HARVEST ENERGY TRUST

ANNUAL INFORMATION FORM

For the year ended December 31, 2005

MARCH 30, 2006

TABLE OF CONTENTS

GLOSSARY OF TERMS

In this Annual Information Form, 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.

"Administration Agreement" means the agreement dated September 27, 2002 between the Trustee and Harvest Operations pursuant to which Harvest Operations provides certain administrative and advisory services in connection with the Trust. See "Governance of the Trust" and "Additional Information Regarding the Harvest Energy Trust Structure".

"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.

"ARTC" means the Alberta Royalty Tax Credit, an Alberta provincial government program under which, in certain circumstances, tax credits may be provided against royalties on oil and natural gas production payable to the Province of Alberta.

"Board of Directors" or **"Harvest Board"** means the board of directors of Harvest Operations.

"Business Day" means a day, other than a Saturday, Sunday or statutory holiday in the Province of Alberta or any other day on which banks in Calgary, Alberta are not open for business.

"Capital Fund" means the cumulative amount of funds that the Trust retains from Cash Available For Distributions to finance future acquisitions and development of properties.

"Cash Available For Distribution" means, for any particular period, all amounts available for distribution during any applicable period by the Trust to holders of Trust Units prior to any obligation pursuant to the DPPO and any retention by the Trust for the Capital Fund. See "Additional Information Regarding the Harvest Energy Trust Structure – Cash Available For Distribution".

"COGPE" means Canadian oil and natural gas property expense, as defined in the Tax Act.

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum;

"Current Bank Facility" means the credit facility provided by the Current Lenders as more fully described under "Additional Information Regarding the Harvest Energy Trust Structure – Borrowings".

"Current Lenders" means a syndicate of lenders to Harvest Operations pursuant to the Current Bank Facility.

"Debenture Indenture" means, collectively, the trust indenture dated January 29, 2004, a supplemental indenture dated August 10, 2004 and a second supplemental indenture dated August 2, 2005 made among the Trust, Harvest Operations and the Debenture Trustee, as trustee.

"Debenture Trustee" means the trustee of the Debentures Series 1, Debentures Series 2 and Debentures Series 3, Valiant Trust Company.

"Debentures Series 1" means the 9% convertible unsecured subordinated debentures of the Trust due May 31, 2009.

"Debentures Series 2" means the 8% convertible unsecured subordinated debentures of the Trust due September 30, 2009.

"Debentures Series 3" means the 6.5% convertible unsecured subordinated debentures of the Trust due December 31, 2010.

"Debentures Series 4" means the 10.5% convertible unsecured subordinated debentures of the Trust due April 30, 2008 assumed on February 3, 2006 pursuant to the terms of the Viking Arrangement.

"Debentures Series 5" means the 6.40% convertible unsecured subordinated debentures of the Trust due October 31, 2012 assumed on February 3, 2006 pursuant to the terms of the Viking Arrangement.

"Deferred Purchase Price Obligation" or "DPPO" means, collectively, the ongoing obligation of the Trust to pay to Harvest Operations, HST and HBT2, to the extent of the Trust's available funds, an amount up to 99% of the cost of, including any amount borrowed to acquire, any Canadian resource property acquired by Harvest Operations, HST or HBT2, and the cost of, including any amount borrowed to fund, certain designated capital expenditures in relation to the Properties.

"Direct Royalties" means royalty interests in petroleum and natural gas rights acquired by the Trust from time to time pursuant to a Direct Royalties Sale Agreement.

"Direct Royalties Sale Agreement" means any purchase and sale agreement between the Trust and an Operating Subsidiary providing for the purchase by the Trust from an Operating Subsidiary of Direct Royalties.

"**DRIP Plan**" means the Trust's Premium Distribution™, Distribution Reinvestment and Optional Trust Unit Purchase Plan.

"East Central Alberta Properties" means Properties located in the East Central Alberta region.

"Exchangeable Shares" means the non-voting exchangeable shares in the capital of Harvest Operations.

"Farmout" means an agreement whereby a third party agrees to pay for all or a portion of the drilling of a well on one or more of the Properties in order to earn an interest therein, with an Operating Subsidiary retaining a residual interest in such Properties.

"GLJ" means GLJ Petroleum Consultants Ltd., independent oil and natural gas reservoir engineers of Calgary, Alberta.

"**Gross**" means:

(a) in relation to the Operating Subsidiaries' interest in production and reserves, its "Corporation gross reserves", which are the Operating Subsidiaries' interest (operating and non-operating) share before deduction of royalties and without including any royalty interest of the Operating Subsidiaries;

(b) in relation to wells, the total number of wells in which the Operating Subsidiaries have an interest; and

(c) in relation to properties, the total area of properties in which the Operating Subsidiaries have an interest.

"Harvest Operations" means the Trust's subsidiary, Harvest Operations Corp.;

"HBT1" or "Breeze Trust No. 1" means Harvest Breeze Trust 1, a trust established under the laws of the Province of Alberta, wholly owned by HST.

“HBT2” or “Breeze Trust No. 2” means Harvest Breeze Trust 2, a trust established under the laws of the Province of Alberta, wholly owned by the Trust.

"HST" or “Sask Trust” means Harvest Sask Energy Trust, a trust established under the laws of the Province of Alberta, wholly owned by the Trust.

“Independent Reserve Engineering Evaluators” means McDaniel, GLJ and Sproule, independent oil and natural gas reservoir engineers of Calgary, Alberta, who evaluated the crude oil, natural gas liquids and natural gas reserves of the Operating Subsidiaries as at December 31, 2005, in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101.

"Initial Public Offering" means the initial public offering of 3,750,000 Trust Units at a price of $8.00 per Trust Unit completed on December 5, 2002, resulting in gross proceeds of $30,000,000, and includes the over-allotment option granted in favour of and exercised by the underwriters to acquire an additional 562,500 Trust Units at a price of $8.00 per Trust Unit, resulting in gross proceeds of $4,500,000.

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

"**Net**" means:

(d) in relation to the Operating Subsidiaries’ interest in production and reserves, the Operating Subsidiaries’ interest (operating and non-operating) share after deduction of royalties obligations, plus the Operating Subsidiaries’ royalty interest in production or reserves.

(e) in relation to wells, the number of wells obtained by aggregating the Operating Subsidiaries’ working interest in each of its gross wells; and

(f) in relation to the Operating Subsidiaries’ interest in a property, the total area in which the Operating Subsidiaries have an interest multiplied by the working interest owned by the Operating Subsidiaries.

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

"Notes" means, collectively, the promissory notes issuable by Harvest Operations in series pursuant to a note indenture to be redeemed in consideration for a portion of the NPI, having a fair market value equal to such principal amount, and being subject to the following terms and conditions:

(a) being unsecured and bearing interest at 6% per annum payable monthly in arrears on the 20th day of the next following month;

(b) being subordinate to all senior indebtedness which includes all indebtedness for borrowed money or owing in respect of property purchases on any default in payment of any such senior indebtedness, and to all trade debt of the Corporation or any subsidiary of the Corporation or the Trust on any creditor proceedings such as bankruptcy, liquidation or insolvency;

(c) being subject to earlier prepayment, being due and payable on the 15th anniversary of the date of issuance;

(d) being subject to such other standard terms and conditions as would be included in a note indenture for promissory notes of this kind, as may be approved by the Harvest Board.

"NPI" means, collectively, the net profit interest owing to the Trust pursuant to the NPI Agreements.

"NPI Agreements" means, collectively, the net profit interest agreement dated July 10, 2002 between Harvest Operations and the Trust as amended, the royalty agreement dated effective January 17, 2003 between WEI and BNY Trust Company of Canada, the net profit interest agreement dated July 10, 2002 between HST and the Trust as amended and the net profit interest agreement dated January 1, 2005 between HBT1 and the Trust as amended and "NPI Agreement" means any one of these agreements, as applicable.

"NYMEX" means the New York Mercantile Exchange.

"Operating Subsidiaries" means, collectively, Harvest Operations, HST, REEI, REP, BRP, HBT1, HBT2, Hay River Partnership, and from and after February 3, 2006 Viking Holdings Inc., each a direct or indirect wholly-owned subsidiary of the Trust, and **"Operating Subsidiary"** means any of Harvest Operations, HST, REEI, REP, BRP, HBT1, HBT2, Hay River Partnership and from and after February 3, 2006 Viking Holdings Inc., as applicable.

