar 2017 WTI costless collar.

Foreign Exchange

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

Term	Notional $USD/month	Boosted notional(1) $USD/month	Strike rate ($CAD/$USD)	Market prices ($CAD/$USD)(3)	Type of contract
March 2017 – February 2018(2)	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, the Corporation pays $USD 3,000,000 multiplied by the difference between the spot rate at expiry and the strike rate.
(2) If the spot rate at expiry of each contract month is above the strike rate, the Corporation receives $USD 1,000,000 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, of which $0.8 million have been recognized as of March 14, 2017.
(3) Market prices are based on forward $CAD/$USD exchange rates as of market close on March 14, 2017.

Subsequent to December 31, 2016, Perpetual realized a loss of $4.3 million on crystallization of a foreign exchange currency option contract that was due to expire in March 2018.

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 53,700,564 Common Shares 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.

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 three series of outstanding 8.75% Senior Notes have currently been assigned ratings of CC by Standard and Poor's Rating Services, a division of McGraw-Hill Companies (Canada) Corporation ("**S&P**") and Caa3 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 CCC-, negative outlook and a credit rating of CC 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. An obligation rated 'CC' is currently highly vulnerable to nonpayment. The 'CC' rating is used when a default has not yet occurred, but S&P Global Ratings expects default to be a virtual certainty, regardless of the anticipated time to default. 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 Caa2, negative outlook, and a credit rating of Caa3 on the 8.75% Senior 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 8.75% Senior 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		
2016[(1)]	**High ($)**	**Low ($)**	**Volume**
January	1.00	0.60	147,300
February	1.20	0.80	48,200
March[(1)]	1.40	1.20	79,300
April	1.37	1.10	67,400
May	1.45	1.10	44,100
June	2.45	1.37	113,800
July	2.50	1.89	94,300
August	2.19	1.79	34,300
September	2.11	1.74	34,900
October	2.09	1.80	42,500
November	2.13	1.48	40,500
December	2.37	1.96	67,300

(1) On March 24th, 2016 Perpetual completed a common share consolidation on the basis of one (1) post-consolidation common share for every twenty (20) pre-consolidation Common Shares. All share values reported are presented on a post-consolidation basis.

Prior Sales

Other than Share Options and Restricted Rights to acquire Common Shares and the three 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 Restricted Rights and Share Options were issued during the most recently completed financial year by Perpetual.

Restricted Rights Granted 2016

Month of Issuance	Number of Restricted Rights	Exercise Price of Restricted Rights
May	344,025	$0.01
June	29,900	$0.01
July	29,550	$0.01
August	83,950	$0.01
September	47,600	$0.01
October	304,799	$0.01
November	37,883	$0.01
December	204,551	$0.01

Share Options Granted in 2016

Month of Issuance	Number of Options	Exercise Price of Options
June 2016	2,275,000	$1.42

DIVIDENDS

The corporation currently does not pay a dividend.

The credit facilities and the terms of the 8.75% Senior 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.

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. ("Paramount Resources") and has been a Director of Paramount Resources since 1978. Until May 2015 he was also the CEO and up until June 2002 he was also the President. He is also the Chairman of the Board of Trilogy Energy 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 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. In 2015 Mr. Riddell was inducted into the Canadian Petroleum Hall of Fame and into the Canadian Business Hall of Fame in 2017.
Susan L. Riddell Rose(5) Alberta, Canada	President, Chief Executive Officer and Director since June 28, 2002	Ms. Riddell Rose is the President and Chief Executive Officer of Perpetual and predecessor Paramount Energy Trust since inception in 2002. 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 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.
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.

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
Robert A. Maitland(1)(2)(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 Altura Energy Inc.
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.
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).
William (Bill) A. Hahn Alberta, Canada	Interim Vice President, Finance & Chief Financial Officer	Mr. Hahn has over 10 years of experience in the field of finance and accounting in the Canadian oil and natural gas industry. Mr. Hahn has been with Perpetual since 2011 holding various positions within the accounting and finance department. His previous industry experience includes Manager of Financial Reporting at Sonde Resources Corp. Prior thereto, he was a senior associate with PricewaterhouseCoopers serving public oil and gas clients. Mr. Hahn is a CPA, CA and received a Bachelor of Commerce from the University of Victoria and a Masters of Professional Accounting from the University of Saskatchewan.
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.
Linda L. McKean Alberta, Canada	Vice President, Production and Development	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

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
		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.
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.

