

AVENIR DIVERSIFIED INCOME TRUST

Annual Information Form

Year Ended December 31, 2009

March 30, 2010

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SCHEDULE "A" FORM NI 51-101F2

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SCHEDULE "C" CHARTER FOR THE AUDIT AND RISK MANAGEMENT COMMITTEE

GLOSSARY OF TERMS

In this Annual Information Form, unless the context otherwise requires, references to "we", "us", "our" or similar terms, or to the "Trust" refer to the Trust (either alone or together with its subsidiaries) and the following terms shall have the meanings set forth below, unless otherwise indicated.

"**ABCA**" means the *Business Corporations Act* (Alberta), together with any or all regulations promulgated thereunder, as amended from time to time.

"**affiliate**" means, with respect to the relationship between corporations, that one of them is controlled by the other or that both of them are controlled by the same Person and for this purpose a corporation shall be deemed to be controlled by the Person who owns or effectively controls, other than by way of security only, sufficient voting shares of the corporation (whether directly through the ownership of shares of the corporation or indirectly through the ownership of shares of another corporation or otherwise) to elect the majority of its board of directors.

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

"**Avenir**", the "**Manager**" or the "**Corporation**" means Avenir Operating Corp., an indirect wholly-owned subsidiary of the Trust.

"**Avenir Financial**" means Avenir Financial Services Acquisition Corp.

"**Avenir Financial Limited Partnership**" means Avenir Financial Services Limited Partnership, a limited partnership formed under the laws of the Province of Alberta.

"**Avenir Real Estate**" means Avenir Real Estate Acquisition Corp.

"**Avenir Real Estate Partnership**" means Avenir Real Estate Limited Partnership, a limited partnership formed under the laws of the Province of Alberta.

"**board of directors**" means the board of directors of the Corporation.

"**Canadian GAAP**" means generally accepted accounting principles in Canada. Unless specified otherwise, all accounting terms in this Annual Information Form shall be construed in accordance with Canadian GAAP.

"**cash flow from operations**" means net earnings plus non-cash balances, such as depletion, depreciation, and amortization asset retirement obligation accretion gain on sale of investments, compensation expense, unrealized loss on financial instruments and unsuccessful acquisition and re-organizational costs.

"**Common Shares**" means common shares of the Manager.

"**CRA**" means the Canada Revenue Agency.

"**Developed Non Producing Reserves**", "**Developed Producing Reserves**", "**Probable Reserves**", "**Proved Developed Reserves**", "**Proved Reserves**", "**Reserves**", "**Royalties**" and "**Undeveloped Reserves**" have the meanings given to those terms under the heading "**Oil and Natural Gas Reserves**".

"**Distributable Cash**" means cash available for distributions to Unitholders from time to time as determined in accordance with the Trust Indenture.

"**Elbow River**" means Elbow River Resources Ltd.

"**Elbow River Partnership**" means Elbow River Marketing Limited Partnership, a limited partnership established under the laws of Alberta.

"Energy Services Division" means collectively, Avenir Energy Services Corp., Avenir Production Services Limited Partnership, Cardinal Well Services Inc., Cascade Services Partnership, Cascade Steaming Holdings Corp., Eagle Oilfield Services Inc., Endless Tubing Services Ltd., Millard Oilfield Services (91) Ltd., Richmond Endless Tubing Services Ltd., Richmond Energy Services L.P. and Westvac Service Partnership.

"EnerVest Trust" means EnerVest Diversified Income Trust, a trust formed under the laws of the Province of Alberta.

"Essential Trust" means Essential Energy Services Trust, a trust formed under the laws of the Province of Alberta.

"Essential Unit" means a trust unit of the Essential Trust.

"Financial Services Contract" means the financial services contract with an affiliate of a major financial services provider, to provide funding for contracts with a cash advance company providing cash advances, cheque cashing and payday loan services.

"Joint Venture Manager" means EnerVest Management Ltd., a corporation incorporated under the ABCA.

"Manager" means Avenir Operating Corp. in its capacity as manager to the Trust.

"McDaniel" means McDaniel & Associates Consultants Ltd., independent oil and natural gas reservoir engineers of Calgary, Alberta.

"McDaniel Report" means the independent engineering report dated March 10, 2010 evaluating the crude oil, natural gas, natural gas liquids and sulphur reserves of the Trust as at December 31, 2009, conducted by McDaniel based on forecast price and cost assumptions.

"NAFTA" means the North American Free Trade Agreement between the government of Canada, the government of Mexico and the Government of the United States, December 17, 1992, entered into force January 1, 1994.

"net debt" means the difference between current assets less current liabilities excluding the balances relating to discontinued operations and add back the current portion of mortgages.

"NI 51-101" means National Instrument 51-101 – Standards of Disclosure for Oil & Gas Activities.

"Notes" means the Subordinated Notes and Series B Subordinated Notes each being unsecured, subordinated 13% promissory notes of the Manager, each having a prescribed principal amount and originally issued pursuant to the Trust Conversion.

"NPI" means, collectively, the net profit interest owing by the Operating Subsidiaries to the Trust pursuant to the NPI Agreement.

"NPI Agreement" means the Net Profit Interests Agreement between the Operating Trust and the Manager dated effective August 1, 2005.

"NRF" means the New Royalty Framework announced by the Alberta government on October 25, 2007.

"Operating Entities" means collectively, Avenir Operating Trust, Avenir Operating Corp., Avenir Financial Services Acquisition Corp., Avenir Financial Services Limited Partnership, Elbow River Marketing Corp., Elbow River Marketing Limited Partnership, Avenir Real Estate Acquisition Corp., 1148447 Alberta Ltd., Avenir Real Estate Acquisition Partnership and Avenir Real Estate Limited Partnership.

"Operating Trust" means Avenir Operating Trust, a trust settled pursuant to the laws of Alberta.

"Operating Trust Units" means trust units of the Operating Trust.

"Ordinary Resolution" means a resolution approved at a meeting of Unitholders by more than 50% of the votes cast in respect of the resolution by or on behalf of Unitholders present in person or represented by proxy at the applicable meeting.

"**Person**" or "**person**" includes an individual, a body corporate, a trust, a union, a pension fund, a government and a governmental agency.

"**production**" means the produced petroleum, natural gas and natural gas liquids attributed to the Properties.

"**properties**" means the working, royalty or other interests of the Trust and its subsidiaries in any petroleum and natural gas rights, tangibles and miscellaneous interests, real estate properties and lease hold and rental properties, including properties which may be acquired by any of the Trust and its subsidiaries from time to time.

"**REIT**" means real estate investment trust.

"**ResourceCo**" means 928719 Alberta Ltd.

"**Ridgeback**" means Ridgeback Exploration Ltd., an Alberta private oil and gas company.

"**Ridgeback Shares**" means the common shares of Ridgeback.

"**Special Resolution**" means a resolution proposed to be passed as a special resolution at a meeting of Unitholders (including an adjourned meeting) duly convened for the purpose and held in accordance with the provisions of the Trust Indenture at which two or more holders of at least 10% of the aggregate number of Trust Units then outstanding are present in person or by proxy and passed by the affirmative votes of the holders of not less than 66 $\frac{2}{3}$ % of the Trust Units represented at the meeting and voted on a poll upon such resolution.

"**subsidiary**" has the meaning ascribed to such term in the ABCA.

"**Tax Act**" means the *Income Tax Act* (Canada), together with any and all regulations promulgated thereunder, as amended from time to time.

"**Trust**" means Avenir Diversified Income Trust, a trust formed pursuant to the laws of the Province of Alberta, and, unless the context otherwise requires, includes its subsidiaries and the Operating Entities.

"**Trust Conversion**" means the conversion of Onward Energy Inc. from a corporate entity to the Trust pursuant to a Plan of Arrangement dated effective January 16, 2003.

"**Trust Indenture**" means the amended and restated trust indenture dated September 24, 2002 as amended and restated effective May 11, 2006 between the Trustee and the Manager, as may be amended from time to time.

"**Trust Unit**" means a trust unit of the Trust.

"**Trustee**" means Olympia Trust Company, or its successor as trustee of the Trust.

"**TSX**" means the Toronto Stock Exchange Inc.

"**Unitholders**" means the holders from time to time of one or more Trust Units.

"**working interest**" means an undivided interest held by a party in an oil and/or natural gas or mineral lease granted by a Crown or freehold mineral owner, which interest gives the holder the right to "work" the property (lease) to explore for, develop, produce and market the lease substances but does not include, among other things, a royalty, overriding royalty, gross overriding royalty, net profits interest or other interest that entitles the holder thereof to a share of production or proceeds of sale of production without a corresponding right or obligation to "work" the property.

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

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

FORWARD LOOKING STATEMENTS

The Trust prepares its financial statements in Canadian dollars and in conformity with Canadian GAAP.

References in this Annual Information Form to research reports or to articles in publications should not be construed as depicting the complete findings of the entire referenced report or article. The information in each report or article is expressly not incorporated by reference into this Annual Information Form.

The Trust's website is located at www.avenirtrust.com. The contents of this website are expressly not incorporated by reference into this Annual Information Form.

SPECIAL NOTE REGARDING FORWARD LOOKING STATEMENTS

Certain of the statements contained herein including, without limitation, financial and business prospects and financial outlook, the effect of government announcements, proposals and legislation, plans in its oil and gas division regarding hedging, wells to be drilled, expected or anticipated production rates, timing of expected production increases, the weighting of production between different commodities, expected commodity prices, exchange rates, production expenses, transportation costs and other costs and expenses, maintenance of productive capacity and capital expenditures; plans in the Elbow River Marketing LP ("**Elbow River**") business regarding plans for its liquefied petroleum gas ("**LPG**") marketing business; plans in the real estate division for the timing in the selling of assets and the nature of capital expenditures; and the timing and method of financing these businesses, may be forward looking statements. Words such as "may", "will", "should", "could", "anticipate", "believe", "expect", "intend", "plan", "potential", "continue", "targeted" and similar expressions may be used to identify these forward looking statements. These statements reflect management's current beliefs and are based on information currently available to management. Forward looking statements involve significant risk and uncertainties. A number of factors could cause actual results to differ materially from the results discussed in the forward looking statements including, but not limited to, risks associated with oil and gas exploration: development, exploitation, production, marketing and transportation, loss of markets, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers and the inability to retain drilling rigs and other services; risks associated with its Elbow River business including, but not limited to, counterparty risk in default, availability of credit; and risks associated with the Real Estate Division including, but not limited to, the impact the overall economy has on valuations, tenants profitability and ability to pay rent; as well as the risks associated with the Trust's incorrect assessment of the value of acquisitions, failure to realize the anticipated benefits of acquisitions, delays resulting from or inability to obtain required regulatory approvals and ability to access sufficient capital from internal and external sources and the risk factors outlined under "Risk Factors" and elsewhere herein. The recovery and reserve estimates of the Trust's reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements.

Forward-looking statements or information are based on a number of factors and assumptions which have been used to develop such statements and information but which may prove to be incorrect. Although the Trust believes that the expectations reflected in such forward-looking statements or information are reasonable, undue reliance should not be placed on forward-looking statements because the Trust can give no assurance that such expectations will prove to be correct. In addition to other factors and assumptions which may be identified in this document, assumptions have been made regarding, among other things: the impact of increasing competition; the general stability of the economic and political environment in which the Trust operates; the timely receipt of any required regulatory approvals; the ability of the Trust to obtain qualified staff, equipment and services in a timely and cost efficient manner; divisional results; the ability of operators to operate the field in a safe, efficient and effective manner; the ability of the Trust to obtain financing on acceptable terms; field production rates and decline rates; the ability to replace and expand oil and natural gas reserves through acquisition; development of exploration; the timing and costs of pipeline, storage and facility construction and expansion and the ability of the Trust to secure adequate product transportation; future oil and natural gas prices; currency, exchange and interest rates; the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which the Trust operates; and the ability of the Trust to successfully market its products, fluctuations in foreign exchange or interest rates and stock market volatility, credit risk and the ability to realize on collateral in the event of default, failure of counter parties to perform on contracts, fluctuation in the value of real property, failure to produce income or revenue from real estate, failure of tenants to meet lease obligations, increase in property taxes and mortgage, maintenance, insurance, operating costs and decreases in occupancy and rental rates, and fixed costs in relation to variable revenue streams. Readers are cautioned that the foregoing list of factors is not exhausted.

These forward-looking statements are made as of the date hereof and the Trust assumes no obligation to update or review them to reflect new events or circumstances except as required by applicable securities laws.

Forward-looking statements and other information contained herein concerning the oil and gas division, Elbow River's business, the real estate division and the Trust's general expectations concerning these industries are based on estimates prepared by each Division's management and from using data from publicly available industry sources as well as from reserve reports, market research and industry analysis and on assumptions based on data and knowledge of these industries which the Trust believes to be reasonable. However, this data is inherently imprecise, although generally indicative of relative market positions, market shares and performance characteristics. While the Trust is not aware of any misstatements regarding any industry data presented herein, these industries involve risks and uncertainties and are subject to change based on various factors.

These factors should not be construed as exhaustive. Other than the continuous disclosure obligations set forth in National Instrument 51-102 – Continuous Disclosure Obligations, neither the Trust nor the Manager undertakes any obligation to publicly update or revise any forward looking statements.

RESERVE DISCLOSURE

With respect to reserve disclosure for the financial year ended December 31, 2009, the Trust was subject to NI 51-101, which was implemented in September 2003 and amended effective December 28, 2007. NI 51-101 prescribes standards for the preparation and disclosure of oil and gas reserves and related estimates, requires the annual public filing of certain of those estimates and other information pertaining to oil and gas activities, and specifies responsibilities of corporate directors. In particular, the definitions of proved reserves and probable reserves contain specific quantifications of levels with respect to certainty of recoverability of 90% for proved reserves and of 50% for proved plus probable reserves.

ABBREVIATIONS

Oil and Natural Gas Liquids

Bbl	Barrel
Bbls	Barrels
Mbbls	thousand barrels
Bbls/d	barrels per day
Mmbbls	million barrels
NGLs	natural gas liquids

Natural Gas

Mcf	thousand cubic feet
Mmcf	million cubic feet
Bcf	billion cubic feet
Mcf/d	thousand cubic feet per day
Mmcf/d	million cubic feet per day
MMBTU	million British Thermal Units
GJ	gigajoule
Mcf/Bbl	thousand cubic feet per barrel

Other

AECO	EnCana Corporation's natural gas storage facility located at Suffield, Alberta.
BOE	means barrel of oil equivalent, using the conversion factor of 6 Mcf of natural gas being equivalent to one Bbl of oil, unless otherwise specified. The conversion factor used to convert natural gas to oil equivalent is not necessarily based upon either energy or price equivalents at this time.
BOE/d	barrels of oil equivalent per day.
COGEH	means Canadian Oil and Gas Evaluation Handbook
COGPE	means Canadian oil and gas property expense, as defined in the Tax Act.
MBOE	means thousand barrels of oil equivalent.
McfGe	means thousand cubic feet of gas equivalent.
MMBOE	means million barrels of oil equivalent.
OOIP	means original oil in place.
WTI	means West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade.
°API	means the measure of the density or gravity of liquid petroleum products derived from a specific gravity.
MW	megawatts of electrical power.
3D	three dimensional.
Darcies	means the measure of permeability (being the ease with which a single fluid will flow through connected pore space when a pressure gradient is applied).
porosity	means the measure of the fraction of pore space of a reservoir.

CONVERSIONS

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

<u>To Convert From</u>	<u>To</u>	<u>Multiply By</u>
Mcf	cubic metres	28.174
cubic metres	cubic feet	35.494
Bbls	cubic metres	0.159
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.471

CURRENCY

All dollar amounts set forth in this Annual Information Form are in Canadian dollars, except where otherwise indicated.

AVENIR DIVERSIFIED INCOME TRUST AND RELATED ENTITIES

General

The Trust is an open-end unincorporated investment trust governed by the laws of the Province of Alberta and created pursuant to the Trust Indenture. The Trust was established to:

- invest in debt, equity and other securities of its operating entities from time to time including, without limitation, the Operating Trust Units and the Common Shares of the Manager;
- either hold directly all types of, or acquire or invest in, securities of any other subsidiary of the Trust and in securities of any other entity including, without limitation, bodies corporate, partnerships or trusts, and borrowing funds for that purpose;
- holding or acquiring royalty or other interests in respect of various assets and businesses discussed above;
- dispose of any part of the monies, properties and assets of the Trust, including, without limitation, any securities of the Manager;
- temporarily hold cash and investments for the purposes of paying the expenses and the liabilities of the Trust, making certain other permitted investments, paying amounts payable by the Trust in connection with the redemption of any Trust Units, and making distributions to Unitholders; and
- pay costs, fees and expenses associated with the foregoing purposes or incidental thereto.

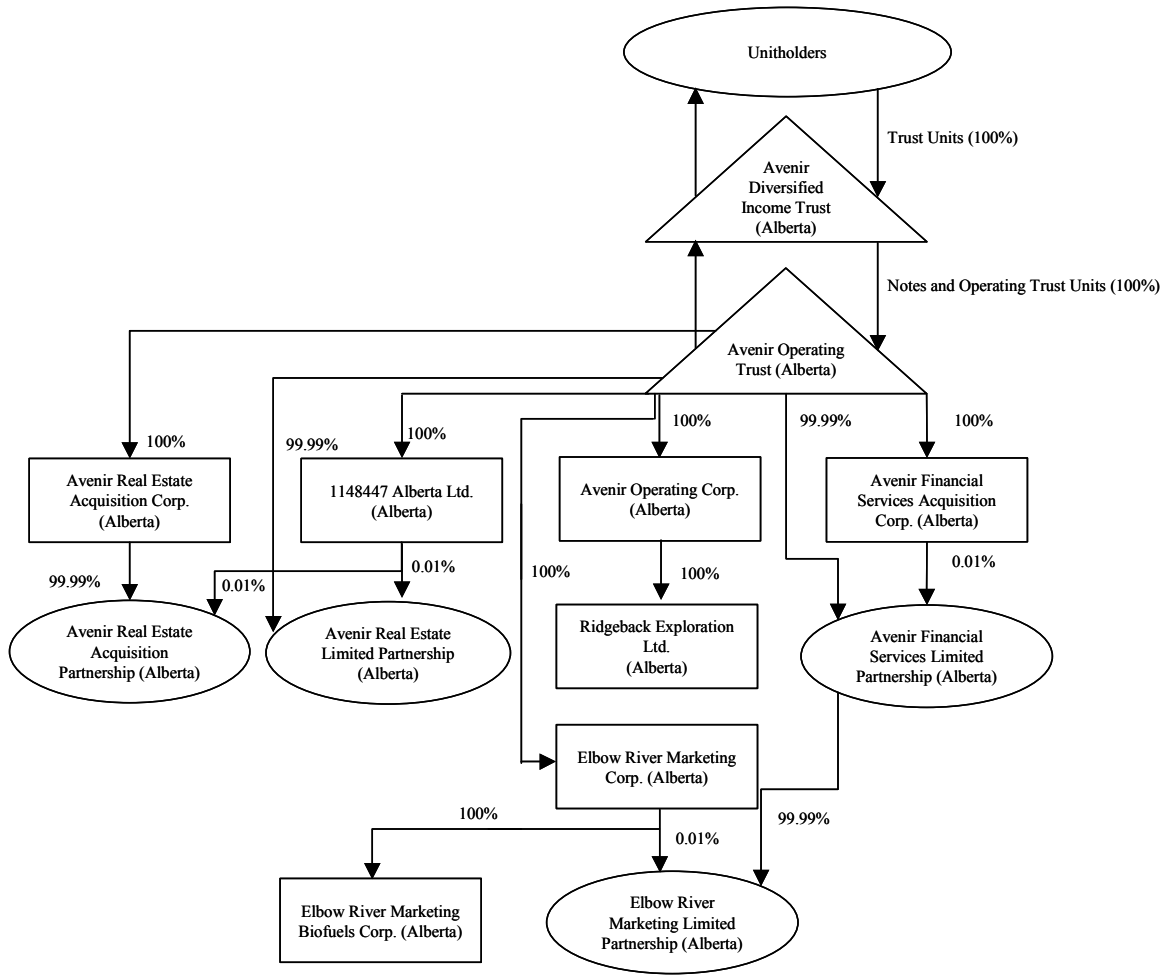
The head and principal office of each of the Trust and its operating or subsidiary entities, is located at Suite 300, 808 - 1st Street S.W., Calgary, Alberta, T2P 1M9. The registered office of the Trust and each of its operating and subsidiary entities is located at Suite 1400, 350 - 7th Avenue S.W., Calgary, Alberta, T2P 3N9.

The principal undertaking of the Trust is to acquire the securities of the Operating Trust and the Manager or any other subsidiary, to fund the acquisition, development, exploitation and disposition of all types of petroleum and natural gas energy related assets, hotel, industrial, residential or commercial real estate and related and ancillary properties, financial contracts and liquid securities of publicly listed entities. The Trust's primary assets are currently the securities and debt of its subsidiary entities.

Through the Trust, Unitholders will participate in distributions from the operating entities of the Trust to the extent authorized by the Board of Directors of the Manager. In accordance with the Trust Indenture, the Trust will make cash distributions to Unitholders of the interest, royalty and dividend income of the Trust, net of the Trust's administrative expenses. In addition, Unitholders may, at the discretion of the Board of Directors of the Manager, receive distributions in respect of repayments of principal made on outstanding debt owing from the operating entities to the Trust. However, the Trust endeavours to reinvest a substantial portion of the principal amount of the debt owing to the Trust, to make capital expenditures to develop the working, royalty or other interests of the Manager, as well as making expenditures to expand the Trust's financial services interests, with a view to enhancing cash flow from operations.

