PERPETUAL ENERGY

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED
DECEMBER 31, 2013

March 7, 2014

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APPENDICES

CORPORATE STRUCTURE

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

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. Perpetual amalgamated with its wholly-owned subsidiaries 1143046 Alberta Ltd., POT Acquisition Company Ltd., Profound Energy Inc. and Starboard Gas (W3) Ltd. on June 30, 2010 and continued as Perpetual Energy Inc.

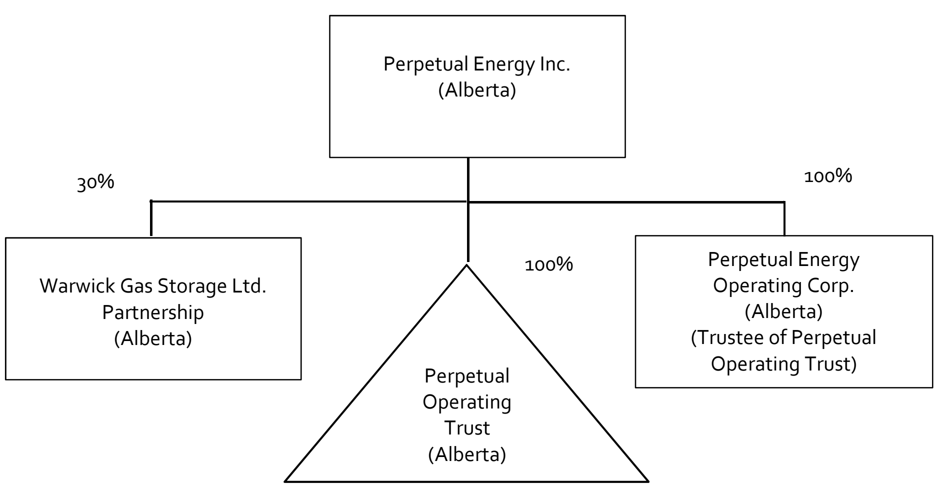
Perpetual's head office and registered office is located at Suite 3200, 605 – 5th Avenue S.W., Calgary, Alberta, T2P 3H5.

Employees

At December 31, 2013, Perpetual had 116 permanent employees and 12 consultants located in its Calgary office and 13 permanent employees in its field offices. The Corporation also had 56 field employees and 30 field hourly consultants in various field locations.

Inter-corporate Relationships

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



GENERAL DEVELOPMENT OF THE BUSINESS

Three Year History

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

2013

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

In the second quarter of 2013, Perpetual exercised its option and acquired an additional 20 percent interest in Warwick Gas Storage LP ("**WGS LP**"), a gas storage facility operated and managed by the Company, thereby increasing its equity ownership to 30 percent.

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

2012

During 2012, the Company remained focused on its asset base transformation and commodity diversification strategy. Capital investment was primarily directed to growing oil and natural gas liquids ("NGL") production, reserves and value in two key proven diversifying growth strategies: Mannville heavy oil in eastern Alberta; and liquids-rich gas in the Wilrich in the greater Edson area of west central Alberta.

During 2012, the Corporation disposed of assets for proceeds of $167.2 million which included its Deep Basin assets in Karr and Carrot Creek, a 90 percent interest in Warwick Gas Storage Inc., and miscellaneous other non-core oil and gas properties including shut-in gas over bitumen ("**GOB**") reserves, and undeveloped lands. It also included the strategic sale of a 33.3 percent interest in one of the Company's heavy oil pools to advance the implementation of an enhanced oil recovery scheme.

After closing on April 25, 2012, Perpetual continued to operate and manage WGS LP and retained an option to buy back up to 30 percent of additional interest within one year. Two new wells were drilled to expand the working gas capacity of the facility to 19 Bcf.

On June 30, 2012, the Corporation had $75 million of 6.50% Convertible Unsecured Subordinated Debentures ("**6.50% Debentures**") mature. Perpetual settled all of the outstanding 6.50% Debentures in cash on the date of maturity and the 6.50% Debentures, which traded under the symbol PMT.DB.C, on the Toronto Stock Exchange were delisted.

2011

In 2011, the Company executed strategies to diversify its commodity mix and create value, capitalizing on Perpetual's substantial inventory of economic opportunities. Combined with ongoing debt reduction initiatives, including asset sales, increased funds flows from oil and liquids rich natural gas strengthened the Corporation's balance sheet. During 2011, the Corporation disposed of assets for proceeds of approximately

$41.7 million which included a number of non-core oil and gas properties and undeveloped Cardium lands in west central Alberta.

On October 19, 2011, the Corporation announced that future dividend payments would be suspended until further notice. Continued payment of a dividend was deemed to be unsustainable given the weakness in natural gas prices. The suspension of the dividend was necessary to drive Perpetual's commitment to maximize Shareholder value. Reinstatement of a dividend in the future will be evaluated at such time as Perpetual's balance sheet has regained strength and commodity prices and costs support a sustainable model where excess free funds flow, over and above capital investments, is once again being generated for distribution to holders ("**Shareholders**") of the Corporation's common shares ("**Common Shares**").

In May 2011, Perpetual announced the reduction of its dividend from $0.03 per share to $0.015 per share. With the strong economic potential of the Wilrich play in west central Alberta well understood and the horizontal development of the Corporation's growing inventory of conventional heavy oil prospects in eastern Alberta showing significant promise, the reduction in the dividend enabled an increased capital spending program in the second half of 2011 to accelerate the commodity diversification strategy and increase future funds flow.

In April 2011 the Corporation set the working gas capacity for the second cycle of its Warwick Gas Storage facility at 17 Bcf.

On March 15, 2011, the Corporation issued $150.0 million aggregate principal amount of 8.75% senior unsecured notes due March 15, 2018 (the "**Notes**").

Significant Acquisitions

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

DESCRIPTION OF THE BUSINESS

General

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

(i) the development and production of shallow natural gas from mature producing regions in eastern Alberta where the Corporation has an established gathering and processing infrastructure;
(ii) exploring and developing the Corporation's natural gas and NGL resource growth opportunities in the deep basin in west central Alberta;
(iii) the exploration for and extraction of heavy oil in eastern Alberta;
(iv) bitumen opportunities in northeast Alberta; and
(v) a commercial gas storage business where the Corporation operates a gas storage facility at Warwick in east central Alberta.

Business Plan

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

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

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

2) Establish excellence in chosen priorities:
    - Safety is job one;
    - Value technical, operational, execution and leadership excellence;
    - Maximize profits through a low-cost culture; and
    - Be accountable for results.

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

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

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

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

- 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.

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

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

The Corporation has had significant success in repositioning its asset base to enhance and diversify its production, reserves and prospect inventory and add high impact, growth-oriented, resource-style opportunities to its asset portfolio, despite diminished funds flows related to low natural gas prices over this period. Diversifying growth opportunities to invest in profitably today include horizontal development of heavy oil at Mannville in east central Alberta, and horizontal development utilizing multi-stage fracture technology for liquids-rich gas in the Wilrich in the greater Edson area of West Central Alberta. Longer term opportunities that have been captured, where resource is being assessed and technologies are being evaluated, include gas development potential in the shallow Viking and Colorado shale in east central Alberta, several bitumen prospects in northeast Alberta and other oil and liquids-rich resource plays in the Alberta deep basin. At the same time, Perpetual remains exposed to significant value upside in its legacy shallow gas asset base related to a potential natural gas price recovery.

Perpetual is focused on five key strategic priorities for 2014:

1) Reduce debt and manage downside risk;
2) Grow Edson liquids-rich gas production, reserves, cash flow, inventory and value;
3) Maximize value of Mannville heavy oil;
4) Maximize cash flow from shallow gas; and
5) Advance and broaden portfolio of high impact opportunities with risk-managed investment.

Operations

Perpetual has made significant progress in transitioning from its legacy asset base of conventional shallow natural gas assets in northeast and east central Alberta to add commodity and play diversification with conventional heavy oil and high impact, resource-style, liquids-rich gas plays in the Alberta deep basin. The continued focus on these two plays has resulted in combined oil and NGL production comprising 21% of 2013 production, up from less than 5% prior to 2010. Perpetual's capital activities for 2014 will continue to focus on value creation through these two key plays. Perpetual also has established several long-term high impact opportunities that will be advanced technically with modest investment. These include exposure to shallow shale gas in eastern Alberta and bitumen opportunities in northeast Alberta.

The following is a description of Perpetual's important oil and natural gas properties at December 31, 2013. Production stated is the Corporation's working interest share of production volumes and, unless otherwise stated, is average production for 2013. The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties due to the effects of aggregation. Unless otherwise specified, gross acres, net acres and well count information are as at December 31, 2013.

West Central Deep Basin

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

Edson

The Edson area is located west of Edmonton, Alberta and is comprised of 55,314 net acres (66% undeveloped) with an average 88% working interest in 46 gross (40.5 net) producing natural gas wells. This area represents approximately 16% of the production from Perpetual's assets for the year 2013. The Company operates the majority of this area which produced 2,940 boe/d in 2013, including 14.5 MMcf/d of natural gas and 531 bbl/d of crude oil and NGL.

Nearly 100% of Perpetual's production from this property is processed through a 100% Company-owned and operated compressor and then passed on to be processed through a third party deep cut plant. The property is also tied in to a third party operated plant in which Perpetual has a 15% ownership interest.

West Edson

The West Edson area is located west of Edson and is comprised of 22,741 net acres (94% undeveloped) with an average 50% working interest in 10 gross (5.0 net) producing natural gas wells and an average 78% working interest in four gross (3.1 net) producing oil wells. This area represents approximately 11% of the production from Perpetual's assets for the year 2013. The Company operates this area which produced 1,962 boe/d in 2013, including 10.8 MMcf/d of natural gas and 164 bbl/d of NGL.

In 2013, Perpetual drilled five (2.5 net) wells. Expansion of the West Edson gas processing facility, which included installation of additional compression as well as refrigeration and liquids handling equipment, was also completed during 2013, expanding capacity of the facility to 37 MMcf/d gross (50% working interest). Perpetual plans to further increase plant capacity in 2014 to accommodate expected incremental production from new drilling activities.

West Central Other

Other non-core assets in the West Central area are comprised of 73,615 net acres (78% undeveloped) with an average 50% working interest in 4 gross (2.0 net) producing oil and natural gas wells.

In the first quarter of 2013, Perpetual closed the sale of undeveloped, non-producing reserves in its Elmworth Montney assets for proceeds of $77.5 million. The disposition had no impact on Perpetual's 2013 production, and represented the vast majority of the 13.1 MMboe reduction in proved and probable reserves related to dispositions in 2013, with a corresponding decrease of $122.8 million in future development capital ("**FDC**"). See **"Statement of Reserves Data and Other Oil and Gas Information"**.

Perpetual entered into a farm-out agreement on 6,240 acres of Duvernay rights in the Waskahigan area. In early 2014, the farmee drilled a horizontal well into the Duvernay which is currently awaiting completion. Once the earning terms have been fulfilled, Perpetual will retain a 35% working interest in 3,840 gross acres and 100% working interest in what remains. Results of this well are expected early in the third quarter of 2014.

In 2013 Perpetual also began to accumulate a land position in a new exploration area in the Alberta deep basin through an acquisition and Crown land sales. To date, Perpetual has an interest in 17,200 net acres of undeveloped land in the Columbia area with a partner. One (0.5 net) well was drilled in 2013 which is currently on production at low rates. These lands are prospective in multiple horizons and provide a new growth area for the Corporation.

Mannville Conventional Heavy Oil

The Mannville heavy oil property is located east of Edmonton, Alberta and stratigraphically overlaps a portion of the Eastern Alberta South shallow gas area. The recognized pools comprise 1,280 net acres of developed land. Perpetual has an additional 10,240 net acres of petroleum and natural gas rights prospective for oil within the Mannville area. Perpetual has an average 94% working interest in 99 gross (93.4 net) producing oil wells. Perpetual operates this area which produced 3,159 boe/d of heavy crude oil in 2013, representing 17% of the Company's 2013 average production.

Perpetual's focus in the Mannville area has been on the exploration and development of cretaceous-aged conventional heavy oil pools geographically synergistic with the Corporation's shallow gas assets. Through Perpetual's extensive database of 2D and 3D seismic and low exposure exploration drilling, seven Lloyd formation pools, four Sparky pools and one Basal Quartz pool have been delineated and development is in progress. In 2013 Perpetual drilled 37 (35.7 net) horizontal wells in this play of which 34 (32.7 net) are producing oil, two (2.0 net) are shut-in, and one (1.0 net) were standing awaiting facilities and start-up operations at year end. In addition, a waterflood pilot in the Mannville I2I pool commenced in December 2013 and additional infill drilling in the I2I pool is planned in the first quarter 2014 to prepare to expand waterflood operations by the end of 2014.