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) 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 25,549,738 voting securities as of March 14, 2017 representing approximately 47.58 percent 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 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 Altura Energy Inc.

Randall E. Johnson

Mr. Johnson has been an independent businessman since 2005. Prior to then 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. He has over 23 years of experience in corporate banking as a lender to oil and gas companies, pipeline and utility companies. Lending transactions required detailed analysis of the borrower's financial statements, and the consistent monitoring of the borrower's disclosure of financial performance. Mr. Johnson's skills are augmented through his MBA with a finance emphasis by previously serving on the audit committee of two other public issuers.

Geoffrey C. Merritt

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. As CEO of a public company for ten years, Mr. Merritt was required to be financially literate. He has taken several accounting courses at the University of Calgary and attended the Harvard Business School (Advanced Management Program) which taught accounting as part of its program. He is currently a member of the Audit Committee at one other public oil and gas company.

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 $526,000 in 2016 and $530,000 in 2015, which includes fees related 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 2016 and nil in 2015.

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 2016 and nil in 2015.

All Other Fees

The aggregate fees billed in the 2016 fiscal year by Perpetual's external auditor for services other than those services reported above were nil. For the 2015 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 percent 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 percent 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 as 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.

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 2016 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, including the governments of Canada and Alberta, both of which investors in the oil and gas industry should carefully consider. All current legislation is a matter of public record and the Corporation is unable to predict what additional legislation or amendments governments may enact in the future. The following comprises 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, 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, regional market and transportation issues also influence prices. 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 underwent a consultation process to update the regulations governing the issuance of export licences. The updating process was 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. The Regulations Amending the *National Energy Board Act Part VI* (Oil and Gas) Regulations came into effect on July 31, 2015 and provides the requirements for obtaining long-term licences.

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 New York Mercantile Exchange 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 per day) must be made pursuant to an NEB order. Natural gas export contracts of a longer duration (to a maximum of 40 years) or that deal with larger quantities of natural gas 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. The new administration in the United States has indicated an intention to seek renegotiation of NAFTA, the impact of which on the oil and gas industry is uncertain.

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 where the Crown does not hold the mineral rights 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 Canadian federal government has signaled that 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 stringent reviews for pipelines and establishing a pan-Canadian framework for combating climate change. These changes could affect earnings of companies operating in the oil and natural gas industry.

Alberta

In Alberta, the Crown owns 81percent of the province's mineral rights. The remaining 19 percent are 'freehold' mineral rights owned by the federal government on behalf of First Nations or in National Parks, and by individuals and companies. Provincial government royalty rates apply to Crown-owned mineral rights. 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 formally took effect on January 1, 2017 for wells drilled after this date. Wells drilled prior to January 1, 2017 will continue to be governed by the "*New Royalty Framework*" (implemented by the *Mines and Minerals (New Royalty Framework) Amendment Act*, 2008) (the "**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 percent 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 total depth, length, and proppant placed). The new royalty rate for Pre-Payout under the MRF 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. Depending on the commodity price of the substance the well is producing, the royalty rate could range from 5percent – 40 percent. The metrics for calculating the Mid-Life phase royalty are based on commodity prices and are intended, on average, to yield the same internal rate of return as under the Alberta Royalty Framework. In the Mature phase of the MRF, once a well reaches the tail end of its cycle and production falls below a Maturity Threshold, currently the equivalent of 194 m^3 (40 barrels of oil equivalent per day or 345,500 m^3 of gas per month), 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.

On July 11, 2016, the Government of Alberta released details of the Enhanced Hydrocarbon Recovery Program and the Emerging Resources Program. These programs, that came into effect on January 1, 2017, are a part of the MRF and account for the higher costs associated with enhanced recovery methods and with developing emerging resources in an effort to make difficult investments economically viable and to increase royalties. Certain eligibility criteria must be satisfied in order for a proposed project to fall under each program. Enhanced recovery scheme applications can be submitted to the AER.