Organizational Structure of the Trust

The following diagram sets forth the organizational structure of the Trust and its material subsidiary entities as at March 30, 2010 with the percentage figures denoting the ownership interest, in each case.



Notes:

- (1) Holders of Trust Units own 100% of the equity of the Trust.
- (2) Cash flow payments are made by way of (i) in the case of the Trust, interest payments and principal repayments, if any, on the outstanding debt owing to the Trust and allocations of income and capital gains by Avenir Operating Trust, and (ii) in all other cases, income received indirectly from the securities of the Manager and under the NPI and Agreement pursuant to which the Manager has granted a net profits interest in favour of Avenir Operating Trust and income through ownership (direct and indirect) of securities of the partnerships in which the Trust holds an interest.
- (3) The Trust may invest repayments of principal on the debt owing to it, indirectly, in the operations of the Manager, Avenir Financial, Avenir Real Estate Acquisition, Avenir Financial Limited Partnership, Elbow River Partnership to make capital expenditures to develop or acquire additional assets.

BUSINESS OF THE TRUST AND ITS OPERATING ENTITIES

This section discusses the major events or conditions that have influenced the general development of the Trust over the last three completed financial years, including significant acquisitions and dispositions which have occurred during the most recently completed financial year.

General Development of the Business

The current operations of the Trust, through its operating subsidiaries, are presently focused in three areas:

Energy:

- oil and gas exploration and development activities, through Avenir Operating Corp.

Financial services:

- wholesale marketing, transporting and supplying of butane and propane through North American and markets ethanol and natural gas and diesel, through Elbow River.

Real estate:

- acquisitions, dispositions and development through Avenir Real Estate and Avenir Real Estate Partnership.

Energy***Trust Conversion and the Acquisition of ResourceCo***

Pursuant to the Trust Conversion, Onward was converted from a corporate entity to the Trust. To facilitate this conversion, all of the common shares and options of Onward were exchanged for an aggregate of 146,289 Trust Units at a deemed price of \$6.00 per unit and \$2,351,305 in cash. As a result, the Trust acquired the oil and gas assets of Onward and \$414,160 in working capital.

In conjunction with this Trust Conversion, the Trust acquired all of the issued and outstanding shares of a private company, ResourceCo, in exchange for an aggregate of 509,991 Trust Units. This transaction was a reverse takeover as the shareholders of ResourceCo controlled the majority of the units in the Trust subsequent to the transaction and the principals of ResourceCo (now the principals of the Manager) have carried on the management of the Trust since such time.

Also as part of this Trust Conversion, the Trust acquired all of the trust units of Avenir Operating Trust and the shares of Avenir Financial and Avenir Oil & Gas Corp. and completed a private placement of an aggregate of 775,023 Trust Units at \$6.00 per unit.

Following completion of the Trust Conversion, each of Onward and ResourceCo were subsequently dissolved, with all their assets and liabilities distributed to a predecessor of the Manager. In converting Onward to a trust structure and acquiring ResourceCo, the Trust, indirectly, holds the oil and gas assets formerly held by Onward and ResourceCo as well as the financial services contracts formerly held by ResourceCo.

Concurrent with the closing of the Trust Conversion, on January 16, 2003, the Trust also indirectly acquired certain oil and gas interests (the "**Response Assets**") in Alberta, British Columbia and Saskatchewan from Response Energy Corporation ("**Response**"), for approximately \$2,040,451.

Minor Smaller Acquisitions

Throughout 2003 to 2006, the Trust acquired a series of smaller oil and gas properties pursuant to separate acquisition agreements involving Lightning Energy Ltd. (2004), PrimeWest Energy Inc. (2004), Val Vista Energy Ltd. (2005), Makah Energy Corporation (2005), a Grand Forks property purchase (2005) and East Central and Southern Alberta property acquisitions (2006). Information on these prior acquisitions can be viewed in the annual information form of the Trust dated March 31, 2009 for the year ended December 31, 2008, which is available on the Trust's SEDAR profile at www.sedar.com.

Noel Acquisition

Effective March 2007, the Trust completed an acquisition of additional working interest in the operated property of Noel in Northeast, British Columbia. The acquisition included 150 BOE/d of sweet natural gas production from assets in which the Trust already holds a majority working interest. Based on a January 1, 2007 effective date and excluding the undeveloped land value of \$253,000 and normal industry closing adjustments, the total consideration paid for the working interest proved plus probable reserves was \$6.9 million for 537 MBOE yielding an acquisition cost of \$12.90 per BOE. The oil and gas transaction was funded through available credit facilities.

Ridgeback Acquisition

On July 31, 2010 the Trust announced that it had acquired over 96% of the issued and outstanding common shares of Ridgeback. Under the offer to purchase (the "**Offer**"), holders of Ridgeback Shares received \$0.62 in cash for each Ridgeback common share tendered to the Offer. As the Offer was accepted by holders of greater than 90% of the Ridgeback Shares, the Trust acquired the

remainder of the Ridgeback Shares pursuant to the compulsory acquisition provisions contained in *the* ABCA. With this acquisition, the Trust purchased 660 BOE/d of production focused in the Peace River Arch comprised of 35% light and medium oil. The assets provide the Trust with a new core area combining an undeveloped land base of 50,000 net acres and 1.7 million BOE of internally audited proved plus probable reserves. Based on an acquisition cost of \$22.0 million adjusted for land and seismic value, the Trust acquired the production and reserves for \$27,633 per BOE/d and \$10.89 per BOE on a proved plus probable basis. The new assets will be managed within the current staff complement of the Trust's Oil and Gas Division.

Oilfield and Energy Production Services Related Operations

Conveyance to Essential Energy Services Trust

Effective April 5, 2006, the Trust conveyed the entirety of its interest in its Energy Services Division pursuant to a plan of arrangement under the ABCA to the then newly formed oilfield services trust called "Essential Energy Services Trust". As consideration for the conveyance, Unitholders received one Essential Unit for each two Trust Units then held. Essential Trust commenced trading as a stand alone entity at the open of markets on the Toronto Stock Exchange on May 31, 2006 under the symbol "ESN.UN". As a result of the divestiture of the Energy Services Division, the Trust's portfolio of businesses consisted of approximately 40% energy and 60% financial services and real estate. Essential Trust provides production services to the oil and gas industry in Western Canada from Fort Nelson in northeastern British Columbia through Alberta into southwest Saskatchewan.

As a result of the conveyance of the Energy Services Division to Essential Trust, the entities that were acquired no longer form part of the Operating Entities of the Trust and thus as at the date hereof and going forward have no business effect on the Trust and its operations.

For information on the prior acquisitions in the Energy Services Divisions, please refer to "Oilfield and Energy Production Services Related Operations" in the Trust's annual information form dated March 26, 2008 for the year ended December 31, 2009, which is available on the Trust's SEDAR profile at www.sedar.com.

Financial Services Operations

Acquisition and Disposition of Financial Services Contracts

In connection with the Trust Conversion, Avenir Financial acquired the Financial Services Contract with an affiliate of a major financial services provider, to provide funding for contracts having a value of \$600,000 with a cash advance company providing cash advance, cheque cashing and payday loan services. The contract had a term of ten years and provided for the payment of a fixed fee per amount provided per day at a rate of \$0.07 per \$100 loaned per day and 25% per annum on unpaid amounts. On January 31, 2003, Avenir executed an additional \$600,000 to provide funding on an additional ten-year contract on identical terms as that set forth above. Throughout 2004 and 2005, the Trust acquired additional service contracts, whereby at the end of 2005, \$19.9 million were outstanding, in each case on substantially the same terms and condition as those described above. Avenir has since redeemed these contracts and at the end of 2007, there were no contracts outstanding.

Acquisition of Elbow River

On April 1, 2005, the Trust completed the acquisition of all of the assets of Elbow River for total consideration \$57.8 million, consisting of \$51.8 million cash and \$6.0 million in the form of escrowed Trust Units. No escrow Trust Units remain in escrow at December 31, 2009. At the end of December 2009, Elbow River was the only active business in the Financial Services Operations.

Acquisition and Disposition of EnerVest Management Company

On October 4, 2005, the Trust, through its wholly-owned subsidiary, EnerVest Limited Partnership, added to the financial services business unit with the acquisition of the joint venture that is the sole shareholder of the EnerVest Management Company, Manager of the EnerVest Trust, the EnerVest Natural Resource Fund and the EnerVest Flow-Through Limited Partnerships. The total cash consideration was \$125.9 million.

On May 16, 2008, the Trust sold the entirety of its interest in the Joint Venture Manager and thereby its interest in the EnerVest group of funds, for a total consideration of approximately \$185 million, subject to customary closing and post-closing adjustments including working capital and debt adjustments based on an April 1, 2008 effective date. As a result of this sale, each of the entities included in

the EnerVest group of funds and the Joint Venture Manager no longer form part of the Operating Entities of the Trust and thus as at the date hereof and going forward have no business effect on the Trust and its operations.

Real Estate Operations

Acquisition of Western Spirit Investments Ltd.

On March 31, 2004, the Trust acquired, indirectly, all of the issued and outstanding common shares of Western Spirit Investments Ltd. ("**Western Spirit**") by way of a plan of arrangement. Concurrently with the completion of the Western Spirit acquisition, which involved five properties, Avenir Real Estate and Western Spirit completed a short form amalgamation under the ABCA to form one company carrying on business under the name "Avenir Real Estate Acquisition Corp." Five buildings were purchased in the acquisition.

In 2005, the Trust sold the CoreMark building located in Calgary. The building was sold for proceeds of \$3.7 million before mortgages of \$1.9 million. The Trust realized a gain on sale on this building of approximately \$0.22 million.

On January 31, 2006, the Trust, through its real estate division, purchased the remaining 50% ownership of its Vaughan, Ontario, Snidercroft building from an arm's length third party for \$1,910,773.

On August 27, 2008, the Trust was successful in completing an agreement for the disposition of its Harris building in Calgary. The building was sold and closed in August 2008. The property was sold at a cap rate of 6.6%. The Trust realized a gain on sale on the Harris Building of approximately \$9.5 million in the third quarter 2008.

On June 30, 2009 the Trust sold its Sunbelt building in Edmonton for net proceeds of \$5,856,900 comprised of cash of \$1,285,603 and mortgage assumptions of \$4,571,297. A gain of \$2,128,729 was recorded relating to this divestiture.

Acquisition and Disposition of Station Crossing Retail Plaza

On February 1, 2005, the Trust through its real estate division purchased a small shopping centre commercial property in Fort Saskatchewan, Alberta from an arm's length party for cash consideration of approximately \$3.1 million.

In September 2008, this building was unconditionally sold and subsequently closed in October 8, 2008. The property was sold at a cap rate of 8.0%. The Trust realized a gain on sale of the Station Crossing centre estimated at \$0.6 million in the fourth quarter 2008.

Acquisition of Portfolio Properties

Effective October 26, 2006, the Trust completed the purchase of two portfolios consisting of 26 buildings and 186,740 leasable square feet. The aggregate purchase price of the two portfolios totals approximately \$29.4 million with mortgaging financing of \$18.4 million provided by two financial institutions with the balance of the funds provided through existing facilities.

The first portfolio contains eleven (11) Kentucky Fried Chicken ("**KFC**") franchise locations and the second portfolio consisted of fifteen (15) Landmark Cinema locations.

During the third quarter of 2009 the Trust disposed of two Landmark properties, which resulted in net proceeds of \$10,669,365, comprised of cash of \$2,948,284 and mortgage assumptions of \$7,721,081.

The Trust portfolio now consists of 30 separate properties with a total area of approximately 405,000 square feet located primarily throughout Western Canada.

Normal Course Issuer Bid

The Trust commenced a normal course issuer bid on October 20, 2008 pursuant to which the Trust could, from time to time, purchase for cancellation up to a maximum of 3,463,769 Trust Units through the TSX. The bid expired on October 19, 2009. The Trust purchased an aggregate of 248,544 Trust Units at an average purchase price of \$4.73 per Trust Unit pursuant to the bid.

The Trust commenced a new normal course issuer bid on December 29, 2009 pursuant to which the Trust can, from time to time, purchase for cancellation up to a maximum of 3,446,355 Trust Units through the TSX. The bid expires on December 28, 2010. As of the date of this AIF, the Trust has not purchased any Trust Units.

Credit Facilities

In relation to its oil and gas division, as at December 31, 2009, the Trust had a combined revolving demand facility with a major Canadian bank in the amount of \$60,000,000 bearing interest ranging from prime plus 0.25% to prime plus 2.50% depending on the debt to cash flow ratio of the Oil and Gas Division. As at December 31, 2009, \$12,300,000 was drawn on the revolving demand facility. The borrowing base was renewed in April 2009 and is scheduled for renewal in April 2010.

In relation to Elbow River, the Trust has a demand revolving loan facility with a Canadian bank in the amount of \$50,000,000 bearing interest as follows at bank prime rate plus 1.0% or the bank's US base rate plus 1.0%. This facility is collateralized by a charge over all of Elbow River's assets. As at December 31, 2009 \$nil was drawn on the demand revolving loan facility. Elbow River was in compliance with all its banking covenants as at December 31, 2009. The borrowing base was renewed in late 2009 and is scheduled for renewal in the fall of 2010.

DESCRIPTION OF THE BUSINESS AND PROPERTIES OF THE TRUST AND ITS OPERATING ENTITIES

The following is a summary of the principal properties currently held by the Trust.

Oil and Gas

The Trust is engaged in the exploration for and development and production of crude oil and natural gas in Western Canada. All of the Trust's current oil and natural gas operations are in the Provinces of Alberta, British Columbia and Saskatchewan.

Principal Properties

The following is a description of the Trust's oil and natural gas properties as at December 31, 2009. Production stated is net production to the Trust and, unless otherwise stated, is average production for 2009. Reserve amounts are stated as at December 31, 2009 based on forecast costs and prices as evaluated in the McDaniel Report (see "*Reserves Data*"). Unless otherwise specified, gross and net acres and well count information are as at December 31, 2009.

BOEs (McfGe or other applicable units of equivalency) may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf/Bbl (or an Mcfe conversion ratio of 1 Bbls/ 6 Mcf) is based on energy equivalence of conversion method primarily applicable at the burner tip and does not represent a value equivalency at the well head. Coalbed methane gas contributes approximately 5% of the Trust's total gas reserves and is included within natural gas reserves reported.

The Trust currently has interests in approximately 953 productive oil wells and 586 productive gas wells located in 78 properties in Western Canada. Over 84% of the value of the properties of the Trust is comprised of interests in 9 properties. These properties are summarized in the table below:

Properties of the Trust	Property Operator	Total Proved Reserves (MBOE) ⁽¹⁾	Number of Gross Wells ⁽²⁾	Number of Net Wells
Noel	Avenir Diversified Income Trust / Encana Corporation / Conoco Canada Resources Limited	2089.4	31	17
Peace River Arch	Avenir Diversified Income Trust / Galleon Energy / Ravenwood Energy	1211.2	22	11
West Saskatchewan	Avenir Diversified Income Trust / Harvest Energy Trust	860.1	331	57
Grand Forks / Bow Island	Avenir Diversified Income Trust / ARC Energy Trust / Celtic Exploration Ltd.	778.3	117	72
Central Alberta Gas	Quicksilver / Conoco Canada Resources Limited	543.8	142	19
Provost / Castor / Killam	Avenir Diversified Income Trust	408.7	40	17
Liege	Bonavista Energy Trust	243.7	20	11
Southeast Saskatchewan	Avenir Diversified Income Trust / Crescent Point / TAQA	177.9	25	7
Turin / Retlaw	Avenir Diversified Income Trust / Baytex Energy Trust	169.3	52	11
Total		6482.4	780	222

Notes:

- (1) Total proven working interest and royalty interest reserves as of December 31, 2009. All such reserves are based on the McDaniel Report – Forecast Prices. See "Oil and Natural Gas Reserves".
- (2) Wells listed are working interest productive wells and do not include suspended wells or royalty interest wells.

Noel, British Columbia

The Noel property is located in British Columbia from Blocks G/93-P-1 to H/93-P-7, approximately 110 kilometres south of Fort St. John. The Noel area is west of the Elmworth gas field and northwest of the Wapiti gas field in the Alberta Deep Basin. The majority of the Trust's production is obtained from the gas bearing Cadotte, Falher and Cadomin formations. The Trust operates 11 of the 31 producing wells in Noel. Sales gas is processed through the Elmworth Deep Cut Gas Plant. In 2009, the Trust undertook an asset acquisition and land sale initiative to strengthen this core area based on the success of the first two operated Cadomin horizontal wells. In the second quarter of 2009, the Trust successfully completed the acquisition of assets from three area producers totalling 306 MBOE of proved plus probable producing reserves and associated undeveloped Cadomin mineral rights. Including the successful Crown land purchases in the first quarter of 2009, the Trust purchased a total of 16,000 net acres of Cadomin rights in the Noel area. Total acquisition and land sale costs were \$8.6 million resulting in acquisition metrics of \$10.13/BOE for proved plus probable reserves and \$339 per acre for the undeveloped land. All totaled, the Trust now has interest in 28,490 gross acres (39 gross sections) of Cadomin mineral rights in the Noel and Kelly Lake areas. Based on the Trust's experience in the area and offset development activity, the technical evaluation of the lands suggests the full development could result in 78 gross drilling locations (48 net locations with 36 at 100% working interest). Working interest production for 2009 was 4,257 Mcf/d of gas. Reserves assigned to this property based on the McDaniel Report are total proved reserves of 2,089 MBOE.

Peace River Arch

The Peace River Arch area was obtained through a corporate acquisition by the Trust in August 2009. The area is located within Townships 72 and 89, Ranges 26 west of the 5th Meridian and 6 west of the 6th Meridian. The acquisition brought interests in 22 gross

and 11 net productive wells and an undeveloped land base of over 50,000 net acres. Average production for the 6 months ending December 2009 was 199 Bbl/d of oil/NGLs and 2,317 Mcf/d of natural gas. The main producing horizons are the Beaverhill Lake, Montney and Bluesky/Gething formations. Post acquisition, the Trust drilled 2.3 net wells in this area resulting in production adds of 160 BOED and reserve adds of over 300 MBOE at a cost of \$11.50/BOE. Three gross (1.7 net), oil wells are planned for this area in 2010. Total proved reserves from the McDaniel report are 1,211 MBOE.

West Saskatchewan

The majority of the west Saskatchewan properties are located in Townships 15-17, Ranges 16-18 W3M, 25 kilometres west of Swift Current, Saskatchewan and in Township 31, Range 20 W3M, 25 kilometres northeast of Kindersley in west central Saskatchewan. The Trust holds 100% working interests in the East Beverly Cantuar and the Antelope Lake Upper Shaunavon Voluntary Units, a 50% working interest in the North Premier Unit #1, a 9.38% working interest in the Eagle Lake Viking Voluntary Unit as well as a combined 3.08% working interest in the North Dodsland Viking Voluntary Units. A 10 well drilling program is planned for early 2010 in the Viking Voluntary Units. The objective is to recover additional oil from these mature Viking pools using new horizontal well technology. Working interest production for 2009 averaged 408 Bbls/d of crude oil and 245 Mcf/d of gas. Reserves attributed to the Trust's interest in these properties in the McDaniel Report are 860 MBOE total proved.

Grand Forks/Bow Island, Alberta

The Grand Forks/Bow Island properties are located in Townships 10-12, Ranges 11-13 W4M, approximately 35 kilometres northeast of Taber in southeast Alberta. The Trust holds various working interests averaging 61% in 72 producing wells spread over approximately 52 sections of land. Heavy oil (22-25 degrees API) is produced from the Jurassic age Sawtooth Formation with high water cuts while gas is produced from the Bow Island and Second White Specks Formations. The Trust operates over 80% of the oil and gas wells in this area through four oil batteries and a compressor station all owned and operated by the Trust. The remaining non-operated oil and gas wells produce through two independently operated properties in which the Trust holds a 32.71% and a 10% working interest in both the wells and facilities. Current working interest production is 432 Bbls/d of crude oil and 202 Mcf/d of gas. Reserves attributed to the Trust's interest in this property in the McDaniel Report are 778 MBOE total proved.

Central Alberta Gas, Alberta

The Trust holds a combination of conventional gas and coal bed methane interests throughout central Alberta. Primary areas include Stettler, Drumheller, Foster, Twinning, Huxley and Three Hills Creek. AOC acquired additional lands and drilled 2 new 100% working interest gas wells in the Stettler area and participated in 6 low working interest CBM drills in the Wood River, Huxley and Rich areas during 2009. With the exception of Stettler, production is primarily low working interest and non-operated. Current working interest production is 1,465 Mcf/d of gas and reserves attributed to the Trust's interest in this property in the McDaniel Report are 543.8 MBOE total proved.

Provost/Castor/Killam, Alberta

The Trust holds significant working interests in over 60 sections of mineral rights in the Provost/Castor area covering Townships 20-42, Ranges 2-15 W4M in East-Central Alberta. The Trust holds various working interests averaging 43% in 40 producing wells producing natural gas from the Mannville and Viking sands and oil from the Glauconite. Production is gathered and processed through third party facilities. The Trust holds an average working interest of 45% in 5,791 gross undeveloped acres. Working interest production for 2009 averaged 1,281 Mcf/d of gas and 62 Bbls/d of crude oil. Reserves assigned to this property based on the McDaniel Report are total proved reserves of 408 MBOE.

Liege, Alberta

The Liege property is located in northern Alberta in Townships 89 and 90, Ranges 20-22 W4M, approximately 100 kilometres west of Fort McMurray. The Trust holds interests of 47% to 77% in 126 sections of contiguous land. Liege is a non-operated property in which the Trust has an average producing working interest of 56%. Gas production is obtained from the Cretaceous Mannville group and the Devonian age Grosmont formation. The gas is sweet and is processed through facilities owned in part by the Trust. Working interest production for 2009 averaged 841 Mcf/d of gas and reserves assigned to this property based on the McDaniel Report are total proved reserves of 244 MBOE.