Eastern Alberta Shallow Gas

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

North

The North area comprises Perpetual's legacy shallow gas assets, located in northeast Alberta, where access is generally winter-only. It includes 1,398,262 net acres (47% undeveloped) with an average 72% working interest in 646 producing wellbores, with 727 gross (532.0 net) producing natural gas zones. The majority of natural gas production from the area is Company operated and processed through Company-owned facilities and associated gathering and processing infrastructure. This area represented approximately 34% of production from Perpetual's assets for the year, with production of 6,431 boe/d in 2013 including 38.5 MMcf/d of natural gas and 7 bbl/d of oil.

South

The South area is generally comprised of conventional shallow gas assets, located east of Edmonton, Alberta it includes 892,770 net acres (41% undeveloped) with an average 80% working interest in 490 producing wellbores, with 555 gross (450.8 net) producing natural gas zones. The majority of operations and production from this area is Company operated. The South area represented approximately 22% of production from Perpetual's assets for the year, with production of 4,186 boe/d in 2013 including 25.1 MMcf/d of natural gas.

Perpetual also has an interest in a Viking/Colorado shale shallow unconventional dry gas play in east central Alberta. With low natural gas prices in 2012 and 2013, the Company allocated limited capital spending to the technical and economic delineation of this vast resource. Based on prior year's activities, and monitoring of competitor activity, an eight well pilot project targeting horizontal development of the Colorado and potentially the Viking formations has been designed for execution with the goal to confirm well orientation, fracture techniques and type curves assumptions to assess the expected economic returns for future recovery of this material natural gas resource. Due to lower natural gas price forecasts by McDaniel, 0.4 MMboe of proved reserves and 7.8 MMboe of probable undeveloped natural gas reserves in the Viking formation, and FDC of $97.9 million related to future development of these reserves, were no longer recognized at December 31, 2013, as compared to year-end 2012. See "**Statement of Reserves Data and Other Oil and Gas Information**". It is expected that these reserves will be recognized again if gas prices improve in the future and capital is committed to their development. No undeveloped reserves are currently assigned to the Colorado formation.

Warwick Gas Storage

The Warwick Gas Storage facility is located east of Edmonton, Alberta and is comprised of a 41 Bcf depleted gas pool with an estimated 21 Bcf of working gas capacity at the end of 2013. Perpetual developed the Warwick Gas Storage facility in 2010 as a grass roots development project where a depleted gas pool was converted for commercial gas storage operations. In 2012, the Company sold 90% of its interest in the Warwick Gas Storage business, while retaining an option to buy back up to an additional 30% ownership interest at the same price as the initial sale plus working capital and other adjustments. After the sale, Perpetual began accounting for its interest in WGS LP as an equity investment. In 2013, Perpetual exercised its option and bought back an additional 20% interest bringing its total ownership in WGS LP to 30% as of April 2013. Perpetual operates the gas storage facility under a management service agreement.

There are 14 horizontal wells and one vertical well that are injector and/or producers in the Warwick Gas Storage reservoir. Additionally, included in the gas storage facility are one standing well, one suspended well, one vertical producing well and three observation wells. During 2013, WGS LP implemented delta pressuring which increased the reservoir pressure and increased working gas capacity from 17 Bcf in 2012 to 21 Bcf at the end of 2013.

Bitumen

Perpetual has positioned itself with 329,003 gross (99.7% net) acres of undeveloped oil sands leases geographically synergistic with seven of its shallow gas operating areas in northeast Alberta including Panny, Liege, Marten Hills, Ells, Wabasca, Hoole and Calling Lake as well as a small project area on the Peace River Arch. The bitumen resource potential on these leases will likely be developed over the long-term using a variety of recovery techniques, ranging from near cold production technologies to in-situ thermal techniques such as SAGD technology.

In 2013 Perpetual received funding approval through the Alberta government's Innovative Energy Technology Program ("IETP") for the Company's Low-Pressure Electro-Thermally Assisted Drive ("LEAD") pilot project to develop bitumen in the Bluesky reservoir in the Panny area of northeast Alberta. Total capital and operating costs for the pilot project are estimated at $18.2 million. Approved funding through IETP is 30% of eligible costs to a maximum of $5.5 million. During the third quarter of 2013, Perpetual drilled a water source well to activate funding under the IETP program. Applications have been submitted for the LEAD pilot but, as operations are restricted by winter access conditions, Perpetual does not expect material capital spending to commence until winter 2014/2015.

Independent contingent resource assessment reports were prepared by McDaniel in 2011 and partially updated in the first quarter 2013, resulting in the assignment of 1.36 billion barrels of discovered bitumen initially in place (best estimate) and 1.88 billion barrels of undiscovered bitumen initially in place (best estimate) on 27,113 acres of Perpetual's oil sands leases, primarily in the Panny Bluesky sandstone and Liege Grosmont and Leduc carbonate reservoirs. McDaniel assessed that this represented 279 million barrels of recoverable contingent resource (best estimate) as well as 467 million barrels of prospective resource (best estimate). See "**Bitumen Contingent Resource**" and "**Notes pertaining to the Reporting of Bitumen Contingent Resource**".

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

February 3, 2014

The reserves data set forth below is based upon the figures contained in the report of McDaniel dated effective December 31, 2013, with a preparation date of February 3, 2014 (the "McDaniel Report") evaluating or reviewing substantially all of Perpetual's crude oil, NGL and natural gas reserves.

Disclosure of Reserves Data

McDaniel evaluated 88% of the total proved plus probable future net revenue discounted at 10%. McDaniel evaluated in the McDaniel Report 77% of the assigned total proved plus probable reserves and reviewed the internal evaluation completed by Perpetual on the remaining portion, which primarily included certain natural gas assets in eastern Alberta. McDaniel prepared their reserve report using their own technical assumptions and interpretations, methodologies and pricing and cost assumptions. Due to rounding, certain columns set forth below in this section may not add.

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

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

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

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

The information relating to the Corporation's crude oil, NGL and natural gas reserves contains forward-looking statements relating to anticipated production, future net revenues, forecast capital expenditures, future development plans and costs related thereto, forecast operating costs, anticipated production and abandonment 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, 2013
FORECAST PRICES AND COSTS

	Light and Medium Crude Oil		Heavy Oil		Natural Gas		Natural Gas Liquids		Oil Equivalent	
Reserves Categories	**Gross(1) (Mbbl)**	**Net(2) (Mbbl)**	**Gross(1) (Mbbl)**	**Net(2) (Mbbl)**	**Gross(1) (MMcf)**	**Net(2) (MMcf)**	**Gross(1) (Mbbl)**	**Net(2) (Mbbl)**	**Gross(1) (Mboe)**	**Net(2) (Mboe)**
Proved Producing	43	50	1,792	1,528	110,269	99,792	893	618	21,106	18,828
Proved Non Producing	-	-	93	82	12,261	11,355	48	40	2,184	2,015
Proved Undeveloped	-	-	537	468	54,217	50,903	1,071	908	10,644	9,860
Total Proved	43	50	2,422	2,078	176,747	162,050	2,012	1,566	33,935	30,703
Total Probable	20	23	1,822	1,503	147,979	129,562	1,777	1,268	28,282	24,387
Proved and Probable	62	73	4,245	3,581	324,727	291,611	3,789	2,834	62,217	55,090

(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, 2013
FORECAST PRICES AND COSTS ($millions)

	Before Income Taxes Discounted at (%)					Unit Value Before Income Tax Discounted At 10%/Year
Reserves Categories	**0%**	**5%**	**10%**	**15%**	**20%**	**($/Boe)**
Proved Producing	$311	$273	$245	$224	$207	$13.03
Proved Non Producing	29	24	21	19	17	10.43
Proved Undeveloped	162	117	87	66	51	8.86
Total Proved	502	414	354	309	275	11.52
Total Probable	536	366	268	208	167	11.00
Proved and Probable	$1,038	$780	$622	$517	$442	$11.29

NET PRESENT VALUE OF FUTURE NET REVENUE
AFTER TAX
as at December 31, 2013
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	$311	$273	245	$224	$207	$13.03
Proved Non Producing	29	24	21	19	17	10.43
Proved Undeveloped	162	117	87	66	51	8.86
Total Proved	502	414	354	309	275	11.52
Total Probable	495	345	257	202	164	10.55
Proved and Probable	$997	$759	$611	$510	$439	$11.09

(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, 2013
FORECAST PRICES AND COSTS ($millions)

Reserves Categories	Revenue	Royalties	Gas over Bitumen Royalty Adjustments	Operating Costs	Development Costs	Abandonment and Reclamation Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes [(1)(2)]
Proved Reserves	1,187	(115)	45	(433)	(149)	(34)	502	-	502
Proved and Probable Reserves	2,281	(271)	45	(741)	(230)	(46)	1,038	41	997

(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, 2013

Reserve Categories	Production Group	Future Net Revenue Before Income Taxes (discounted at 10%/year) ($millions)	Unit Value ($/Mcfe) ($/boe)
Proved Reserves	Natural Gas and NGL (including by products but excluding solution gas from wells)	282	1.77/Mcfe
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by products)	4	73.51/boe
Proved Reserves	Heavy Oil (including solution gas and other by products)	68	32.70/boe
Proved Reserves – Total		354	11.52/boe
Proved and Probable Reserves	Natural Gas and NGL (including by products but excluding solution gas from wells)	499	1.73/Mcfe
Proved and Probable Reserve	Light and Medium Crude Oil (including solution gas and other by products)	5	71.28/boe
Proved and Probable Reserves	Heavy Oil (including solution gas and other by products)	118	33.03/boe
Proved and Probable Reserves – Total		622	11.29/boe

Forecast Prices and Costs

Pricing Assumptions (Forecast Prices and Costs)

SUMMARY OF PRICING ASSUMPTIONS
AS AT DECEMBER 31, 2013
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)]
2014	95.00	95.00	67.50	4.00	0.95
2015	95.00	96.50	70.40	4.25	0.95
2016	95.00	97.50	71.20	4.55	0.95
2017	95.00	98.00	71.50	4.75	0.95
2018	95.30	98.30	71.80	5.00	0.95
2019	96.60	99.60	72.70	5.25	0.95
2020	98.50	101.60	74.20	5.35	0.95
2021	100.50	103.60	75.60	5.45	0.95
2022	102.50	105.70	77.20	5.55	0.95
2023	104.60	107.90	78.80	5.65	0.95
2024	106.70	110.00	80.30	5.75	0.95
2025	108.80	112.20	81.90	5.90	0.95
2026	111.00	114.50	83.60	6.00	0.95
2027	113.20	116.70	85.20	6.15	0.95
2028	115.50	119.10	86.90	6.25	0.95

(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, 2013 of $3.53/Mcf, including $0.27/Mcf of realized hedging gains for natural gas. The weighted average AECO daily gas index price for the same 12 month period was $3.17/Mcf. Perpetual's realized oil and NGL price averaged $66.48 per bbl including $0.97 per bbl of realized hedging losses relative to the benchmarks primarily as a result of wider heavy oil differentials and lower NGL prices. The West Texas Intermediate benchmark price for 2013 was $US97.97/bbl.

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

	Gross Proved				Gross Probable				Gross Proved + Probable			
Factors	**Oil Mbbl**	**Gas MMcf**	**Liquids Mbbl**	**Oil Equivalent Mboe**	**Oil Mbbl**	**Gas MMcf**	**Liquids Mbbl**	**Oil Equivalent Mboe**	**Oil Mbbl**	**Gas MMcf**	**Liquids Mbbl**	**Oil Equivalent Mboe**
December 31, 2012[(2)]	2,110	185,819	3,019	36,099	1,960	202,782	2,939	38,696	4,070	388,602	5,958	74,795
Improved Recoveries, Extensions and Discoveries[(3)]	968	33,426	563	7,102	586	30,442	536	6,196	1,554	63,867	1,099	13,298
Technical Revisions	545	28,015	12	5,226	(692)	(6,014)	(492)	(2,187)	(147)	22,001	(481)	3,039
Acquisitions	-	197	1	34	-	70	-	12	-	266	2	46
Dispositions	-	(33,083)	(1,290)	(6,804)	-	(30,703)	(1,192)	(6,309)	-	(63,786)	(2,482)	(13,113)
Production	(1,155)	(32,202)	(238)	(6,761)	-	-	-	-	(1,155)	(32,202)	(238)	(6,761)
Economic Factors	(4)	(5,425)	(54)	(962)	(11)	(48,597)	(15)	(8,126)	(15)	(54,022)	(69)	(9,087)
December 31, 2013	2,465	176,747	2,012	33,935	1,842	147,979	1,777	28,282	4,307	324,727	3,789	62,217

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

(2) The opening balance on December 31, 2012 includes all of Perpetual's reserves, including reserves that were shut-in or identified for shut-in as a result of the GOB issue. At December 31, 2012 and 2013 all reserves shut-in as a result of the GOB issue were categorized as probable reserves.