Oil sands projects are also subject to Alberta's royalty regime. The MRF does not change the oil sands royalty framework, however, the Government of Alberta plans to increase transparency in the method and figures by which the royalties are calculated. 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 percent and 9 percent 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 percent 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 percent 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 between 1 percent and 9 percent and the net revenue royalty based on the net revenue royalty rate. Net revenue royalty rates start at 25 percent and increase for every dollar of market price of oil increase above $55 up to 40 percent 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 Alberta Royalty Framework until January 1, 2027. Royalty rates for conventional oil are set by a single sliding scale 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 percent. Royalty rates for natural gas under the royalty regime depends on the price of each of the components of the gas stream, the productivity of the well, its acid gas factor and the depth of the producing zone. These factors are employed on a sliding scale formula to determine the natural gas royalty rate per well with the maximum royalty payable under the royalty regime set at 36 percent and a minimum royalty rate of 5 percent.

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 lands where the Crown does not hold the rights to mines and minerals 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 percent of revenues reported from freehold mineral title properties.

In addition, municipalities (including counties) have the ability to assess owners of oil and gas properties for annual property taxes. In Alberta, municipalities assess such owners on the basis of the market value, based on typical market conditions. The calculation of the applicable property tax also includes a 'mill rate' that accounts for the revenues that the municipality requires to balance its budget, which is multiplied against the assessed market value of the property. This rate is not capped within the legislative framework, and as such, the applicable taxes vary by municipality.

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 ten-year period, until January 1, 2027. Specifically:

- Coalbed methane wells will receive a maximum royalty rate of five percent 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 five percent 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 5percent 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 five percent 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.

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.

The province of Alberta has implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or licence. It 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 licences issued after January 1, 2009 at the conclusion of the primary term of the lease or licence.

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, producers 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 environmental regulation under a variety of Canadian federal, provincial, territorial and municipal laws and regulations, 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. The regulatory regimes set 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 licences and authorizations, civil liability and the imposition of material fines and penalties. In addition to these specific, known requirements, future changes to environmental legislation, including anticipated legislation for air pollution and greenhouse gas ("**GHG**") emissions, may impose further requirements on operators and other companies in the oil and natural gas industry.

Federal

Canadian environmental regulation is the responsibility of the federal government and provincial governments. Where there is a direct conflict between federal and provincial environmental legislation in relation to the same matter, the federal law will prevail, however, such conflicts are uncommon. The federal government has primary jurisdiction over federal works, undertakings and federally regulated industries such as railways, aviation and interprovincial transport. *The Canadian Environmental Protection Act, 1999* and the *Canadian Environmental Assessment Act, 2012* provide the foundation for the federal government to protect the environment and cooperate with provinces to do the same.

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 environmental 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.

On June 20, 2016, the federal government launched a review of current environmental and regulatory processes with a focus on rebuilding trust in the environmental assessment processes, modernizing the NEB, and introducing modernized safeguards to both the *Fisheries Act* and the *Navigation Protection Act*. An Expert Panel has been convened and is expected to complete its work by March 31, 2017. At such time, the Minister of Environment and Climate Change will consider the recommendations in the Panel's report and identify next steps to improve federal environmental processes, which is expected to take place during the summer/fall of 2017. Until this process is complete, the Federal Government's interim principles released January 27, 2016 will continue to guide decision-making authorities for projects currently undergoing environmental assessment. The Federal Government has not provided any indication on what changes—if any—will be implemented or when, but increased delays and uncertainty surrounding the environmental assessment process should be expected for large projects.

In a further development, on November 29, 2016, the Government of Canada announced that it would introduce legislation by spring 2017 to formalize a moratorium for crude oil tankers on British Columbia's north coast. It is unclear how the proposed moratorium may affect ongoing LNG export projects currently under consideration and development. On the same day, the Government of Canada also approved, subject to a number of conditions, the Trans Mountain Pipeline system expansion backed by Kinder Morgan Canada as well as the replacement of Enbridge Inc.'s plan to replace its Line 3 pipeline system, while also rejecting Enbridge Inc.'s proposed Northern Gateway project. On January 11, 2017, the Government of British Columbia confirmed that the conditions to the approval of the Trans Mountain Pipeline have been satisfied. Additionally, the new administration in the United States has indicated a willingness to revisit other pipeline projects that had been previously rejected.