Southeast Saskatchewan

The Southeast Saskatchewan properties are located in Townships 7-5, Ranges 14-6 W2M, approximately 125 kilometres southeast of Regina. The core property is Weyburn which produces light quality sweet crude from the Midale formation at a depth of 1,300 meters. The Trust has an average working interest of 30% in the Crescent Point operated Weyburn Midale Pool and the associated oil processing facilities. The Trust also holds a 14% interest in 2 Bakken wells located at Benson (Township 6, Range 9W2) and interests in Lampman (Township 5, Range 6W2). The Trust's current working interest production for Southeast Saskatchewan is 73 Bbls/d of crude oil and reserves assigned to this property based on the McDaniel Report are total proved reserves of 178 MBOE.

Turin/Retlaw, Alberta

The Turin/Retlaw property is located 20 kilometres west of Grand Forks Townships 11 & 12, Ranges 17-19W4. The property consists of 52 gross (10.7 net) wells that produce primarily from the Mannville formation at a depth of approximately 1,000 meters. Current working interest production is 79 Bbls/d of crude oil and 145 Mcf/d of gas. Reserves attributed to the Trust's interest in this property in the McDaniel Report are 169 MBOE total proved.

OIL AND NATURAL GAS RESERVES

In accordance with NI 51-101, McDaniel prepared the McDaniel Report dated March 10, 2010, evaluating the crude oil, natural gas, natural gas liquids and sulphur reserves of the Trust as at December 31, 2009. The McDaniel Report evaluated effective as at December 31, 2009, the Trust's oil, NGL and natural gas reserves. The tables below are a summary of the Trust's oil, NGL and natural gas reserves and the net present value of future net revenue attributable to such reserves as evaluated in the McDaniel Report based on forecast price and cost assumptions. The information set forth below is prepared in accordance with standards contained in the COGEH and the reserves definitions contained in NI 51-101 and the COGEH. The tables summarize the data contained in the McDaniel Report and as a result may contain slightly different numbers than such report due to rounding. Also, due to rounding, certain columns may not add exactly. The net present value of future net revenue attributable to the Trust's reserves is stated without provision for interest costs and general and administrative costs, but after providing for estimated royalties, production costs, development costs, other income, future capital expenditures, and well abandonment costs for only those wells assigned reserves by McDaniel. It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to the Trust's reserves estimated by McDaniel represent the fair market value of those reserves. Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized herein. The recovery and reserve estimates of the Trust's oil, NGL and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates provided herein.

The McDaniel Report is based on certain factual data supplied by the Trust and McDaniel's opinion of reasonable practice in the industry. The extent and character of ownership and all factual data pertaining to the Trust's petroleum properties and contracts (except for certain information residing in the public domain) were supplied by the Trust to McDaniel and accepted without any further investigation. McDaniel accepted this data as presented and neither title searches nor field inspections were conducted.

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

Levels of Certainty for Reported Reserves

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

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

A qualitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using

deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

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

Reserves Data - Forecast Prices and Costs Summary of Oil and Gas Reserves

Summary of Oil and Gas Reserves: Effective December 31, 2009

	Gross Reserves ⁽¹⁾				Net Reserves ⁽²⁾			
	Light and Medium Crude Oil	Heavy Oil	Natural Gas Liquids	Natural Gas	Light and Medium Crude Oil	Heavy Oil	Natural Gas Liquids	Natural Gas
	Mbbls	Mbbls	Mbbls	Mmcf	Mbbls	Mbbls	Mbbls	Mmcf
Proved								
Developed Producing	1,989.9	826.1	103.9	18,573.6	1,696.0	785.2	73.1	15,661.3
Developed Non-Producing	210.8	4.0	11.9	1,500.0	137.5	3.5	8.2	1,217.7
Undeveloped	75.0	0.0	9.3	5,836.6	53.2	0.0	7.7	4,724.5
Total Proved	<u>2,275.8</u>	<u>830.1</u>	<u>125.0</u>	<u>25,910.2</u>	<u>1,886.6</u>	<u>788.7</u>	<u>88.9</u>	<u>21,603.5</u>
Total Probable	<u>764.1</u>	<u>248.9</u>	<u>67.9</u>	<u>10,230.1</u>	<u>586.4</u>	<u>230.1</u>	<u>44.0</u>	<u>8,241.4</u>
Total Proved plus Probable ⁽³⁾	<u>3,039.9</u>	<u>1,079.0</u>	<u>192.9</u>	<u>36,140.2</u>	<u>2,473.0</u>	<u>1,018.8</u>	<u>132.9</u>	<u>29,844.9</u>

Notes:

- (1) Gross reserves include working interest reserves before deduction of royalties but do not include royalty interest reserves.
- (2) Net reserves include working interest reserves less the deduction of royalties plus royalty interest reserves.
- (3) Some totals may differ slightly due to rounding.

Net Present Value of Future Net Revenue of Oil and Gas Reserves

RESERVES CATEGORY	NET PRESENT VALUES OF FUTURE NET REVENUE				
	BEFORE INCOME TAXES DISCOUNTED AT				
	(%/year)				
	0	5	10	15	20
	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)
Proved					
Producing	175,138.5	145,393.9	124,447.2	109,110.3	97,446.2
Non-Producing	8,292.8	7,896.8	7,545.5	7,213.6	6,898.8
Undeveloped	14,067.6	10,533.7	8,081.2	6,296.5	4,944.6
Total Proved	<u>197,498.9</u>	<u>163,824.5</u>	<u>140,074.1</u>	<u>122,620.4</u>	<u>109,289.6</u>
Probable	<u>93,109.7</u>	<u>62,159.5</u>	<u>44,908.8</u>	<u>34,374.4</u>	<u>27,452.1</u>
Total Proved plus Provable	<u>290,608.7</u>	<u>225,984.0</u>	<u>184,982.8</u>	<u>156,994.8</u>	<u>136,741.6</u>

The following table provides an estimate of the net present value of future net revenue on an after-tax basis assuming that the Trust would be subject to the equivalent of corporate income tax on its income beginning in 2011, that the Trust distributes all of its trust-level income to the Unitholders and that the Trust continues to operate in its current structure. It should be noted that this estimate does not take into account any corporate tax deductions such as interest and general and administrative expenses or any tax pools generated by capital expenditures beyond those that exist in the forecast.

RESERVES CATEGORY	AFTER INCOME TAXES DISCOUNTED AT (%/year)					UNIT VALUE BEFORE INCOME TAX DISCOUNTED AT 10%/year
	0	5	10	15	20	
	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(\$/BOE)
Proved						
Producing	168,718.6	140,397.3	120,496.3	105,942.2	94,873.6	24.10
Non-Producing	6,058.4	5,878.9	5,724.8	5,569.7	5,412.5	21.43
Undeveloped	10,906.2	7,813.2	5,702.9	4,190.6	3,060.4	9.53
Total Proved	185,683.2	154,089.4	131,924.0	115,702.6	103,346.5	22.01
Probable	72,697.0	47,613.5	33,982.8	25,820.5	20,531.2	20.10
Total Proved plus Provable	258,380.2	201,702.9	165,906.9	141,523.1	123,877.7	21.51

Note: Unit values are based on net reserve volumes.

Additional Information Concerning Future Net Revenue - (Undiscounted)

	Revenue	Royalties	Operating Costs	Development Costs	Abandonment and Reclamation Costs	Future Net Revenue Before Income Taxes	Future Income Tax Expenses	Future Net Revenue After Income Taxes
	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)
Total Proved Reserves	461,746	78,359	152,420	15,521	17,947	197,499	11,816	185,683
Total Proved plus Probable	651,382	118,295	206,815	16,945	18,717	290,609	32,229	258,380

Future net Revenue by Production Group

	Future Net Revenue Before Income Taxes and Discounted at 10% ⁽⁴⁾ (M\$)
Total Proved	
Light and Medium Crude Oil ⁽²⁾	67,689
Heavy Oil	22,714
Natural Gas ⁽³⁾	49,671
Total	140,074
Proved plus Probable	
Light and Medium Crude Oil ⁽²⁾	85,204
Heavy Oil	28,522
Natural Gas ⁽³⁾	71,257
Total	184,983

Notes:

- (1) Columns may not add due to rounding.
- (2) Gas reserves included in light, medium and heavy oil are solution gas reserves only.
- (3) Non-Associated gas including by-products.
- (4) Processing income is included where applicable.

Notes to Reserves Data Tables:

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

Reserve Categories

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on

- analysis of drilling, geological, geophysical and engineering data;
- the use of established technology; and
- specified economic conditions, which are generally accepted as being reasonable, and shall be disclosed.

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

- (a) **Proved reserves** are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.
- (b) **Probable reserves** are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

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

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

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

In multi-well pools it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

Levels of Certainty for Reported Reserves

The qualitative certainty levels referred to in the definitions above are applicable to individual reserve entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level

sum of individual entity estimates for which reserves are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

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

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

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

3. Estimated future abandonment costs related to a property have been taken into account by McDaniel in determining reserves that should be attributed to a property and in determining the aggregate future net revenue therefrom, there was deducted the reasonable estimated future well abandonment costs for wells to which reserves were assigned. No allowance was made, however, for reclamation of wellsites or the abandonment and reclamation of any facilities.
4. On March 11, 2010 the Alberta government announced changes to Alberta's royalty system intended to increase Alberta's competitiveness in the oil and natural gas industry, which included a decrease in the maximum royalty rates for conventional oil and natural gas production effective for the January 2011 production month and certain temporary incentive programs currently in place being made permanent. See "*Industry Conditions*". Further details with respect to the changes to Alberta's royalty system are expected to be provided in the coming months. Reserves and net present values reflected in the above tables do not reflect the potential effect of these new changes to Alberta's royalty system and no sensitivities were provided by McDaniel as to the potential impact of same.
5. Forecast Prices and Costs

The forecast cost and price assumptions assume increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. Crude oil and natural gas benchmark reference pricing, inflation and exchange rates utilized by McDaniel in the McDaniel Report were McDaniel's forecasts, as at January 1, 2010, as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
FORECAST PRICES AND COSTS

Year	OIL			Alberta AECO Spot Gas Price (\$Cdn/GJ)	Pentanes Plus Edmonton (\$Cdn/Bbl)	Butanes Price Edmonton (\$Cdn/Bbl)	Inflation Rates ⁽¹⁾ %/Year	Exchange Rate ⁽²⁾ (\$US/\$Cdn)
	WTI Cushing Oklahoma (\$US/Bbl)	Edmonton Oil Price 40° API (\$Cdn/Bbl)	Bow River Hardisty 24.9° API (\$Cdn/Bbl)					
Forecast								
2010	80.00	83.20	72.30	6.05	85.20	64.00	2.0	0.950
2011	83.60	87.00	73.80	6.75	89.00	66.90	2.0	0.950
2012	87.40	91.00	74.40	7.15	93.10	70.00	2.0	0.950
2013	91.30	95.00	75.80	7.45	97.10	73.10	2.0	0.950
2014	95.30	99.20	79.20	7.80	101.40	76.30	2.0	0.950
2015	99.40	103.50	82.60	8.15	105.70	79.60	2.0	0.950
2016	101.40	105.60	84.30	8.40	107.90	81.20	2.0	0.950
2017	103.40	107.70	85.90	8.55	110.00	82.80	2.0	0.950
2018	105.40	109.80	87.60	8.70	112.10	84.50	2.0	0.950
2019	107.60	112.10	89.40	8.90	114.50	86.20	2.0	0.950
2020+	Escalated oil, gas and product prices at approximately 2% per year thereafter							

Notes:

- (1) Inflation rates for forecasting prices and costs.
(2) Exchange rates used to generate the benchmark reference prices in this table.

Weighted average historical price realized by the Trust for the year ended December 31, 2009 is \$5.58/Mcf for natural gas and \$58.75/Bbl for oil.

Estimated future abandonment costs related to a working interest have been taken into account by McDaniel in determining reserves that should be attributed to a property and in determining the aggregate future net revenue therefrom, there was deducted the reasonable estimated future well abandonment costs. No allowance was made, however, for reclamation of wellsites or the abandonment of any facilities.

The extent and character of all factual data supplied to McDaniel were accepted by McDaniel as represented. No field inspection was conducted.

Reconciliations of Changes in Reserves and Future Gross Revenue

Reserves Reconciliation

The following table sets forth a reconciliation of the Trust's total gross (working interest) proved, probable and total gross (working interest) reserves as at December 31, 2009 against such reserves as at December 31, 2008 based on forecast price and cost assumptions.

	Light and Medium Crude Oil			Heavy Oil			Associated and Non-Associated Gas		
	Proved Reserves	Probable Reserves	Proved Plus Probable	Proved Reserves	Probable Reserves	Proved Plus Probable	Proved Reserves	Probable Reserves	Proved Plus Probable
	Mbbls	Mbbls	Mbbls	Mbbls	Mbbls	Mbbls	Mmcf	Mmcf	Mmcf
Opening Balance									
December 31, 2008	1,937	622	2,559	924	262	1,186	20,029	7,302	27,331
Extensions/Infill	208	62	270	0	0	0	5,044	1,986	7,030
Improved Recovery	0	0	0	0	0	0	80	40	120
Technical Revisions	(5)	(124)	(129)	61	(13)	49	(204)	(1,195)	(1,398)
Discoveries	0	0	0	0	0	0	0	0	0
Acquisitions	539	228	767	0	0	0	5,217	2,097	7,313
Dispositions	(85)	(24)	(109)	0	0	0	0	0	0
<u>Production</u>	(319)	0	(319)	(155)	0	(155)	(4,256)	0	(4,256)
Closing Balance									
December 31, 2009	2,276	764	3,040	830	249	1,079	25,910	10,230	36,140

	Natural Gas Liquids			Total Oil Equivalent		
	Proved Reserves	Probable Reserves	Proved Plus Probable	Proved Reserves	Probable Reserves	Proved Plus Probable
	Mbbls	Mbbls	Mbbls	MBOE	MBOE	MBOE
Opening Balance						
December 31, 2008	109	45	154	6,308	2,145	8,453
Extensions/Infill Drilling	6	2	8	1,055	395	1,450
Improved Recovery	0	0	0	13	7	20
Technical Revisions	18	12	30	40	(324)	(283)
Discoveries	0	0	0	0	0	0
Acquisitions	20	9	29	1,429	586	2,015
Dispositions	0	0	0	(85)	(24)	(109)
<u>Production</u>	<u>(28)</u>	<u>0</u>	<u>(28)</u>	<u>(1,211)</u>	<u>0</u>	<u>(1,211)</u>
Closing Balance						
December 31, 2009	125	68	193	7,549	2,786	10,335

Additional Information Relating to Reserves Data

Undeveloped Reserves

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

Proved Undeveloped Reserves

Year	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Natural Gas (MMcf)		Natural Gas Liquids (Mbbl)	
	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	66.6	94.7	0.0	0.0	935.2	1,763.3	1.3	5.1
2007	75.0	135.0	0.0	0.0	469.5	1,984.8	0.4	1.5
2008	0.0	0.0	0.0	0.0	2,301.6	2,831.7	3.5	3.9
2009	75.0	75.0	0.0	0.0	3,902.0	5,836.6	6.4	9.3

Probable Undeveloped Reserves

Year	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Natural Gas (MMcf)		Natural Gas Liquids (Mbbl)	
	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	91.3	98.4	0.0	0.0	423.1	834.5	0.7	2.3
2007	69.6	99.7	0.0	0.0	212.1	981.3	0.2	0.7
2008	0.0	26.8	0.0	0.0	529.2	732.3	0.7	1.0
2009	30.0	30.0	0.0	0.0	1,421.4	1,866.9	2.2	3.0

In general, once proved and/or probable undeveloped reserves are identified they are scheduled into Avenir's development plans. The Trust plans to develop its proved and probable undeveloped reserves within two years. Undeveloped reserves make up 14% of total proven reserves and 12% of total probable reserves. Undeveloped reserves that are carried over from previous years (not first attributed) comprise 4% of total proven bookings and 3% of total probable reserves. A number of factors that could result in delayed or cancelled development are as follows:

- changing economic conditions (due to pricing, operating and capital expenditure fluctuations);

- changing technical conditions (production anomalies such as water breakthrough, accelerated depletion);
- multi-zone developments (such as a prospective formation completion may be delayed until the initial completion is no longer economic);
- a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization;
- surface access issues (landowners, weather conditions, regulatory approvals); and
- factors affecting partners or offsite producers may result in the delay of proposed projects.

Significant Factors or Uncertainties Affecting Reserves Data

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 reserve estimates contained herein are based on current production forecasts, prices and economic conditions. The Trust's reserves are evaluated by McDaniel, an independent engineering firm.

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 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. See "Risk Factors".

Future Development Costs

The table below sets out the development costs deducted in the estimation of future net revenue attributable to proved reserves (using forecast prices and costs) and proved plus probable reserves (using forecast prices and costs only).

	Forecast Prices and Costs	
	Total Proved Reserves	Total Proved Plus Probable Reserves
	(M\$)	(M\$)
2010	15,123	15,962
2011	237	445
2012	0	2
2013	0	0
2014	141	174
<u>Thereafter</u>	<u>20</u>	<u>362</u>
Total Undiscounted	15,521	16,945

The future development costs are capital expenditures required for the Trust to convert undeveloped reserves to developed producing reserves. The undiscounted development costs are \$15,521 for proved reserves and \$16,945 for proved plus probable reserves (in each case based on forecast prices and costs).

The Trust's internally generated cash flow was sufficient to fund the development costs disclosed above. It typically has available three sources of funding to finance its capital expenditure program: internally generated cash flow from operations, debt financing when appropriate, and new equity issues if available on favourable terms. The Trust expects to fund the total 2010 capital program with internally generated cash flow and, although quarterly fluctuations in funding levels are expected, the objective is to remain at the current net debt level throughout the 2010 financial year. The Trust's objective is to maintain its debt to cash flow ratio at less than 1.0 times estimated future cash flows.

Oil and Gas Wells

The following table sets forth the number and status of wells in which the Trust has a working interest as at December 31, 2009.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing ⁽³⁾		Producing		Non-Producing	
	Gross ⁽¹⁾	Net ⁽²⁾	Gross	Net	Gross	Net	Gross	Net
British Columbia	0	0.0	0	0.0	29	13.5	8	1.8
Alberta	412	167.0	107	43.2	557	170.0	46	27.0
Saskatchewan	541	94.7	123	26	0	0.0	1	0.1
Total	953	261.7	230	69.2	586	183.5	55	28.9

Notes:

- (1) "Gross" wells means the number of wells in which the Trust has a working interest.
- (2) "Net" wells means the aggregate number of wells obtained by multiplying each gross well by the Trust's percentage working interest therein.
- (3) Non-producing includes wells shut-in for economic reasons, wells not capable of production and wells used for disposal of water.

Properties With No Attributed Reserves

The following table summarizes the gross and net acres of unproved properties in which we have an interest. The Trust does not have any properties that are unproductive at this time.

The following table sets out the Trust's undeveloped land holdings as at December 31, 2009.

	Undeveloped Acres	
	Gross	Net
British Columbia	37,128	22,041
Alberta	372,136	157,816
Saskatchewan	16,040	5,652
Total	425,304	185,509

The Trust estimates the value of this land at \$14,961,571 based on an independent third party evaluation by Seaton-Jordan & Associates Ltd. ("**Seaton-Jordan**") effective December 31, 2009. The land value calculations were estimated in accordance with National Instrument 51-101 and the Canadian Oil & Gas Valuation Handbook. Seaton-Jordan performed a full independent evaluation of all properties. The following is a summary of the procedures used by Seaton-Jordan.

Evaluated Procedures

The following is a summary of the procedures used by Seaton-Jordan:

1. the acquisition cost of the unproved property to the Trust, provided there have been no material changes in the unproved property, the surrounding properties, or the general oil and gas economic climate since acquisition;
2. recent sales by others of interests in the same unproved property;
3. terms and conditions, expressed in monetary terms, of recent farm-in agreements related to the unproved property;
4. terms and conditions, expressed in monetary terms, of recent work commitments related to the unproved property;
5. recent sales of similar properties in the same general area;
6. recent exploration and discovery activity in the general area;
7. the remaining term of the unproved property; and

8. burdens (such as overriding royalties) that impact on the value of the property.

The Trust expects that rights to 23,743 net acres of its undeveloped land holdings will expire by December 31, 2010, a portion of which may be continued by drilling. The Trust is considering whether or not to drill or submit application to continue selected portions of the above acreage.

Drilling Activity

The following table summarizes the Trust's drilling results for the year ended December 31, 2009.

	Gross	Net
Oil	4.0	1.43
Natural Gas	5.0	3.19
Coal bed methane	5.0	0.45
Dry & Abandoned	0.0	0.0
Total	<u>14.0</u>	<u>5.06</u>

In 2010, the Trust will focus development activities towards the operated properties of Noel, Central Alberta and the Peace River Arch.

Forward Contracts

The Trust has the following financial hedge contracts outstanding as at December 31, 2009 relating to its oil and gas division:

- a fixed price AECO swap for the period April, 2010 to March 31, 2011 on 1,000 GJs/d of natural gas with a price of \$8.25/GJ; and
- a fixed price WTI collar for the period August 1, 2009 to July 31, 2010 on 200 Bbls/d of crude oil with a floor price of \$65.00 US/Bbl and a ceiling price of \$83.50 US/Bbl; and
- a fixed price WTI collar for the period September 1, 2009 to August 31, 2010 on 100 Bbls/d of crude oil with a floor price of \$70.00 US/Bbl and a ceiling price of \$91.25 US/Bbl; and
- a fixed price WTI collar for the period January 1, 2010 to December 31, 2010 on 200 Bbls/d of crude oil with a floor price of \$80.00 US/Bbl and a ceiling price of \$96.15 US/Bbl; and
- a fixed price WTI swap for the period August 1, 2010 to July 31, 2011 on 200 Bbls/d of crude oil with a price of \$90.05/Bbl.