(3) The Corporation includes all reserve additions resulting from capital expenditures in Improved Recoveries, Extensions and Discoveries.

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)		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	307	92	128	128	64,653	22,990	820	514
2011	19	19	354	354	17,411	28,454	686	1,075
2012	-	-	463	686	20,597	49,844	763	1,866
2013	-	-	347	537	23,034	54,217	395	1,071

The Corporation has a large inventory of proved undeveloped reserves. In 2013, Perpetual added proved undeveloped reserves associated with its successful Mannville heavy oil program in eastern Alberta and the 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 four years as part of larger drilling programs subject to commodity prices. The Corporation uses many factors to determine its annual budgets and all projects, whether booked as undeveloped reserves or unbooked and residing in Perpetual's prospect inventory, compete based on these factors with funds balanced to maximize returns from capital investments as well as drive strategic initiatives.

Probable Undeveloped Reserves

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

	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		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	110	46	86	86	131,713	101,690	755	600
2011	93	93	480	480	18,358	116,820	674	1,320
2012	-	-	964	1,116	44,465	118,236	1,616	2,519
2013	-	-	245	637	25,595	61,582	461	1,374

The Corporation has a large inventory of probable undeveloped reserves. Low forecast gas prices have resulted in all probable undeveloped Viking reserves to be deemed uneconomic. This was offset by Perpetual adding probable undeveloped reserves associated with its successful Mannville heavy oil program in eastern Alberta and the liquids-rich Wilrich gas program in west central Alberta. These reserves are booked as per the COGE handbook to company lands. McDanield has forecast the development of these probable undeveloped reserves over the next five years as part of larger drilling programs subject to commodity prices. As stated above, the Corporation uses many factors to determine its annual budgets and all projects, whether booked as probable undeveloped reserves or unbooked and residing in Perpetual's prospect inventory, compete based on these factors with funds balanced to maximize returns from capital investment as well as drive strategic initiatives.

Significant Factors or Uncertainties

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

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

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

Future Development Costs

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

FUTURE DEVELOPMENT COSTS
FORECAST PRICES AND COSTS ($millions)

Year	Proved Reserves		Proved and Probable Reserves	
	0%	10%	0%	10%
2014	51.6	49.4	57.1	54.5
2015	44.7	39.5	52.6	46.5
2016	45.1	36.1	56.0	44.8
2017	6.8	4.8	52.1	37.3
2018	0.1	0.0	11.1	7.2
Thereafter	0.3	0.1	1.3	0.6
Total	148.6	130.0	230.0	190.9

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 $230.0 million will be required over the life of the Corporation's proved and probable reserves for the drilling, completion, equipping and tie-in of one conventional vertical gas well, 20 conventional horizontal Mannville heavy oil wells, 51 horizontal gas wells targeting the Wilrich and one targeting other west central zones. Future capital costs also include recompletion of up to 243 gas wells included in Perpetual's proved and probable reserves. As the Corporation continues to invest capital to bring on additional production, development of the undeveloped reserves will be undertaken over the next several years.

Bitumen Contingent Resource - Net Present Value of Resource

All of Perpetual's contingent resources currently have an "undetermined" economic status as sub-classification into economic and uneconomic categories has not been evaluated. Contingencies affecting the classification of the resources referred to in the McDaniel reports referenced in the sections above as reserves include corporate development plans, the need for regulatory approval, and the need to perform an economic study regarding production. There is no certainty that it will be commercially viable to produce any portion of the resources. Please see "**Notes Pertaining to the Reporting of Bitumen Contingent Resource**" at the back for applicable definitions and risk factors.

The bitumen in place and recoverable resource estimates, prepared by McDaniel in 2011 in accordance with the COGE Handbook, are as follows:

	Discovered[(1)]				Undiscovered[(1)]			
Resource Category[(1)]	**Gross Area (hectares)**	**Company WI**	**DBIIP (Mbbl)**	**Gross Recoverable Contingent Resource (Mbbl) [(1)]**	**Gross Area (hectares)**	**Company WI**	**UDBIIP (Mbbl)**	**Gross Recoverable Prospective Resource (Mbbl) [(1)]**
Panny								
Low Estimate		100%	509,242	50,924		-	-	-
Best Estimate	5,184	100%	755,009	132,127	-	-	-	-
High Estimate		100%	983,040	245,760		-	-	-
Other Clastics[(2)]								
Low Estimate		100%	36,467	5,470		100%	71,800	7,719
Best Estimate	610	100%	70,691	14,178	676	100%	82,802	17,604
High Estimate		100%	128,406	33,589		100%	167,274	46,737
Liege Carbonates								
Low Estimate		100%	432,554	42,015		100%	1,467,773	138,833
Best Estimate	4,376	100%	529,769	132,442	16,267	100%	1,797,648	449,412
High Estimate		100%	648,832	291,974		100%	2,201,660	990,747
Total All Areas								
Low Estimate		100%	978,263	98,408		100%	1,539,573	146,552
Best Estimate	10,170	100%	1,355,469	278,747	16,943	100%	1,880,450	467,016
High Estimate		100%	1,760,278	571,323		100%	2,368,934	1,037,484

(1) Contingent and prospective resources have been evaluated by McDaniel using the definitions is as defined in section five of the COGE Handbook. All volumes are reported before the deduction of royalties payable to others. Contingent resource assignments are in addition to any reserve assignments associated with these assets. Please refer to the detailed definitions contained under the heading "**Notes Pertaining to the Reporting of Bitumen Contingent Resources**".

(2) Includes MartenHills/Hoole

OTHER OIL AND GAS INFORMATION

Oil and Gas Properties

A description of Perpetual's important oil and natural gas properties as at December 31, 2013 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, 2013.

	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								
Edson	46	40.5	4	3.1	23	17.8	-	-
West Edson	10	5.0	-	-	2	1.5	-	-
West Central Other	1	0.3	4	2.2	18	13.3	2	0.8
	57	45.7	8	5.3	43	32.6	2	0.8
Mannville Heavy Oil	-	-	99	93.3	-	-	15	14.0
Eastern Alberta Shallow Gas								
North	646	468.0	5	5.0	1,039	827.0	4	2.8
South	490	393.4	10	7.1	639	540.8	20	11.6
	1,136	861.4	15	12.1	1,678	1,367.8	24	14.4
Total	1,193	907.1	122	110.7	1,721	1.400.4	41	29.2

(1) "**Gross**" refers to the number of wells, respectively, in which a working interest is held by the Corporation. In addition the Corporation held royalty interests in 330 producing wells at December 31, 2013.

(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 68 gross (57 net) wells shut-in as a result of GOB regulatory rulings.

(4) Allowance for the abandonment costs associated with the well bores was made in the McDaniel Report. There are 39 gross (28 net) wells that are classified as service wells not included in the gross/net well count.

(5) Warwick Gas Storage producing gas wells are injectors and producers for commercial gas storage operations.

Acreage Information

The following table sets out Perpetual's developed and undeveloped land holdings as at December 31, 2013. The Corporation does not have any material work commitments on any of Perpetual's properties.

	Developed Acres		Undeveloped Acres[3]	
Property	**Gross[1]**	**Net[2]**	**Gross[1]**	**Net[2]**
West Central Deep Basin				
Edson	26,560	18,933	44,960	36,381
West Edson	3,040	1,280	38,880	21,461
West Central Other	43,199	16,354	98,443	68,131
	72,799	36,568	182,283	125,973
Eastern Alberta Shallow Gas				
North	1,098,006	745,981	907,517	657,721
South	807,436	524,602	396,280	368,168
	1,900,962	1,266,423	1,303,797	1,025,888
Mannville Heavy Oil[4]	1,280	1,280	-	-
Bitumen	-	-	329,003	327,979
Total	1,979,520	1,308,431	1,815,083	1,479,840

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

During 2014, 160,636 net acres are set to expire. A total of 154,317 net acres expired in 2013. 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 production estimated by McDaniel on a proved and probable basis for the year ended December 31, 2014, which is reflected in the estimate of future net revenue disclosed in the tables.

2014 McDaniel Forecast Production[1]	**Natural Gas (MMcf/d)**	**Crude Oil (bbl/d)**	**Natural Gas Liquids (bbl/d)**
Proved	86.0	2,802	780
Probable	7.7	604	70
Total Proved and Probable	93.7	3,406	850

(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:

	2013 Quarter Ended			
Production	**Dec 31**	**Sept 30**	**June 30**	**Mar 31**
Average Daily Natural Gas Production (MMcf/d)	90.3	85.3	91.9	88.6
Average Daily Oil & NGL Production (bbl/d)	3,509	4,064	4,384	3,483
Total (boe/d)	18,559	18,274	19,708	18,244
Average Realized Price ($/boe)	30.09	32.55	32.60	26.78
Royalties ($/boe)	(2.39)	(3.03)	(4.12)	(1.51)
Operating Costs ($/boe)	(10.47)	(10.47)	(12.15)	(11.06)
Transportation Costs ($/boe)	(1.59)	(1.40)	(1.52)	(1.43)
Operating Netback ($/boe)	15.64	17.65	14.81	12.78

The following table indicates Perpetual's average daily production from each of the Corporation's core areas for the year ended December 31, 2013:

Property	**Average Annual Daily Production (Boe/d)**
West Central Deep Basin	
Edson	2,926
West Edson	1,962
West Central Other	14
	4,902
Eastern Alberta Shallow Gas	
North	6,438
South	4,203
	13,787
Mannville Heavy Oil	3,159
Total	18,696

Capital Expenditures

The following table summarizes capital expenditures related to Perpetual's activities for the year ended December 31, 2013:

($ thousands)	**2013**	**2012**
Exploration and development	95,404	79,624
Geological and geophysical costs[1]	1,279	12
Interest in WGS LP	19,129	–
Acquisitions	8,135	2,407
Dispositions	(78,975)	(167,170)
Other	120	271
Total	45,092	(84,856)

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

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells in which the Corporation participated during the year ended December 31, 2013:

Exploratory Wells	**Gross**	**Net**
Heavy Oil	-	-
Natural Gas	1	0.5
Dry	-	-
Evaluation (Oil Sands)	-	-
Total	1	0.5
Success Rate (%)	100%	100%
Development Wells		
Heavy Oil	37	35.7
Natural Gas	5	2.5
Dry	-	-
Evaluation and Service Wells	-	-
Total	42	38.2
Success Rate (%)	100%	100%
Total Exploration & Development	43	38.7

Additional Information Concerning Abandonment and Reclamation Costs

In addition to the abandonment cost estimates provided by McDaniel inclusive in their reserve assessment, Perpetual compiles annually an 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 value of Perpetual's future asset retirement obligations, net of the estimated salvage value of facilities and equipment and discounted at eight percent is $67 million as at December 31, 2013. The McDaniel Report includes an undiscounted amount of $46 million 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 Funds Flow table. see "**Net Present Value** ("**NPV**") of Reserves Summary". Of the total future well abandonment costs included in the McDaniel Report an undiscounted amount of $43 million relates to Perpetual's developed reserves. The following table presents the estimated future asset retirement obligations and estimated net salvage values at various discount rates:

Abandonment and Reclamation Costs

($ millions, net to Perpetual)	**Undiscounted**	**5%**	**8%**	**Discounted at 10%**
Total estimated future abandonment and reclamation costs(1)	237	151	119	103
Salvage value	(104)	(66)	(52)	(45)
Abandonment and reclamation costs, net of salvage	133	85	67	58
Well abandonment costs for developed reserves included in McDaniel Report	(43)	(28)	(22)	(19)
Estimate of additional future abandonment and reclamation costs, net of salvage(1)	90	57	45	39

(1) Estimated internally in accordance with NI 51-101

(2) Future abandonment and reclamation costs not included in the McDaniel Report, net of salvage value.

RISK MANAGEMENT

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

Natural Gas

Perpetual has in place natural gas hedges on 42 percent of estimated natural gas production and deemed natural gas production for the remainder of 2014. The following tables provide a summary of derivative natural gas contracts in place as at March 5, 2014:

Fixed price natural gas forward sales arrangements (net of related financial fixed-price natural gas purchase contracts) at the AECO trading hub:

Type of contract	Term[(1)]	Volumes at AECO (GJ/d)	Price ($/GJ)[(2)]	Futures market ($/GJ)[(3)]
Financial	April – June 2014	20,825	4.01	4.36
Financial	April – October 2014	26,100	4.02	4.35
Physical	April – October 2014	5,275	4.06	4.35
Financial	April – December 2014	10,000	3.71	4.39
Financial	July – December 2014	22,500	4.25	4.41

(1) Excludes settled and prompt month contracts.
(2) Average price calculated using weighted average price for net open contracts.
(3) Futures market prices are based on closed forward AECO prices as of March 5, 2014.