Alberta

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 provides for engagement and consultation with stakeholders and the public and examines the cumulative impacts of development on the environment and communities, by incorporating the management of all resources, including energy, minerals, land, air, water and biodiversity. While the AER is the primary regulator for energy development, several other governmental departments and agencies may be involved in land use issues, including Alberta Environment and Parks, Alberta Energy, 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, licences, 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 percent 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 44percent 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.

Phase 1 Consultation of the North Saskatchewan Region Plan ("**NSRP**") has been completed and the Regional Advisory Council is currently preparing its Recommendation to Government report. The NSRP is located in central Alberta and is approximately 85,780 square kilometres in size and affects activities in central Alberta, and encompasses an area between the province's borders with British Columbia and Saskatchewan. The Upper Peace Region Plan, Lower Peace Region Plan, Red Deer Region Plan and Upper Athabasca Region Plan have not been started.

Liability Management Rating Programs

Alberta

In Alberta, the AER administers the Licensee Liability Rating Program (the "**AB LLR Program**"). The AB LLR Program is a liability management program governing most conventional upstream oil and gas wells, facilities and pipelines. Alberta's *Oil and Gas Conservation Act* ("**OGCA**") 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 or is unable to meet its obligations. 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 to 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 assets to deemed liabilities is assessed once each month and failure to post the required security deposit may result in the initiation of enforcement action by the AER. The AER publishes the liability management rating for each licensee on a monthly basis.

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.

On June 20, 2016, the AER issued *Bulletin 2016-16, Licensee Eligibility—Alberta Energy Regulator Measures to Limit Environmental Impacts Pending Regulatory Changes to Address the Redwater Decision* ("**Bulletin 16**") in an urgent response to a decision from the Alberta Court of Queen's Bench, which is currently under appeal with the Court of Appeal of Alberta. In *Redwater Energy Corporation (Re)*, 2016 ABQB 278 ("**Redwater**"), Chief Justice Wittman found that there was an operational conflict between the abandonment and reclamation provisions of the OGCA and the *Bankruptcy and Insolvency Act* ("**BIA**"), and that receivers and trustees have the right to renounce assets within insolvency proceedings. Such a conflict renders the AER's legislated authority unenforceable to impose abandonment orders against licensees or to require a licensee to pay a security deposit before approving a transfer when such a licensee is insolvent. Effectively, this means that abandonment costs will be borne by the industry-funded Orphan Well Fund or the province in these instances because any resources of the insolvent licensee will first be used to satisfy secured creditors under the BIA. Bulletin 16 provides interim rules to govern while the case is appealed and while the Government of Alberta can develop appropriate regulatory measures to adequately address environmental liabilities. Three changes were implemented to minimize the risk to Albertans:

- The AER will consider and process all applications for licence eligibility under *Directive 067: Applying for Approval to Hold EUB Licences* as non-routine and may exercise its discretion to refuse an application or impose terms and conditions on a licencee eligibility approval if appropriate in the circumstances.

- For holders of existing but previously unused licence eligibility approvals, prior to approval of any application (including licence transfer applications), the AER may require evidence that there have been no material changes since approving the licence eligibility. This may include evidence that the holder continues to maintain adequate insurance and that the directors, officers, and/or shareholders are substantially the same as when licence eligibility was originally granted.

- As a condition of transferring existing AER licences, approvals, and permits, the AER will require all transferees to demonstrate that they have a liability management rating ("**LMR**"), being the ratio of a licensee's assets to liabilities, of 2.0 or higher immediately following the transfer.