At December 31, 2009, the following contracts were outstanding with respect to the physical deliveries of oil and gas product:

- a physical fixed price sale for the period April 1, 2009 to March 31, 2010 on 2,000 GJ per day of gas at a price of \$7.92/GJ; and
- a physical fixed price sale for the period January 1, 2009 to December 31, 2010 on 1,000 GJ per day of gas at a price of \$7.95/GJ; and
- a physical fixed price sale for the period February 1, 2009 to March 31, 2011 on 1,000 GJ per day of gas at a price of \$6.79/GJ; and
- a physical fixed price sale for the period September 1, 2009 to March 31, 2011 on 1,000 GJ per day of gas at a price of \$5.20/GJ; and
- a physical fixed price sale for the period December 1, 2009 to June 31, 2010 on 1,000 GJ per day of gas at a price of \$4.79/GJ; and

- a physical fixed price sale for the period November 1, 2009 to October 31, 2010 on 1,000 GJ per day of gas at a price of \$5.95/GJ; and
- a physical fixed price sale for the period April 1, 2010 to March 31, 2010 on 1,000 GJ per day of gas at a price of \$6.43/GJ.

The mark-to-market value of these contracts as at December 31, 2009 was an unrealized gain of \$2.9 million.

Subsequent to December 31, 2009, the Trust entered into the following additional contracts:

- a physical fixed price sale for the period July 1, 2010 to June 30, 2011 on 1,000 GJ per day of gas at a price of \$5.80/GJ

Additional Information Concerning Abandonment and Reclamation Costs

The Trust typically estimates well abandonment costs area by area. Such costs are included in the McDaniel Report as deductions in arriving at future net revenue. The expected total abandonment costs included in the McDaniel Report for 292 net wells under the proved reserves category is an estimated \$7,230,190 discounted at 8.5%, of which a total of approximately \$1,282,200 is estimated to be incurred in 2010, 2011 and 2012. (This estimate does not include expected reclamation costs for surface leases). Expected future abandonment costs related to well site facilities are expected to match the salvage value recovery.

The Trust typically estimates that the additional reclamation costs associated with both active and inactive surface leases, wells and major facilities not captured in the McDaniel Report is \$9,509,317 discounted at 8.5%. The abandonment cost for each surface lease was estimated using the lease liability rating system that is available through the Energy Resources Conservation Board of Alberta. An average abandonment cost of \$30,000 per wellbore was used in the McDaniel Report and is believed to be representative of a typical abandonment operation.

The following table sets forth abandonment costs deducted in the estimation of the Trust's future net revenue:

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

Year	Abandonment Costs (Undiscounted)
2010	38.6
2011	438.4
2012	805.2
Thereafter	16,664.6
Total Undiscounted	<u>17,946.8</u>
Total Discounted @ 10%	<u>6,880.0</u>

Tax Horizon

The Trust is a taxable entity under the Tax Act and is taxable only on income that is not distributed or distributable to the Unitholders. As the Trust distributes all of its taxable income to the Unitholders pursuant to the Trust Indenture and currently satisfies the requirements of the Tax Act applicable to the Trust, the Trust does not expect to pay income taxes until the earlier of January 1, 2011 or if and when it ceases to be a trust. The SIFT Tax (defined below under "Risk Factors – Federal Tax Changes") will not impose a tax on distributions from entities, such as the Trust, until January 1, 2011 as long as that the Trust experiences only "normal growth" as set out in the Guidelines (defined below under "Risk Factors – Federal Tax Changes"). Commencing in January 2011, the Trust will be liable for tax on all distributions of income paid or payable to Unitholders, which distributions the Trust will no longer be able to deduct in computing its taxable income.

Exploration and Development Activities

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

	Exploration		Development	
	Gross	Net	Gross	Net
Light and Medium Oil	0	0.0	4	1.4
Heavy Oil	0	0.0	0	0.0
Natural Gas	0	0.0	10	3.6
Dry	0	0.0	0	0.0
Total:	0	0.0	14	5.1

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

Costs Incurred

The following table summarizes the Trust's property acquisition costs, exploration costs and development costs for the year ended December 31, 2009:

	Property Acquisition Costs				Total
	Proved Properties	Unproved Properties	Exploration Costs	Development Costs	
Total (M\$)	20,234	7,409	0	10,689	38,332

Production Estimates

The following tables set out the volume of our production using forecast prices and costs for the year ended December 31, 2009, which is reflected in the estimate of future net revenue disclosed in the tables contained under "Disclosure of Reserves Data".

Forecast Prices and Costs

Total Proved

	Light and Medium Oil & NGL (Bbls/d)	Heavy Oil (Bbls/d)	Natural Gas (Mcf/d)	BOE (BOE/d)
Noel	13	0	8,665	1,457
Peace River Arch	438	0	2,684	885
West Saskatchewan	317	0	188	348
Grand Forks/Bow Isl.	0	423	197	456
Central AB Gas	10	0	2,186	374
Provost/Castor/Killam	61	0	1,076	240
Liege	0	0	896	149
Southeast Saskatchewan	73	0	0	73
Turin/Retlaw	74	0	139	98
Other Properties	285	0	2,224	655
Total Proved	1,269	423	18,255	4,735

Total Proved Plus Probable

	Light and Medium Oil & NGL (Bbls/d)	Heavy Oil (Bbls/d)	Natural Gas (Mcf/d)	BOE (BOE/d)
Noel	14	0	9,544	1,605
Peace River Arch	458	0	3,130	980
West Saskatchewan	327	0	194	359
Grand Forks/Bow Isl	0	432	202	465
Central AB Gas	10	0	2,339	400
Provost/Castor/Killam	62	0	1,134	251
Liege	0	0	918	153
Southeast Saskatchewan	75	0	0	75
Turin/Retlaw	76	0	129	98
Other Properties	293	0	2,388	690
Total Proved plus Probable	1,315	432	19,978	5,077

Production History

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

	Quarter Ended 2009			
	Mar 31	June 30	Sep 30	Dec 31
Average Daily Production ⁽¹⁾				
Light / Medium Crude Oil (Bbls/d)	889	785	987	1000
Heavy Oil (Bbls/d)	445	434	416	407
Gas (Mcf/d)	11,069	12,510	12,162	11,937
<u>NGLs (Bbls/d)</u>	121	61	71	60
Combined (BOE/d)	3,300	3,365	3,502	3,456
Average Price Received				
Light/Med/ Crude Oil (\$/Bbl)	50.68	62.83	62.44	64.60
Heavy Oil (\$/Bbls/d)	46.72	59.44	58.39	60.53
Gas (\$/Mcf)	6.17	5.14	4.80	5.43
<u>NGLs (\$Bbls/d)</u>	32.36	33.52	39.81	44.22
Combined (\$/BOE)	41.82	42.00	42.01	45.35
Royalties Paid (\$/BOE)				
Light/Med/ Crude Oil (\$/Bbl)	2.88	8.36	14.13	13.21
Heavy Oil (\$/Bbls/d)	2.34	2.95	2.92	3.03
Gas (\$/Mcf)	0.65	0.45	0.48	0.67
<u>NGLs (\$Bbls/d)</u>	9.69	11.72	12.79	15.89
Combined (\$/BOE)	3.63	4.22	6.26	6.77
Operating Expenses (\$/BOE)				
Light/Med/ Crude Oil (\$/Bbl)	17.00	16.58	12.66	14.21
Heavy Oil (\$/Bbls/d)	27.10	26.83	26.02	25.45
Gas (\$/Mcf)	2.85	2.75	2.40	2.30
<u>NGLs (\$Bbls/d)</u>	12.41 ⁽³⁾	12.66 ⁽³⁾	11.83 ⁽³⁾	12.07 ⁽³⁾
Combined (\$/BOE)	17.79	17.55	15.00	15.05
Netback Received (\$/BOE) ⁽²⁾				
Light/Med/ Crude Oil (\$/Bbl)	30.81	37.88	35.64	37.18
Heavy Oil (\$/Bbls/d)	17.28	29.25	29.45	32.05
Gas (\$/Mcf)	2.67	1.94	1.92	2.46
<u>NGLs (\$Bbls/d)</u>	22.67	21.80	27.02	28.32
Combined (\$/BOE)	20.40	20.23	20.76	23.53

Notes:

- (1) Before deduction of royalties.
- (2) Netbacks are calculated by subtracting royalties and operating and transportation costs from revenues.
- (3) Values are included in Gas (\$/Mcf) noted directly above.

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

	Light and Medium Crude Oil & NGL's (Bbls/d)	Heavy Oil (Bbls/d)	Gas (Mcf/d)	BOE (BOE/d)
Alberta Properties				
Peace River Arch	199	0	2,317	586
Grand Forks/Bow River	0	425	178	454
Central Alberta Gas	9	0	1,465	254
Provost/Castor/Killam	62	0	1,281	276
Liege	0	0	841	140
Turin/Retlaw	79	0	145	103
Total Alberta Properties	349	425	6,227	1,813
British Columbia Properties				
Noel	5	0	4,251	714
Total British Columbia Properties	5	0	4,251	714
Saskatchewan Properties				
West Saskatchewan	334	0	245	375
Southeast Saskatchewan	74	0	0	74
Total Saskatchewan Properties	408	0	245	449
Other Areas	232	0	1,200	432
Grand Total	994	425	11,923	3,406

ELBOW RIVER MARKETING LIMITED PARTNERSHIP

Elbow River is involved in the business of marketing and transporting natural gas liquids ("NGLs") and ethanol. The primary business of the company is to act as a wholesale, transporter and supplier of butane to major refineries and propane to major retailer in North America. Within Elbow River, there was two business segments, the Liquefied Petroleum Gasoline ("LPG") business, which includes the marketing of propane, butane and natural gasoline; and the Biofuels business, which includes the marketing of ethanol.

Avenir purchased Elbow River in April of 2005. At that time Elbow River had been in business for over 20 years and as result had developed numerous relationships with companies and individuals throughout North America. Elbow Rivers's strength was strong customer relations, great customer service and a thorough understanding of the markets they served. The 2005 and 2006 trading years saw an increase in sales and growth. During 2006, Elbow River created a biofuels group that included the marketing of ethanol and bio-diesel. Management considered fiscal 2007 to be a slower year relative to 2005 and 2006 due to the significant increase in the number of competitors in the LPG and biofuels businesses. During the first half of 2008, Elbow River increased its marketing of bio-diesel in the United States and overseas; however, in the fourth quarter of 2008 the Trust announced that Elbow River would be exiting from the marketing of bio-diesel due to the risk and uncertainty within this market. In March of 2009 the Trust announced that as of March 2009, all bio-diesel related inventory, contracts, tankage and tank car obligations had been sold or transferred and staffing requirements related to bio-diesel marketing had been reduced. Elbow River will continue to market ethanol, which management of Elbow River expects to continue to grow through new marketing strategies and an expected increase in the overall market.

Butane and propane are extracted from natural gas and crude oil during the production, processing and refining process. Butane is used in the refinery process for blending with gasoline. Propane is mainly used for heating fuel in areas where natural gas is not available. Propane is heavily dependant on winter weather conditions while butane continues to be the most steady contributor to Elbow River's business success in the LPG marketing business. Management believes the natural gasoline business has experienced steady growth due to the rapid pace of development in the Alberta Oil Sands.

Suppliers on the NGL side of the business are generally major oil and gas companies in Canada and the United States. Elbow River takes title of the product, arranges transportation and delivery, mainly by rail tank cars, with Elbow River paying for the product and transportation. The product prices are normally determined by the spot market price. Elbow River typically has low product risk as the delivery price is generally fixed at the time Elbow River takes title. See "*Industry Conditions – Natural Gas Liquids Wholesale Brokerage Industry.*"

REAL ESTATE PROPERTIES

The following is a summary of the principal properties currently held by the Trust.

KFC/Taco Bell Portfolio, Northern Alberta and British Columbia

Consists of a portfolio containing thirteen (13) franchise locations situated in north central Alberta and British Columbia. The KFC leases are 10 year terms and are cross-collateralized locations and consist of 36,951 square feet in aggregate. The buildings are all freestanding properties in each location.

Landmark Theatres, Western Canada

Consists of a portfolio containing fifteen (15) locations situated in western Canada primarily in Alberta and British Columbia. The Landmark Theatre leases are 20 year terms, cross-collateralized across locations and consist of 155,465 square feet in aggregate.

222 Snidercroft Road, Vaughan, Ontario

This office and manufacturing facility is located in Greater Toronto's 600 million square foot industrial market, backing onto Highway 407 in a well established business park in Vaughan. Built in two stages (1970 and 1980) for the present tenant Scintrex Limited, this renovated facility comprises approximately 71,000 square feet resting on 4.0 acres, with site coverage of only 29%. The facility is air conditioned and offers mechanical and electrical systems suited to advanced technology and flex office users. The Trust initially owned a 50% interest in this property; however, on January 31, 2006 the Trust purchased the remaining 50%.

1800 Huron Street, London, Ontario

This manufacturing/warehouse facility sits adjacent to London International Airport in the northeast industrial area of London, Ontario. With convenient access to Highway 401, the facility is suited to users that serve the huge southern Ontario and nearby north central U.S. markets. The tenant is Magee Rieter Automotive Systems, a partnership between subsidiaries of Magee Industrial Enterprises, a privately held US company, and Rieter AG, a publicly traded Swiss company. Built in 1989, the building is fully air conditioned and initially comprised 112,000 square feet on 12.65 acres. The building was expanded in 2005 to approximately 141,343 square feet.

DESCRIPTION OF THE TRUST UNITS

Terms of Securities

An unlimited number of Trust Units may be created and issued pursuant to the Trust Indenture. As at December 31, 2009, 42,110,678 Trust Units were issued and outstanding. Each Trust Unit represents an equal fractional undivided beneficial interest in any distribution from the Trust (whether of net income, net realized capital gains or other amounts) and in any net assets of the Trust in the event of termination or winding up of the Trust. All Trust Units outstanding from time to time shall be entitled to equal shares of any distribution by the Trust, and in the event of termination or winding up of the Trust, in any net assets of the Trust. All Trust Units of the Trust shall rank among themselves equally and rateably without discrimination, preference or priority. Each Trust Unit is transferable, is not subject to any conversion or pre-emptive rights and entitles the holder thereof to require the Trust to redeem any or all of the Trust Units held by such holder and to one vote at all meetings of Unitholders for each Trust Unit held.

The Trust Units do not represent a traditional investment and should not be viewed by investors as "shares" in either the Manager or the Trust. As holders of the Trust Units in the Trust, Unitholders will not have the statutory rights normally associated with ownership of shares of a corporation including, for example, the right to bring "oppression" or "derivative" actions. The Trust Units also do not represent a debt obligation and should not be viewed by investors as bonds, debentures or other debt instruments. Unitholders will not

have the contractual rights normally associated with debt instruments, such as the right to demand repayment and commence collection proceedings if monthly cash distributions are not made or are less than expected.

Trust Units are redeemable at any time on demand by the holders thereof upon delivery to the Trust of the certificate or certificates representing such Trust Units. Upon receipt of the redemption request by the Trust, the holder thereof shall only be entitled to receive a price per Trust Unit (the "**Market Redemption Price**") equal to the lesser of (i) 90% of the "market price" of the Trust Units on the principal market on which the Trust Units are quoted for trading during the 10 day trading period commencing immediately after the date on which the Trust Units are surrendered for redemption, and (ii) the "closing market price" on the principal market on which the Units are quoted for trading on the date that the Trust Units are surrendered for redemption.

The market price for the Trust Units shall be an amount equal to the simple average of the closing price of the Trust Units for each of the ten trading days on which there was a closing price; provided that if the applicable exchange or market does not provide a closing price but only provides the highest and lowest prices of the Trust Units traded on a particular day, the market price shall be an amount equal to the simple average of the average of the highest and lowest prices for each of the trading days on which there was a trade; and provided further that if there was trading on the applicable exchange or market for fewer than five of the 10 trading days, the market price shall be the simple average of the following prices established for each of the 10 trading days: the average of the last bid and last ask prices for each day on which there was no trading; the closing price of the Trust Units for each day that there was trading if the exchange or market provides a closing price; and the average of the highest and lowest prices of the Trust Units for each day that there was trading, if the market provides only the highest and lowest prices of Trust Units traded on a particular day.

The closing market price for the Trust Units shall be an amount equal to the closing price of the Trust Units if there was a trade on the date; an amount equal to the average of the highest and lowest prices of Trust Units if there was trading and the exchange or other market provides only the highest and lowest prices of Trust Units traded on a particular day; and the average of the last bid and last ask prices if there was no trading on the date.

The Trust Units are not "deposits" within the meaning of the *Canada Deposit Insurance Corporation Act* (Canada) and are not insured under the provisions of that act or any other legislation. Furthermore, the Trust is not a trust company and is not registered under any trust and loan company legislation as it does not carry on or intend to carry on the business of a trust company. The Trust is not considered as a mutual fund pursuant to Canadian securities legislation and does not operate in accordance with the rules applicable to mutual funds enacted by the Canadian Securities regulators.

Trust Unitholder Limited Liability

The Trust Indenture provides that no Unitholder, in its capacity as such, shall incur or will be subject to any liability in contract or in tort in connection with the Trust or its obligations and affairs and, in the event that a court determines Unitholders are subject to any such liabilities, the liabilities will be enforceable only against, and will be satisfied only out of the Unitholder's share of, the Trust's assets. Pursuant to the Trust Indenture, the Trust will indemnify and hold harmless each Unitholder from any cost, damages, liabilities, expenses, charges and losses suffered by a Unitholder from or arising as a result of such Unitholder not having such limited liability.

The Trust Indenture provides that all contracts signed by or on behalf of the Trust must contain a provision to the effect that such obligation will not be binding upon Unitholders personally. Notwithstanding the terms of the Trust Indenture, Unitholders may not be protected from liabilities of the same extent as a shareholder is protected from the liabilities of a corporation. Personal liability may also arise in respect of claims against the Trust (to the extent that claims are not satisfied by the Trust) that do not arise under contract, including claims in tort, claims for taxes and possibly certain other statutory liabilities. The possibility of any personal liability to the Unitholders of this nature arising is considered unlikely in view of the fact that the undertaking of the Trust is to hold securities of the Operating Trust, and all of the business operations in which the Trust is interested will be carried on by the Manager directly or indirectly or by a limited partnership.

The business of the Trust and its wholly-owned subsidiary, the Manager, will be conducted, upon the advice of counsel, in such a way and in such jurisdictions as to avoid, as far as possible, any material risk of liability to the Unitholders from claims against the Trust by obtaining appropriate insurance, where available, for the operations of the Manager and having contracts signed by or on behalf of the Trust, including a provision that such obligations are not binding upon the Unitholders personally.

Restrictions on Non-Resident Ownership

The Trust Indenture provides that at no time may more than one-half of the outstanding Trust Units be held by non-residents of Canada within the meaning of the Tax Act ("**Non-Residents**"). If at any time the Trustee becomes aware that the beneficial owners of 25% of the Trust Units then outstanding are or may be Non-Residents or that such a situation is imminent, the Manager shall thereafter request declarations as to beneficial ownership as provided for in the Trust Indenture from Unitholders at least annually in conjunction with the annual meeting of Unitholders to be called by the Manager. If at any time the Trustee becomes aware that the beneficial owners of 49% of the Trust Units then outstanding are or may be Non-Residents or that such a situation is imminent, the Manager may make a public announcement thereof and shall not accept the subscription for Trust Units from or issue or register a transfer of Trust Units to a person unless the person provides a declaration pursuant to the terms of the Trust Indenture that the person is not a Non-Resident. Notwithstanding the foregoing, if the Manager determines that the majority of the Trust Units are held by Non-Residents the Manager may send a notice to Non-Resident holders of Trust Units, chosen in inverse order to the order of acquisition or registration or in such other manner as the Trustee may consider equitable and practicable, requiring them to sell their Trust Units or a specified portion thereof within a specified period of not less than 60 days in accordance with the terms and conditions of the Trust Indenture. If the Unitholders receiving such notice have not sold the specified number of Trust Units or provided the Trustee with satisfactory evidence that they are not Non-Residents within such period, the Manager may on behalf of such Unitholders sell such Trust Units and, in the interim, shall suspend the voting and distribution rights attached to such Trust Units and shall make any distribution in respect of such Trust Units by depositing such amount in a separate bank account in a Canadian chartered bank (net at any applicable tax). Any sales shall be made on any stock exchange on which the Trust Units are then listed and, upon such sale, the affected holder shall cease to be holders of Trust Units and their rights shall be limited to receiving the net proceeds of sale upon surrender of Trust Certificates representing such Trust Units. Notwithstanding any other provision of the Trust Indenture, Non-Residents shall not be entitled to vote in respect of any Special Resolutions of Unitholders to amend the sections of the Trust Indenture concerning Non-Resident Unitholders.

CASH DISTRIBUTIONS

The Trustee may declare payable to the Unitholders all or any part of the net income of the Trust earned from any income or dividends, less all expenses and liabilities of the Trust due and accrued and which are chargeable to the net income of the Trust. In addition, Trust Unitholders may, at the discretion of the Trustee, receive distributions in respect of repayments of principal by any of the operating subsidiaries of the Trust to the Trust on any outstanding debt. It is anticipated however, that the Trust will reinvest a portion of any repayments of principal to make capital expenditures to develop the business of the Trust with a view to enhancing the Trust's cash flow from operations.