Sold natural gas call option:

Type of contract	Term	Expiry date	Volumes at AECO (GJ/d)	Strike price ($/GJ)	Futures market ($/GJ)[(1)]
Call	April – December 2014	Monthly 2014	10,000	4.25	4.39

(1) Futures market prices are based on closed forward AECO prices as of March 5, 2014.

Financial forward gas sales arrangements to fix the basis differentials between NYMEX and AECO trading hubs:

Type of contract	Term[(1)]	Volumes at NYMEX-AECO (MMBtu/d)	Price ($/MMBtu)[(2)]	Futures market ($/MMBtu)[(3)]
Financial	April – October 2014	7,500	(0.48)	(0.37)

(1) Excludes settled and prompt month contracts.
(2) Average price is in USD and calculated using weighted average price for net open contracts; the price at which these contracts settle is equal to the NYMEX index less a fixed basis amount.
(3) Futures market prices are based on closed forward NYMEX-AECO differential prices as of March 5, 2014.

Crude Oil

Perpetual has crude oil financial contracts in place for 1,750 bbl/day of crude oil production for the remainder of 2014 with non-triggered WTI call options of 2,000 bbl/day for 2014 and 1,500 bbl/day for 2015. The following tables provide a summary of derivative crude oil contracts in place as at March 5, 2014:

Fixed price oil sales arrangements in $USD:

Type of contract	Term(1)	Volumes at WTI (bbl/d)	Price ($/GJ)(2)	Futures market ($/GJ)(3)
Financial	March – June 2014	750	90.00	99.70
Financial	March – December 2014	250	90.00	96.90

(1) Excludes settled contracts.
(2) Average price calculated using weighted average price for net open contracts.
(3) Futures market prices are based on forward WTI oil prices as of March 5, 2014.

Costless collar oil sales arrangements in $USD:

Type of contract	Term(1)	Volumes at WTI (bbl/d)	Floor price ($US/bbl)(2)	Ceiling price ($US/bbl)(2)	Futures market ($US/bbl)(3)
Collar	March – December 2014	500	85.00	91.10	96.90
Collar	March – December 2014	500	85.00	91.20	96.90
Collar(4)	March – December 2014	500	90.00	103.15	96.90

(1) Excludes settled contracts.
(2) Average price calculated using weighted average price for net open contracts.
(3) Futures market prices are based on forward WTI oil prices as of March 5, 2014.
(4) In this collar arrangement Perpetual received a ceiling price above the market price for such collars, and in exchange should the WTI index settle above $US103.15/bbl in any month during the contract period Perpetual will receive a price of $US93.00/bbl.

Costless collar oil sales arrangements in $CAD:

Type of contract	Term(1)	Volumes (bbl/d)	Floor price ($CAD/bbl)	Ceiling price ($CAD/bbl)	Futures market ($CAD/bbl)(2)
Collar	January – December 2015	500	87.50	95.25	88.30
Collar	January – December 2015	500	87.50	95.75	88.30

(1) Excludes settled contracts.
(2) Futures market prices are based on forward WTI oil prices as of March 5, 2014.

Basis differential contracts between WTI and WCS trading:

Type of contract	Term(1)	Volumes (bbl/d)	WTI-WCS differential ($US/bbl)(2)	Futures market ($US/bbl)(3)
Financial	April – December 2014	2,000	(21.64)	(21.90)

(1) Excludes settled and prompt month contracts.
(2) Average price calculated using weighted average price for net open contracts; the price at which these contracts settle is equal to the WTI index less a fixed basis amount.
(3) Futures market prices are based on forward WTI-WCS differential prices as of March 5, 2014.

Oil call options sold:

Type of contract	Term	Expiry date	Volumes at WTI (bbl/d)	Strike price ($US/bbl WTI)	Futures market ($US/bbl WTI)(1)
Call	March – December 2014	Monthly 2014	2,000	105.00	96.90
Call	January – December 2015	Monthly 2015	1,500	100.00	88.30

(1) Futures market prices are based on forward WTI oil prices as of March 5, 2014.

Foreign Exchange

U.S. dollar forward sales arrangements:

Type of contract	Notional $USD / month	Exchange rate ($CAD / $USD)	Term[(1)]
Financial	1,000,000	1.1000	March 2014 – June 2015

(1) Excludes settled contracts.

The Corporation receives $1,000 each day during the month that the daily exchange rate is between $1.0000 and $1.1000. If the average monthly exchange rate is greater than $1.1000 the Corporation pays USD$1,000,000 multiplied by the difference between the average monthly exchange rate and $1.1000. No settlement occurs between the Corporation and the counterparty if the average monthly exchange rate settles below $1.0000.

Type of contract	Notional floor $USD / month	Notional ceiling $USD / month	Exchange rate floor ($CAD / $USD)	Exchange rate ceiling ($CAD / $USD)	Term
Financial	2,500,000	5,000,000	1.0400	1.1410	July 2014 – December 2015

If the average monthly exchange rate is greater than the exchange rate ceiling, the Corporation pays $USD5,000,000 multiplied by the difference between the average monthly exchange rate and $1.1000. If the monthly average exchange rate settles below the exchange rate floor, the Corporation receives $USD2,500,000 multiplied by the difference between the average monthly exchange rate and the exchange rate floor.

Type of contract	Notional amount $USD / month	Notional ceiling $USD / month	Exchange rate floor ($CAD / $USD)	Exchange rate ceiling ($CAD / $USD)	Term
Financial	1,000,000	2,000,000	1.1000	1.1225	March – June 2014
Financial	1,000,000	2,000,000	1.1000	1.1305	March – June 2014

(1) Excludes settled contracts.

If the average monthly exchange rate is less than the exchange rate floor, the Corporation receives $USD1,000,000 multiplied by the difference between the average monthly exchange rate and the exchange rate floor. If the monthly average exchange rate is between the exchange rate ceiling and exchange rate floor, the Corporation receives $USD1,000,000 multiplied by the difference between the average monthly exchange rate and the exchange rate ceiling. If the average monthly exchange rate is greater than the exchange rate ceiling, the Corporation pays $USD2,000,000 multiplied by the difference between the average monthly exchange rate and the exchange rate ceiling.

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

Common Shares in respect of return of capital on dissolution, to share rateably, together with the holders of shares of any other class of shares of Perpetual ranking equally with the Common Shares in respect of return of capital, in such assets of Perpetual as are available for distribution.

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

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

Constraints

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

Ratings

The following information relating to our credit ratings is provided as it relates to our financing costs and liquidity. Credit ratings affect our ability to obtain short-term and long-term financing and the cost of such financing. A negative change in our ratings outlook or any downgrade in our current credit ratings by our ratings agencies could adversely affect our cost of borrowing and/or access to sources of liquidity and capital. We believe that our credit ratings will allow us 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 Notes have currently been assigned ratings of CCC+ by Standard and Poor's Rating Services, a division of McGraw-Hill Companies (Canada) Corporation ("**S&P**") and Caa1/LGD 4-52%% 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+, stable outlook and a credit rating of CCC+ on the Notes. An obligation rated "CCC" is currently vulnerable and dependant on favourable business, financial and economic conditions to meet financial commitments. Adverse business, financial, or economic conditions will likely impair the obligor's capacity or willingness to meet its financial commitment on the obligation. The ratings from AA to CCC may be modified by the addition of a plus (+) or a minus (-) sign to show relative standing within the major rating categories. In addition, S&P may add a rating outlook of "positive", "negative" or "stable" which assesses the potential direction of a long-term credit rating over the intermediate term (typically six months to two years).

Moody's credit ratings are on a long-term debt rating scale that ranges from AAA to C, which represents the range from highest to lowest quality of such securities rated. Moody's has assigned Perpetual a corporate family credit rating of Caa1, negative outlook, and a credit rating of Caa1/LGD 3-46%, negative outlook on the Notes. According to the Moody's rating system, securities rated ''Caa'' are judged to be of poor standing and are subject to very high credit risk. Moody's appends numerical modifiers 1, 2 and 3 to each generic rating classification from AA through C. The modifier 1 indicates that the security ranks in the higher end of its generic rating category, the modifier 2 indicates a mid-range ranking and the modifier 3 indicates a ranking in the lower end of its generic rating category. In addition, Moody's may add a rating outlook of ''positive'', ''negative'' or ''stable'', which assess the likely direction of an issuer's rating over the medium term.

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

MARKET FOR SECURITIES

Trading Price and Volume

The outstanding Common Shares, 7.25% Convertible Debentures and 7.00% Convertible Debentures are listed and posted for trading on the TMX under the trading symbols "PMT", "PMT.DB.D" and "PMT.DB.E", respectively. The following tables set forth the closing price range and trading volume of each of these securities as reported by the TMX for the periods indicated:

Common Shares

	Price Range		
	High ($)	**Low ($)**	**Volume**
2013			
January	1.22	0.95	4,990,048
February	1.04	0.78	4,243,529
March	1.25	0.78	3,440,826
April	1.24	1.02	3,789,965
May	1.31	1.12	2,659,530
June	1.29	1.10	2,946,095
July	1.24	1.10	2,070,987
August	1.17	0.98	1,256,244
September	1.09	0.95	2,014,144
October	1.10	0.94	2,195,240
November	1.17	0.96	2,734,034
December	1.12	0.95	2,944,118

7.25% Convertible Debentures (PMT.DB.D)

	Price Range		
	High ($)	Low ($)	Volume
2013			
January	96.99	94.00	9,050
February	94.66	91.00	6,060
March	95.00	89.50	6,130
April	96.61	94.02	7,230
May	96.50	94.25	13,760
June	98.25	95.76	13,850
July	97.90	96.51	3,840
August	98.00	96.15	8,270
September	97.95	96.00	2,480
October	98.00	95.40	5,940
November	99.00	95.00	5,230
December	99.37	94.51	7,470

7.00% Convertible Debentures (PMT.DB.E)

	Price Range		
	High ($)	Low ($)	Volume
2013			
January	95.00	92.00	13,590
February	93.00	91.00	6,590
March	93.99	89.00	16,850
April	94.90	93.50	16,570
May	95.50	93.00	9,390
June	97.58	95.50	21,470
July	97.00	96.00	3,650
August	96.60	95.07	3,270
September	95.15	92.60	3,480
October	94.00	92.15	9,130
November	94.25	92.31	4,330
December	95.75	93.00	4,680

Prior Sales

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

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

Date of Grant	Number of Share Options Granted	Exercise Price
March 21, 2013	80,000	$1.18
May 23, 2013	140,000	$1.21
August 20, 2013	2,445,000	$1.11

Date of Grant	Number of Restricted Rights Granted	Exercise Price
March 21, 2013	45,000	$0.01
May 23, 2013	65,000	$0.01

Date of Grant	Number of Performance Share Rights Granted	Exercise Price
February 7, 2013	1,151,000	$0.00

DIVIDENDS

On October 19, 2011 after having reduced its monthly dividend from $0.03 per Share to $0.015 in May, the Corporation announced that future dividend payments would be suspended until further notice. Continued payment of a dividend was not sustainable given the continued weakness in natural gas prices, and it was deemed that it would inhibit Perpetual's continuing efforts to implement its strategy of commodity and asset base diversification. The continued execution of the strategies to diversify commodity mix and create value, capitalizing on Perpetual's substantial inventory of economic opportunities, is expected to grow funds flow. Combined with ongoing debt reduction initiatives, including asset sales, stronger diversified funds flows will strengthen the Corporation's balance sheet. The suspension of the dividend was necessary to drive Perpetual's commitment to maximize Shareholder value. Reinstatement of a dividend in the future will be evaluated at such time as Perpetual's balance sheet has regained strength and commodity prices and costs support a sustainable model where excess free funds flow, over and above capital investments, is once again being generated for distribution to Shareholders.

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

The historical dividends described below may not be reflective of future dividends, which will be subject to review by the board of directors of the Corporation taking into account the prevailing circumstances at the relevant time. See "**Risk Factors**".

The accompanying table summarizes cash dividends to shareholders for each of the last three years:

For the Period Ended	Payment Date	Dividend per Common Share(1)
January 31, 2011	February 15, 2011	$0.03
February 28, 2011	March 15, 2011	$0.03
March 31, 2011	April 11, 2011	$0.03
April 30, 2011	May 16, 2011	$0.03
May 31, 2011	June 15, 2011	$0.015
June 30, 2011	July 15, 2011	$0.015
July 31, 2011	August 15, 2011	$0.015
August 31, 2011	September 15, 2011	$0.015
September 30, 2011	October 17, 2011	$0.015

(1) Prior to the payment made on August 16, 2010, amounts represented distributions on the Trust Units of Paramount Energy Trust (the Corporation's predecessor).