"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 meeting.

"Ordinary Trust Units" means the ordinary Trust Units of the Trust created, issued, and certified under the Trust Indenture and for the time being outstanding and entitled to the benefits thereof.

"**Permitted Investments**" means:

(a) loan advances to Harvest Operations;

(b) interest bearing accounts of certain financial institutions including Canadian chartered banks and the Trustee;

(c) obligations issued or guaranteed by the Government of Canada or any province of Canada or any agency or instrumentality thereof;

(d) term deposits, guaranteed investment certificates of deposit or bankers' acceptances of or guaranteed or accepted by any Canadian chartered bank or other financial institution (including the Trustee and any Affiliate of the Trustee) the short term debt or deposits of which have been rated at least A or the equivalent by Standard & Poor's Corporation or Moody's Investors Service, Inc. or Dominion Bond Rating Service Limited;

(e) commercial paper rated at least A or the equivalent by Dominion Bond Rating Service Limited; and

(f) investments in bodies corporate, partnerships or trusts engaged in the oil and natural gas business, including the Operating Subsidiaries;

provided that an investment is not a Permitted Investment if it:

(g) would result in the cost amount to the Trust of all "foreign property" (as defined in the Tax Act) which is held by the Trust to exceed the amount prescribed by Regulation 5000(1) of the Regulations to the Tax Act;

(h) is a "small business security" as that term is used in Part L1 of the Regulations to the Tax Act; or

(i) would result in the Trust not being considered either a "unit trust" or a "mutual fund trust" for purposes of the Tax Act.

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

"Pro Rata Share" means, of any particular amount in respect of a Unitholder at any time, the product obtained by multiplying the number of Trust Units that are owned by that Unitholder at that time by the quotient obtained when the particular amount is divided by the total number of all Trust Units that are issued and outstanding at that time.

"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 Operating Subsidiaries in any petroleum and natural gas rights, tangibles and miscellaneous interests, including properties which may be acquired by the Operating Subsidiaries from time to time.

"Property Interests" means petroleum and natural gas rights and related tangibles and miscellaneous interests beneficially owned by the Operating Subsidiaries.

"Provost Properties Vendors" means, collectively, the vendors from whom the Operating Subsidiaries acquired the Provost Properties.

"PV10" means present value of future net revenue discounted at 10%.

"Record Date" means December 31 of each year hereafter and the last day of each calendar month or such other date as may be determined from time to time by the Trustee upon the recommendation of the Board of Directors.

"REEI" means Red Earth Energy Inc., a corporation formed under the laws of the province of Alberta and wholly owned by Harvest Operations.

"REP" means Red Earth Partnership, a partnership established under the laws of Alberta.

"Reserve Fund" means the cumulative amount of production and other revenues entitled to be retained by the Operating Subsidiaries pursuant to the NPI Agreements to provide for payment of production costs which the Operating Subsidiaries estimate will or may become payable in the following six months for which there may not be sufficient production revenues to satisfy such production costs in a timely manner. See "Additional Information Regarding the Harvest Energy Trust Structure – Net Profits Interest Agreements".

"Reserve Life Index" or **"RLI"** means the amount obtained by dividing the quantity of proved plus probable reserves as at the end of the previous year, by the annualized production of petroleum, natural gas and natural gas liquids from those reserves, in the following year, as projected in the Reserve Report.

"Reserve Report" means, collectively, the report prepared by the Independent Reserve Engineering Evaluators dated January 1, 2006 evaluating the crude oil, natural gas liquids and natural gas reserves of the Operating Subsidiaries as at December 31, 2005, in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101.

"Reserve Value" means, for any petroleum and natural gas property at any time, the present worth of all of the estimated pre-tax cash flow net of capital expenditures from the proved plus probable reserves shown in the Reserve Report for such property, discounted at 10% and using forecast price and cost assumptions (a common benchmark in the oil and natural gas industry).

"Senior Indebtedness" means all indebtedness, liabilities and obligations of the Trust (whether outstanding as at the date of the Indenture or thereafter created, incurred or assumed or for which it is liable in respect of any guarantee, indemnity, suretyship or joint and several liability) (i) in respect of borrowed money of itself or any subsidiary; (ii) in connection with the acquisition of any business, properties or asset by itself or any subsidiary; (iii) in connection with risk mitigation instruments or agreements of itself or a subsidiary; (iv) to any trade creditors of itself or any subsidiary; or (v) renewals, extensions, restructurings, refinancings and refunding of any of the foregoing; unless the instrument creating or evidencing any of the foregoing provides that such indebtedness, liabilities or obligations are to rank *pari passu*, or subordinate, in right of payment to the Debentures.

"Special Trust Units" means the special Trust Units of the Trust created, issued, and certified under the Trust Indenture and for the time being outstanding and entitled to the benefits thereof.

"Sproule" means Sproule Associates Limited, independent oil and natural gas reservoir engineers of Calgary, Alberta.

"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 2/3% of the Trust Units represented at the meeting and voted on a poll upon such resolution.

"Special Warrants" means the special trust unit purchase warrants sold to a syndicate of underwriters on February 4, 2003, which warrants were exchanged for Trust Units upon their deemed exercise on March 7, 2003.

"Storm" means Storm Energy Ltd.

"Subsequent Investments" means any of the investments that the Trust may make pursuant to the Trust Indenture, which includes:

(a) making payments to Harvest Operations pursuant to the Deferred Purchase Price Obligations under the NPI Agreement;

(b) making loans to Harvest Operations in connection with the Capital Fund; and

(c) temporarily holding cash and investments for the purposes of paying the expenses and liabilities of the Trust, making certain other investments as contemplated by Section 4.2 of the Trust Indenture, paying amounts payable by the Trust in connection with the redemption of any Trust Units, and making distributions to Unitholders;

provided that such investments will not be a Subsequent Investment if it:

(d) would result in the cost amount to the Trust of all "foreign property" (as defined in the Tax Act) which is held by the Trust to exceed the amount prescribed by Regulation 5000(1) of the Regulations to the Tax Act;

(e) is a "small business security" as that term is used in Part L1 of the Regulations to the Tax Act; or

(f) would result in the Trust not being considered either a "unit trust" or a "mutual fund trust" for purposes of the Tax Act.

"Tax Act" means the *Income Tax Act* (Canada) and the regulations thereunder.

"Trust" or **"Harvest"** means Harvest Energy Trust.

"Trust Fund" at any time, shall mean any of the following monies, properties and assets that are at such time held by the Trustee on behalf of the Trust for the purposes of the Trust under the Trust Indenture:

(a) the amount paid to settle the Trust;

(b) all funds realized from the issuance of Trust Units;

(c) any Permitted Investments in which funds may from time to time be invested;

(d) all rights in respect of and income generated under the NPI Agreement with the Corporation, including the applicable NPI;

(e) all rights in respect of and income generated under a Direct Royalties Sale Agreement;

(f) any Subsequent Investment;

(g) any proceeds of disposition of any of the foregoing property including, without limitation, the Direct Royalties; and

(h) all income, interest, profit, gains and accretions and additional assets, rights and benefits of any kind or nature whatsoever arising directly or indirectly from or in connection with or accruing to such foregoing property or such proceeds of disposition.

"Trust Indenture" means the amended and restated trust indenture dated July 10, 2003 between the Trustee and the Corporation as such indenture may be further amended by supplemental indentures from time to time.

"Trust Unit" means a trust unit of the Trust and unless the context otherwise requires means Ordinary Trust Units and Special Trust Units.

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

"TSX" means the Toronto Stock Exchange.

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

"U.S. Securities Act" means the *United States Securities Act of 1933*, as amended.

“VERT” or “Viking” means Viking Energy Royalty Trust.

“VHI” or “Viking Holdings” means Viking Holdings Inc.

“Viking Arrangement” means the Plan of Arrangement involving Harvest, Harvest Operations, VERT, VHI, Harvest securityholders and Viking unitholders as approved by the Harvest securityholders and the Viking unitholders on February 2, 2006 and effective February 3, 2006.

"WEI" means the Trust's former wholly-owned subsidiary, Westcastle Energy Inc., a corporation incorporated under the *Business Corporations Act* (Alberta) and which amalgamated with Harvest Operations on January 1, 2004, with the amalgamated corporation continuing under the name "Harvest Operations Corp.".

"Working Interest" or **"WI"** 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.