In order to clarify and revise the interim rules in Bulletin 16, the AER issued *Bulletin 2016-21: Revision and Clarification on Alberta Energy Regulator's Measures to Limit Environmental Impacts Pending Regulatory Changes to Address the Redwater Decision* ("**Bulletin 21**") on July 8, 2016 and reaffirmed its position that an LMR of 1.0 is not sufficient to ensure that licensees will be able to address their obligations throughout the life cycle of energy development, and 2.0 remains the requirement for transferees. However, Bulletin 21 did provide the AER with additional flexibility to permit licensees to acquire additional AER-licensed assets if:

- The licensee already has an LMR of 2.0 or higher;

- The acquisition will improve the licensee's LMR to 2.0 or higher; or

- The licensee is able to satisfy its obligations, notwithstanding an LMR below 2.0, by other means.

The AER provided no indication of what other means would be considered. In the short term the interim measures caused delays in completing transactions and reduced the pool of possible purchasers, however, transactions have been approved following a more rigorous review by the AER, despite a transferee's LMR not meeting the interim requirement. The Alberta Court of Appeal heard the appeal of the Redwater decision on October 11, 2016, with the Court reserving its decision.

Perpetual's current LMR is shown under the Abandonment and Reclamation Cost section.

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 five years. As of April 1, 2015, each licensee is required to bring 20 percent of its inactive wells into compliance every year, either by reactivating or by 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. The AER has announced that from April 1, 2015 to April 1, 2016, the number of noncompliant wells subject to the IWCP fell from 25,792 to 17,470 with 76 percent of licensees operating in the province having met their annual quota.

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.

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.

As 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), the Government of Canada announced on January 29, 2010 that it will seek a 17 percent reduction in GHG emissions from 2005 levels by 2020; however, the GHG emission reduction targets are not binding. In May 2015, Canada submitted its Intended Nationally Determined Contribution ("**INDC**") to the UNFCCC. INDCs were communicated prior to the 2015 United Nations Climate Change Conference, held in Paris, France, which led to the Paris Agreement that came into force November 4, 2016 (the "**Paris Agreement**"). Among other items, the Paris Agreement constitutes the actions and targets that individual countries will undertake to help keep global temperatures from rising more than 2° Celsius and to pursue efforts to limit below 1.5° Celsius. The Government of Canada ratified the Paris Agreement on December 12, 2016, and pursuant to the agreement, Canada's INDC became its Nationally Determined Contributions ("**NDC**"). As a result, the Government of Canada replaced its INDC of a 17 percent reduction target established in the Copenhagen Accord with an NDC of 30 percent reduction below 2005 levels by 2030.

On June 29, 2016, the North American Climate, Clean Energy and Environment Partnership was announced among Canada, Mexico and the United States, which announcement included an action plan for achieving a competitive, low-carbon and sustainable North American economy. The plan includes setting targets for clean power generation, committing to implement the Paris Agreement, setting out specific commitments to address certain short-lived climate pollutants, and the promotion of clean and efficient transportation.

Additionally, on December 9, 2016, the Government of Canada formally announced the Pan-Canadian Framework on Clean Growth and Climate Change. As a result, the federal government will implement a Canada-wide carbon pricing scheme beginning in 2018. This may be implemented through either a cap and trade system or a carbon tax regime at the option of each province or territory. The federal government will impose a price on carbon of $10 per tonne on any province or territory which fails to implement its own system by 2018. This amount will increase by $10 annually until it reaches $50 per tonne in 2022 at which time the program will be reviewed.

In general, there is some uncertainty with regard to the impacts of federal or provincial climate change and environmental laws and regulations, as it is currently not possible to predict the extent of future requirements. Any new laws and regulations, or additional requirements to existing laws and regulations, could have a material impact on the Corporation's operations and cash flow.

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 GHG emissions 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. As of 2015, Regulated Emitters are required to reduce their emissions intensity by two percent from their baseline in the fourth year of commercial operation, four percent of their baseline in the fifth year, six percent of their baseline in the sixth year, eight percent of their baseline in the seventh year, ten percent of their baseline in the eighth year, and twelve percent 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 percent in 2016 and 20 percent in 2017.