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 has been the Chairman of the Board and Chief Executive Officer of Paramount since 1978. Until June 2002 he was also the President. He 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, Geologists and Geophysicists of Alberta, the Canadian Association of Petroleum Producers, the Canadian Society of Petroleum Geologists, and the American Association of Petroleum Geologists.
Susan L. Riddell Rose(4)(5) Alberta, Canada	President, Chief Executive Officer and Director since June 28, 2002	Ms. Riddell Rose is President and Chief Executive Officer of Perpetual Energy Inc. through the corporate conversion of Paramount Energy Trust. Ms. Riddell Rose graduated from Queen's University, Kingston, Ontario with a Bachelor of Science in Geological Engineering (1986) and has over 28 years of experience in the Canadian oil and natural gas industry. She began her career as a geological engineer with Shell Canada. From 1990 until 2002 Sue was employed by Paramount Resources Ltd. in various capacities culminating in the position of Corporate Operating Officer. She has been a director of Paramount Resources Ltd. since 2000. Ms. Riddell is also on the board of directors of Newalta Inc. and Brookfield Office Properties. She is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta, the Canadian Society of Petroleum Geologists, the American Association of Petroleum Geologists and is a Governor of the Canadian Association of Petroleum Producers.
Karen A. Genoway(2)(3)(5)(6) Alberta, Canada	Director since June 28, 2002	Ms. Genoway is a professional landman with over 30 years' experience in the oil and natural gas industry. Currently, she is the Vice President, Land with

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
		Rimfire Energy Inc., a private company. Prior to that Ms. Genoway was the Vice President, Land of Onyx. From February 2001 she was Vice President of Request Management Inc., manager of Request Income Trust until its acquisition by Pulse Data Inc. in January 2002. Ms. Genoway was with Enerplus Resources Fund where she held the positions of Senior Vice President (1997 to 2000), Vice President Land (1989 to 1997) and Land Manager (1987 to 1989). Ms. Genoway is a graduate of the ICD Corporate Governance College, Directors Education Program, February 2006 and received her accreditation from the Institute of Corporate Directors, Institute-Certified Director, ICD.D, April 2006.
Randall E. Johnson(1)(3)(5)(6) Alberta, Canada	Director since June 20, 2006	Mr. Johnson's skills and experience that enable him to make decisions on the suitability of the Corporation's compensation policies and practices are derived from Mr. Johnson's corporate banking experience and as a director of other issuers. 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.
Robert A. Maitland(1)(3)(5)(6) Alberta, Canada	Director since February 7, 2008	Mr. Maitland has over 30 years of senior business experience, primarily in the oil and gas industry. He received a Bachelor of Commerce degree in 1975 from the University of Calgary, received his Chartered Accountant designation in 1977 and his ICD.D designation from the Institute of Corporate Directors in 2005. Since 2007, he has been a financial consultant. Previous to 2007, he has been the Vice President and Chief Financial Officer of Fairquest Energy Ltd., Fairborne Energy Ltd., Canadian Midstream Services Limited, Shiningbank Energy Income Fund, Post Energy Ltd. and Summit Resources Ltd. Mr. Maitland currently sits on the board of Rock Energy Inc. and GasFrac Energy Services Inc. and two private companies.

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
Geoffrey C. Merritt(1)(2)(4)(5)(6) Alberta, Canada	Director since June 17, 2010	Mr. Merritt has 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 currently sits on the board of Zargon Oil and Gas Ltd. Mr. Merritt received a B.Sc. in Chemical Engineering from the University of Alberta in 1978 and is a graduate of the Harvard Business School.
Donald J. Nelson(2)(4)(5)(6) Alberta, Canada	Director since June 28, 2002	Mr. Nelson is President of Fairway Resources Inc., an oil and gas consulting firm. Prior to his current occupation, Mr. Nelson held the consecutive positions of Vice President, Operations and President and Director with Summit Resources Limited from July 1996 to June 2002. Mr. Nelson is a director of Keyera Corp. and Enerplus Corporation, two publicly traded issuers 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 LLP), Barristers and Solicitors. He had been a member of the Law Society of Alberta since 1975. He also has served as a director of the following publicly traded entities: Blue Sky Resources Ltd. (July 1999 to July 2000); Cabre Exploration Ltd. (June 1981 to December 2000); Jet Energy Corp. (August 1995 to November 1999); and Tuscany Resources Ltd. (October 1997 to October 2001).
Jeffrey R. Green Alberta, Canada	Vice President, Corporate and Engineering Services	Mr. Green has over 28 years of experience in the Canadian oil and natural gas industry. His previous industry experience includes Vice President of

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
		Production Operations & Administration, Manager, Acquisitions and Divestitures with Paramount Energy Trust and Exploitation Manager and Production Manager at Anadarko Canada Corp. Mr. Green has held additional technical and supervisory positions in other organizations including Norcen and Union Pacific Resources.
Gary C. Jackson Alberta, Canada	Vice President, Land, Acquisitions & Divestitures	Mr. Jackson has over 35 years of experience in the Canadian oil and natural gas industry. He was Vice President, Land of Summit Resources Limited from 2000 to 2002. His career has included the position of Manager of Acquisitions and Divestitures, Joint Venture Midstream and Land Services at Petro-Canada Oil and Gas as well as various positions related to land and contracts with Amerada Hess Canada and Placer Cego Petroleum.
Marcello M. Rapini Alberta, Canada	Vice President, Marketing	Mr. Rapini joined Perpetual Energy Inc. in December 2005 and has over 25 years of gas marketing and trading experience in the natural gas industry. His previous positions include Vice President of Trade at Sempra Energy Trading, Senior Trader at Mirant Energy Marketing Ltd. and Senior Trader at Duke Energy Marketing.
Cameron R. Sebastian Alberta, Canada	Vice President, Finance and Chief Financial Officer	Mr. Sebastian has over 26 years of experience in the North American energy industry. He was Vice President, Finance of Summit Resources Ltd. from 2000 to 2002 and the company's Controller from 1994 to 1997. Prior thereto he was Vice President, Finance of Pursuit Resources Corp. and Controller of Coho Energy Inc. in Dallas, Texas.
Vicki L. Benoit Alberta, Canada	Vice President, Production Operations	Ms. Benoit has over 25 years of oil and gas experience leading operations, production and asset teams for Devon Energy Corp., Southward Energy Corp., Starboard Energy Ltd. and consulting in an engineering capacity for various energy companies including Resolute Energy Corp., Omers Energy and Viking Energy Corp.
Linda L. McKean Alberta, Canada	Vice President, Exploitation	Ms. McKean has over 25 years of experience in the Canadian oil and natural gas industry. Ms. McKean has been with Perpetual and the predecessor Paramount Energy Trust since 2004 in the positions of Eastern District Manager and consulting engineer. Her previous industry technical experience

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
		includes reservoir engineering positions at Berkley Petroleum and Anadarko Canada Corp, and 10 years at Shell Canada working as a development geologist and as a reservoir engineer.

(1) Member of the Audit Committee.
(2) Member of the Reserves Committee.
(3) Member of the Compensation and Corporate Governance Committee.
(4) Member of the Environmental, Health and Safety Committee.
(5) The terms of office of all directors of the Company will expire on the date of the next annual shareholders' meeting.
(6) Ms. Genoway, Mr. Johnson, Mr. Maitland, Mr. Nelson, Mr. Merritt and Mr. Ward are independent, non-employee directors.

The directors and officers of Perpetual, as a group, beneficially own or control or direct, directly or indirectly an aggregate of 37,633,932 voting securities as of March 6, 2014 representing approximately 25.34% 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 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.

From 1997 to 2003, Mr. Maitland was a director of Military International Ltd. which was cease traded for failure to file financial statements, which cease trade order is still in effect.

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.

Penalties or Sanctions

To the knowledge of the Corporation, no director or executive officer of the Corporation (nor any personal holding company of any of such persons), or shareholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation, has been subject to: (a) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or (b) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

Conflicts of Interest

Certain officers and directors of the Corporation are also officers and/or directors of other entities engaged in the oil and gas business generally. As a result, situations may arise where the interest of such directors and officers conflict with their interests as directors and officers of other companies. The resolution of such conflicts is governed by applicable corporate laws, which require that directors act honestly, in good faith and with a view to the best interests of the Corporation. Conflicts, if any, will be handled in a manner consistent with the procedures and remedies set forth in the ABCA. The ABCA provides that in the event that a director has an interest in a contract or proposed contract or agreement, the director shall disclose his interest in such contract or agreement and shall refrain from voting on any matter in respect of such contract or agreement unless otherwise provided by the ABCA.

AUDIT COMMITTEE INFORMATION

Audit Committee Charter

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

Audit Committee

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

The Audit Committee must liaise with the Reserves Committee on matters relating to reserves valuations which impact Perpetual's financial statements.

Composition of the Audit Committee

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

Relevant Education and Experience

Robert A. Maitland

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

Randall E. Johnson

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

Geoffrey C. Merritt

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

Pre-Approval of Policies and Procedures

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

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

External Auditor Service Fees

Audit Fees

The aggregate fees billed by Perpetual's external auditor in each of the last two fiscal years for audit services were $485,000 in 2013 and $716,000 in 2012, which includes fees related to offering documents and the Corporation's year-end audit and quarterly reviews.

Audit-Related Fees

The aggregate fees billed in each of the last two fiscal years for assurance related services by Perpetual's external auditor that are reasonably related to the performance of the audit or review of the financial statements that are not reported under Audit Fees above were $30,000 in 2013 and $50,000 in 2012.

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 $0 in 2013 and $0 in 2012.

These services relate to the determination and reporting of taxability of security dividends for each of Canada and the United States, the preparation and filing of Canadian trust and corporate income tax returns, and services with respect to discussions on tax compliance in various foreign jurisdictions.

All Other Fees

The aggregate fees billed in the 2013 fiscal year by Perpetual’s external auditor for services other than those services reported above were $0. For the 2012 fiscal year those fees totalled $0.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

Legal Proceedings

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

Regulatory Actions

There are no:

(a) penalties or sanctions imposed against Perpetual by a court relating to securities legislation or by a securities regulatory authority during Perpetual's financial year;

(b) 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

(c) settlement agreements Perpetual entered into before a court relating to securities legislation or with a securities regulatory authority during Perpetual's financial year.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

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

TRANSFER AGENT AND REGISTRAR

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

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.

INTEREST 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 Rules of Professional Conduct of Institute of Chartered Accountants of Alberta.

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, 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 very competitive. The Canadian Association of Petroleum Producers estimates that there are over 1,000 exploration and production companies in Canada. Perpetual controls less than one percent of the business in western Canada, but where it is active, Perpetual believes it has a strong competitive position to optimize value by driving strategy, operating and executing activities, controlling infrastructure, minimizing costs, maximizing production, and capturing new opportunities.

Companies operating in the petroleum industry must manage risks which are beyond the direct control of company personnel. Among these risks are those associated with exploration, reservoir management, commodity prices, markets, foreign exchange rates and interest rates.

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. The exploration for and the development of oil and natural gas reserves is dependent on access to areas where drilling is to be conducted. Seasonal weather variation, including "freeze-up" and "break-up", affect access in certain circumstances. See "**Risk Factors – Seasonality**".

Environmental Protection

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

Reorganizations

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

Environmental, Health and Safety Policies

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

The Corporation develops emergency response practices, procedures and readiness plans in conjunction with local authorities, emergency services and the communities in which it operates in order to effectively respond to an environmental or safety incident should it arise. The effectiveness of these plans are 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 2013 Perpetual conducted an internal maintenance audit. This audit allows the Corporation to maintain its COR accreditation which demonstrates the Corporation has exceeded the Alberta Employment and Immigration Workplace Partnerships standard, an accomplishment shared amongst a select few in the oil and gas industry. As part of the COR accreditation an external auditor is required to audit the Corporation every three years.

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

INDUSTRY CONDITIONS

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

Pricing and Marketing

Oil

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

Natural Gas

Alberta'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 such as the Alberta "NIT" (Nova Inventory Transfer), 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 (NGX), Intercontinental Exchange or the New York Mercantile Exchange (NYMEX) in the United States, spot and future prices can also be influenced by supply and demand fundamentals on these platforms. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m^3/day) must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or for a larger quantity requires an exporter to obtain an export licence from the NEB.