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

Other

AECO	EnCana Corporation's natural gas storage facility located at Suffield, Alberta.
BOE	barrel of oil equivalent, using the conversion factor of 6 Mcf of natural gas being equivalent to one Bbl of oil, unless otherwise specified. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
BOE/d	barrels of oil equivalent per day.
MBOE	thousand barrels of oil equivalent.
MMBOE	million barrels of oil equivalent.
OOIP	original oil in place.
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade.
ºAPI	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	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	the measure of the fraction of pore space of a reservoir.
$000	thousands of dollars
$millions	millions of dollars

CONVERSIONS

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

To Convert From	To	Multiply By
Mcf	cubic metres	28.174
cubic metres	cubic feet	35.494
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

ALL DOLLAR AMOUNTS SET FORTH IN THIS ANNUAL INFORMATION FORM ARE IN CANADIAN DOLLARS, EXCEPT WHERE OTHERWISE INDICATED.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Annual Information Form and documents incorporated by reference into this Annual Information Form contain forward-looking statements. Such forward looking statements are subject to certain risks and uncertainties that could cause actual results to differ materially from those included in the forward-looking statements. The words "believe," "expect," "intend," "estimate" or "anticipate" and similar expressions, as well as future or conditional verbs such as "will," "should," "would," and "could" often identify forward-looking statements. Specific forward-looking statements contained in this Annual Information Form and the documents incorporate by reference herein include, among others, statements regarding our:

- expected financial performance in future periods;
- expected increases in revenue attributable to development and production activities;
- estimated capital expenditures for fiscal 2006 and subsequent periods;
- competitive advantages and ability to compete successfully;
- intention to continue adding value through drilling and exploitation activities;
- emphasis on having a low cost structure;
- intention to retain a portion of our cash flows after distributions to repay indebtedness and invest in further development of our properties;
- reserve estimates and estimates of the present value of our future net cash flows;
- methods of raising capital for exploitation and development of reserves;
- factors upon which we will decide whether or not to undertake a development or exploitation project;
- plans to make acquisitions and expected synergies from acquisitions made;
- expectations regarding the development and production potential of our properties; and
- treatment under government regulatory regimes.

With respect to forward-looking statements contained in this Annual Information Form and the documents incorporate by reference herein, we have made assumptions regarding, among other things:

- future oil and natural gas prices and differentials between light, medium and heavy oil prices;
- the cost of expanding our property holdings;
- our ability to obtain equipment in a timely manner to carry out development activities;
- our ability to market oil and natural gas successfully to current and new customers;
- the impact of increasing competition;
- our ability to obtain financing on acceptable terms; and
- our ability to add production and reserves through our development and exploitation activities.

Some of the risks that could affect our future results and could cause results to differ materially from those expressed in our forward-looking statements include:

- the volatility of oil and natural gas prices, including the differential between the price of light, medium and heavy oil;
- the uncertainty of estimates of oil and natural gas reserves;
- the impact of competition;
- difficulties encountered during the drilling for and production of oil and natural gas;
- difficulties encountered in delivering oil and natural gas to commercial markets;
- foreign currency fluctuations;
- the uncertainty of our ability to attract capital;
- changes in, or the introduction of new, government regulations relating to the oil and natural gas business;
- costs associated with developing and producing oil and natural gas;
- compliance with environmental regulations;
- liabilities stemming from accidental damage to the environment;
- loss of the services of any of our senior management or directors; and
- adverse changes in the economy generally.

Statements relating to "reserves" or "resources" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the resources and reserves described can be profitably produced in the future. Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward looking statements contained in this Annual Information Form and the documents incorporated by reference herein are expressly qualified by this cautionary statement. Except as required by law, neither the Trust nor the Corporation undertakes any obligation to publicly update or revise any forward-looking statements and readers should also carefully consider the matters discussed under the heading "Risk Factors" in this Annual Information Form.

SUPPLEMENTAL DISCLOSURE

Cash available for distribution is not a recognized generally accepted accounting principle. Management believes that in addition to net income and net income per Trust Unit, cash available for distribution is a useful supplemental measure as it provides investors with information on cash available for distribution. Investors are cautioned that cash available for distribution should not be construed as an alternate to net income as determined by Canadian generally accepted accounting principles.

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, 2005.

STRUCTURE OF HARVEST ENERGY TRUST

Harvest Energy Trust

Harvest Energy Trust (the "Trust") is an open-ended, unincorporated investment trust established under the laws of the Province of Alberta on July 10, 2002 pursuant to the Trust Indenture between Harvest Operations Corp. ("Harvest Operations"), a wholly owned subsidiary and manager of the Trust, and Valiant Trust Company as Trustee. The Trust Indenture has been amended from time to time, the latest material amendments being approved at the special meeting of Unitholders held February 2, 2006. The Trust's assets consist of the securities of several direct and indirect subsidiaries, unsecured debt issued by Harvest Operations, Harvest Breeze Trust No. 1 ("Breeze Trust No 1") and Harvest Breeze Trust No. 2 ("Breeze Trust No 2") to the Trust, 99% net profits interests on the oil and natural gas assets of Harvest Operations, Harvest Sask Energy Trust ("Sask Trust") and Breeze Trust No. 1 and direct ownership of royalties on certain petroleum and natural gas properties. The head and principal office of the Trust is located at Suite 2100, 330 - 5th Avenue S.W., Calgary, Alberta T2P 0L4 while the registered office of the Trust is located at Suite 1400, 350 – 7th Avenue S.W., Calgary, Alberta T2P 3N9. The trust is managed by Harvest Operations pursuant to the Administration Agreement dated September 27, 2002.

The beneficiaries of the Trust are the holders of its Trust Units who receive monthly distributions from the Trust's net cash flow from its various investments after certain administrative expenses and the provision for interest due to the holders of convertible debentures. Pursuant to the Trust Indenture, the Trust is required to distribute 100% of its taxable income to its Unitholders each year and its activities are limited to holding and administering permitted investments and making distributions to its Unitholders.

The business of the Trust is to indirectly exploit, develop and hold interests in petroleum and natural gas properties through its investments. Cash flow from the petroleum and natural gas properties flows to the Trust by way of payments by Harvest Operations, Sask Trust and Breeze Trust No. 1 pursuant to net profit interests held by the Trust, interest and principal payments by Harvest Operations, Breeze Trust No. 1 and Breeze Trust No. 2 on unsecured debt owing to the Trust and payments by Sask Trust, Breeze Trust No. 2 and the Redearth Partnership of trust and partnership distributions. The Trust also receives cash flow from its direct royalties on certain petroleum and natural gas properties. Subsequent to its merger with Viking on February 3, 2006, the Trust will also receive payments from Viking Holdings Inc. ("Viking Holdings") pursuant to a net profits interest on certain petroleum and natural gas properties as well as payments of interest and principal pursuant to unsecured debt acquired by the Trust

Pursuant to the terms of each respective net profits interest agreement, the Trust is entitled to payments equal to the amount by which 99% of the gross proceeds from the sale of production from petroleum and natural gas properties exceed 99% of certain deductible expenditures. Deductible expenditures may include discretionary amounts to fund capital expenditures, to repay third party debt and to provide for working capital required to maintain the operations of the operating subsidiaries.

Operating Subsidiaries

The business of the Trust is carried on by Harvest Operations and its other operating subsidiaries, Sask Trust, Breeze Trust No. 1, Breeze Trust No. 2 and the Redearth Partnership, and subsequent to its merger with Viking on February 3, 2006, Viking Holdings. The activities of the operating subsidiaries are financed through interest bearing notes from the Trust, the purchase of net profit interests by the Trust and third party debt.

Harvest Operations Corp., a taxable corporation

Harvest Operations was incorporated under the ABCA on May 14, 2002 as 989131 Alberta Ltd. and on May 17, 2002, changed its name to Coyote Energy Inc. and then changed its name again on September 17, 2005 to "Harvest Operations Corp." On January 1, 2004, Harvest Operations amalgamated with WEI and continued as "Harvest

Operations Corp." On June 30, 2004, Harvest Operations amalgamated with Storm Energy Ltd. and continued as "Harvest Operations Corp." All of the issued and outstanding common shares of Harvest Operations are held for the benefit of the Trust. The exchangeable shares of Harvest Operations are held by the public.

In addition to administering the affairs of the Trust, Harvest Operations manages the affairs of the other subsidiaries and is responsible for providing all of the technical, engineering, geological, land management, financial, administrative and commodity marketing services relating to Harvest's petroleum and natural operations.