Pursuant to the provisions of the Trust Indenture all income earned by the Trust in a fiscal year, not previously distributed in that fiscal year, must be distributed to Unitholders of record on December 31. This excess income, if any, will be allocated to Unitholders of record at December 31 but the right to receive this income, if the amount is not determined and declared payable at December 31, will trade with the Trust Units until determined and declared payable in accordance with the rules of the Toronto Stock Exchange. To the extent that a Unitholder trades Trust Units in this period they will be allocated such income but will dispose of their right to receive such distribution.

In each of the three most recently completed financial years, the Trust has made the following cash distributions to holders of Trust Units:

Period covered	Date of record	Date of Distribution	Per unit \$
January 1, 2007 to January 31, 2007	31/01/07	15/02/07	0.083
February 1, 2007 to February 28, 2007	28/02/07	15/03/07	0.083
March 1, 2007 to March 31, 2007	30/03/07	16/04/07	0.083
April 1, 2007 to April 30, 2007	30/04/07	15/05/07	0.083
May 1, 2007 to May 31, 2007	31/05/07	15/06/07	0.083
June 1, 2007 to June 30, 2007	29/06/07	16/07/07	0.083
July 1, 2007 to July 31, 2007	31/07/07	15/08/07	0.083
August 1, 2007 to August 31, 2007	31/08/07	17/09/07	0.083
September 1, 2007 to September 30, 2007	28/09/07	15/10/07	0.083
October 1, 2007 to October 31, 2007	31/10/07	15/11/07	0.083
November 1, 2007 to November 30, 2007	30/11/07	17/12/07	0.083
December 1, 2007 to December 31, 2007	31/12/07	15/01/08	0.083
January 1, 2008 to January 31, 2008	31/01/08	15/02/08	0.083
February 1, 2008 to February 29, 2008	29/02/08	17/03/08	0.083
March 1, 2008 to March 31, 2008	31/03/08	15/04/08	0.083
April 1, 2008 to April 30, 2008	30/04/08	15/05/08	0.083
May 1, 2008 to May 31, 2008	30/05/08	16/06/08	0.083
June 1, 2008 to June 30, 2008	30/06/08	15/07/08	0.083
July 1, 2008 to July 31, 2008	31/07/08	15/08/08	0.083
August 1, 2008 to August 31, 2008	29/08/08	15/09/08	0.083
September 1, 2008 to September 30, 2008	30/09/08	15/10/08	0.083
October 1, 2008 to October 31, 2008	31/10/08	17/11/08	0.083
November 1, 2008 to November 30, 2008	28/11/08	15/12/08	0.083
December 1, 2008 to December 31, 2009	31/12/08	15/01/09	0.083
Special Distribution	31/12/08	16/02/09	0.600
January 1, 2009 to January 31, 2009	30/01/09	16/02/09	0.083
February 1, 2009 to February 28, 2009	27/02/09	16/03/09	0.083
March 1, 2009 to March 31, 2009	31/03/09	15/04/09	0.083
April 1, 2009 to April 30, 2009	30/04/09	15/05/09	0.083
May 1, 2009 to May 31, 2009	29/05/09	15/06/09	0.060
June 1, 2009 to June 30, 2009	30/06/09	15/07/09	0.060
July 1, 2009 to July 31, 2009	31/07/09	17/08/09	0.060
August 1, 2009 to August 31, 2009	31/08/09	15/09/09	0.060
September 1, 2009 to September 30, 2009	30/09/09	15/10/09	0.060
October 1, 2009 to October 31, 2009	30/10/09	16/11/09	0.060
November 1, 2009 to November 30, 2009	30/11/09	15/12/09	0.060
December 1, 2009 to December 31, 2009	31/12/09	15/01/10	0.060
January 1, 2010 to January 31, 2010	31/01/10	15/02/10	0.060
February 1, 2010 to February 28, 2010	26/02/10	15/03/10	0.060
March 1, 2010 to March 31, 2010	31/03/10	15/04/10	0.060

The Trust expects cash distributions will continue to be made on or about the 15th day of each month to Unitholders of record on the immediately preceding distribution record date.

DIRECTORS AND OFFICERS

The Manager has a Board of Directors currently comprised of eight individuals. The directors are elected by the Unitholders by Ordinary Resolution, and hold office until the next annual meeting of the Trust. The names, places of residence, the offices held by each in the Manager, and the principal occupation of the directors and officers, the period served as director and the number of securities of the Trust owned by such individual is as follows:

Name and Place of Residence	Position Held ⁽⁸⁾	Year Became Director or Officer	Number of Trust Units Held ⁽¹⁾	Principal Occupation and Positions for the Past Five Years
William M. Gallacher ⁽³⁾⁽⁴⁾ Alberta, Canada	President, Chief Executive Officer and a Director	2003	357,376(0.85%)	President & Chief Executive Officer of Avenir; President of Avenir Capital Corporation, a private merchant bank.
Gary H. Dundas Alberta, Canada	Vice President, Finance, Chief Financial Officer and a Director	2003	225,540 (0.54%)	Chief Financial Officer of the Manager; prior thereto, Chief Financial Officer and Vice President Finance; General Manager Corporate Development, Marketing; and Controller at Maxx Petroleum Ltd., a publicly traded junior exploration & production company.
David E. Butler ⁽²⁾⁽⁴⁾ Alberta, Canada	Director	2003	78,666 (0.19%)	President of Passport Petroleums Ltd., a private oil and gas company.
Stuart Y. Chow ⁽³⁾⁽⁴⁾ Alberta, Canada	Director	2003	42,397 (0.10%)	President of Bravo Energy Inc., a private oil and gas company; formerly President of Onward Energy Inc. (prior to its acquisition by the Trust in January 2003).
William Patterson ⁽²⁾⁽³⁾ Alberta, Canada	Director	2005	15,000 (0.04%)	Currently an Independent Tax and Business Consultant; previously Vice President, Finance and Chief Financial Officer for Energy North Inc. (January 1999 – July 2004).
Alan C. Moon ⁽²⁾⁽³⁾⁽⁶⁾ Alberta, Canada	Director	2003	33,040(0.08%)	President of Crescent Enterprise Inc., a private consulting firm and corporate director.
Jeffery D. Kohn Alberta, Canada	Director	2003	147,050(0.35%)	Currently, the President of MDC Property Services Ltd., the Trust's real estate management company. Previously the CEO of TGS North American REIT ("TGS") from December 2003 to June 2006. Prior to TGS, he was Chairman and Founder of Tonko Development Corp, a public real estate advisory firm.
Dennis B. Balderston Alberta, Canada	Director	2010	nil	From July 2005 to present, Independent Businessman. Prior thereto, from September 1990 to June 2005, a Partner with Ernst & Young LLP, a firm of Chartered Accountants.

Notes:

- (1) "Trust Units Held" indicates units beneficially owned or controlled, directly or indirectly.
- (2) Member of the Audit and Risk Management Committee.
- (3) Member of the Corporate Governance and Compensation Committee.
- (4) Member of the Reserves, Review and Environmental, Health and Safety Committee.
- (5) The Manager does not have an Executive Committee of its Board of Directors.
- (6) Mr. Moon serves as Lead Director.
- (7) The directors, executive officers, advisors, managers and officers of the Trust as a group beneficially own, directly or indirectly, or exercise control or direction over, 966,657 Units, representing approximately 2.3% of the issued and outstanding Trust Units. This value includes the Trust Units referenced in Note 1 above.
- (8) Each office of the directors expires at the next annual meeting of Unitholders of the Trust.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

Other than as set forth below, to our knowledge no director or executive officer of the Corporation: (i) is, or has been in the last 10 years, a director or executive officer of an issuer that, while that person was acting in that capacity, (a) was the subject of a cease trade order or similar order or an order that denied the issuer access to any exemptions under securities legislation, for a period of more than 30 consecutive days, (b) was subject to an event that resulted, after that person ceased to be a director or executive officer, in the

issuer being the subject of a cease trade or similar order or an order that denied the issuer access to any exemption under securities legislation, for a period of more than 30 consecutive days, or (c) within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; (ii) has, within the last 10 years, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangements or compromises with creditors, or had a receiver or receiver manager or trustee appointed to hold his assets; or (iii) has been subject to: (a) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority, or (b) any other penalties or sanctions imposed by a court or regulatory body.

Mr. Gallacher and Mr. Dundas, directors of the Corporation, are currently serving as directors of Mahalo Energy Ltd. ("**Mahalo**") and Mr. Gallacher currently serves as the Chairman of the Board of Mahalo. In addition, Mr. Butler served as a director of Mahalo until July 13, 2009. On May 22, 2009, Mahalo obtained an order from the Court of Queen's Bench of Alberta, Judicial District of Calgary, for protection under the *Companies' Creditors Arrangement Act* (Canada). Mr. Dundas is also the sole director of Mahalo Energy (USA) Inc., a subsidiary of Mahalo, which filed for and received Chapter 11 protection in the United States on May 21, 2009.

Mr. William Patterson was Chief Financial Officer of a private company, which was petitioned into bankruptcy in March of 2007. Mr. Patterson left employment with the company in November of 2006. Mr. Patterson was an Officer and Director of Javelin Energy Inc. ("**Javelin**"). On December 9, 2009, Javelin, by order of the Court of Queens' Bench of Alberta, was put into receivership. Mr. Patterson had resigned as an Officer and Director of Javelin July 27, 2009.

Conflicts of Interest

Directors and officers of the Manager may, from time to time, be involved with the business and operations of other oil and gas issuers, in which case a conflict may arise. See "*Risk Factors*."

HUMAN RESOURCES

As at December 31, 2009, the Trust had 42 full time employees, 5 officers and 23 other part time consultants. See "*Directors and Officers of the Trust*".

CORPORATE GOVERNANCE

General

In general, the Trust has been delegated substantially all of our management decisions. Unitholders are entitled to elect the board of directors of the Trust pursuant to the terms of the Trust Indenture.

Additional information in respect of corporate governance matters will be contained in the information circular and proxy statement in respect of our annual and special meeting of securityholders currently scheduled to be held on June 23, 2010, which will be filed on SEDAR at www.sedar.com.

Trust Indenture

Pursuant to the Trust Indenture, Unitholders are entitled to direct the manner in which Common Shares are voted in the Manager at all meetings in respect of matters relating to the election of the directors of the Manager, approving its financial statements and appointing auditors of the Manager who shall be the same as our auditors. Prior to voting Common Shares in the Manager, in respect of such matters, each Unitholder is entitled to vote in respect of the matter on the basis of one vote per Trust Unit held, and the Trust is required to vote our Common Shares in the Manager in accordance with the result of the vote of Unitholders.

Decision Making

The Manager and the Trust have entered into the Administration Agreement pursuant to which the board of directors of the Manager is delegated the significant management decisions of the Trust. In particular, the Trustee has delegated to the Manager responsibility for any and all matters relating to the following: (i) calculating or causing the calculating of any amounts to be paid by the Trustee to Unitholders in accordance with the Trust Indenture; (ii) ensuring compliance by the Trust with its legal obligations, including its

continuous disclosure obligations under all applicable securities legislation; (iii) preparing and furnishing to Unitholders all reports, financial statements, all necessary tax information and other information required to be sent to Unitholders; (iv) calling, holding or distributing material in respect of any meeting of Unitholders as required pursuant to the Trust Indenture; and (v) certain matters relating to the specific powers and authorities as set forth in the Trust Indenture.

In addition, pursuant to the Trust Indenture, the board of directors of the Manager shall exercise all rights, powers, responsibilities and privileges of the Trustee in relation to a response to an offer for Trust Units or for all or substantially all of the property and assets of the Trust or the Manager or any subsidiary of the Manager or the Trust including entering into any Unitholder rights protection plan either prior to or during the course of any offer, any defensive action in the course of any offer, the preparation of any directors' circular in response to an offer and consideration on behalf of Unitholders and a recommendation to Unitholders in respect of any offer and any regulatory or court action in respect thereof.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

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

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

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There were no material interests, direct or indirect, of directors or executive officers of the Trust, of any shareholder who beneficially owns, directly or indirectly, or exercises control or direction over more than 10% of the outstanding Units, or any other informed person (as defined in National Instrument 51-102) or any known associate or affiliate of such persons, in any transaction within the three most recently completed financial years or during the current financial year that has materially affected or would materially affect the Trust or any of its subsidiaries.

PRICE RANGE AND TRADING VOLUME OF THE TRUST UNITS

The outstanding Trust Units are currently traded on the TSX under the trading symbol "AVF.UN". The following table sets forth the price range and trading volume of the Trust Units as reported by the TSX for the periods indicated.

Period	High	Low	Volume
<u>2009</u>			
January	5.35	4.65	2,049,463
February	5.00	4.01	1,640,397
March	4.51	2.88	1,798,254
April	3.41	2.95	1,922,940
May	3.87	3.00	3,599,781
June	3.80	3.31	1,747,200
July	4.38	3.53	1,270,128
August	5.17	4.11	1,783,006
September	4.99	4.51	1,90,662
October	5.03	4.32	2,254,680
November	5.00	4.69	1,865,018
December	4.94	4.75	1,846,777

PRIOR SALES

Date	Securities	Number of Securities	Price per Security
January 1, 2009	Issuance of options ⁽¹⁾	29,500	\$5.15
July 2, 2009	Issuance of options ⁽¹⁾	691,200	\$3.71
August 15, 2009	Issuance of options ⁽¹⁾	4,500	\$4.64
December 1, 2009	Issuance of options ⁽¹⁾	31,250	\$4.84

Note:

(1) Options vest one-third on each of the three anniversaries following the date of grant.

INDUSTRY CONDITIONS

Introduction

The industries in which the Trust operates are subject to controls and regulations imposed by various levels of government. Outlined below are some of the more significant aspects of the legislation, regulations and agreements governing the oil and gas industry, the financial services industry, the real estate industry and the energy, construction and utility service industry. All current legislation is a matter of public record and it is not possible to predict what additional legislation or amendments may be enacted.

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, transportation, and marketing) as a result of legislation enacted by various levels of government and with respect to the pricing and taxation of oil and natural gas through agreements among the governments of Canada, Alberta and British Columbia 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 Trust'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 Trust is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry.

Pricing and Marketing

Oil

The producers of oil are entitled to negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Oil prices are primarily based on worldwide supply and demand. The specific price depends in part on oil quality, prices of competing fuels, distance to market, the 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 and the issuance of such a licence requires a public hearing and the approval of the Governor in Council.

Natural Gas

The price of natural gas is determined by negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m³/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 and the issuance of such a licence requires a public hearing and the approval of the Governor in Council.

The governments of Alberta, British Columbia and Saskatchewan also regulate the volume of natural gas that may be removed from those provinces for consumption elsewhere based on such factors as reserve availability, transportation arrangements, and market considerations. As yet, Manitoba does not have natural gas production in commercial quantities and does not therefore impose such export restrictions.

Pipeline Capacity

Although pipeline expansions are ongoing, the lack of firm pipeline capacity continues to affect the oil and natural gas industry and limits the ability to produce and to market oil and natural gas production. In addition, the pro rationing of capacity on the inter provincial pipeline systems also continues to affect the ability to export oil and natural gas.

The North American Free Trade Agreement

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

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

Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations which govern royalties, production rates and other matters. The royalty regime in a given province is a significant factor in the profitability of crude oil, natural gas liquids, sulphur and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiation between the mineral freehold owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. 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, from time to time, carved out of the working interest owner's interest through non public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests, or net carried interests.

Occasionally the governments of the western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays 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.

On October 25, 2007, the Government of Alberta released a report entitled "The New Royalty Framework" ("**NRF**") containing the Government's proposals for Alberta's new royalty regime which were subsequently implemented by the Mines and Minerals (New Royalty Framework) Amendment Act, 2008. The NRF took effect on January 1, 2009. On March 11, 2010, the Government of Alberta announced changes to Alberta's royalty system intended to increase Alberta's competitiveness in the upstream oil and natural gas sectors; specifically, the maximum royalty rates for conventional oil and natural gas production will be decreased effective for the

January 2011 production month and certain temporary incentive programs currently in place will be made permanent. Further details with respect to the changes to Alberta's royalty system are expected to be provided in the coming months.

With respect to conventional oil, the NRF eliminated the classification system used by the previous royalty structure which classified oil based on the date of discovery of the pool. Under the NRF, 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. Royalty rates for conventional oil under the NRF range from 0-50%, an increase from the previous maximum rates of 30-35% depending on the vintage of the oil, and rate caps are set at \$120 per barrel. Effective January 1, 2011, the maximum royalty payable under the NRF will be reduced to 40%.

Royalty rates for natural gas under the NRF are similarly determined using a single sliding rate formula incorporating separate variables to account for production rates and market prices. Royalty rates for natural gas under the NRF range from 5-50%, an increase from the previous maximum rates of 5-35%, and rate caps are set at \$17.75/GJ. Effective January 1, 2011, the maximum royalty payable under the NRF will be reduced to 36%.

Oil sands projects are also subject to the NRF. Prior to payout, 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: 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. An oil sands project reaches payout when its cumulative revenue exceeds its cumulative costs. Costs include specified allowed capital and operating costs related to the project plus a specified return allowance. As part of the implementation of the NRF, the Government of Alberta renegotiated existing contracts with certain oil sands producers that were not compatible with the NRF.

In August 2006, the Government of Alberta introduced the Innovative Energy Technologies Program (the "IETP"), which has a stated objective of promoting producers' investment in research, technology and innovation for the purposes of improving environmental performance while creating commercial value. The IETP is backed by a \$200 million funding commitment over a five-year period beginning April 1, 2005 and provides royalty adjustments to specific pilot and demonstration projects that utilize innovative technologies to increase recovery from existing reserves.

On April 10, 2008, the Government of Alberta introduced two new royalty programs to be implemented along with the NRF and intended to encourage the development of deeper, higher cost oil and gas reserves. A five-year program for conventional oil exploration wells over 2,000 metres provides qualifying wells with up to a \$1 million or 12 months of royalty relief, whichever comes first, and a five-year program for natural gas wells deeper than 2,500 metres provides a sliding scale royalty credit based on depth of up to \$3,750 per metre.

On November 19, 2008, in response to the drop in commodity prices experienced during the second half of 2008, the Government of Alberta announced the introduction of a five-year program of transitional royalty rates with the intent of promoting new drilling. The 5-year transition option is designed to provide lower royalties at certain price levels in the initial years of a well's life when production rates are expected to be the highest. Under this new program companies drilling new natural gas or conventional oil deep wells (between 1,000 and 3,500 m) are given a one-time option, on a well-by-well basis, to adopt either the new transitional royalty rates or those outlined in the NRF. Pursuant to the changes made to Alberta's royalty structure announced on March 11, 2010, producers will only be able to elect to adopt the transitional royalty rates prior to January 1, 2011 and producers that have already elected to adopt the transitional royalty rates as of that date will be permitted to switch to Alberta's conventional royalty structure. On December 31, 2013, all producers operating under the transitional royalty rates will automatically become subject to Alberta's conventional royalty structure.

On March 3, 2009, the Government of Alberta announced a three-point incentive program in order to stimulate new and continued economic activity in Alberta. The program introduced a drilling royalty credit for new conventional oil and natural gas wells and a new well royalty incentive program, both applying to conventional oil or natural gas wells drilled between April 1, 2009 and March 31, 2010. The drilling royalty credit provides up to a \$200 per metre royalty credit for new wells and is primarily expected to benefit smaller producers since the maximum credit available will be determined using the company's production level in 2008 and its drilling activity between April 1, 2009 and March 31, 2010, favouring smaller producers with lower activity levels. The new well incentive program initially applied to wells that began producing conventional oil or natural gas between April 1, 2009 and March 31, 2010 and provided for a maximum 5% royalty rate for the first 12 months of production on a maximum of 50,000 barrels of oil or 500 MMcf of natural gas. In June, 2009, the Government of Alberta announced the extension of these two incentive programs for one year to

March 31, 2011. On March 11, 2010, the Government of Alberta announced that the incentive program rate of 5% for the first 12 months of production would be made permanent, with the same volume limitations.

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

British Columbia

Producers of oil and natural gas from Crown lands in British Columbia 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. 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 based on the determination of whether the oil is produced from a pool discovered before October 31, 1975 ("old oil"), between October 31, 1975 and June 1, 1998 ("new oil"), or after June 1, 1998 ("third-tier oil"). 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 as an incentive for the production and marketing of natural gas which might otherwise have been flared.

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. For natural gas, the freehold production tax 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.

As at the beginning of 2009, British Columbia maintained a number of targeted royalty programs for key resource areas intended to increase the competitiveness of British Columbia's low productivity wells. These include both royalty credit and royalty reduction programs, including the following:

- *Summer Royalty Credit Program* providing a royalty credit of 10% of drilling and completion costs up to \$100,000 for wells drilled between April 1 and November 30 of each year, intended to increase summer drilling activity, employment and business opportunities in northeastern British Columbia;
- *Deep Royalty Credit Program* providing a royalty credit equal to approximately 23% of 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 2,300 metres spud between December 1, 2003 and September 1, 2009;
- *Deep Re-Entry Royalty Credit Program* providing royalty credits for deep re-entry wells with a true vertical depth greater than 2,300 metres and a re-entry date subsequent to December 1, 2003;
- *Deep Discovery Royalty Credit Program* providing the lesser of a 3-year royalty holiday or 283,000,000 m³ 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 m³ 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 royalty breaks for low productivity natural gas wells with average monthly production under 25,000 m³ during the first 12 production months and average daily production less than 23 m³ for every metre of marginal well depth;
- *Ultra-Marginal Royalty Reduction Program* providing additional royalty breaks for low productivity shallow natural gas wells with a true vertical depth of less than 2,300 metres, average monthly production under 60,000 m³ during the first 12 production months and average daily production less than 11.5 m³ (development wells) or 17 m³ (exploratory wildcat wells) for every 100 metres of marginal well depth;
- *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 event on either Crown or freehold land and completed in a new pool discovery 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 m³ of production, whichever comes first.