The North American Free Trade Agreement

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

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

Royalties and Incentives

General

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

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

Alberta

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

Royalties are currently paid pursuant to "The New Royalty Framework" (implemented by the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*) and the "Alberta Royalty Framework", which was implemented in 2010. Royalty rates for conventional oil are set by a single sliding rate formula, which is applied monthly and incorporates separate variables to account for production rates and market prices. The maximum royalty payable under the royalty regime is 40%. Royalty rates for natural gas under the royalty regime are similarly determined using a single sliding rate formula with the maximum royalty payable under the royalty regime set at 36%.

Oil sands projects are also subject to Alberta's royalty regime. Prior to payout of an oil sands project, the royalty is payable on gross revenues of an oil sands project. Gross revenue royalty rates range between 1-9% depending on the market price of oil, determined using the average monthly price, expressed in Canadian dollars, for WTI crude oil at Cushing, Oklahoma: rates are 1% when the market price of oil is less than or equal to $55 per barrel and increase for every dollar of market price of oil increase to a maximum of

9% when oil is priced at $120 or higher. After payout, the royalty payable is the greater of the gross revenue royalty based on the gross revenue royalty rate of 1-9% and the net revenue royalty based on the net revenue royalty rate. Net revenue royalty rates start at 25% and increase for every dollar of market price of oil increase above $55 up to 40% when oil is priced at $120 or higher. In addition, concurrent with the implementation of The New Royalty Framework, the Government of Alberta renegotiated existing contracts with certain oil sands producers that were not compatible with the new royalty regime.

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

The Government of Alberta has presently prescribed a GOB financial solution through amendments to the royalty regulation with respect to natural gas ("**GOB Royalty Regulation**"), which provide a mechanism whereby the Government may prescribe additional royalty components to effect a reduction in gas royalties otherwise payable in the royalty calculated through the Crown royalty system for operators of gas wells which have been denied the right to produce by the AEUB, or its successor the ERCB, as a result of certain bitumen conservation decisions. The formula for calculation of the royalty reduction provided in the GOB Royalty Regulation is:

0.5 x ((deemed production volume x 0.80) x (Alberta Gas Reference Price - $0.3791/GJ))

Through this formula, operating expenses are effectively deemed to be $0.40 per Mcf, royalties are deemed to be 20 percent, the deemed production is assigned the Alberta Gas Reference Price, which includes a transportation component and the entire formula is assigned a 50 percent reduction factor. The deemed production volumes are reduced by ten percent annually for a period of up to 10 years.

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 GOB 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 financial assistance 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**"). Specifically:

- Coalbed methane wells will receive a maximum royalty rate of 5% for 36 producing months on up to 750 MMcf of production, retroactive to wells that began producing on or after May 1, 2010;

- Shale gas wells will receive a maximum royalty rate of 5% for 36 producing months with no limitation on production volume, retroactive to wells that began producing on or after May 1, 2010;

- Horizontal gas wells will receive a maximum royalty rate of 5% for 18 producing months on up to 500 MMcf of production, retroactive to wells that commenced drilling on or after May 1, 2010; and

- Horizontal oil wells and horizontal non-project oil sands wells will receive a maximum royalty rate of 5% with volume and production month limits set according to the depth of the well (including the horizontal distance), retroactive to wells that commenced drilling on or after May 1, 2010.

The Emerging Resource and Technologies Initiative will be reviewed in 2014, and the Government of Alberta has committed to providing industry with three years notice if it decides to discontinue the program.

British Columbia

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

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

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

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

- *Summer Royalty Credit Program* providing a royalty credit equal to 10% of the goods and services costs up to $100,000 per well for wells spudded after March 31 and before December 1 each year;

- *Deep Royalty Credit Program* providing a royalty credit for natural gas wells defined in terms of a dollar amount applied against royalties, is well specific and applies to drilling and completion costs for vertical wells with a true vertical depth greater than 2,500 metres and horizontal wells with a true vertical depth greater than 1,900 metres (or 2,300 metres if spud before September 1, 2009) and if certain other criteria are met and is intended to reflect the higher drilling and completion costs;

- *Deep Re-Entry Royalty Credit Program* providing a royalty credit for deep re-entry wells with a true vertical depth to the top of pay of the re-entry well event that is greater than 2,300 metres and a re-entry date after November 30, 2003; or if the well was spud on or after January 1, 2009, with a true vertical depth to the completion point of the re-entry well event being greater than 2,300 metres;

- *Deep Discovery Royalty Credit Program* providing the lesser of a 3-year royalty holiday or 283,000,000 m^3 of royalty free gas for deep discovery wells with a true vertical depth greater than 4,000 metres whose surface locations are at least 20 kilometres away from the surface location of any well drilled into a recognized pool within the same formation;

- *Coalbed Gas Royalty Reduction and Credit Program* providing a royalty reduction for coalbed gas wells with average daily production less than 17,000 m^3 as well as a royalty credit for coalbed gas wells equal to $50,000 for wells drilled on Crown land and a tax credit equal to $30,000 for wells drilled on freehold land;

- *Marginal Royalty Reduction Program* providing a monthly royalty reduction for low productivity natural gas wells with an average daily rate of production less than 23 m^3 for every metre of marginal well depth in the first 12 months of production. To be eligible, wells must have been spudded after May 31, 1998 and the first month of marketable gas production must have occurred between June 2003 and August 2008. Once a well passes the initial eligibility test, a reduction is realized in each month that average daily production is less than 25,000m^3;

- *Ultra-Marginal Royalty Reduction Program* providing royalty reductions for low productivity, shallow natural gas wells. Vertical wells must be less than 2,500 metres and horizontal wells less than 2,300 metres to be eligible. Production in the first 12 months ending after January 2007 must be less than 17m^3 per metre of depth for exploratory wildcat wells and less than 11m^3 per metre of depth for development wells and exploratory outpost wells. The well must have been spudded or re-entered after December 31, 2005. A reduction is realized in each month that average daily production is less than 60,000m^3; and

- *Net Profit Royalty Reduction Program* providing reduced initial royalty rates to facilitate the development and commercialization of technically complex resources such as coalbed gas, tight gas, shale gas and enhanced-recovery projects, with higher royalty rates applied once capital costs have been recovered.

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

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

The Petroleum and Natural Gas Royalty and Freehold Production Tax Regulation has been amended effective April 1, 2013 to provide for a 3% minimum royalty on affected wells with deep well/deep re-entry credits. The 3% minimum royalty applies to deep wells when the net royalty payable would otherwise be zero for a production month.

Saskatchewan

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

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

The amount payable as a Crown royalty or a freehold production tax in respect of natural gas production is determined by a sliding scale based on the actual price received, the quantity produced in a given month, the type of natural gas, and the classification of the natural gas. Like conventional oil, natural gas may be classified as "non-associated gas" (gas produced from gas wells) or "associated gas" (gas produced from oil wells) and royalty rates are determined according to the finished drilling date of the respective well. Non-associated gas is classified as new gas (having a finished drilling date before February 9, 1998 with a first production date on or after October 1, 1976), third tier gas (having a finished drilling date on or after February 9, 1998 and before October 1, 2002), fourth tier gas (having a finished drilling date on or after October 1, 2002) and old gas (not classified as either third tier, fourth tier or new gas). A similar classification is used for associated gas except that the classification of old gas is not used, the definition of fourth tier gas also includes production from oil wells with a finished drilling date prior to October 1, 2002, where the individual oil well has a gas-oil production ratio in any month of at least 3,500 m^3 of gas for every

m^3 of oil, and new gas is defined as oil produced from a well with a finished drilling date before February 9, 1998 that received special approval, prior to October 1, 2002, to produce oil and gas concurrently without gas-oil ratio penalties.

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

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

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

- *Royalty/Tax Incentive Volumes for Vertical Oil Wells Drilled on or after October 1, 2002* providing reduced Crown royalty (a Crown royalty rate of the lesser of "fourth tier oil" Crown royalty rate and 2.5%) and freehold tax rates (a freehold production tax rate of 0%) on incentive volumes of 8,000 m^3 for deep development vertical oil wells, 4,000 m^3 for non-deep exploratory vertical oil wells and 16,000 m^3 for deep exploratory vertical oil wells (more than 1,700 metres or within certain formations) and after the incentive volume is produced, the oil produced will be subject to the "fourth tier" royalty tax rate;

- *Royalty/Tax Incentive Volumes for Exploratory Gas Wells Drilled on or after October 1, 2002* providing reduced Crown royalty (a Crown royalty rate of the lesser of "fourth tier oil" Crown royalty rate and 2.5%) and freehold tax rates (a freehold production tax rate of 0%) on incentive volumes of 25,000,000 m^3 for qualifying exploratory gas wells;

- *Royalty/Tax Incentive Volumes for Horizontal Oil Wells Drilled on or after October 1, 2002* providing reduced Crown royalty (a Crown royalty rate of the lesser of "fourth tier oil" Crown royalty rate and 2.5%) and freehold tax rates (a freehold production tax rate of 0%) on incentive volumes of 6,000 m^3 for non-deep horizontal oil wells and 16,000 m^3 for deep horizontal oil wells (more than 1,700 metres total vertical depth or within certain formations) and after the incentive volume is produced, the oil produced will be subject to the "fourth tier" royalty tax rate;

- *Royalty/Tax Incentive Volumes for Horizontal Gas Wells drilled on or after June 1, 2010 and before April 1, 2013* providing for a classification of the well as a qualifying exploratory gas well and resulting in a reduced Crown royalty (a Crown royalty rate of the lesser of "fourth tier oil" Crown royalty rate and 2.5%) and freehold tax rates (a freehold production tax rate of 0%) on incentive volumes of 25,000,000 m^3 for horizontal gas wells and after the incentive volume is produced, the gas produced will be subject to the "fourth tier" royalty tax rate;

- *Royalty/Tax Regime for Incremental Oil Produced from New or Expanded Waterflood Projects Implemented on or after October 1, 2002* whereby incremental production from approved waterflood projects is treated as fourth tier oil for the purposes of Crown royalty and freehold tax calculations;

- *Royalty/Tax Regime for Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing prior to April 1, 2005* providing lower Crown royalty and freehold tax determinations based in part on the profitability of EOR projects during and subsequent to the payout of the EOR operations;

- *Royalty/Tax Regime for Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing on or after April 1, 2005* providing a Crown royalty of 1% of gross revenues on EOR projects pre-payout and 20% of EOR operating income post-payout and a freehold production tax of 0% pre-payout and 8% post-payout on operating income from EOR projects; and

- *Royalty/Tax Regime for High Water-Cut Oil Wells* designed to extend the product lives and improve the recovery rates of high water-cut oil wells and granting "third tier oil" royalty/tax rates with a Saskatchewan Resource Credit of 2.5% for oil produced prior to April 2013 and 2.25% for oil produced on or after April 1, 2013 to incremental high water-cut oil production resulting from qualifying investments made to rejuvenate eligible oil wells and/or associated facilities.

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

Land Tenure

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

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

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

Environmental Regulation

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

Federal

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

Alberta

The regulatory landscape in Alberta has undergone a transformation from multiple regulatory bodies to a single regulator for upstream oil and gas, oil sands and coal development activity. On June 17, 2013, the Alberta Energy Regulator (the "**AER**") assumed the functions and responsibilities of the former Energy Resources Conservation Board, including those found under the *Oil and Gas Conservation Act* ("**ABOGCA**"). On November 30, 2013, the AER assumed the energy related functions and responsibilities of Alberta Environment and Sustainable Resource Development ("**AESRD**") in respect of the disposition and management of public lands under the *Public Lands Act*. On March 30, 2014, the AER is expected to assume the energy related functions and responsibilities of AESRD in the areas of environment and water under the *Environmental Protection and Enhancement Act* and the *Water Act*, respectively. 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 the transformation to a single regulator is the creation of 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.

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

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

and conservation directives, which are explicit declarations contained in a regional plan to set aside specified lands in order to protect, conserve, manage and enhance the environment.

On August 22, 2012, the Government of Alberta approved the Lower Athabasca Regional Plan ("**LARP**") which came into force on September 1, 2012. The LARP is the first of seven regional plans developed under the ALUF. LARP covers a region in the northeastern corner of Alberta that is approximately 93,212 square kilometres in size. The region includes a substantial portion of the Athabasca oilsands area, which contains approximately 82% of the province's oilsands resources and much of the Cold Lake oilsands 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, oilsands companies' tenure has been (or will be) cancelled in conservation areas and no new oilsands 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.

The next regional plan to take effect is the South Saskatchewan Regional Plan ("**SSRP**") which covers approximately 83,764 square kilometres and includes 45 % of the provincial population. The SSRP was released in draft form in 2013 and is expected to come into force on April 1, 2014.

With the implementation of the new Alberta regulatory structure under the AER, AESRD will remain responsible for development and implementation of regional plans. However, the AER will take on some responsibility for implementing regional plans in respect of energy related activities.