Harvest Sask Energy Trust, a commercial trust

Sask Trust is an unincorporated commercial trust established under the laws of the Province of Saskatchewan on September 29, 2003 pursuant to a Trust Indenture dated September 29, 2003 between the Trust and Harvest Operations as trustee. The trustee of Sask Trust is currently 1115650 Alberta Ltd. Sask Trust is wholly owned by the Trust and its assets consist of the direct ownership of properties located in southeast Saskatchewan purchased in October 2003. The Sask Trust assets are subject to a 99% net profits interest in favour of the Trust. On February 3, 2006, Sask Trust sold all of its direct ownership interests in petroleum and natural gas properties to Harvest Operations and the remainder of its other assets to the Trust.

Harvest Breeze Trust No. 1, a commercial trust

Breeze Trust No.1 is an unincorporated commercial trust established under the laws of the Province of Alberta on July 8, 2004 pursuant to a Trust Indenture dated July 8, 2004 between Sask Trust and 1115638 Alberta Ltd. as trustee. Breeze Trust No. 1 is wholly owned by Sask Trust and its assets consist of the intangible portion of direct ownership interests in petroleum and natural gas properties purchased from the Breeze Resources Partnership and the Hay River Partnership and a 99% interest in each of those partnerships.

Harvest Breeze Trust No. 2, a commercial trust

Breeze Trust No. 2 is an unincorporated commercial trust established under the laws of the Province of Alberta on July 8, 2004 pursuant to a Trust Indenture dated July 8, 2004 between the Trust and 1115650 Alberta Ltd. as trustee. Breeze Trust No. 2 is wholly owned by the Trust and its assets consist of a 1% interest in each of the Breeze Resources Partnership and the Hay River Partnership

Breeze Resource Partnership, a general partnership

Breeze Resource Partnership is a general partnership formed on June 30, 2004 under the laws of the Province of Alberta pursuant to a partnership agreement dated June 30, 2004. Breeze Resource Partnership's assets consist of the tangible portion of direct ownership interest in petroleum and natural gas properties located in east central Alberta and southern Alberta purchased in September 2004.

Hay River Partnership, a general partnership

Hay River Partnership is a general partnership formed on December 20, 2004 under the laws of the Province of Alberta pursuant to a partnership agreement dated December 20, 2004. Hay River Partnership's assets consist of the tangible portion of direct ownership interests in petroleum and natural gas properties located in northeastern British Columbia purchased in August 2005.

Redearth Partnership, a general partnership

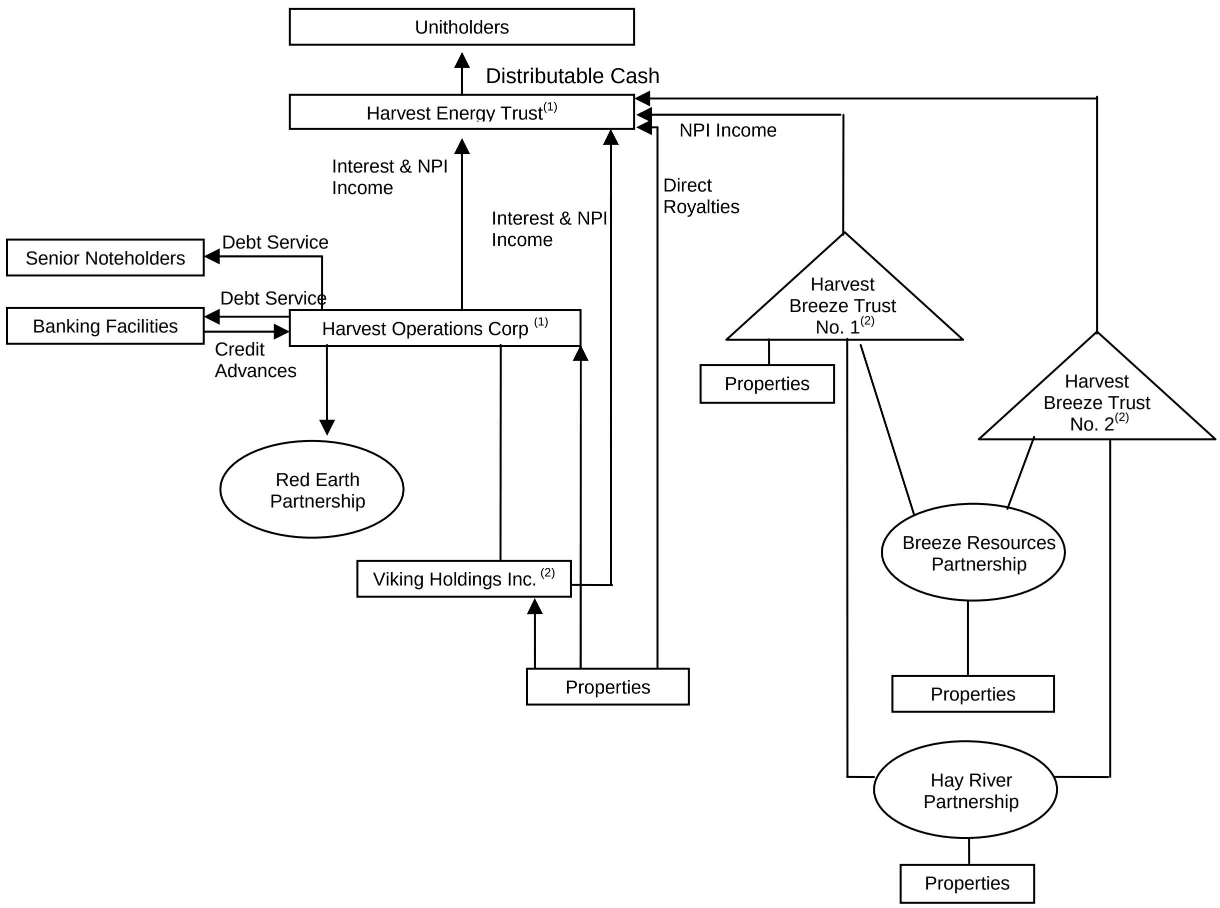
Redearth Partnership is a general partnership formed on August 23, 2002 under the laws of the Province of Alberta pursuant to a partnership agreement dated August 23, 2002. Harvest Operations holds a 60% ownership interest in Redearth Partnership. Redearth Partnership's assets consist of direct ownership interest in properties located in north central Alberta purchased in June 2004 as part of the Storm Energy Ltd. acquisition.

Viking Holdings Inc., a taxable corporation

Viking Holdings was incorporated under the ABCA on August 13, 1997 and is the surviving entity of numerous amalgamations with related corporate entities. Effective February 3, 2006, Viking Holdings is wholly owned by Harvest Operations. Viking Holding's assets consist of all of Viking's petroleum and natural gas properties which are also subject to a net profits interest in favour of the Trust. In addition, the Trust has acquired certain unsecured debt of Viking Holdings and commencing February 3, 2006, will be entitled to receive payments of interest and principal payments on this unsecured debt now owing to the Trust.

Intercorporate Relationships and Structure of the Trust - Post-Plan of Arrangement with Viking

As at March 20, 2006, after giving effect to the Viking Arrangement on February 3, 2006, the structure of the Trust and its significant subsidiaries including the flow of cash from the Properties through to the Unitholders is set forth below:



Notes:

(1) The Trust receives regular monthly payments in accordance with the net profits interest agreements as well as interest and principal payments from Harvest Operations Corp., Viking Holdings Inc., Harvest Breeze Trust No. 1 and trust and partnership distributions from Harvest Breeze Trust No. 2 and Redearth Partnership.

(2) Harvest Breeze Trust No. 1and Harvest Breeze Trust No. 2 have also issued priority units to Harvest Operations Corp.

GENERAL DEVELOPMENT OF THE BUSINESS

Harvest was formed in July 2002 and subsequently acquired 2,750 boe/d of medium gravity oil production in the Thompson Lake area of east central Alberta for cash consideration of $27.2 million. In November 2002, Harvest acquired an additional 5,750 boe/d of heavy oil production in the Hayter area also in east central Alberta for cash consideration of $49.0 million. These acquisitions were funded by an initial $5 million of founders' capital, $31.7 million of net proceeds from Harvest's initial public offering and borrowings under term credit facilities. By the end of 2002, Harvest had declared its first cash distribution of $0.20 per trust unit for unitholders of record on December 31, 2002 and payable on January 15, 2003.