A Regulated Emitter can meet its 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. On June 7, 2016, the *Climate Leadership Implementation Act* ("**CLIA**") was passed into law. The CLIA enacted the *Climate Leadership Act* ("**CLA**") introducing a carbon tax on all sources of GHG emissions, subject to certain exemptions. An initial economy-wide levy of $20 per tonne was implemented on January 1, 2017, increasing to $30 per tonne in January of 2018. All fuel consumption—including gasoline and natural gas—will be subject to the levy, with certain exemptions, and directors of a corporation may be held jointly and severally liable with a corporation when the corporation fails to remit an owed carbon levy. Regulated Emitters will remain subject to the SGER framework until the end of 2017 and are exempt from paying the carbon levy on fuels used in operations until this time. Upon the expiry of the SGER, the Government of Alberta intends to transition to a proposed Carbon Competitiveness Regulation, in which sector specific output-based carbon allocations will be used to ensure competitiveness. A 100 megatonne per year limit for GHG emissions was implemented 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.

There are certain exemptions to the carbon levy imposed by the CLA. Until 2023, fuels consumed, flared or vented in a production process by conventional oil and gas producers will be exempt from the carbon levy. An exemption also applies for biofuels and fuels sold for export. In addition, marked fuels used in farming operations as well as personal and band uses by First Nations are exempt.

The passing of the CLIA is the first step towards executing the Climate Leadership Plan (other legislation is still pending). In addition to enacting the CLA, the CLIA also enacted the *Energy Efficiency Alberta Act*, which enables the creation of Energy Efficiency Alberta, a new Crown corporation to support and promote energy efficiency programs and services for homes and businesses.

The Government of Alberta also signaled its intention through its Climate Leadership Plan to implement regulations that would lower methane emissions by 45 percent by 2025. Regulations are planned to take effect in 2020 to ensure the 2025 target is met.

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.

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 participation 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 and development 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 ensure 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, shut-ins of wells resulting from extreme weather conditions, insufficient storage or transportation capacity or 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 emerging economies, market volatility and disruptions in Asia, sovereign debt levels and political upheavals 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 the case of Alberta, at the provincial level, and the resultant uncertainty surrounding regulatory, tax, royalty changes and environmental regulation that have been announced or 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 downward price pressure on oil and gas produced in Western Canada and 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, rendering certain reserves 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. Consequently, 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 or reduction in liabilities 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 or reduction in liabilities 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, produced, or discovered by the Corporation. The Corporation's ability to market its oil and natural gas may depend upon its ability to acquire capacity 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; and 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 and political 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 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, OPEC's recent decisions pertaining to the oil production of OPEC member countries, and non-OPEC member countries' decisions on production levels, 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 production, 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, political uncertainties, 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 by third parties 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 may realize less on disposition than their carrying value on the financial statements of the Corporation.

Political Uncertainty

In the last several years, the United States and certain European countries have experienced significant political events that have cast uncertainty on global financial and economic markets. During the recent presidential campaign a number of election promises were made and the new American administration has begun taking steps to implement certain of these promises. Included in the actions that the administration has discussed are the renegotiation of the terms of the North American Free Trade Agreement, withdrawal of the United States from the Trans-Pacific Partnership, imposition of a tax on the importation of goods into the United States, reduction of regulation and taxation in the United States, and introduction of laws to reduce immigration and restrict access into the United States for citizens of certain countries. It is presently unclear exactly what actions the new administration in the United States will implement, and if implemented, how these actions may impact Canada and in particular the oil and gas industry. Any actions taken by the new United States administration may have a negative impact on the Canadian economy and on the businesses, financial conditions, results of operations and the valuation of Canadian oil and gas companies, including the Corporation.

In addition to the political disruption in the United States, the citizens of the United Kingdom recently voted to withdraw from the European Union and the Government of the United Kingdom has begun taken steps to implement such withdrawal. Some European countries have also experienced the rise of anti-establishment political parties and public protests held against open-door immigration policies, trade and globalization. To the extent that certain political actions taken in North America, Europe and elsewhere in the world result in a marked decrease in free trade, access to personnel and freedom of movement it could have an adverse effect on the Corporation's ability to market its products internationally, increase costs for goods and services required for the Corporation's operations, reduce access to skilled labour and negatively impact the Corporation's business, operations, financial conditions and the market value of its Common Shares.