British Columbia

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

Saskatchewan

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

Liability Management Rating Programs

Alberta

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

Effective May 1, 2013, the AER implemented important changes to the AB LLR Program that resulted in a significant increase in the number of oil and gas companies in Alberta that are required to post security. Some of the important changes include:

- a 25% increase to the prescribed average reclamation cost for each individual well or facility (which will increase a licensee's deemed liabilities);
- a $7,000 increase to facility abandonment cost parameters for each well equivalent (which will increase a licensee's deemed liabilities);
- a decrease in the industry average netback from a five-year to a three-year average (which will affect the calculation of a licensee's deemed assets, as the reduction from five to three years means the average will be more sensitive to price changes); and
- a change to the present value and salvage factor, increasing to 1.0 for all active facilities from the current 0.75 for active wells and 0.50 for active facilities (which will increase a licensee's deemed liabilities).

The changes will be implemented over a three-year period, ending May 2015. The changes to the LLR Program stem from concern that the previous regime significantly underestimated the environmental liabilities of licensees.

British Columbia

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

Saskatchewan

In Saskatchewan, the Ministry of Economy implements the Licensee Liability Rating Program (the "**SK LLR Program**"). The SK LLR Program is designed to assess and manage the financial risk that a licensee's well and facility abandonment and reclamation liabilities pose to an orphan fund (the "**Oil and Gas Orphan**

Fund") established under the SKOGCA. The Oil and Gas Orphan Fund is responsible for carrying out the abandonment and reclamation of wells and facilities contained within the SK LLR Program when a licensee or WIP is defunct or missing. The SK LLR Program requires a licensee whose deemed liabilities exceed its deemed assets to post a security deposit. The ratio of deemed liabilities to deemed assets is assessed once each month for all licensees of oil, gas and service wells and upstream oil and gas facilities.

Climate Change Regulation

Federal

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

On April 26, 2007, the Government of Canada released "Turning the Corner: An Action Plan to Reduce Greenhouse Gases and Air Pollution" (the "**Action Plan**") which set forth a plan for regulations to address both GHGs and air pollution. An update to the Action Plan, "Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions" was released on March 10, 2008 (the "**Updated Action Plan**"). The Updated Action Plan outlines emissions intensity-based targets, for application to regulated sectors on a facility-specific, sector-wide basis or company-by-company basis. Although the intention was for draft regulations aimed at implementing the Updated Action Plan to become binding on January 1, 2010, the only regulations being implemented are in the transportation and electricity sectors. The federal government indicates that it is taking a sector-by-sector regulatory approach to reducing GHG emissions and is working on regulations for other sectors. Representatives of the Government of Canada have indicated that the proposals contained in the Updated Action Plan will be modified to ensure consistency with the direction ultimately taken by the United States with respect to GHG emissions regulation. In June 2012, the second US-Canada Clean Energy Dialogue Action Plan was released. The plan renewed efforts to enhance bilateral collaboration on the development of clean energy technologies to reduce GHG emissions.

Alberta

As part of Alberta's 2008 Climate Change Strategy, the province committed to taking action on three themes: (a) conserving and using energy efficiently (reducing GHG emissions); (b) greening energy production; and (c) implementing carbon and capture storage.

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 CCEMA is based on an emissions intensity approach and aims for a 50% reduction from 1990 emissions relative to GDP by 2020. 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 facilities emitting more than 100,000 tonnes of GHGs a year are subject to compliance with the CCEMA. Alberta is the first jurisdiction in North America to impose regulations requiring large facilities in various sectors to reduce their GHG emissions.

The SGER, effective July 1, 2007, applies to facilities emitting more than 100,000 tonnes of GHGs in 2003 or any subsequent year, 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. The SGER distinguishes between "Established Facilities" and "New Facilities". Established Facilities are defined as facilities that completed their first year of commercial operation prior to January 1, 2000 or that have completed eight or more years of commercial operation. Established Facilities are required to reduce their emissions intensity by 12% of their baseline emissions intensity for 2008 and subsequent years. Generally, the baseline for an Established Facility reflects the average of emissions intensity in 2003, 2004 and 2005. New Facilities are defined as facilities that completed their first year of commercial operation on December 31, 2000, or a subsequent year, and have completed less than eight years of commercial operation, or are designated as New Facilities in accordance with the SGER. New Facilities are required to reduce their emissions intensity by 2% from baseline in the fourth year of commercial operation, 4% of their baseline in the fifth year, 6% of their baseline in the sixth year, 8% of their baseline in the seventh year and 10% of their baseline in the eighth year. The CCEMA does not contain any provision for continuous annual improvements in emissions intensity reductions beyond those stated above.

The CCEMA provides that regulated emitters can meet their emissions intensity targets by contributing to the Climate Change and Emissions Management Fund at a rate of $15 per tonne of CO_2 equivalent. The funds contributed by industry to the Climate Change and Emissions Management Fund will be used to drive innovation and test and implement new technologies for greening energy production. Emissions credits can also be purchased from regulated emitters that have reduced their emissions below the 100,000 tonne threshold or non-regulated emitters that have generated emissions offsets through activities that result in emissions reductions in accordance with established protocols published by the Government of Alberta.

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

British Columbia

In February 2008, British Columbia announced a revenue-neutral carbon tax that took effect July 1, 2008. The tax is consumption-based and applied at the time of retail sale or consumption of virtually all fossil fuels purchased or used in British Columbia. The current tax level is $30 per tonne of CO_2 equivalent. The final scheduled increase took effect on July 1, 2012. There is no plan for further rate increases or expansions at this time. In order to make the tax revenue-neutral, British Columbia has implemented tax credits and reductions in order to offset the tax revenues that the Government of British Columbia would otherwise receive from the tax.

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

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

Saskatchewan

On May 11, 2009, the Government of Saskatchewan announced *The Management and Reduction of Greenhouse Gases Act* (the "**MRGGA**") to regulate GHG emissions in the province. The MRGGA received Royal Assent on May 20, 2010 and will come into force on proclamation. The MRGGA establishes a framework for achieving the provincial target of a 20% reduction in GHG emissions from 2006 levels by 2020. The MRGGA and related regulations have yet to be proclaimed in force.

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. Gas Over Bitumen Matters

The Alberta Energy Regulator ("**AER**") has established a process to identify gas production in Alberta that may pose an unacceptable risk to the ultimate recovery and economic viability of co-located bitumen resources and has ordered the shut-in of certain natural gas production in northeast Alberta. These "shut-in orders" have called into question the ability to produce natural gas when the production of natural gas is deemed to interfere with potentially recoverable bitumen. In particular, the AER, as part of its broad bitumen conservation strategy, has ordered the shut-in of natural gas production in the Wabiskaw and McMurray formations in certain parts of the Athabasca Oil Sands Area in northeast Alberta. Certain of the Corporation's assets are directly affected by such shut-in orders. The Corporation cannot ensure that additional production will not be shut-in in the future or that it will be able to negotiate adequate compensation for having to shut-in any such production. This could have a material adverse effect on our business, financial condition and operations.

The Corporation is currently receiving GOB royalty reductions and there is no assurance that such reductions will continue to be received by the Corporation or that the Corporation will have sufficient gas crown royalties against which to apply the royalty reductions.

Solution Gas Ownership

A portion of the Corporation's natural gas production is from properties where third parties hold bitumen rights. Certain of these third parties have suggested that "solution gas" exists within the bitumen and that therefore this solution gas is the property of the bitumen rights holder. If this is proven to be correct, and if it is demonstrated that this solution gas has been or may continue to be produced in association with the recovery of Perpetual's conventional natural gas rights, these facts may give rise to a third party claim for compensation and impact future production and reserves. A successful claim in this regard may have a material adverse effect on our business, financial condition and operations.

Exploration, Development and Production Risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of the Corporation depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, the Corporation's existing reserves, and the production from them, will decline over time as the Corporation produces from such reserves. A future increase in the Corporation's reserves will depend on both the ability of the Corporation to explore and develop its existing properties and its ability to select and acquire suitable producing properties or prospects. There is no assurance that the Corporation will be able continue to find satisfactory properties to acquire or participate in. Moreover, management of the Corporation may determine that current markets, terms of acquisition, participation or pricing conditions make potential acquisitions or participations uneconomic. There is also no assurance that the Corporation will discover or acquire further commercial quantities of oil and natural gas.

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

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

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including, but not limited to, fire, explosion, blowouts, cratering, sour gas releases, spills and other environmental hazards. These typical risks and hazards could result in substantial damage to oil and natural gas wells, production facilities, other property, the environment and personal injury. Particularly, the Corporation may explore for and produce sour natural gas in certain areas. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to the Corporation.

Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations as well as equipment failure and downtime related to company-owned and third party infrastructure and facilities. 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.

Global Financial Markets

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the American and European sovereign debt levels, have caused significant volatility in commodity prices. These events and conditions have caused a decrease in confidence in the broader United States and global credit and financial markets and have created a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. While there are signs of economic recovery, these factors have negatively impacted company valuations and are likely to continue to impact the performance of the global economy going forward. Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and demand of these commodities due to the current state of the world economies, actions taken by the Organization of the Petroleum Exporting Countries ("**OPEC**") and the ongoing global credit and liquidity concerns. This volatility may in the future affect the Corporation's ability to obtain equity or debt financing on acceptable terms.

Prices, Markets and Marketing

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

Prices for oil and natural gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors beyond the control of the Corporation. These factors include economic conditions, in the United States, Canada and Europe, the actions of OPEC, governmental regulation, political stability in the Middle East, Northern Africa and elsewhere, the foreign supply 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. 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 of the Corporation's reserves. The Corporation might also elect not to produce from certain wells at lower prices.

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

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

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.

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.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

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

Operational Dependence

Other companies operate some of the assets in which the Corporation has an interest. The Corporation has limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect the Corporation's financial performance. The Corporation's return on assets operated by others depends upon a number of factors that may be outside of the Corporation's control, including, but not limited to, the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

Project Risks

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

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

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

Gathering and Processing Facilities, Pipeline Systems and Rail

The Corporation delivers its products through gathering and processing facilities and pipeline systems some of which it does not own and by rail. The amount of oil and natural gas that the Corporation can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities, pipeline systems and railway lines. The lack of availability of capacity in any of the gathering and processing facilities, pipeline systems and railway lines, and in particular the processing facilities, could result in the Corporation's inability to realize the full economic potential of its production or in a reduction of the price offered for the Corporation's production. Although pipeline expansions are ongoing, the lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to produce and market oil and natural gas production. In addition, the pro-rationing of capacity on inter-provincial pipeline systems continues to affect the ability to export oil and natural gas. Furthermore, producers are increasingly turning to rail as an alternative means of transportation. In recent years, the volume of crude oil shipped by rail in North America has increased dramatically and it is projected to continue in this upward trend. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities could harm the Corporation's business and, in turn, the Corporation's financial condition, results of operations and cash flows.

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. These recommendations include, among others, the imposition of higher standards for all DOT-111 tank cars carrying crude oil and the increased auditing of shippers to ensure they properly classify hazardous materials and have adequate safety plans in place. The increased regulation of rail transportation may reduce the ability of railway lines to alleviate pipeline capacity issues and add additional costs to the transportation of crude oil by rail.

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

Competition

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

Cost of New Technologies

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

Alternatives to and Changing Demand for Petroleum Products

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

Regulatory

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

Royalty Regimes

There can be no assurance that the federal government and the provincial governments of the western provinces will not adopt new royalty regimes or modify the existing royalty regimes which may have an impact on the economics of the Corporation's projects. An increase in royalties would reduce the Corporation's earnings and could make future capital investments, or the Corporation's operations, less economic.

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.

Environmental

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain oil and gas industry operations. In addition, such legislation sets out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites.

Compliance with environmental legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Corporation to incur costs to remedy such discharge. Although the Corporation believes that it will be in material compliance with current applicable environmental legislation, no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Liability Management

Alberta, Saskatchewan and British Columbia have developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder becomes defunct. These programs generally involve an assessment of the ratio of a licensee's deemed assets to deemed liabilities. If a licensee's deemed liabilities exceed its deemed assets, a security deposit is required. Changes of the ratio of the Corporation' deemed assets to deemed liabilities or changes to the requirements of liability management programs may result in significant increases to the security that must be posted. This is of particular concern to junior oil and gas companies as they may be disproportionately affected by price instability. See "**Industry Conditions**".

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 greenhouse gas ("**GHG**") emissions legislation at the provincial or federal level. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place. As a signatory to the *United Nations Framework Convention on Climate Change* (the "**UNFCCC**") and a participant to the Copenhagen Agreement (a non-binding agreement created by the UNFCCC), the Government of Canada announced on January 29, 2010 that it will seek a 17% reduction in GHG emissions from 2005 levels by 2020. These GHG emission reduction targets are not binding, however. 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. 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. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact on the Corporation and its operations and financial condition.