Year ended December 31, 2003

Harvest continued its acquisition of heavy oil production in east central Alberta with the purchase of two properties in the Killarney area during April/May for cash consideration of $13.2 million plus the issuance of 200,000 Trust Units with an aggregate ascribed value of $2.1 million. At the time of the acquisition, these properties were producing approximately 925 boe/d.

On June 27, 2003, Harvest acquired approximately 1,350 boe/d of heavy oil production in east central Alberta with its acquisition of all the common shares of Westcastle Energy Inc., a private company, and a net profits interest in certain producing properties held by that company. In addition to assuming $2.8 million in bank debt and a $2.3 million working capital deficiency, Harvest's acquisition costs included cash consideration of $3.0 million plus the issuance of 625,000 trust units with an ascribed value of $6.3 million and a $0.9 million unsecured promissory note for an aggregate purchase price of approximately $15.3 million.

On October 1, 2003, Harvest acquired approximately 5,200 boe/d of light oil production in Carlyle area of southeast Saskatchewan for cash consideration of $79.5 million, prior to adjustments and transaction costs.

For the year, Harvest's production averaged approximately 11,000 boe/d with a year end exit rate of 15,400 boe/d comprised of approximately 60% light and medium oil and 40% heavy oil. Throughout 2003, monthly cash distributions were maintained at $0.20 per trust unit while capital spending on internal development opportunities totalled $27.2 million.

Year ended December 31, 2004

On June 30, 2004, Harvest acquired approximately 4,000 boe/d of light oil production in the Red Earth area of north central Alberta with its acquisition of all of the common shares of Storm Energy Ltd. In addition to assuming bank debt of $56.8 million and a working capital deficiency of $10.5 million, Harvest's acquisition costs included $75.0 million of cash consideration, and the issuance of 2,720,837 Trust Units and 600,587 Exchangeable Shares with ascribed values of $40.2 million and $8.9 million, respectively, for an aggregate consideration of approximately $192.2 million including $0.8 million of transaction costs.

On September 2, 2004, Harvest acquired approximately 20,000 boe/d of production in east central Alberta and southern Alberta, including approximately 28,000 mcf/d of natural gas production at Crossfield and Cavalier, with its acquisition of the Breeze Resources Partnership for cash consideration of $511.4 million. The more significant oil properties included in this acquisition were the heavy oil assets at Suffield and medium gravity production at Badger.

During 2004, Harvest's production averaged approximately 23,000 boe/d with a year end exit rate of 37,000 boe/d comprised of approximately 43% light and medium oil, 41% heavy oil and 16% natural gas and associated liquids. Throughout 2004, monthly cash distributions were maintained at $0.20 per trust unit while capital spending on internal development opportunities increased to $42.7 million.

Year ended December 31, 2005

On August 2, 2005, Harvest acquired approximately 5,200 boe/d of medium gravity oil production (24° API) in northeastern British Columbia with its acquisition of the Hay River Partnership for cash consideration of $237.8 million. The production from Hay River sells at a premium to Harvest's other medium gravity production and due to its northern location, receives preferred royalty treatment afforded to heavy oil producers.

During 2005, Harvest's production averaged approximately 36,500 boe/d with a year end exit rate of approximately 38,800 boe/d comprised of approximately 53% light and medium oil, 34% heavy oil and 13% natural gas and associated liquids. Bouyed by its recent acquisitions and significantly improved commodity prices in 2005, Harvest maintained monthly cash distributions of $0.20 per trust unit through June, then increased its distribution to $0.25 per trust unit for the month of July and commencing with the August distribution payable in September, increased the monthly distribution to $0.35 per Trust Unit for the balance of the year. Capital spending on internal development opportunities increased to $120.5 million, an increase of $77.8 million over the prior year.

Plan of Arrangement with Viking Energy Royalty Trust

On November 28, 2005 Harvest entered into a Pre-Arrangement Agreement outlining the terms and conditions upon which Harvest and Viking Energy Royalty Trust ("Viking") were prepared to complete a business combination and on December 23, 2005, Harvest and Viking entered into an Arrangement Agreement to merge the two trusts based on an exchange ratio of 0.25 Harvest Trust Units for every Viking trust unit, representing an issuance of approximately 46.0 million Harvest Trust Units, with Harvest receiving all of the assets of Viking.

On February 2, 2006, the securityholders of Harvest and the unitholders of Viking voted to approve a resolution to affect a plan of arrangement with the Alberta Court of Queens Bench granting the required order on February 3, 2006. In addition to the issuance of 46.0 million Trust Units with an ascribed value of approximately $1.6 billion, Harvest has also assumed the obligations of Viking's 10.5% and 6.4% unsecured subordinated convertible debentures with approximately $34.0 million and $175.0 million of face value outstanding, respectively. The final purchase price will be determined as the required working capital information becomes available.

On February 3, 2006, John Zahary became the President and Chief Executive Officer of Harvest with the supporting senior management team including Robert Fotheringham as Vice President Finance and Chief Financial Officer; Rob Morgan as Vice President, Engineering and Chief Operating Officer; Al Ralston as Vice President, Production; James Campbell as Vice President, Geosciences; and Jacob Roorda as Vice President, Corporate. In addition, the Harvest Board of Directors was expanded to include the following former Viking directors: Dale Blue, David Boone and William Friley (See – DIRECTORS AND OFFICERS OF HARVEST OPERATIONS for further information on the additions to the officers and directors).

Harvest believes that its merger with Viking will create a stronger single entity with a more balanced production portfolio with significant undeveloped land and property enhancement opportunities. Harvest's securityholders should benefit from improved liquidity and participation in one of the largest oil and natural gas royalty trusts in Canada with an initial productive capacity of 64,000 boe/d comprised of approximately 50% light and medium gravity oil, 25% heavy oil and 25% natural gas.

The following tables are an aggregate roll-up of the Harvest reserves and Viking reserves, prepared as at March 20, 2006 assuming that all reserves were held by Harvest as at December 31, 2005. The Harvest and Viking reserves were evaluated by the independent reserve evaluators McDaniel & Associates Consultants Ltd., GLJ Petroleum Consultants Ltd., and Sproule Associates Limited in accordance with National Instrument 51-101 ("NI 51-101") for the year ended December 31, 2005. For the purposes of the roll-up tables, Harvest and Viking's reserves were both evaluated using the forecast price and cost assumptions of McDaniel & Associates Consultants Ltd. Complete NI 51-101 oil and gas reserves disclosure for both Harvest and Viking on a "stand-alone" basis as at December 31, 2005 is included in Appendix A and B, respectively.

SUMMARY OF PRO FORMA OIL AND NATURAL GAS RESERVES
AND PRO FORMA NET PRESENT VALUES OF FUTURE NET REVENUE
as of December 31, 2005
FORECAST PRICES AND COSTS

	PRO FORMA RESERVES					
	LIGHT AND MEDIUM OIL(4)		HEAVY OIL(4)		NATURAL GAS	
RESERVES CATEGORY	Gross(1) (Mbbl)	Net(2) (Mbbl)	Gross(1) (Mbbl)	Net(2) (Mbbl)	Gross(1) (Mmcf)	Net(2) (Mmcf)
PROVED						
Developed Producing	62,341.2	55,879.8	32,280.3	29,171.7	189,532.3	156,563.5
Developed Non-Producing	1,155.7	1,034.8	1,826.0	1,521.0	27,326.1	22,493.8
Undeveloped	6,292.7	5,181.7	4,564.4	3,850.7	7,964.3	6,378.0
TOTAL PROVED	69,789.6	62,096.3	38,670.7	34,543.4	224,822.7	185,435.3
PROBABLE	23,139.4	20,219.3	17,971.2	15,864.4	70,726.9	58,466.7
TOTAL PROVED PLUS PROBABLE	92,929.0	82,315.6	56,641.9	50,407.8	295,549.6	243,902.0

	PRO FORMA RESERVES			
	NATURAL GAS LIQUIDS		TOTAL OIL EQUIVALENT	
RESERVES CATEGORY	Gross(1) (Mbbl)	Net(2) (Mbbl)	Gross(1) (Mboe)	Net(2) (Mboe)
PROVED				
Developed Producing	5,082.5	3,919.6	131,340.7	115,103.1
Developed Non-Producing	343.2	255.5	7,882.3	6,560.3
Undeveloped	234.9	170.8	12,419.4	10,266.2
TOTAL PROVED	5,660.6	4,345.9	151,591.4	131,891.5
PROBABLE	1,684.9	1,278.3	54,610.3	47,133.5
TOTAL PROVED PLUS PROBABLE	7,345.5	5,624.2	206,254.7	179,066.9