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 reimbursement 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 or recovering amounts owing to the Corporation from such operators for their share of abandonment and reclamation obligations. Any of these factors could have a material adverse effect on 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 very limited ability to exercise influence over the decision of companies to drill and produce from lands in which the Corporation has a royalty interest. The Corporation's return on lands in 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.

Financial difficulty of companies who have lands 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 overruns 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, hydraulic fracturing, and waterfloods 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 an demand for oil and natural gas;
- the availability of alternative fuel sources;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- the availability of equipment and manpower for completion and fracking operations;
- 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, pipeline systems and, in certain circumstances, 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 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 transport produced oil and gas to market. 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. As a result, 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 or uncertainty in constructing new infrastructure systems and facilities could harm the Corporation's business and, in turn, the Corporation's financial condition, operations and cash flows. In addition, the federal government has signaled that it plans to review the National Energy Board approval process for large federally regulated 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 and 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 adds additional costs to the transportation of crude oil by rail. On July 13, 2016, the Minister of Transport (Canada) issued Protective Direction No. 38, which directed that the shipping of crude oil on DOT-111 tank cars end by November 1, 2016. Tank cars entering Canada from the United States will be monitored to ensure they are compliant with Protective Direction No. 38.

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 exploration, development, production and 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. Some of these companies not only explore for, develop and produce oil and natural gas, but also carry on refining operations and market oil and natural gas on an international basis. As a result of these complementary activities, some of these competitors may have greater and more diverse competitive resources to draw on than 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, process, 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. If the Corporation does implement such technologies, there is no assurance that the Corporation will do so successfully. 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, or is unsuccessful in implementing certain technologies, 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 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 at the provincial and federal level. 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, certain federal legislation such as the *Competition Act* and the *Investment Canada Act* could negatively affect the Corporation's business, financial condition and the market value of its Common Shares or its assets, particularly when undertaking, or attempting to undertake, acquisition or disposition activity.

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 took effect on January 1, 2017. 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 seismic activity reported in the Fox Creek area of Alberta, the Alberta Energy Regulator ("**AER**") announced in February 2015, 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 AER continues to monitor seismic activity around the province and may extend these requirements to other areas of the province if necessary.

Waterflood

The Corporation undertakes or intends to undertake certain waterflooding programs which involve the injection of water or other liquids into an oil reservoir to increase production from the reservoir and to decrease production declines. To undertake such waterflooding activities the Corporation needs to have access to sufficient volumes of water, or other liquids, to pump into the reservoir to increase the pressure in the reservoir. There is no certainty that the Corporation will have access to the required volumes of water. In addition, in certain areas there may be restrictions on water use for activities such as waterflooding. If the Corporation is unable to access such water it may not be able to undertake waterflooding activities, which may reduce the amount of oil and natural gas that the Corporation is ultimately able to produce from its reservoirs. In addition, the Corporation may undertake certain waterflood programs that ultimately prove unsuccessful in increasing production from the reservoir and as a result have a negative impact on the Corporation's results of operations.

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 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 compliance requirements 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 has 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 is unable to satisfy its obligation. 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 to the required ratio of the Corporation's deemed assets to deemed liabilities or other changes to the requirements of liability management programs may result in significant increases to the Corporation's compliance requirement. 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 that 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 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 would seek a 17percent reduction in GHG emissions from 2005 levels by 2020; however, these GHG emission reduction targets were not binding. As a result of the UNFCCC adopting the Paris Agreement on December 12, 2015, which Canada ratified on October 3, 2016, the Government of Canada implemented new GHG emission reduction targets of a 30percent reduction from 2005 levels by 2030. In addition, the Government of Canada announced it would implement a Canada wide price on carbon to further reduce its GHG emissions. In addition, on January 1, 2017 the CLA came into effect in the Province of Alberta introducing a carbon tax on almost all sources of GHG emissions at a rate of $20 per tonne, increasing to $30 per tonne in January 2018. 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. 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. 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 and political 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.

As a result of global economic and political volatility, the Corporation may from time to time have restricted access to capital and increased borrowing costs. Failure to obtain such financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Corporation's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect the Corporation's ability to expend the necessary capital to replace its reserves or to maintain its production. 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.