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, Canadian/United States exchange rates could affect the future value of the Corporation's reserves as determined by independent evaluators.

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

An increase in interest rates could result in a significant increase in the amount the Corporation pays to service debt, 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);
- 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. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Corporation. The inability of the Corporation to access sufficient capital for its operations could have a material adverse effect on the Corporation's business financial condition, results of operations and prospects.

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. There is risk that if the economy and banking industry experienced unexpected and/or prolonged deterioration, the Corporation's access to additional financing may be affected.

Because of global economic 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. Failure to obtain any financing necessary for the Corporation's capital expenditure plans may result in a delay in development or production on the Corporation's properties.

Credit Facility Arrangements

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

The Corporation's lenders use the Corporation's reserves, commodity prices, applicable discount rate and other factors, to periodically determine the Corporation's borrowing base. A material decline in 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 bank indebtedness.

Issuance of Debt

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

Hedging

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

- production falls short of the hedged volumes;
- 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 in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar. However, if the Canadian dollar declines in value compared to the United States dollar, the Corporation will not benefit from the fluctuating exchange rate.

Availability of Drilling Equipment and Access

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

Diluent Supply

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

Title to Assets

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise. The actual interest of the Corporation in properties may accordingly vary from the Corporation's records. If a title defect does exist, it is possible that the Corporation may lose all or a portion of the properties to which the title defect relates, which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. There may be valid challenges to title or legislative changes, which affect the Corporation's title to the oil and natural gas properties the Corporation controls that could impair the Corporation's activities on them and result in a reduction of the revenue received by the Corporation.

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth in this document are estimates only. Generally, estimates of economically recoverable oil and natural gas reserves and the future net cash flows from such estimated reserves are based upon a number of variable factors and assumptions, such as:

- historical production from the properties;
- production rates;
- ultimate reserve recovery;
- timing and amount of capital expenditures;
- marketability of oil and natural gas;
- royalty rates; and

- the assumed effects of regulation by governmental agencies and future operating costs (all of which may vary materially from actual results).

For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times may vary. The Corporation's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates and such variations could be material.

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

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

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

Insurance

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

Geopolitical Risks

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

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

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

Litigation

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

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

Intellectual Property Litigation

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

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights in portions of western Canada. The Corporation is not aware that any claims have been made in respect of its properties and assets. However, if a claim arose and was successful, such claim may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Breach of Confidentiality

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

Income Taxes

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

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

Seasonality

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

Third Party Credit Risk

The Corporation may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production and other parties. In the event such entities fail to meet their contractual obligations to the Corporation, such failures may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry and of joint venture partners may 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.

Conflicts of Interest

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

Reliance on Key Personnel

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

Expansion into New Activities

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

Forward-Looking Information May Prove Inaccurate

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

Share Price Volatility

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

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

Future Acquisition Activities May Have Adverse Effects

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

Internal Controls

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

Additional information on the risks, assumption and uncertainties are found under the heading "**Forward-Looking Statements**".

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, 2013. 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

NOTES PERTAINING TO THE REPORTING OF BITUMEN CONTINGENT RESOURCES

The following are excerpts from the definitions of resources and reserves, contained in Section 5 of the COGE Handbook, which is referenced by the Canadian Securities Administrators in NI 51-101.

Definitions

Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political, and regulatory matters, or a lack of markets. It is also appropriate to classify as contingent resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage. Contingent Resources are further classified in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status. Criteria for determining commerciality are further detailed in the COGE Handbook Section 5.3.4.

Discovered Petroleum Initially-In-Place (DPIIP) (equivalent to discovered resources) is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production. The recoverable portion of discovered petroleum initially in place includes production, reserves, and contingent resources; the remainder is unrecoverable.

Economic Contingent Resources are those contingent resources which are currently economically recoverable.

Prospective Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects.

Undiscovered Petroleum Initially-In-Place (UDPIIP) (equivalent to undiscovered resources) is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations yet to be discovered. The recoverable portion of undiscovered petroleum initially in place is referred to as "prospective resources"; the remainder as unrecoverable.

Total Petroleum Initially-In-Place (PIIP) is that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations, prior to production, plus those estimated quantities in accumulations yet to be discovered (equivalent to "total resources").

Uncertainty Categories for Resource Estimates

The range of uncertainty of estimated recoverable volumes may be represented by either deterministic scenarios or by a probability distribution. Resources should be provided as low, best, and high estimates as follows:

Low Estimate: This is considered to be a conservative estimate of the quantity that will actually be recovered. It is likely that the actual remaining quantities recovered will exceed the low estimate. If probabilistic methods are used, there should be at least a 90 percent probability (P90) that the quantities actually recovered will equal or exceed the low estimate.

Best Estimate: This is considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. If probabilistic methods are used, there should be at least a 50 percent probability (P50) that the quantities actually recovered will equal or exceed the best estimate.

High Estimate: This is considered to be an optimistic estimate of the quantity that will actually be recovered. It is unlikely that the actual remaining quantities recovered will exceed the high estimate. If probabilistic methods are used, there should be at least a 10 percent probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

This approach to describing uncertainty may be applied to reserves, contingent resources, and prospective resources. There may be significant risk that sub-commercial and undiscovered accumulations will not achieve commercial production. However, it is useful to consider and identify the range of potentially recoverable quantities independently of such risk.

Levels of Certainty for Reported Reserves

With respect to contingent resources, not all technically feasible development plans will be commercial. The commercial viability of a development project is dependent on the forecast of fiscal conditions over the life of the project. For contingent resources the risk component relating to the likelihood that an accumulation will be commercially developed is referred to as the "chance of development." For contingent resources the chance of commerciality is equal to the chance of development.

Risk Factors for Resource Estimates

In general, estimates of gross original resources and recoverable resources are based upon a number of factors and assumptions made as of the date on which the estimates were determined, such as geological, technological and engineering estimates and are subject to a variety of risks and uncertainties and other factors that could cause actual events or results to differ materially from those anticipated in forward-looking estimates.

These risks and uncertainties include but are not limited to: (1) the fact that there is no certainty that the zones of interest will exist to the extent estimated or that the zones will be found to have oil with characteristics that meet or exceed the minimum criteria in terms of net pay thickness, porosity or oil saturation, or that the oil will be commercially recoverable to the extent estimated; (2) risks inherent in the heavy oil and oil sands industry; (3) the lack of additional financing to fund the Corporation's exploration activities and continued operations; (4) fluctuations in foreign exchange and interest rates; (5) the number of competitors in the oil and gas industry with greater technical, financial and operations resources and staff; (6) fluctuations in world prices and markets for oil and gas due to domestic, international, political, social, economic and environmental factors beyond the Corporation's control; (7) changes in government regulations affecting oil and gas operations and the high compliance cost with respect to governmental regulations; (8) potential liabilities for pollution or hazards against which the Corporation cannot adequately insure or which the Corporation may elect not to insure; (9) the Corporation's ability to hire and retain qualified employees and consultants; (10) contingencies affecting the classification as reserves versus resources which relate to the following issues as detailed in the COGE Handbook: ownership considerations, drilling requirements, testing requirements, regulatory considerations, infrastructure and market considerations, timing of production and development, and economic requirements; (11) the fact that there is no certainty that any portion of contingent resources will be commercially viable to produce; (12) the fact that there is no certainty that any portion of the prospective resources will be discovered and if discovered, there is no certainty that it will be commercially viable to produce any portion of the resources; and (13) other factors beyond the Corporation's control. Any reference in this Annual Information Form to DPIIP, UDPIIP, contingent resources and prospective resources are not, and should not be confused with oil and gas reserves.

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;
- expected realization of GOB royalty adjustments;
- deferred income tax and its effect on funds flow;
- intentions with respect to preservation of tax pools and taxes payable by the Corporation;
- funding of and anticipated results from capital expenditure programs;
- renewal of and borrowing costs associated with the credit facility;
- future debt levels, financial capacity, liquidity and capital resources;
- future contractual commitments;
- drilling, completion, facilities and construction plans;
- future drilling, workovers and recompletions estimated in Perpetual's prospect inventory;
- the impact of Canadian federal and provincial governmental regulation on the Corporation relative to other issuers;
- Crown royalty rates;
- working gas capacity and other operating and marketing parameters related to WGS LP;
- the Corporation's treatment under governmental regulatory regimes;
- business strategies and plans of management, including future changes in the structure of business operations; and
- reliance on third parties in the industry to develop and expand the Corporation's assets and operations.

The forward-looking information and statements contained in this Annual Information Form reflect several material factors and expectations and assumptions of the Corporation including, without limitation, that

Perpetual will conduct its operations in a manner consistent with its expectations and, where applicable, consistent with past practice; the general continuance of current or, where applicable, assumed industry conditions; the continuance of existing, and in certain circumstances, the implementation of proposed tax, royalty and regulatory regimes; the ability of Perpetual to obtain equipment, services, and supplies in a timely manner to carry out its activities; the accuracy of the estimates of Perpetual's reserve volumes; the timely receipt of required regulatory approvals; certain commodity price and other cost assumptions; the ability to secure adequate product transportation; the continued availability of adequate debt and/or equity financing and funds flow to fund the Corporation's capital and operating requirements as needed; and the extent of Perpetual's liabilities.

Perpetual believes the material factors, expectations and assumptions reflected in the forward-looking information and statements are reasonable but no assurance can be given that these factors, expectations and assumptions will prove to be correct. The forward-looking information and statements included in this Annual Information Form are not guarantees of future performance and should not be unduly relied upon. Such information and statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information or statements including, without limitation:

- volatility in market prices for oil, natural gas, NGL, power and other products;
- supply and demand regarding Perpetual's products;
- risks inherent in Perpetual's operations, such as production declines, unexpected results, geological, technical, or drilling and process problems;
- unanticipated operating events that can reduce production or cause production to be shut-in or delayed, including plant upsets, transportation bottlenecks and market disruptions;
- unanticipated well or facility operating performance that impacts storage operations or working gas capacity;
- changes in exploration or development plans by Perpetual or by third party operators of Perpetual's properties;
- reliance on industry partners;
- uncertainties or inaccuracies associated with estimating reserves and resource volumes;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands, skilled personnel, equipment for drilling, completions, facilities and pipeline construction and maintenance;
- increased service and operational costs;
- incorrect assessments of the value of acquisitions;
- increased debt levels or debt service requirements;
- industry conditions including fluctuations in the price of natural gas and related commodities;
- royalties payable in respect of Perpetual's production;
- governmental regulation of the oil and gas industry, including environmental regulation;
- fluctuation in foreign exchange or interest rates;
- the need to obtain required approvals from regulatory authorities;
- changes in laws applicable to the Corporation, royalty rates, or other regulatory matters;
- general economic conditions in Canada, the United States and globally;
- stock market volatility and market valuations;
- limited, unfavourable, or a lack of access to capital markets; and

certain other risks detailed from time to time in Perpetual's public disclosure documents including, without limitation, those risks and contingencies described above and under "**Risk Factors**" in this Annual Information Form. The foregoing list of risk factors should not be considered exhaustive.

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

ADDITIONAL INFORMATION

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

Additional information, including directors' and officers' remuneration and indebtedness, principal holders of the Corporation's securities and securities authorized for issuance under equity compensation plans is contained in the Corporation's information circular for the Corporation's most recent annual meeting of securityholders 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, which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2013, estimated using forecast prices and costs.

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; 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 5th day of March, 2014.

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

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

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

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

APPENDIX B

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

Attention: The Board of Directors of Perpetual Energy Inc.

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

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

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

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

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

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

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated and reviewed by us, for the year ended December 31, 2013, and identifies the respective portions thereof that we have evaluated, reviewed and reported on to the Company's management:

		Net Present Value of Future Net Revenue $M (before income taxes, 10% discount rate)			
Preparation Date of Evaluation Report	**Location of Reserves**	**Audited**	**Evaluated**	**Reviewed**	**Total**
February 3, 2014	Canada	-	545,139	76,753	621,892

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 4 for events and circumstances occurring after the preparation date.

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 3, 2014

APPENDIX C

AUDIT COMMITTEE CHARTER

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 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 Perpetual'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 Perpetual'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 the Corporation.

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 Perpetual'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 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 Director, 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 Perpetual'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 Perpetual 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 Perpetual 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 Perpetual and report on same to the Board;
- establish procedures for:
  - (a) the receipt, retention and treatment of complaints received by the Corporation 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 the Corporation's 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 the Corporation, including complaints regarding financial reporting and confidential submissions by employees;
- review and validate Perpetual management's annual review of fraud risk assessment;
- review and approve Perpetual'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 the Corporation.