Notes:

(1) "Gross" reserves means the total working interest share of Harvest's and Viking's remaining recoverable reserves before deductions of royalties payable to others.
(2) "Net" reserves means Harvest's and Viking's gross reserves less all royalties payable to others.
(3) Columns may not add due to rounding.
(4) The reserves attributable to Harvest's Hay River property, which is an area that produces medium gravity crude oil (average 24° API), are subject to a heavy oil royalty regime in British Columbia and would be required, under NI 51-101, to be classified as heavy oil for that reason. We have presented Hay River reserves as medium gravity crude in the following reserve tables as they would otherwise be classified in this fashion were it not for the lower rate royalty regime applied in British Columbia. If the Hay River reserves were included in the heavy crude oil category, it would increase the gross heavy oil reserves and reduce the light/medium oil reserves by the following amounts: Proved Developed Producing: 11,445.0 Mboe, Proved Undeveloped: 3,407.1 Mboe, Total Proved: 14,852.1 Mboe, Probable: 3,874.3 Mboe and Proved plus Probable: 18,726.4 Mboe, and would increase the net heavy oil reserves and reduce the light/medium oil reserves by the following amounts: Proved Developed Producing: 10,100.7 Mboe, Proved Undeveloped: 2,778.6 Mboe, Total Proved: 12,879.3 Mboe, Probable: 3,247.6 Mboe, and Proved plus Producing: 16,126.9 Mboe.

RESERVES CATEGORY	PRO FORMA NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAXES DISCOUNTED AT (%/year) (1) 0% ($million)	5% ($million)	10% ($million)	15% ($million)	20% ($million)
PROVED					
Developed Producing	3,134.5	2,519.0	2,146.0	1,891.1	1,703.7
Developed Non-Producing	233.8	167.3	131.9	110.1	95.2
Undeveloped	226.3	181.1	145.8	118.4	96.8
TOTAL PROVED	3,594.5	2,867.4	2,423.7	2,119.6	1,895.7
PROBABLE	1,422.3	905.0	648.8	500.2	404.2
TOTAL PROVED PLUS PROBABLE	5,016.8	3,772.4	3,072.5	2,619.8	2,299.9

Note:
(1) Columns may not add due to rounding.

New Credit Facility

Concurrent with the closing of its merger with Viking on February 3, 2006, Harvest entered into a new $750 million three year extendible revolving credit facility. With the consent of the lenders, this facility may be extended on an annual basis for an additional 364 days and may also be increased to $900 million during secondary syndication which is expected to close by March 31, 2006. The facility is secured by a $1.5 billion first floating charge over all of the assets of the operating subsidiaries and a guarantee from the Trust. Amounts borrowed under this facility bear interest at a floating rate based on bankers acceptances plus 65 basis points to 115 basis points depending on the Trust's debt to cash flow ratio. Availability under this facility is subject to quarterly financial covenants requiring that the senior debt to cash flow ratio is less than 3 to 1, the total debt to cash flow ratio is less than 3.5 to 1, senior debt to total capitalization is less than 50% and total debt to total capitalization is less than 55%.

Significant Acquisitions

On August 2, 2005, Harvest closed an acquisition of approximately 5,200 boe/d of medium gravity oil (24° API) in the Hay River area of northeastern British Columbia for cash consideration of approximately $237.8 million, after closing adjustments. The Trust has filed a Business Acquisition Report dated October 14, 2005 in respect of the acquisition on SEDAR, which Form 51-102F4 is incorporated herein by reference.

On February 3, 2006, Harvest completed the Viking Arrangement. In connection with the special meeting of Harvest Securityholders which was held to approve this transaction, the Trust delivered to its Securityholders a joint information circular and proxy statement of Harvest and Viking dated December 30, 2005, which has been filed on SEDAR at www.sedar.com.

GENERAL BUSINESS DESCRIPTION

Overview

Harvest is an oil and natural gas royalty trust, which indirectly benefits from the operation of petroleum and natural gas assets located in Alberta, Saskatchewan and British Columbia. We employ a disciplined approach to management and acquire high working interest, large resource-in-place, producing properties and employ "best practice" technical and field operational processes to extract maximum value. These operational processes include: diligent hands-on management to maintain and maximize production rates, the application of technology and selective capital investment to maximize reservoir recovery and the enhancement of operational efficiencies to control and reduce expenses. As at March 20, 2006, Harvest Operations employs 323 full-time employees, 185 of which are located in the head office and 138 of which are located in the field.

For detailed information about Harvest's assets and operations for the year ended December 31, 2005, please see Appendix A-3 "HARVEST ENERGY STATEMENT OF RESERVES DATA". For detailed information relating to the assets and operations acquired through the Viking Arrangement, please refer to Appendix B-3 "VIKING ENERGY ROYALTY TRUST STATEMENT OF RESERVES DATA".

Business Strategies, Policies & Practices

Harvest's business strategy is focused on cash flow generation and increasing the value of its assets. The following strategies and business practices have been established to enhance the predictability of cash flow available for distribution by capturing the maximum cash flow, production and reserve recovery from the Properties on a longer term basis. The key elements of Harvest's strategy include the following:

Improve the Operating Netbacks of our Mature Properties

Harvest continues to fine-tune each well and improve all aspects of its operations. Harvest is focused on reducing costs, which increases netbacks and cash flow; strengthens net asset value and increases proved reserves. Harvest also intends to increase net revenues through proactive marketing initiatives.

Minimize Risk to Assets and Operating Results

Harvest employs a conservative fiscal management approach to minimize risk to assets and operating results which includes:

(i) Maintaining a strong balance sheet with prudent levels of debt,

(ii) Employing comprehensive risk-management tools to protect its assets and provide a reliable near-term cash flow. Price risk management includes hedging a significant portion of its commodity price risk and using fixed price forward purchase contracts for a significant portion of its electrical power consumption. Harvest has hedged the WTI price on approximately 56% of its expected 2006 oil production as well as the AECO price on approximately 5% of its expected 2006 natural gas production. In addition, Harvest has entered into fixed price forward purchase contracts for approximately 65% of its estimated 2006 electricity consumption. Harvest has constructed its hedging positions such that its exposure to downward movement of oil prices has been protected while maintaining some participation in the upward movement of commodities through the use of indexed puts and participating swaps. For further details on Harvest's price risk management contracts refer to Note 16 in Harvest's Consolidated Financial statements for the year ended December 31, 2005 filed on www.sedar.com.

(iii) In addition to its preventative maintenance of field facilities, Harvest maintains comprehensive insurance programs, continuing to seek out assets which increase Harvest's geographical and product diversification while acquiring a high working interests to maintain control over results and a strong environmental, health and safety program – See "Environmental, Health & Safety Policies & Practices").

(iv) Maintaining a conservative payout ratio, which is the ratio of funds distributed to its cash flow (as defined in Harvest's Management Discussion & Analysis filed on www.sedar.com). A conservative payout ratio provides Harvest with greater flexibility to repay indebtedness and continue to invest in capital projects throughout the commodity price cycle.

Selectively Acquire Mature Properties.

Harvest will continue to selectively acquire properties with an established production history. Once an asset is acquired, Harvest focuses its technical teams on improving resource recovery, reducing costs and extending reserve life from these properties. This approach is designed to increase production levels and extend property life thereby creating additional value for its unitholders. Harvest will continue to evaluate all future acquisitions on the basis of recycle ratio, which is the ratio of the operating netback per boe of production to the cost of acquiring a boe of reserves, targeting ratios in excess of 2 to 1 which should result in strong internal rates of return.

Continue to Recruit Excellent People.

Maximizing the value of Harvest's assets requires excellent technical, financial and managerial talent. Recruiting staff who share Harvest's goal of technical excellence, and institutionalizing a team oriented culture of value maximization and comprehensive risk management are key business principles for Harvest. Harvest has further strengthened its talent pool with selective personnel additions associated with asset acquisitions.