On March 2, 2009, the Government of British Columbia announced the 2009 Infrastructure Royalty Credit Program (the "**Infrastructure Royalty Credit Program**") which allocates \$120 million in royalty credits for oil and gas companies. The Infrastructure Royalty Credit Program provides royalty credits for up to 50% of the cost of certain approved road construction or pipeline infrastructure projects intended to improve, or make possible, the access to new and underdeveloped oil and gas areas. The Government of British Columbia has recently announced the same level of funding for the 2010 Infrastructure Royalty Credit Program.

On August 6, 2009, the Government of British Columbia announced an oil and gas stimulus package designed to attract investment in and create economic benefits for British Columbia. The stimulus package includes four royalty initiatives related primarily to natural gas drilling and infrastructure development. Natural gas wells spudded within the 10-month period from September 1, 2009 to June 30, 2010 and brought on production by December 31, 2010 qualify for a 2% royalty rate for the first 12 months of production, beginning from the first month of production for the well (the "**Royalty Relief Program**"). British Columbia's existing Deep Royalty Credit Program was permanently amended for wells spudded after August 31, 2009 by increasing the royalty deduction on deep drilling for natural gas by 15% and extending the program to include horizontal wells drilled to depths of between 1,900 and 2,300 metres. Wells spud between September 1, 2009 and June 30, 2010 may qualify for both the Royalty Relief Program and the Deep Royalty Credit Program but will only receive the benefits of one program at a time. An additional \$50 million was also allocated to be distributed through the Infrastructure Royalty Credit Program to stimulate investment in oilfield-related road and pipeline construction.

Land Tenure

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

Each of the provinces of Alberta, British Columbia, Saskatchewan and Manitoba 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.

In Alberta, the NRF includes a policy of "shallow rights reversion" which provides, for the first time in western Canada, 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. Holders of leases or licences that have been continued indefinitely prior to January 1, 2009 will receive a notice regarding the reversion of the shallow rights, which will be implemented three years from the date of the notice. The order in which these agreements will receive the reversion notice will depend on their vintage and location, with the older leases and licenses receiving reversion notices first beginning in January 2011. Leases and licences that were granted prior to January 1, 2009 but continued after that date will not be subject to shallow rights reversion until they reach the end of their primary term and are continued

(at which time deep rights reversion will be applied); thereafter, the holders of such agreements will be served with shallow rights reversion notices based on vintage and location similar to leases and licences that were already continued as of January 1, 2009.

Environmental Regulation

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

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 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. The *Alberta Land Stewardship Act* (the "**ALSA**") was proclaimed in force in Alberta on October 1, 2009, providing the legislative authority for the Government of Alberta to implement the policies contained in the ALUF. Regional plans established pursuant to the ALSA are deemed to be legislative instruments equivalent to regulations and are 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, approvals and authorizations in order 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. Although no regional plans have been established under the ALSA, the planning process is underway for the Lower Athabasca Region (which contains the majority of oil sands development) and the South Saskatchewan Region. While the potential impact of the regional plans established under the ALSA cannot yet be determined, it is clear that such regional plans may have a significant impact on land use in Alberta and may affect the oil and gas industry.

Climate Change Regulation

Federal

In December 2002, the Government of Canada ratified the Kyoto Protocol ("**Kyoto Protocol**"), which requires a reduction in greenhouse gas emissions by signatory countries between 2008 and 2012. The Kyoto Protocol officially came into force on February 16, 2005 and commits Canada to reduce its greenhouse gas emissions levels to 6% below 1990 "business-as-usual" levels by 2012.

In anticipation of the expiry of the Kyoto Protocol in 2012, government leaders and representatives from approximately 170 countries met in Copenhagen, Denmark from December 6 to 18, 2009 (the "**Copenhagen Conference**") to attempt to negotiate a successor to the Kyoto Protocol. The primary result of the Copenhagen Conference was the Copenhagen Accord, which represents a broad political consensus rather than a binding international treaty like the Kyoto Protocol and has not been endorsed by all participating countries. The Copenhagen Accord reinforces the commitment to reducing GHG emissions contained in the Kyoto Protocol and promises funding to help developing countries mitigate and adapt to climate change. Although certain countries, including Canada, have committed to reducing their emissions individually or jointly by at least 80% by 2050, the Copenhagen Accord does not establish binding GHG emissions reduction targets. The Copenhagen Accord calls for a review and implementation of its stated goals by 2016.

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

On February 14, 2007, the House of Commons passed Bill C-288, *An Act to ensure Canada meets its global climate change obligations under the Kyoto Protocol*. The resulting *Kyoto Protocol Implementation Act* came into force on June 22, 2007. Its stated

purpose is to "ensure that Canada takes effective and timely action to meet its obligations under the Kyoto Protocol and help address the problem of global climate change." It requires the federal Minister of the Environment to, among other things, produce an annual climate change plan detailing the measures to be taken to ensure Canada meets its obligations under the Kyoto Protocol. It also authorizes the establishment of regulations respecting matters such as emissions limits, monitoring, trading and enforcement.

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

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

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

Given the large number of small facilities within the upstream oil and gas and natural gas pipeline sectors, facilities within these sectors will only be subject to emissions intensity targets if they meet certain minimum emissions thresholds. That threshold will be (i) 50,000 tonnes of CO₂ equivalents per facility per year for natural gas pipelines; (ii) 3,000 tonnes of CO₂ equivalents per facility per year for the upstream oil and gas facility; and (iii) 10,000 boe/d/company. These regulatory thresholds are significantly lower than the regulatory threshold in force in Alberta, discussed below. In all other sectors governed by the Updated Action Plan, all facilities will be subject to regulation.

Four separate compliance mechanisms are provided for in the Updated Action Plan in respect of the above targets: Technology Fund contributions, offset credits, clean development credits and credits for early action. Regulated entities will be able to use Technology Fund contributions to meet their emissions intensity targets. The contribution rate for Technology Fund contributions will increase over time, beginning at \$15 tonnes per CO₂ equivalent for the 2010-12 period, rising to \$20 in 2013, and thereafter increasing at the nominal rate of GDP growth. Maximum contribution limits will also decline from 70% in 2010 to 0% in 2018. Monies raised through contributions to the Technology Fund will be used to invest in technology to reduce greenhouse gas emissions. Alternatively, regulated entities may be able to receive credits for investing in large-scale and transformative projects at the same contribution rate and under similar requirements as described above.

The offset system is intended to encourage emissions reductions from activities outside of the regulated sphere, allowing non-regulated entities to participate in and benefit from emissions reduction activities. In order to generate offset credits, project proponents must propose and receive approval for emissions reduction activities that will be verified before offset credits will be

issued to the project proponent. Those credits can then be sold to regulated entities for use in compliance or non-regulated purchasers that wish to either purchase the offset credits for cancellation or banking for future use or sale.

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

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

Alberta

Alberta enacted the *Climate Change and Emissions Management Act* (the "**CCEMA**") on July 1, 2007, amending it 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 similar to the Updated Action Plan and aims for a 50% reduction from 1990 emissions relative to GDP by 2020.

Alberta facilities emitting more than 100,000 tonnes of greenhouse gases a year are subject to comply with the CCEMA. Similarly to the Updated Action Plan, the CCEMA and the associated *Specified Gas Emitters Regulation* make a distinction between "Existing Facilities" and "New Facilities". Existing Facilities are defined as facilities that completed their first year of commercial operation prior to January 1, 2008 or that have completed 8 or more years of commercial operation. Existing Facilities were required to reduce their emissions intensity by March 31, 2008 by 12% from a baseline established by their average emissions intensity between 2003 and 2005. New Facilities are defined as facilities that completed their first year of commercial operation subsequent to December 31, 2008, have completed less than 8 years of commercial operation, or are designated as New Facilities in accordance with the *Specified Gas Emitters Regulation*. New Facilities are also required to reduce their emissions intensity by 12% but this target is based on the emissions intensity of the facility in its third year of commercial operation and does not apply during the first 3 years of operation of the New Facility. Unlike the Updated Action Plan, the CCEMA does not contain any provision for continuous annual improvements beyond the 12% emissions intensity required.

The CCEMA contains similar compliance mechanisms as the Updated Action Plan. Regulated emitters can meet their emissions intensity targets by contributing to the Climate Change and Emissions Management Fund (the "**Fund**") at a rate of \$15 per tonne of CO₂ equivalent. Unlike the Updated Action Plan, CCEMA contains no provisions for an increase to this contribution rate. Emissions credits can 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. Unlike the Updated Action Plan, the CCEMA does not contemplate a linkage to external compliance mechanisms such as the Kyoto Protocol's Clean Development Mechanism.

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 initial level of the tax was set at \$10 per tonne of CO₂ equivalent and rose to \$15 per tonne of CO₂ equivalent on July 1, 2009. It is scheduled to further increase at a rate of \$5 per tonne of CO₂ equivalent on July 1 of every year until it reaches \$30 per tonne of CO₂ equivalent on July 31, 2012. 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.

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 will come into force by regulation of the Lieutenant Governor in Council. 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 greenhouse gas emissions. It is expected that greenhouse gas emissions restrictions will be applied to facilities emitting more than 25,000 tonnes of CO₂ equivalents per year, which will be required to meet established targets through a combination of emissions allowances issued by the Government of British Columbia and the purchase of emissions offsets generated through activities that result in a reduction in greenhouse gas emissions. Although more specific details of British Columbia's cap and trade plan have not yet been finalized, on January 1, 2010, new reporting regulations came into force requiring all British Columbia

facilities emitting over 10,000 tonnes of CO₂ equivalents per year to begin reporting their emissions. Facilities reporting emissions greater than 25,000 tonnes of CO₂ equivalents per year are required to have their emissions reports verified by a third party.

Natural Gas Liquids Wholesale Brokerage Industry

The natural gas liquids wholesale brokerage industry in Canada is mature. Products compete with other energy sources such as natural gas, fuel oil, electricity and wood for traditional uses, and gasoline and other alternative fuels for transportation uses. In Canada, the cheapest source of heating fuel is predominately natural gas. Where natural gas is available, other products like propane can be used as a portable fuel and as a standby fuel for peak period requirements for industrial applications. In areas where natural gas is not available, propane is an alternative due to its portability. Natural gas products are generally less expensive than electricity but more expensive than fuel oil on a heat content basis depending upon regional market conditions. However, the cleanliness, versatility, and operating efficiencies of natural gas products make them competitive with fuel oil for heating purposes. Additionally, with a high level of environmental concerns alternative fuels such as ethanol, natural gasoline and bio-diesel are making inroads into the market offering both risk and opportunity.

The propane market has seen several market shifts in terms of mid stream competition, retailer consolidation, increased railroad costs and increased storage costs. Butane is different from propane in that there are many different grades and hence the knowledge of these specifications is essential in maintaining a competitive advantage. Natural gasoline has seen explosive tank car growth with the introduction of natural gasoline as both a denaturant to ethanol producers and as a diluent for the Alberta Oil Sands, however there are logistical and specification challenges in this market.

Ethanol output reached a peak around 2000 and there was considerable optimism in the agricultural community regarding future demand for ethanol. Low corn prices and relatively high gasoline prices combined to provide a strongly positive environment for the ethanol industry. However, the reverse occurred in the late 90s and in the past year where there are corn supply issues and lower gasoline prices, which put pressure on ethanol manufacturers' margins. The industry can contract and plants can potentially shut down. The United States ethanol industry is closely tied to federal government policies. An exemption from the federal gasoline excise tax allows ethanol to be cost-competitive in fuel markets. Other government policies also promote ethanol demand. In the early 90s in Canada, the government made the decision to grant an excise tax exemption for ethanol used in blended fuels. In addition, tax exemptions for alternative fuels are provided by several provincial governments. Because of these policies and growing consumer demand for environmentally superior fuels, sales of ethanol-blended gasoline have grown rapidly in Canada although the Canadian industry remains much smaller than the United States industry.

Real Estate

Over the past few years, the income trust and the real estate sector have performed quite well collectively as they have utilized their competitive edge structurally to meet the strong demand by yield oriented investors. The Trust's tax advantaged regular distributions have compared very favourably in such a low interest rate environment to traditional fixed income instruments and in other sectors of the equity markets that, until 2003, had performed relatively poorly. Additionally, the low interest environment has also been favourable to REIT's from a mortgage perspective, as debt servicing remains at an attractive level. The demand for trust units has led to unit price appreciation that has enhanced investors' returns. Non-dividend paying real estate operating companies have not appeared to compete with the trusts for investors' capital such that the market has, and will likely continue to, discount real estate companies compared to real estate trusts. Unlike fixed-income securities, however, income trusts do not have a fixed obligation to make payments to investors. Such entities have the ability to reduce or suspend distributions if circumstances warrant.

RISK FACTORS

The following is a summary of certain risk factors relating to the business of the Trust. The following information is a summary only of certain risk factors and is qualified in its entirety by reference to, and must be read in conjunction with, the detailed information appearing elsewhere in this document. Unitholders and potential Unitholders should consider carefully the information contained herein and, in particular, the following risk factors and the discussion under "*Avenir Diversified Income Trust and Related Entities – Recent Tax Developments*". **Investors should carefully consider the risk factors set out below and consider all other information contained herein and in the Trust's other public filings before making an investment decision.**

General

The Trust is a limited purpose trust, which will be entirely dependent upon the operations and assets of the Operating Trust, the Manager, Avenir Financial, Avenir Real Estate and Avenir Financial Limited Partnership, as well as the underlying assets of all such

entities. The Trust's income will be received, directly or indirectly, from (i) the production of oil and natural gas from Canadian resource properties and will be susceptible to the risks and uncertainties associated with the oil and natural gas industry generally, (ii) revenues generated from the Elbow River Marketing Limited Partnership (Financial Services Division), and (iii) revenues generated from real estate interests acquired by the Trust.

Capital Markets

As a result of the weakened global economic situation, the Trust along with all participants in the junior oil and gas industry, will have restricted access to capital and increased borrowing costs. The lending capacity of all financial institutions has diminished and risk premiums have increased independent of the Trust's businesses and asset base. As future capital expenditures will be financed out of cash generated from operations, borrowings and possible future equity sales, the Trust's ability to do so is dependent on, among other factors, the overall state of capital markets and investor demand for investments in the energy industry and the Trust's securities in particular.

Global Financial Crisis

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

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

Nature of Trust Units

Each Trust Unit represents an equal undivided beneficial interest in the Trust. The Trust Units do not represent debt instruments and there is no principal amount owing to Unitholders under the Trust Units. The Trust Units do not represent shares in the Trust, Manager, its affiliates or any other company.

The Trust Units are not "deposits" within the meaning of the *Canada Deposit Insurance Corporations Act* (Canada) and are not insured under the provisions of that Act or any other legislation. Furthermore, the Trust is not a trust company and, accordingly, is not registered under any trust and loan company legislation as it does not carry on or intend to carry on the business of a trust company.

Dependence on Management

Unitholders must rely upon the experience and expertise of the management of the Manager. The Trust's continued success is dependent upon its ability to attract and retain experienced management. Although employment agreements are being finalized, the Manager does not have in place employment agreements or key man insurance on its management.

The existing directors and officers of the Manager are involved with a number of other ventures, and, accordingly, will only devote a portion of their time to the business and affairs of the Manager.

Cash Distributions Are Not Guaranteed

Cash distributions are not guaranteed and will fluctuate with the performance of the Partnerships and its subsidiaries. The Board of Directors has the discretion to determine the amount of cash distributions to be paid to Unitholders each month. In determining the level of cash distributions, the Board of Directors will take into consideration current and expected future levels of earnings, operating cash flow, income taxes, maintenance capital, growth capital expenditures, debt repayments, working capital requirements and other factors.

Conflicts of Interest

The directors of the Manager are engaged and will continue to be engaged in the search for oil and gas interests and other businesses on their own behalf and on behalf of other companies, and situations may arise where the directors and officers may be in direct competition with the Manager. Conflicts of interest, if any, which arise will be subject to and governed by the procedures prescribed by the ABCA, which require a director or 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 Manager to disclose his 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.

Possible Failure to Realize Anticipated Benefits of Acquisitions

The Trust makes acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner as well as the Trust's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Trust. The integration of acquired business may require substantial management effort, time and resources and may divert management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of services provided and assets required to provide such services. In this regard, non core assets are periodically disposed of, so that the Trust 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 Trust, if disposed of, could be expected to realize less than their carrying value on the financial statements of the Trust.

Remedies In the Event of Restructuring and Third Party Claims

The Trust is not a legally recognized entity within the relevant definitions of the *Bankruptcy and Insolvency Act* (Canada), and the *Companies' Creditors Arrangement Act* (Canada) or in some cases, the *Winding Up and Restructuring Act* (Canada) and, therefore, would not be able to access the remedies available thereunder in the event that a restructuring is necessary. As a result, Unitholders may not avail themselves of the remedies typically available to a shareholder of a corporate entity. As a result, Distributable Cash otherwise payable may be subordinate to third party debt such as mortgages, bank facilities and other borrowing arrangements.

Redemption of Units

It is anticipated that the redemption right associated with Trust Units will not be the primary mechanism for holders of Trust Units to dispose of their Trust Units. Notes, which may be distributed *in specie* to Unitholders in connection with redemption, will not be listed on any stock exchange and no market is expected to develop in such Notes. Notes will not be qualified investments for trusts governed by registered retirement savings plans, registered retirement income funds or deferred profit sharing plans.

Federal Tax Changes

On October 31, 2006 the Federal Minister of Finance proposed to apply a tax at the trust level on distributions of certain income from publicly traded mutual fund trusts at rates of tax comparable to the combined federal and provincial corporate tax and to treat such distributions as dividends to the unitholders (the "**SIFT Tax**"). On December 21, 2006 the Federal Minister of Finance released draft legislation to implement the SIFT Tax pursuant to which, commencing January 1, 2011 (provided the Trust only experiences "normal growth" and no "undue expansion" before then) certain distributions from us which would have otherwise been taxed as ordinary income generally will be characterized as dividends in addition to being subject to tax at corporate rates at the Trust level. On June 22, 2007, the legislation received Royal assent. The implementation of the SIFT Tax is expected to result in adverse tax consequences to us and certain Unitholders (including most particularly Unitholders that are tax deferred or non-residents of Canada) and may impact the level of cash distributions from us.

Management believes that the SIFT Tax has reduced, and may further reduce, the value of the Trust Units, which would be expected to increase the cost to the Trust of raising capital in the public capital markets. In addition, management believes that the SIFT Tax: (a) has substantially eliminated any competitive advantage that the Trust and other Canadian energy trusts have enjoyed relative to their corporate peers in raising capital in a tax-efficient manner; and (b) may place the Trust and other Canadian energy trusts at a competitive disadvantage relative to industry competitors, including U.S. master limited partnerships, which will continue to not be subject to entity level taxation. The SIFT Tax may also make the Trust Units less attractive as an acquisition currency. As a result, it may become more difficult for us to compete effectively for acquisition opportunities.

Further, the SIFT Tax provides that, while there is no intention to prevent "normal growth" during the transitional period, any "undue expansion" would result in the transition period being terminated with the loss of the benefit to us of that transitional period. As a result, the adverse tax consequences resulting from the SIFT Tax could be borne sooner than January 1, 2011. On December 15, 2006, the Department of Finance issued guidelines with respect to what is meant by "normal growth" in this context (the "**Guidelines**"). Specifically, the Department of Finance stated that "normal growth" would include equity growth within certain "safe harbour" limits, measured by reference to a "specified investment flow-through's" ("**SIFT**") market capitalization as of the end of trading on October 31, 2006 (which would include only the market value of the SIFT's issued and outstanding publicly-traded trust units, and not any convertible debt, options or other interests convertible into or exchangeable for trust units). Those safe harbour limits are 40% for the period from November 1, 2006 to December 31, 2007, and 20% each for calendar 2008, 2009 and 2010. Moreover, these limits are cumulative, so that any unused limit for a period carries over into the subsequent period. Additional details of the Department of Finance's guidelines include the following:

- (a) new equity for these purposes includes units and debt that is convertible into units (and may include other substitutes for equity if attempts are made to develop those);
- (b) replacing debt that was outstanding as of October 31, 2006 with new equity, whether by a conversion into trust units of convertible debentures or otherwise, will not be considered growth for these purposes and will therefore not affect the safe harbour; and
- (c) the exchange, for trust units, of exchangeable partnership units or exchangeable shares that were outstanding on October 31, 2006 will not be considered growth for those purposes and will therefore not affect the safe harbour where the issuance of the trust units is made in satisfaction of the exercise of the exchange right by a person other than the SIFT.

On December 4, 2008, the Federal Minister of Finance announced changes to the Guidelines to allow a SIFT to accelerate the utilization of the SIFT annual safe harbour amount for each of 2009 and 2010 so that the safe harbour amounts for 2009 and 2010 are available on and after December 4, 2008. This change does not alter the maximum permitted expansion threshold for a SIFT, but it allows a SIFT to use its normal growth room remaining as of December 4, 2008 in a single year, rather than staging a portion of the normal growth room over the 2009 and 2010 years.

The Trust's market capitalization as of the close of trading on October 31, 2006, having regard only to its issued and outstanding publicly-traded Trust Units, was approximately \$413.6 million, which means the "safe harbour" equity growth amount for the period ending December 31, 2009 was approximately \$294.8 million, and for each of calendar 2009 and 2010 is an additional approximately \$83 million (in any case, not including equity, including convertible debentures, issued to replace debt that was outstanding on October 31, 2006).

While the Guidelines are not expected to affect our ability to raise the capital required to maintain and grow our existing operations in the ordinary course during the transition period, they could adversely affect the cost of raising capital and our ability to undertake more significant acquisitions.