Lending Arrangements

The Corporation currently has lending arrangements whereby the amount authorized thereunder is dependent on the collateral value determined by its lenders. The Corporation is required to comply with covenants under its lending arrangements 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 lending arrangements, 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 lending arrangements 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 credit facility 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.

The Corporation's TOU share loan lenders use the value of the pledged TOU Shares combined with the value of the floor price protection on such pledged TOU Shares to determine payment at maturity. Although decreases to the value of TOU Share market prices receive protection through the floor price, the impact of lower TOU Share prices impacts the Corporations ability to refinance these obligations using TOU shares which could result in the requirement to repay a portion, or all, of the Corporation's TOU share loans through the repayment of cash or settlement of the pledged TOU Shares.

Issuance of Debt

From time to time, the Corporation may enter into transactions to acquire assets or shares of other entities. 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. Furthermore, if underlying commodity prices or production decreases materially, revenue may be significantly reduced also increasing the percentage of revenue impacted by foreign exchange swaps.

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) as well as skilled personnel trained to use such equipment in the areas where such activities will be conducted. Demand for such limited equipment and skilled personnel, or access restrictions, may affect the availability of such equipment and skilled personnel 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 a 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;
- transportation and marketability of oil, NGL 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 are often 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, including changes in political regimes or the parties in power, 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, relating to personal injuries, including resulting from exposure to hazardous substances, property damage, property taxes, land and access rights, environmental issues, including claims relating to contamination or natural resource damages and contract disputes. The outcome with respect to 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 proceedings, the proceedings could be costly and time-consuming and may divert the attention of management and key personnel from business operations, which could have an adverse effect on the Corporation's 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. In addition, the process of addressing such claims, regardless of the outcome, is expensive and time consuming and could result in delays which could have a material adverse effect on the Corporation's business and financial results.

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 generally 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. 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. In addition, extreme cold weather, heavy snowfall and heavy rainfall may restrict the Corporation's ability to access its properties and cause operational difficulties. 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.

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 personnel 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.

Information Technology Systems and Cyber-Security

The Corporation has become increasingly dependent upon the availability, capacity, reliability and security of our information technology infrastructure and our ability to expand and continually update this infrastructure, to conduct daily operations. The Corporation depends on various information technology systems to estimate reserve quantities, process and record financial data, manage its land base, analyze seismic information, administer our contracts with our operators and lessees and communicate with employees and third-party partners.

Further, the Corporation is subject to a variety of information technology and system risks as a part of its normal course operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of the Corporation's information technology systems by third parties or insiders. Unauthorized access to these systems by employees or third parties could lead to corruption or exposure of confidential, fiduciary or proprietary information, interruption to communications or operations or disruption to our business activities or our competitive position. Further, disruption of critical information technology services, or breaches of information security, could have a negative effect on our performance and earnings, as well as on our reputation. The Corporation applies technical and process controls in line with industry-accepted standards to protect our information assets and systems; however, these controls may not adequately prevent cyber-security breaches. The significance of any such event is difficult to quantify, but may in certain circumstances be material and could have a material adverse effect on the Corporation's business, financial condition and results of operations.

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 risks and uncertainties, of both a general and specific nature, that could cause actual results to differ materially from those suggested by the forward-looking information or contribute to the possibility that predictions, forecasts or projections will prove to be materially inaccurate.

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, 2016. 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;
- 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 14th day of March, 2017.

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

"*signed by William A. Hahn*"
William A. Hahn
Interim VP Finance and Chief Financial Officer

"*signed by Robert A. Maitland*"
Robert A. Maitland
Director

"*signed by 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 the Company's reserves data as at December 31, 2016. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2016 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.
3. We carried out our evaluation 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 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, 2016, and identifies the respective portions thereof that we have evaluated 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, 2016	Canada	-	380,731	-	380,731

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 7, 2017

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

1. The Audit Committee will be comprised of three or more Directors as determined from time to time by resolution of the Board.
2. 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.
3. 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.
4. 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.
5. 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.
6. 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.