Insurance

Harvest maintains an insurance program with coverage levels determined after considering the perceived risk of a loss occurring, estimating maximum foreseeable loss potential and a review of the respective premiums and related deductibles. Currently, Harvest has property damage including business interruption coverage with an aggregate annual loss limit of $55 million plus separate coverage for machinery and boiler damage and related business interruption coverage also with an annual loss limit of $55 million, both with deductibles of $100,000 or less with the waiting period for business interruption being 15 days or less. In addition, Harvest carries $20 million of third party liability insurance and control well insurance in the amount of $15 million for a drilling or workover incident and $10 million for a producing or shit-in incident. In respect of its directors and officers, Harvest maintains a $20 million of liability coverage. Harvest believes these coverages are typical within the petroleum and natural gas industry.

In respect of the assets acquired pursuant to the Viking Arrangement, the insurance coverage in place on February 3, 2006 does not differ materially from the Harvest coverage. During 2006, Harvest will consolidate its insurance program in conjunction with a comprehensive assessment of the combined organization's requirements.

Environment, Health and Safety Policies and Practices

The petroleum and natural gas industry in Alberta, Saskatchewan and British Columbia is subject to extensive federal and provincial laws, rules and regulations relating to environmental, health and safety practices. Harvest is committed to ensuring its operations comply with the various laws, rules and regulations.

Harvest has established internal environmental, health and safety guidelines and system to ensure the health and safety of its employees, contractors and neighbouring residents and to ensure compliance with environmental laws, rules and regulations. These systems require Harvest to regularly conduct emergency response planning exercises to ensure its plans are effective and to inspect suspended wells, abandoned wells as well as site restoration plans and activities. Harvest's Manager of Environment, Health and Safety is responsible to monitor regulatory requirements and when required, implement appropriate compliance procedures and to cause our operations practices to be carried out in accordance with the applicable environmental requirements with adequate safety precautions. The Reserves, Safety and Environmental Committee of Harvest Operations' Board of Directors regularly reviews the results of these internal programs. Although the existence of these controls cannot guarantee total compliance with environmental laws, rules and regulations, Harvest believes that its operations are in material compliance with the applicable requirement.

Harvest is a Platinum Level participant in the Environmental, Health and Safety Stewardship Program initiated by the Canadian Association of Petroleum Producers (CAPP). This stewardship program provides comparison on key benchmarks including recordable and lost time injuries for employees and contractors. In 2005, Harvest's recordable injury frequency rate was 0.96 hours per 200,000 man hours with its contractors recording a lost time frequency rate of 1.16 per 200,000 man hours. As a Platinum Level, Harvest will conduct regular compliance audits of our safety program, will track and monitor our Green House Gas (GHG) emissions and report to CAPP annually.

In 2005, Harvest also implemented an Award of Excellence program to recognize employees making extraordinary contributions to environmental responsibility, regulatory compliance, and health and safety.

Harvest tracks asset retirement obligations and manages an active program to reduce obligations. In 2005, Harvest spent $4.2 million to abandon wells and to remediate and reclaim well sites and for 2005, has budgeted over $8 million for similar activities.

Unit Based Compensation

Harvest Operations' compensation includes the granting of rights under both its Unit Incentive Plan and Unit Award Incentive Plan each as more fully described in the Trust's Information Circular – Proxy Statement for the Annual and Special Meeting to be held on May 23, 2006 and filed on www.sedar.com.

As at March 20, 2006, there are 2,211,425 of rights granted under the Unit Incentive Plan and a further 189,915 rights granted under the Unit Award Incentive Plan.

Impact of Volatility in Commodity Prices

Our operational results and financial condition will be dependent on the prices received for oil and natural gas production. Oil and natural gas prices have fluctuated widely during recent years and are determined by supply and demand factors, including weather and general economic conditions, as well as conditions in other oil and natural gas regions. Any decline in oil and natural gas prices could have an adverse effect on our financial condition. We mitigate such price risk through closely monitoring the various commodity markets and establishing hedging programs, as deemed necessary, to provide stability to Unitholders' cash distributions.

A summary of financial and physical contracts in respect of hedging activities can be found in Note 16 "Financial Instruments and Risk Management Contracts" to our audited consolidated financial statements for the year ended December 31, 2005 and under the heading "Risk Management Contracts" in our management discussion and analysis and results of operations for the year ended December 31, 2005 which have been filed on www.sedar.com. Both Note 16 of the audited consolidated financial statements for the year ended December 31, 2005 and the "Risk Management Contracts" section of our 2005 management's discussion and analysis are incorporated herein by reference.

Renegotiation or Termination of Contracts

As at the date hereof, Harvest is not aware of any aspect of our business that will be materially affected in the remainder of 2006 by the renegotiation or termination of contracts or subcontracts.

ADDITIONAL INFORMATION REGARDING THE HARVEST ENERGY TRUST STRUCTURE

The Net Profits Interest Agreements

The net profits interests consist of the rights to receive a monthly payment from the Operating Subsidiaries pursuant to the terms of the net profits interest agreements equal to the amount by which ninety-nine (99%) percent of the gross proceeds from the sale of production attributable to Property Interests for such month (the "NPI Revenues") exceed ninety-nine (99%) percent of certain deductible production costs for such period. The residual 1% share of gross proceeds from the sale of production that does not form part of the net profits interests is retained by the Operating Subsidiaries, together with any income derived from Properties that are not Working Interests in Canadian resource properties. This residual revenue is used to defray certain expenses and capital expenditures of the Operating Subsidiaries.

In calculating the NPI Revenues, the Operating Subsidiaries deduct various costs and expenses. The Trust also reimburses the Operating Subsidiaries for Crown royalties and other Crown charges that are not deductible for income tax purposes and are payable by the Operating Subsidiaries in respect of production from or ownership of Operating Subsidiaries' Properties. The Operating Subsidiaries are entitled to set off the right to be so reimbursed against the obligation to the net profits interests.

Pursuant to the net profits interest agreements, the Trust must pay to the Operating Subsidiaries the Deferred Purchase Price Obligation. To satisfy the Deferred Purchase Price Obligation, the net proceeds of any issue of the Trust Units or the proceeds from the disposition of the net profits interest on any Properties are paid to the Operating Subsidiaries. The Trust is not required to pay an amount as a Deferred Purchase Price Obligation except to the extent the Trust has such proceeds available. See "Deferred Purchase Price Obligation" below for a more detailed description of the Deferred Purchase Price Obligation.

Pursuant to the net profits interest agreements, substantially all of the economic benefit derived from the assets of the Operating Subsidiaries accrues to the benefit of the Trust and ultimately to the Unitholders. The term of each of the net profit interest agreements is for so long as there are petroleum and natural gas rights to which the net profits interest agreement applies.

In addition to the net profits interests, the Trust owns a beneficial interest in the Direct Royalties and the Trust may acquire further Direct Royalties. Such Direct Royalties may consist of direct petroleum and natural gas royalty interests and may be acquired from time to time.

Deferred Purchase Price Obligation

Pursuant to the net profits interest agreements, the Deferred Purchase Price Obligation consists of an ongoing obligation of the Trust to pay to the Operating Subsidiaries, to the extent of the Trust's available funds, an amount equal to the sum of the following, less amounts financed by the Operating Subsidiaries from debt:

(a) the portion of acquisition costs incurred by the Operating Subsidiary from time to time which are attributable to Canadian resource property; plus

(b) certain designated drilling, completion, equipping and other costs, in respect of the Properties; plus

(c) the portion of indebtedness incurred in respect of such acquisition costs and capital expenditures, payable at the time of satisfaction by the Operating Subsidiary of such indebtedness.

To satisfy the Deferred Purchase Price Obligation, the Trust is required to pay over to the Operating Subsidiaries the net proceeds of any issue of the Trust Units or the proceeds from the disposition of the net profits interest of any Properties held by the Operating Subsidiaries. The Trust is not obligated to pay an amount as a Deferred Purchase Price Obligation except to the extent the Trust has such proceeds available.

To the extent that the Operating Subsidiaries designates an expenditure as a Deferred Purchase Price Obligation:

(d) if the designated expenditure is funded by issuing additional Trust Units, by the proceeds of dispositions of the Canadian resource property component of Properties, by the disposition of Direct Royalties or by the issuance of debt, it will not be a charge against the net profits interest, and therefore will not reduce payments from the net profits interest to the Trust or distributions to Unitholders;

(e) the Trust will be obliged to pay to the Operating Subsidiaries 99% of the amount of the designated expenditure to the extent not funded by borrowing by the Operating Subsidiaries;

(f) the cost to the Trust of the designated expenditure will be added to the Canadian oil and gas property expense ("COGPE") account of the Trust, thus creating additional tax deductions (see "Canadian Federal Income Tax Considerations"); and

(g) the additional revenue generated from the Properties acquired by the designated expenditure will be added to the revenues used to calculate income from the net profits interest, thereby potentially increasing the amount payable to the Trust under the net profits interest agreements.