Currently, the SIFT Tax rules provide that the SIFT Tax rate will be the federal general corporate income tax rate (which is anticipated to be 16.5 percent in 2011 and 15 percent in 2012) plus the provincial SIFT tax rate.

The provincial SIFT tax rate is based on the general provincial corporate income tax rate in each province in which the Trust has a permanent establishment. For purposes of calculating this component of the tax, the general corporate taxable income allocation formula will be used. Specifically, once the Trust is subject to the SIFT Tax, the Trust's taxable distributions, if any, will be allocated to provinces by taking half of the aggregate of:

- that proportion of the Trust's taxable distributions, if any, for the year that the Trust's wages and salaries in the province are of its total wages and salaries in Canada; and
- that proportion of the Trust's taxable distributions, if any, for the year that the Trust's gross revenues in the province are of its total gross revenues in Canada.

It is anticipated that the Trust would be considered to have a permanent establishment only in Alberta, where the provincial tax rate in 2011 is expected to be 10%, which will result in a combined federal and provincial corporate tax rate of 26.5% in 2011. Taxable

distributions, if any, that are not allocated to any province would instead be subject to a 10% rate constituting the provincial component.

Although the SIFT Tax is not expected to affect the Trust until 2011, the Trust could become subject to the trust-level tax sooner if it experiences growth other than "normal growth" before then.

The long term effect of the SIFT Tax on us cannot be determined at this time, but may be materially adverse to us and some or all of our Unitholders. There can be no assurance that we will be able to generate sufficient tax pools and/or reorganize our legal and tax structure in order to mitigate, in whole or in part, the expected impact of the SIFT Tax.

Changes in Tax and Other Laws may Adversely Affect Unitholders

Income tax laws, or other laws or government incentive programs relating to the oil and gas industry, such as the treatment of mutual fund trusts and resource allowance, may in the future be changed or interpreted in a manner that adversely affects us and our Unitholders.

Additionally, legislation may be implemented to limit the investment in income funds and royalty trusts by certain investors or to change the manner in which these entities are taxed. Tax authorities having jurisdiction over us or our Unitholders may disagree with how we calculate our income for tax purposes or could change administrative practices to our detriment or the detriment of our Unitholders.

Mutual Fund Trust Status

So long as the Trust continues to operate in trust form, we intend to continue to qualify as a mutual fund trust for purposes of the Tax Act. We may not, however, always be able to satisfy any future requirements for the maintenance of mutual fund trust status. Should status as a mutual fund trust be lost or successfully challenged by a relevant tax authority, certain adverse consequences may arise for Unitholders. Some of the significant consequences of losing mutual fund trust status are as follows:

- The Trust would be taxed on certain types of income distributed to Unitholders, including income generated by the royalties held by us. Payment of this tax may have adverse consequences for some Unitholders, particularly Unitholders that are not residents of Canada and residents of Canada that are otherwise exempt from Canadian income tax.
- The Trust would cease to be eligible for the capital gains refund mechanism available under Canadian tax laws.
- Trust Units held by Unitholders that are not residents of Canada would become taxable Canadian property. These non-resident holders would be subject to Canadian income tax on any gains realized on a disposition of Trust Units held by them.
- Trust Units would cease to be a qualified investment for trusts governed by registered retirement savings plans ("RRSPs"), registered education savings plans ("RESPs"), deferred profit sharing plans ("DPSPs"), registered disability savings plan ("RDSPs"), registered retirement income funds ("RRIFs") and tax free savings accounts ("TFSAs"). Where, at the end of a month, a RRSP, DPSP, RESP or RRIF holds Trust Units that cease to be a qualified investment, the plan must, in respect of that month, pay a tax equal to 1% of the fair market value of the Trust Units at the time such Trust Units were acquired by the plan. Trusts governed by RRSPs, RDSPs, TSFAs or RRIFs which hold Trust Units that are not qualified investments will be subject to tax on the income attributable to the Trust Units while they are not qualified investments, including the full capital gains, if any, realized on the disposition of such Trust Units. Where a trust governed by a RRSP or a RRIF acquires Trust Units that are not qualified investments, the value of the investment is included in the income of the annuitant for the year of the acquisition. Trusts governed by RESPs which hold Trust Units that are not qualified investments can have their registration revoked by the CRA. The holder of a RDSP or TSFA which holds Trust Units that are not qualified investments will be subject to tax equal to 50% of the fair market value of the Trust Units.

In addition, the Trust may take certain measures in the future to the extent we believe necessary to ensure that we maintain the status as a mutual fund trust. These measures could be adverse to certain holders of Trust Units, particularly non-residents of Canada as defined in the Tax Act. See "*Risk Factors – Non-Resident Ownership of Trust Units*".

Unitholder Limited Liability

On July 11, 2004, the *Income Trusts Liability Act* (Alberta) (the "**ITLA**") came into force. The ITLA protects unitholders of Alberta income trusts, such as the Trust, from legal uncertainties regarding potential liability by providing a statutory limitation on unitholders' liability. Specifically, the ITLA provides that a unitholder will not be, as a beneficiary, liable for any act, default, obligation or liability of the trustee that arises after the ITLA comes into force. The ITLA has not been subject to interpretation by courts in the Province of Alberta or elsewhere.

The Trust Indenture provides that no Unitholder, in its capacity as such, shall incur any liability, direct or indirect, absolute or contingent in contract or in tort or of any other kind whatsoever to any person in connection with the "Trust Fund" (as defined in the Trust Indenture) or the ownership, use, operation, acquisition or disposition thereof or exercise or enjoyment of the rights, privileges, conditions or benefits attached thereto, associated therewith or derived therefrom or the obligations or the activities or the affairs of the Trust or with respect to any act performed by the Trustee or by any other person pursuant to the Trust Indenture or with respect to any act or omission of the Trustee or any other person in respect of the activities or affairs of the Trust (whether or not authorized by or pursuant to the Trust Indenture) or with respect to any act or omission of the Trustee or any other person in the performance or exercise, or purported performance or exercise, of any obligation, power, discretion or authority conferred upon the Trustee or such other person in respect of the activities or affairs of the Trust (whether or not authorized by or pursuant to the Trust Indenture) or with respect to any transaction entered into by the Trustee or by any other person or for any taxes, levies, imposts or charges or fines, penalties or interest in respect thereof payable by the Trust or by the Trustee or by any other person on behalf of or in connection with the activities or affairs of the Trust. The Trust Indenture also provides that no Unitholder shall be liable to indemnify the Trustee or any such other person with respect to any such liability or liabilities incurred by the Trustee or by any such other person or persons or with respect to any taxes payable by the Trust or by the Trustee or by any other person on behalf of or in connection with the Trust. Notwithstanding the foregoing, to the extent that any Unitholders are found by a court of competent jurisdiction to be subject to any such liability, such liability shall be enforceable only against, and shall be satisfied only out of, the Trust Fund and the Trust (to the extent of the Trust Fund) is liable to, and shall indemnify and save harmless any Unitholder against any costs, damages, liabilities, expenses, charges or losses suffered by any Unitholder from or arising as a result of such Unitholder not having any such limited liability.

The Trust Indenture provides that the Trustee and the Manager shall make all reasonable efforts to include in every contract entered into by or on behalf of the Trust whether by the Trustee or the Manager, or otherwise, a provision to the effect that such obligation will not be binding upon Unitholders personally. Notwithstanding the terms of the Trust Indenture, Unitholders may not be protected from liabilities of the Trust to the same extent a shareholder is protected from the liabilities of a corporation. Personal liability may also arise in respect of claims against the Trust (to the extent that claims are not satisfied by the Trust) that do not arise under contracts, including claims in tort, claims for taxes and possibly certain other statutory liabilities. The possibility of any personal liability to Unitholders of this nature arising is considered unlikely in view of the fact that the primary activity of the Trust is to hold securities, and all of the business operations currently carried on by the Trust are carried on by the Manager, directly or indirectly.

The activities of the Trust and its direct and indirect wholly-owned subsidiaries, including the Commercial Trust and, the Manager, will be conducted, upon the advice of counsel, in such a way and in such jurisdictions as to avoid as far as possible any material risk of liability to the Unitholders for claims against the Trust including by obtaining appropriate insurance, where available, for the operations of the Trust's direct and indirect subsidiaries and having contracts signed by or on behalf of the Trust include a provision that such obligations are not binding upon Unitholders personally.

Investment Eligibility

We will endeavour to ensure that the Trust Units continue to be qualified investments for registered retirement savings plans, registered education savings plans, deferred profit sharing plans, registered retirement income funds, registered disability savings plans and tax-free savings accounts. The Tax Act imposes penalties for the acquisition or holding of non-qualified or ineligible investments and there is no assurance that the conditions prescribed for such qualified or eligible investments will be adhered to at any particular time.

Oil and Gas Division

Reserve Estimates

The reserve and recovery information contained in the reserve reports summarized in this document are only estimates and the actual production and ultimate reserves from the properties may be greater or less than the estimates prepared by such reports. In addition,

probable reserves estimate for properties may require revision based on the actual development strategies employed to prove such reserves. Estimated reserves may also be affected by changes in oil and natural gas prices. Declines in the reserves of the Trust, which are not offset by the acquisition or development of additional reserves, may reduce the underlying value of Trust Units to Unitholders.

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 Trust depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, any existing reserves the Trust may have at any particular time, and the production therefrom will decline over time as such existing reserves are exploited. A future increase in the Trust's reserves will depend not only on its ability to explore and develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. No assurance can be given that the Trust will be able to continue to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, management of the Trust may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by the Trust.

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

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, cratering, sour gas releases and spills, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or personal injury. In particular, the Trust 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 Trust. In accordance with industry practice, the Trust is not fully insured against all of these risks, nor are all such risks insurable. Although the Trust maintains liability insurance in an amount that it considers consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits, in which event the Trust could incur significant costs. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks may have a material adverse effect on the Trust's business, financial condition, results of operations and prospects.

Prices, Markets and Marketing

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

The prices of oil and natural gas prices may be volatile and subject to fluctuation. Any material decline in prices could result in a reduction of the Trust's net production revenue. The economics of producing from some wells may change as a result of lower prices, which could result in reduced production of oil or gas and a reduction in the volumes of the Trust's reserves. The Trust might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in the Trust's expected net production revenue and a reduction in its oil and gas acquisition, development and exploration activities. Prices for oil and gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond the control of the Trust. These factors include economic conditions, in the United States and Canada, the actions of OPEC, governmental regulation, political stability in the Middle East and elsewhere, the foreign supply of

oil and gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Any substantial and extended decline in the price of oil and gas would have an adverse effect on the Trust's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on the Trust's business, financial condition, results of operations and prospects.

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

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

Dependence on Operators

The principal source of income of the Trust is generated by the production and sale of petroleum products. Such production and sale is dependent in part on the managerial ability of the operator of a program. Where the Trust is dependent on the operator of programs, in some cases it may be unable to direct such operators. In such cases, it will review all proposed drilling prospects prior to advancing funds. To the extent that an operator does not appropriately perform its obligations, the income of the Trust could be significantly reduced. Payments from production generally flow through the operator and there is a risk of delay and additional expense in receiving such revenues if the operator becomes insolvent. The amount of, and time of, cash distributions may be delayed as a result of delays in the Trust receiving payment of revenue from resource companies. As well, resource companies may fail to comply with the provisions of the applicable participation agreements; however, it has been the experience of management of the Trust that none of the resource companies which have entered into participation agreements with affiliated entities have breached the provisions thereof.

Depletion of Reserves

To the extent we distribute income to our Unitholders, we will not be reinvesting cash flow in the same manner as other industry participants as we conduct only minimal exploratory activities. Accordingly, absent capital injections, our initial production levels and reserves will decline and the level of income available for distributions will be reduced.

Our future oil and natural gas reserves and production, and therefore our cash flows, will be highly dependent on our success in exploiting our reserve base and acquiring additional reserves. Without reserve additions through acquisition or development activities, our reserves and production will decline over time as reserves are exploited.

To the extent that external sources of capital, including the issuance of additional Trust Units become limited or unavailable, our ability to make the necessary capital investments to maintain or expand our oil and natural gas reserves will be impaired. To the extent that we are required to use cash flow to finance capital expenditures or property acquisitions, the level of income available for distributions will be reduced.

There can be no assurance that we will be successful in developing or acquiring additional reserves on terms that meet our investment objectives.

Kyoto Protocol

Canada is a signatory to the United Nations Framework Convention on Climate Change and has ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nationwide emissions of carbon dioxide, methane, nitrous oxide and other so-called "greenhouse gases". The Trust's exploration and production facilities and other operations and activities emit greenhouse gases which will require the Trust to comply with the new regulatory framework announced on March 10, 2008 by the Federal Government which is intended to force large industries to reduce emissions of greenhouse gases, in addition to the proposed *Clean Air Act* (Canada) of 2006 and Alberta's recently enacted *Climate Change and Emissions Management Act* and *Specified Gas Emitters Regulation*. The direct or indirect costs of these regulations may have a material adverse effect on the Trust's business, financial condition, results of operations and prospects. See "*Industry Conditions – Environmental Regulation*".

Environmental

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Trust to incur costs to remedy such discharge. Although the Trust believes that it will be in material compliance with current applicable environmental regulations, no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on the Trust's business, financial condition, results of operations and prospects. See "*Industry Conditions – Environmental Regulation*".

Climate Change

Canada is a signatory to the United Nations Framework Convention on Climate Change and has ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nationwide emissions of carbon dioxide, methane, nitrous oxide and other so called "greenhouse gases". Recently, representatives from approximately 170 countries met in Copenhagen, Denmark to attempt to negotiate a successor to the Kyoto Protocol. Pursuant to the resulting Copenhagen Accord, a non-binding political consensus rather than a binding international treaty such as the Kyoto Protocol, the Government of Canada revised its emissions reduction targets slightly. There has been much public debate with respect to Canada's ability to meet these targets and the Government's strategy or alternative strategies with respect to climate change and the control of greenhouse gases. The Trust may also be required comply with the regulatory scheme for greenhouse gas emissions ultimately adopted by the federal government, which is now expected to be modified to ensure consistency with the regulatory scheme for greenhouse gas emissions adopted by the United States. The direct or indirect costs of these regulations may have a material adverse effect on the Trust's business, financial condition, results of operations and prospects. The future implementation or modification of greenhouse gases regulations, whether to meet the limits required by the Kyoto Protocol, the Copenhagen Accord or as otherwise determined, could have a material impact on the nature of oil and natural gas operations, including those of the Trust. 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 Trust and its operations and financial condition. See "*Industry Conditions – Climate Change Regulation*".

Variations in Foreign Exchange Rates and Interest Rates

World oil and gas prices are quoted in United States dollars and the price received by Canadian producers is therefore affected by the Canadian/U.S. dollar exchange rate, which will fluctuate over time. In recent years, the Canadian dollar has increased materially in value against the United States dollar. Material increases in the value of the Canadian dollar negatively impact the Trust's production revenues. Future Canadian/United States exchange rates could accordingly impact the future value of the Trust's reserves as determined by independent evaluators.

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

An increase in interest rates could result in a significant increase in the amount the Trust pays to service debt, which could negatively impact the market price of the Trust Units.

Additional Funding Requirements

The Trust's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times. From time to time, the Trust may require additional financing in order to carry out its oil and gas acquisition, exploration and development activities. Failure to obtain such financing on a timely basis could cause the Trust to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Trust's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect the Trust's ability to expend the necessary capital to replace its reserves or to maintain its production. If the Trust's cash flow from operations is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or, if available, on terms acceptable to

the Trust. Continued uncertainty in domestic and international credit markets could materially affect the Trust's ability to access sufficient capital for its capital expenditures and acquisitions, and as a result, may have a material adverse effect on the Trust's ability to execute its business strategy and on its business, financial condition, results of operations and prospects.

Hedging

From time to time the Trust may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline; however, if commodity prices increase beyond the levels set in such agreements, the Trust will not benefit from such increases and the Trust may nevertheless be obligated to pay royalties on such higher prices, even though not received by it, after giving effect to such agreements. Similarly, from time to time the Trust 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 Trust 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 Trust and may delay exploration and development activities.

Title to Assets

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 Trust and may delay exploration and development activities.

Expiration of Licences and Leases

The Trust's properties are held in the form of licences and leases and working interests in licences and leases. If the Trust 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 Trust's licences or leases or the working interests relating to a licence or lease may have a material adverse effect on the Trust's business, financial condition, results of operations and prospects.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights to portions of western Canada. The Trust 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 Trust's business, financial condition, results of operations and prospects.

Seasonality

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

Third Party Credit Risk

The Trust 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 Trust, such failures may have a material adverse effect on the Trust's business, financial condition,

results of operations and prospects. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in the Trust's ongoing capital program, potentially delaying the program and the results of such program until the Trust finds a suitable alternative partner.

Additional Financing

To the extent that external sources of capital, including the issuance of additional Trust Units, become limited or unavailable, the Trust's ability to make the necessary capital investments to maintain or expand its oil and gas reserves will be impaired.

Competition

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

Elbow River Marketing Limited Partnership

General

Energy marketing operations expose the Trust to the risk of trading losses and liquidity constraints. The Trust tries to mitigate the trading risk through hedging transactions.

NGL Products

Historically, overall demand from non-automotive end-use applications has been stable. However, weather conditions and general economic conditions affect market volumes. Weather influences the demand for product primarily for heating uses. Inventory is accumulated during the summer months for delivery to customers during the winter heating season. The cost of inventory may be higher or lower than market prices at the time of sale and can impact profitability. Over the long term, business will depend, in part, on the level of demand for NGLs and natural gas in the geographic areas in which deliveries are made by pipelines and the ability and willingness of shippers having access or rights to utilize the pipelines to supply such demand. The Trust cannot predict the impact of future economic conditions, fuel conservation measures, alternative fuel requirements, governmental regulation or technological advances in fuel economy and energy generation devices, all of which could reduce the demand for natural gas and NGLs.

BioFuels

In November of 2008 Elbow River made the decision to exit from marketing bio-diesel due to the higher risk/reward nature of the business which was not inline with the Trust's business model. The global financial crisis and changing international government regulations added further counterparty risk. Elbow River formally exited from all bio-diesel operations in Q1 of 2009.

As announced in the press release dated March 9, 2009, Elbow River advised of a significant increase in the provision for uncollectable accounts. Elbow River had been advised by one of its joint venture parties that the party's bank and equity holder had demanded payment from the party and were claiming 100% of the proceeds earned under the "Memorandum of Understanding" not just the party's proportionate share. To that end, Elbow River had to take a provision of \$35.7 million for bad debts in its December 31, 2008 financial statements to cover bio-diesel uncollectable accounts. In response to the joint venture parties, Elbow River filed an injunction to freeze the funds and a lawsuit against the parties in efforts to recover the funds. Although the court denied Elbow River's emergency motion for a preliminary injunction to freeze certain funds, the court has not made a determination of the merits of Elbow River's claim to the monies at issue. Elbow's lawsuit remains on course to proceed to trial on the merits, and Elbow River continues to pursue its legal rights with respect to these monies, including vigorously prosecuting the lawsuit.

Reliance on Principal Customers and Operators

The Trust relies on several significant customers to carry on business within its Elbow River marketing business. If for any reason these parties are unable to perform their obligations under the various agreements with Elbow River, the revenue and distributions of the Trust, and the operations of the business could be negatively impacted.

Third Party Credit Risk

The Trust may be exposed to third party credit risk through its contractual arrangements with its current or future partners. In the event such entities fail to meet their contractual obligations to the Trust, such failures may have a material adverse effect on the Trust's business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry and of joint venture partners may impact a partner's willingness to participate and potentially delay results until the Trust finds a suitable alternative partner.

Hedging

Elbow uses hedging transaction in order to mitigate the risk associated with its marketing transactions. In many circumstances, purchase and sale contracts are not perfectly matched as they are entered into at different times and at different values. In both Elbow's NGL and biofuels businesses, margins can vary significantly from period to period and volatility in the markets for these products may cause distortions in financial results from period to period that are not replicable. There is no guarantee that hedging and other efforts to manage the marketing and inventory risks will generate profits or mitigate all the market and inventory risk associated with these activities. As well, by Elbow hedging its commodity price exposure, it may forego the benefits that may otherwise be experienced if commodity prices were to increase by decreasing its available credit lines.

Variations in Foreign Exchange Rates

Elbow takes on foreign exchange risk with respect to its purchase and sale of commodities and with respect to its U.S. investment. Commodity prices are often quoted in U.S. dollars and the price paid and received by it for these commodities is therefore affected by the Canadian – U.S. exchange rate which may fluctuate over time and such fluctuations could have an adverse effect on Elbow's financial condition with respect to its net income and cash flow. Elbow tries to mitigate part of this risk through hedging transactions.

To the extent that the Trust engages in risk management activities related to foreign exchange rates, there remains a credit risk associated with counterparties with which the Trust partners or contracts to.

Foreign Operations

Elbow is actively involved in U.S. NGL markets and makes a significant percentage of its sales into U.S. markets and also purchases a significant amount of NGLs in U.S. markets. Elbow's significant reliance on these markets means that it is subject to downturns in the U.S. economy, weather patterns in the U.S., protectionist actions by U.S. legislators and other political developments, all of which could have an adverse impact on Keyera's financial results.

Access to Credit/Capital

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions, have caused significant instability for businesses like Elbow River as there is a dependence on credit and access to capital. As a result the Trust may have restricted access to capital, bank debt and equity, and is likely to face increased borrowing costs. Significant changes in the commodities and financial markets could require us to provide additional liquidity if additional collateral is required to be placed with counterparties, or reduce some of our activities. The lending capacity of all financial institutions has diminished and risk premiums have increased. To the extent that external sources of capital become limited or unavailable or available on onerous terms, the Trust's ability to make capital investments, maintain existing assets and pay distributions may be impaired, and its assets, liabilities, business, financial condition and results of operations may be materially and adversely affected as a result. Based on current working capital, expected funds generated from operations, and the credit facilities in place, the Trust believes it has sufficient funds available to carry on its business as planned. However, if funds generated from operations are lower than expected or if the Trust incurs major unanticipated expenses related to development or maintenance of its existing business, or that the credit facility can not be redefined on terms acceptable to Elbow or the lenders, it may

be required to seek additional capital or credit to maintain planned levels. Failure to obtain this capital/credit may result in the deterioration in value of the business.

Seasonality

The level of activity in the natural gas liquids brokerage business is influenced by seasonal weather patterns of the industry. Inventory is accumulated during the summer months for delivery to customers during the winter heating season. The fourth quarters and first quarters are typically higher volume months with the second and third quarters lower volume/revenue quarters.

Real Estate Division

Value of Real Property

The value of a real property and any improvements thereto may depend on the credit and financial stability of the tenants. Avenir Real Estate's projected income would be adversely affected if a significant number of tenants were to be unable to meet their obligations to Avenir Real Estate or if Avenir Real Estate were unable to continue to lease a significant amount of available space in its properties on economically favourable lease terms. In the event of default by a tenant, Avenir Real Estate may experience delays in enforcing its rights as lessor and may incur substantial costs in protecting its investment. Avenir Real Estate's ability to rent unleased space in its properties is affected by many factors. Avenir Real Estate may also incur costs in making improvements or repairs to a property required by a new tenant. The failure by Avenir Real Estate to rent unleased space on a timely basis or at all would likely have an adverse affect on Avenir Real Estate's financial condition.

Speculative Nature of Income Producing Property Acquisition and Management

The acquisition and management of income producing real estate may result in a failure to produce income or revenue. Moreover, the industry is subject to significant risk factors including changes in economic conditions, competition from other properties, the failure of tenants to meet lease obligations, increases in property taxes and mortgage, maintenance, insurance and other operating costs and decreases in occupancy and rental rates.

Real Estate Industry Risks

Real estate investments are generally subject to varying degrees of risk, depending on the nature of the property. These risks include: (i) changes in general economic conditions, (ii) changes in local conditions, (iii) changes to government regulations, (iv) the attractiveness of a property to potential tenants, (v) competition from others with available space, and (vi) the ability of the landlord or owner to provide adequate maintenance economically.

Certain significant expenditures, including property taxes, maintenance costs, mortgage payments, insurance costs and related charges, must be made regardless of whether or not a property is producing sufficient income to service these expenses. The Trust's properties will be subject to mortgages, which require significant debt service payments. If the Trust is unable or unwilling to meet the mortgage payments on any of its properties, losses could be sustained as a result of the mortgagee's exercise of its rights of foreclosure or of sale. In addition, financial difficulties of other property owners, resulting in distress sales, may depress real estate values in the markets in which the Trust will operate.

Since August 2007, the subprime crisis in the United States resulted in a volatile borrowing environment in the United States and Canada to some extent, with bond yields fluctuating dramatically, and interest spreads increasing due to the lack of liquidity. For the most part, however, due to the size and diversity of the Trust's operations, management of the Trust feels the Trust is well positioned to mitigate the downward pressure and other negative effects of the subprime crisis in the United States.

Real Estate Investments Illiquidity Risk

An investment in real estate is relatively illiquid. Such illiquidity will tend to limit the ability of the Trust to vary its portfolio promptly in response to changing economic or investment conditions. In recessionary times it may be difficult to dispose of certain types of real estate. The costs of holding real estate are considerable and during an economic recession the Trust may be faced with ongoing expenditures with a declining prospect of incoming receipts. In such circumstances, it may be necessary for the Trust to dispose of properties at lower prices in order to generate sufficient cash for operations and making distributions.

Competition Risk

The Trust will compete with other investors, developers, managers and owners of properties in seeking tenants and for the purchase and development of desirable real estate properties. Some of the competitors of the Trust are newer, better located or better capitalized than the Trust. Certain of these competitors have greater financial and other resources and greater operating flexibility than the Trust. The existence of competing developers, managers and owners could have a material adverse effect on the ability of the Trust to acquire attractive properties, to lease space in its units and on the rents charged by the Trust, and could adversely affect the revenues of the Trust and its ability to meet its obligations. In addition, the commercial and industrial real estate industry in Canada is generally characterized by a high degree of competition. In addition to facing competition from existing building of a similar nature, the Trust's properties may face heightened competition from the construction of new buildings. Avenir Real Estate's limited property portfolio makes it especially vulnerable to competition.

Short-Term Debt

The Trust will need to refinance its short-term debt upon its expiry. This carries with it the potential for negative impact on Distributable Cash if such debt is replaced by new debt with less favourable terms or such debt cannot be replaced. In addition, distributions from the Trust may be restricted if the Trust fails to maintain certain covenants under the credit agreements in connection with such debt, such as a failure to maintain customary financial ratios, if such are applicable at the time.

Environmental Liability

As a real property owner, the Trust is subject to various federal and provincial environmental laws and regulations. Such laws provide that the Trust is liable for costs of removal and remediation of certain hazardous toxic substances released on or in its properties or disposed of at other locations. The failure to remove or remediate such substances, if any, could adversely affect an owner's ability to sell such real estate or to borrow using such real estate as collateral and could potentially also result in claims against the owner. The Trust is not aware of any claims involving a breach of environmental laws in relation to any of its properties.

Nature of Operations

The acquisition and management of commercial and industrial real estate involves many risks that management's experience, knowledge and careful consideration may not be able to overcome. There is no certainty that the Trust's properties will generate income.

MATERIAL CONTRACTS

The Trust currently has in place the following material contracts:

1. Trust Indenture referred to under "Avenir Diversified Income Trust";
2. NPI Agreement referred to under "Organizational Structure of the Trust";
3. Note Indenture dated January 16, 2003 with respect to the issuance of Notes of the Operating Trust;
4. Avenir National Bank of Canada credit agreement dated October 27, 2006; and
5. Elbow River Partnership HSBC Bank of Canada credit agreement dated August 31, 2006.

TRANSFER AGENT AND REGISTRAR

Olympia Trust Company at its principal office in Calgary, Alberta, and Toronto, Ontario, is the Transfer Agent and Registrar of the Trust.

AUDIT COMMITTEE INFORMATION

Audit Committee Mandate and Terms of Reference

The Mandate and Terms of Reference of the Audit Committee of the Board of Directors is attached hereto as **Schedule "C"**. The members of the Audit Committee are William Patterson (Chairman), David E. Butler and Alan C. Moon.

Composition of the Audit Committee

The members of the Audit Committee are independent (in accordance with National Instrument 52-110) and are financially literate. The following table sets out the assessment of each of Audit Committee member's independence, financial literacy and relevant educational background and experience supporting such financial literacy.

Name and Place of Residence	Independent	Financially Literate	Relevant Education and Experience
William Patterson Alberta, Canada	Yes	Yes	Mr. Patterson is a graduate of the University of Calgary with a degree in economics and political science. He received his Chartered Accountancy designation in 1973 and is currently an independent business consultant. He was Vice President of Finance and Chief Financial Officer of Energy North Inc, a Toronto listed public company from 1999 to 2004. Prior to that he was a partner with PricewaterhouseCoopers, Chartered Accountants and a predecessor firm Coopers & Lybrand, Chartered Accountants from 1989 to 1998. He was a partner with Collins Barrow, Chartered Accountants from 1981 to 1989.
David E. Butler Alberta, Canada	Yes	Yes	President of Passport Petroleum Ltd., a private oil and gas company. Mr. Butler also acts as a director for Mahalo Energy Ltd., an oil and gas exploration company listed on the TSX. As a businessman with over the 30 years of experience, Mr. Butler's experience has provided him with 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 accounting issues that can reasonably be expected to be raised by the Trust's financial statements.
Alan C. Moon Alberta, Canada	Yes	Yes	President of Crescent Enterprise Inc., a private consulting firm. As a businessman with an MBA, Mr. Moon engaged in reviewing issuers' financial statements and acquired an understanding of generally accepted accounting principles and financial statements. This experience has provided Mr. Moon with 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 accounting issues that can reasonably be expected to be raised by the Trust's financial statements.
Dennis B. Balderston Alberta, Canada	Yes	Yes	Chartered Accountant was formerly an audit partner at Ernst & Young LLP in Calgary. As an audit partner he was responsible for a portfolio of public clients, the majority in the oil and gas sector. Now retired he has served on a number of public entity Boards and is currently a Board member of Ember Resources Inc., Suroco Energy Inc. and Harvest Operations Corp.

Pre-Approval of Policies and Procedures

The Audit Committee must pre-approve all non-audit services, greater than \$50,000, to be provided to the Trust or its subsidiary entities by its external auditors or the external auditors of the Trust's subsidiary entities, as applicable. Prior to engaging the auditors to provide any services over and above the regular audit engagement, management will contact the Chair of the Audit Committee for approval. The Chair of the Audit Committee will assess whether or not he should seek the approval of the entire Audit Committee prior to approving the engagement.

Audit Service Fees

The following table sets forth the audit service fees paid by the Trust to the external auditors, Ernst & Young LLP, for the periods indicated:

Type of Fees	Fiscal Year Ended December 31	Aggregate Fees Billed (\$)	Nature of Services Performed
Audit Fees	2009	623,000	Annual audits, quarterly review and regulatory filings
	2008	631,711	
	2007	471,500	
	2006	438,500	
	2005	732,200	
Audit – Related Fees	2009	39,000	M&A Due Diligence
	2008	43,485	
	2007	65,000	
	2006	191,700	
	2005	670,900	
Tax Fees	2009	179,950	Tax Advisory services including M&A
	2008	179,950	
	2007	201,405	
	2006	362,330	
	2005	166,000	

INTERESTS OF EXPERTS

Certain legal matters in connection with this Annual Information Form are being reviewed, on behalf of the Trust and the Manager, by Burnet, Duckworth & Palmer LLP, Calgary, Alberta. As of the date hereof, the partners and associates of Burnet, Duckworth & Palmer LLP, as a group, and the shareholders of McDaniel & Associates Consultants Ltd., as a group, owned less than 1% of the outstanding Trust Units.

The Trust's auditor is Ernst & Young LLP, Chartered Accountants, Ernst & Young Tower, 1000, 440 – 2nd Avenue SW, Calgary, Alberta, T2P 5E9. Ernst & Young LLP is independent in accordance with the Rules of Professional Conduct as outlined by the Institute of the Chartered Accountants of Alberta.

ADDITIONAL INFORMATION

Additional information about the Trust, including directors' and officers' remuneration and indebtedness, principal holders of Trust Units and options to purchase securities, if applicable, is contained in the Trust's information circular for the most recent annual meeting of unitholders that involved the election of directors. Additional financial information is provided for in our financial statements and management's discussion and analysis for the year ended December 31, 2009. Documents affecting the rights of securityholders, along with other information relating to the Trust, may be found on SEDAR at www.sedar.com.

SCHEDULE "A"

FORM NI 51-101F2

**REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED
RESERVES EVALUATOR OR AUDITOR**

Preparation Date of Evaluation Report	Location of Reserves	Net Present Value of Future Net Revenue \$M (before income taxes, 10% discount rate)			
		Audited	Evaluated	Reviewed	Total
March 10, 2010	Canada	-	184,983	-	184,983

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.
6. We have no responsibility to update our report referred to in paragraph 4 for events and circumstances occurring after the preparation date.
7. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

Executed as to our report referred to above:

McDANIEL & ASSOCIATES CONSULTANTS LTD.



P. A. Welch, P. Eng.
President & Managing Director

Calgary, Alberta

SCHEDULE "B"

FORM 51-101F3

**REPORT OF MANAGEMENT AND DIRECTORS
ON RESERVES DATA AND OTHER INFORMATION**

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

An independent qualified reserves evaluator has evaluated the reserves data of the Trust. The report of the independent qualified reserves evaluator is included in this Annual Information Form.

The Reserves Committee of the Board of Directors of the Manager has:

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

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

(Signed) "William Gallacher"
William Gallacher
Director, President and Chief Executive Officer

(Signed) "Gary Dundas"
Gary Dundas
Vice President, Finance and Chief Financial Officer

(Signed) "Stuart Chow"
Stuart Chow
Director and Chairman of Reserves Committee

(Signed) "David Butler"
David Butler
Director and Member of Reserves Committee

March 30, 2010

SCHEDULE "C"

CHARTER FOR THE AUDIT AND RISK MANAGEMENT COMMITTEE

CHARTER FOR THE AUDIT AND RISK MANAGEMENT COMMITTEE

GENERAL

The primary function of the Audit and Risk Management Committee is to assist the Board in fulfilling its oversight responsibilities through (i) the review of financial information to be provided to the Unitholders and others, (ii) the review of the systems of internal controls and management information systems established by management, (iii) the review of the Trust's external audit process, and (iv) monitoring compliance with the Trust's legal and regulatory requirements with respect to its financial statements.

The Committee is accountable to the Board. In the course of fulfilling its specific responsibilities hereunder, the Committee is expected to attempt to maintain an open communication between the Trust's external Auditors and the Board.

The responsibilities of a member of the Committee are in addition to such member's duties as a member of the Board.

The Committee does not plan or perform audits or warrant the accuracy or completeness of the Trust's financial statements or financial disclosure or compliance with generally accepted accounting procedures, as these are the responsibility of management and the external Auditors.

The Committee also assists the Board in fulfilling its oversight responsibilities with respect to the Trust's risk management policies and procedures, taking into account the risks inherent in the Trust's businesses, facilities and strategic plan.

PROCEDURAL MATTERS

The Committee shall be governed by the Terms of Reference for Committees adopted by the Board, save as modified by the following procedural requirements and powers. The Committee:

- a. shall meet at least four times per year, either by telephone conference or in person;
- b. may invite the Trust's external Auditors, the Chief Financial Officer, and such other persons as deemed appropriate by the Committee to attend meetings of the Committee;
- c. shall report material decisions and actions of the Committee to the Board, together with such recommendations as the Committee may deem appropriate, at the next Board meeting;
- d. has the power to conduct or authorize investigations into any matter within the scope of its responsibilities. It has the right to engage independent counsel and other advisors as it determines necessary to carry out its duties and the right to set the compensation for any advisors employed by the Committee;
- e. has the right to communicate directly with the CFO and other members of management who have responsibility for the external audit process; and
- f. has the right to pre-approve non-audit services, in accordance with the Committee's pre-approval policies and procedures, to be performed by the external Auditors. The Committee may delegate certain pre-approval functions for non-audit services to one or more independent members of its Committee if it first adopts specific policies and procedures respecting same and provided such decisions are presented to the full Committee for approval at its next meeting.

RESPONSIBILITIES

The Committee has primary responsibility for the selection, appointment, dismissal, compensation and oversight of the external Auditors, subject to the overall approval of the Board. For this purpose, the Committee may consult with management.

External Auditors

The responsibilities of the Committee are:

- a. to recommend to the Board either that the current external Auditor should be reappointed for the ensuing year or, if the current external Auditor is not to be reappointed, select and recommend a suitable alternative;
- b. to oversee the work of the external Auditors engaged for the purpose of preparing or issuing an Auditors' report or performing other audit, review or attest services for the Trust, and to review the amount of compensation payable;
- c. to resolve disagreements, if any, between management and the external Auditors regarding financial reporting. The Committee will provide the Board with such recommendations and reports with respect to the financial statements of the Trust as it deems advisable;
- d. to take reasonable steps to confirm the independence of the external Auditors, including but not limited to pre-approving any non-audit related services provided by the external Auditors to the Trust with a view to ensuring independence of the external Auditors, and in accordance with any applicable regulatory requirements with respect to approval of non-audit related services performed by the external Auditors;
- e. to obtain from the external Auditors confirmation that the external Auditors are a 'participating audit' firm for the purpose of National Instrument 52-108 Auditor Oversight and are in compliance with governing regulations;
- f. to review and evaluate the performance of the external Auditors including the external Auditors' internal quality-control procedures; and
- g. to review and approve the Trust's hiring policy regarding partners, employees and former partners and employees of the Trust's external Auditors.

Audit and Review Process and Results

The Committee has a duty to receive, review and make any inquiry regarding the completeness, accuracy and presentation of the Trust's financial statements to ensure that the financial statements fairly present the financial position and risks of the organization and that they are prepared in accordance with generally accepted accounting principles. To accomplish this, the Committee is required to:

- a. review annually the Trust's internal system of audit and financial controls, internal audit procedures and results of such audits;
- b. prior to the annual audit by external Auditors, consider the scope and general extent of the external Auditors' review, including their engagement letter;
- c. ensure the external Auditors have full, unrestricted access to required information and have the cooperation of management;
- d. review with the external Auditors and, if necessary, legal counsel, any litigation, claim or contingency, including tax assessments, that could have a material effect upon the financial position of the Trust and the manner in which these matters are being disclosed in the financial statements;
- e. review the appropriateness and disclosure of any off-balance sheet matters;
- f. review disclosure of related-party transactions;
- g. receive and review with the external Auditors, the external Auditors' audit report and the audited financial statements;
- h. make recommendations to the Board respecting approval of the audited financial statements;
- i. meet with the external Auditors separately from management to review the integrity of the Trust's financial reporting, including the clarity of financial disclosure and the degree of conservatism or aggressiveness of the accounting policies and estimates, the performance of internal audit management, any significant disagreements or difficulties in obtaining information, the adequacy of internal controls over financial reporting and the degree of compliance of the Trust with prior recommendations of the external Auditors;

- j. direct management to implement such changes as the Committee considers appropriate, subject to any required approvals of the Board arising out of the review; and
- k. meet at least annually with the external Auditors, independent of management, and report to the Board on such meetings.

Interim Financial Statements

The Committee shall:

- a. review on an annual basis the Trust's practice with respect to review of interim financial statements by the external Auditors;
- b. conduct all such reviews and discussions with the external Auditors and management as it deems appropriate and make recommendations to the Board respecting approval of the interim financial statements.

Involvement with Management

The Committee has primary responsibility for overseeing the actions of management in all aspects of financial management and reporting. The Committee:

- a. shall review the Trust's public disclosure of financial information extracted from the Trust's financial statements, if such financial statements have not previously been reviewed by the Committee prior to such information being made public by the Trust, and for such purpose, the CFO assumes responsibility for providing the information to the Committee for their review;
- b. consult annually, and more often if required, with the Trust's CEO and CFO respecting the adequacy of the internal controls and review any breaches or deficiencies;
- c. obtain such certifications by the CEO and CFO attesting to internal controls, disclosure and procedures as are required by Multilateral Instrument 52-109;
- d. review management's response to significant written reports and recommendations issued by the external Auditors and the extent to which such recommendations have been implemented by management;
- e. review as required with management the annual financial statements, the quarterly financial statements, MD&A's, annual information forms, future-oriented financial information or pro-forma information and other financial disclosure in continuous disclosure documents;
- f. review annual and interim earnings press releases before the Trust publicly discloses this information;
- g. review with management the Trust's compliance with applicable laws and regulations respecting financial matters;
- h. review proposed regulatory changes and their impact on the Trust with management; and
- i. review with management and approve public disclosure of the Committee's Charter in the Trust's annual information form, information circular and on the Trust's website.

Risk Management

With respect to the Trust's enterprise risk management policies and procedures review, the Committee shall review with management on an annual basis the following:

- a. the material financial risks inherent in the Trust's businesses, facilities and strategic direction;
- b. the plan that management has implemented to monitor and deal with such risks and the success of management in following the plan;
- c. the use of derivative financial instruments, if any;

- d. the signing authority granted to the various levels of management;
- e. the overall financing of risk including insurance coverage;
- f. the risk retention philosophy and the resulting uninsured exposure of the Trust; and
- g. loss prevention policies, risk management programs, standards and accountabilities of the Trust in the context of competitive and operational considerations.

If any changes are considered to be advisable, the Committee shall make the appropriate recommendations to the Board for approval.

COMPLAINTS – Accounting, Internal Accounting Controls, Auditing Matters

The Committee shall establish procedures for:

- a. the receipt, retention and treatment of complaints received by the Trust regarding accounting, internal accounting controls, or auditing matters; and
- b. the confidential, anonymous submission by employees of the Trust of concerns regarding questionable accounting or auditing matters.

Complaints regarding accounting, internal accounting controls, or auditing matters may be submitted as outlined in the Trust's Whistle Blower Policy. Complaints may be made anonymously and, if not made anonymously, the identity of the person submitting the complaint will be kept confidential. Upon receipt of a complaint, the Chair will conduct or designate a member of the Committee to conduct an initial investigation. In all cases, the matter will be brought before the Committee for a determination of further investigation and action. Records of complaints made and the resulting action or determination with respect to the complaint shall be documented and kept in the records of the Committee for a period of three years.

The Committee shall review the Whistle Blower Policy annually.

COMPLAINTS – Environmental, Human Resource & Safety Matters

The Committee shall establish procedures for:

- a. the receipt, retention and treatment of complaints received by the Trust regarding EHR&S matters; and
- b. the confidential, anonymous submission by employees of the Trust of concerns regarding questionable EHR&S matters.

Complaints regarding EHR&S matters may be submitted as outlined in the Trust's Whistle Blower Policy. Complaints may be made anonymously and, if not made anonymously, the identity of the person submitting the complaint will be kept confidential. Upon receipt of a complaint from the Audit Chair, the Chair will conduct or designate a member of the Committee to conduct an initial investigation. In all cases, the matter will be brought before the Committee for a determination of further investigation and action. Records of complaints made and the resulting action or determination with respect to the complaint shall be documented and kept in the records of the Committee for a period of three years.

REPORTING

The Committee shall make regular reports to the Board concerning its activities.