Reserve Fund

Under the net profits interest agreements, the Operating Subsidiaries are entitled to pay such amounts of the revenues received from Production and other income received by the Operating Subsidiaries in respect of the Properties into the Reserve Fund if, as and when Harvest Operations determines, in its reasonable discretion, that it is prudent to do so in accordance with prudent business practices, to provide for payment of production costs that Harvest Operations estimates will or may become payable in the next six months for which there may not be sufficient revenues to satisfy such costs in a timely manner. Funds retained by the Operating Subsidiaries in the Reserve Fund are required to be used by the Operating Subsidiaries to fund the payment of production costs. To the extent that funds are drawn from the Reserve Fund and used to pay production costs, such amounts will be deducted from the net profits interest.

Reclamation Fund

Each of the Operating Subsidiaries is liable for their share of ongoing environmental obligations and for the ultimate reclamation of the Properties upon abandonment. Pursuant to the net profits interest agreements, the Operating Subsidiaries have established a funding strategy for the purpose of funding currently estimated future environmental and reclamation obligations. To the extent that funds from the reclamation funds are used for site restoration and well and facility abandonment expenditures such amounts are deducted in calculating income from the net profits interest.

Ongoing environmental obligations are currently expected to be funded out of debt and future cash flow and will reduce the amount of income from the net profits interest payable to the Trust. At this time, the Operating Subsidiaries have not established a reclamation account to finance these obligations.

In addition to the identified producing wells and wells capable of production, the Properties include interests in approximately 612 gross (583 net) active injection, disposal or service wells and 696 gross (636 net) suspended or shut-in wells, all of which have been included in the total estimate of the Corporation's future environmental and reclamation obligations.

Cash Available For Distribution

Cash Available For Distribution consists of any amounts received by the Trust pursuant to the net profits interests and the Direct Royalties, any interest or other income from Permitted Investments, ARTC received by the Trust net of non-deductible Crown royalties that are reimbursed by the Trust to the Operating Subsidiaries, dividends on the shares of the Operating Subsidiaries or any other dividends on securities of the Operating Subsidiaries less all expenses and liabilities of the Trust, including debt service costs, which are due or accrued and which are chargeable to income.

Pursuant to the Trust Indenture and the Administration Agreement, Harvest Operations calculates income from the net profits interests for each calendar month and arranges for payment of certain direct expenses of the Trust from the proceed of the net profits interests.

The actual amount of Cash Available For Distribution depends on, among other things, the quantity and quality of crude oil, natural gas and natural gas liquids produced, prices received for such production, direct expenses of the Trust, taxes, operating costs, transportation and processing costs, capital expenditures, debt service costs, Crown and other royalties, other Crown charges, net contributions to the reclamation funds, net contributions by the Operating Subsidiaries to the Reserve Fund, and general and administrative costs of the Trust and the Operating Subsidiaries. See "Risk Factors".

The Operating Subsidiaries also have the discretion to incur debt or retain cash in order to modify seasonal and other variations in Cash Available For Distribution. Unitholders may also receive distributions of the net proceeds received from sales of Properties to the extent Harvest Operations determines not to use those proceeds to acquire additional Properties.

Unitholders of record on a Record Date are entitled to receive monthly cash distributions of the Distributable Cash which will become payable on the 15th day following the Record Date, and if such date of payment is not a Business Day on the next Business Day after the 15th day following the Record Date.

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 if 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.

Any portion of Distributions to Unitholders that is deducted by the Trust for its income tax purposes is treated as a return of capital for unitholders and reduces the adjusted cost base of their trust units held. In this respect, the taxation of capital distributions is deferred until an actual or deemed disposition of Trust Units occurs or a unitholder's Trust Units have an adjusted cost base that is less than zero.

Borrowing

The Operating Subsidiaries and the Trust are permitted to incur indebtedness to purchase Property Interests, fund capital expenditures or other obligations or expenditures in respect of the Properties or for working capital purposes. Indebtedness of the Operating Subsidiaries to fund the purchase of Canadian resource properties may be repaid with funds received from the Trust pursuant to the Deferred Purchase Price Obligation. All borrowings by the Trust and the Operating Subsidiaries require approval by the Board of Directors of Harvest Operations.

The Board of Directors of Harvest Operations has established the following guidelines with respect to the indebtedness of the Operating Subsidiaries: (i) amounts borrowed to finance the purchase of Properties should not exceed 50% of the Reserve Value of all Properties including those to be acquired at the time of borrowing as shown on the latest available independent engineering report, unless specifically approved by the Board of Directors; and (ii) the estimated annual debt service costs for the 12 months following the borrowing on amounts borrowed to finance capital expenditures or other financial obligations or expenditures required to maintain or improve production from the Properties should not exceed 50% of the estimated income from the NPI and income from Direct Royalties for such 12 month period, unless specifically approved. The Operating Subsidiaries are entitled to grant security in priority to the various net profits interests and the Trust is permitted to grant security on the various net profits interests and Direct Royalties to secure the loan of funds directly to the Trust or secure guarantees granted by the Trust of indebtedness of the Operating Subsidiaries.

Debt service costs of the Operating Subsidiaries are deducted in computing NPI income and debt service costs of the Trust are deducted in computing Cash Available For Distribution to unitholders.

Senior Credit Facility

At December 31, 2005, Harvest had $13.9 million drawn under a $400 million credit facility. The $400 million credit facility consisted of a $375 million production facility plus a $25 million operating facility. This credit facility enabled funds to be borrowed, repaid and re-borrowed within the term in either Canadian or U.S. dollars and it may have been extended for an additional 364 day period on an annual basis with the agreement of the lenders. If the term was not extended, the credit facilities would have converted to a 366 non-revolving term loan with no payment due until August 2, 2007. Amounts borrowed under the production and operating facilities bear interest at a floating rate based on the applicable Canadian or U.S. prime rate plus a range of 0 to 225 basis points depending on the type of borrowing and Harvest’s debt to annualized cash flow ratio, as defined in the Credit Agreement. Availability under this facility was subject to a reserve based borrowing calculation performed by the lender at least on a semi annual basis. As at December 31, 2005, Harvest was in compliance with all covenants.

The facility described above was repaid February 3, 2006 with proceeds from a new credit facility entered into concurrent with the closing of the Viking Arrangement. The new credit facility is a $750 million three year extendible revolving credit facility. With the consent of the lenders, this facility may be extended on an annual basis for an additional 364 days and may also be increased to $900 million during secondary syndication which is expected to close by March 31, 2006. The new facility is secured by a $1.5 billion first floating charge over all of the assets of the operating subsidiaries and a guarantee from the Trust. Amounts borrowed under this facility bear interest at a floating rate based on bankers acceptances plus a range of 65 to 115 basis points depending on Harvest's ratio of senior debt (excluding convertible debentures) to earnings before interest, taxes, depletion, amortization and other non-cash amounts. Availability under this facility varies depending on the following quarterly financial covenant requirements:

Covenant Ratio	**Covenant Requirement**
Senior Debt to EBITDA	3 to 1 or less
Total Debt to EBITDA	3.5 to 1 or less
Senior Debt to Capitalization	50% or less
Total Debt to Capitalization	55% or less

As of March 20, 2006, approximately $200 million is outstanding under Harvest's credit facility.

$7^{7/8}$% Senior Notes

On October 14, 2004, Harvest Operations completed a private placement of US$250 million of $7^{7/8}$% Senior Notes due October 15, 2011. The Senior Notes are unsecured and were sold at a price of 99.3392% of their principal amount with interest payable semi-annually on April 15 and October 15. The $7^{7/8}$% Senior Notes are unconditionally guaranteed by the Trust and the Operating Subsidiaries. On January 10, 2005, Harvest Operations completed an exchange offer whereby the outstanding US $250 million of $7^{7/8}$% Senior Notes were exchanged for US $250 million of new $7^{7/8}$% Senior Notes which were registered under the Securities Act of 1933 and thereafter were tradable securities.

Commencing on October 15, 2008, the $7^{7/8}$% Senior Notes may be redeemed at a price of 103.938% of the principal amount plus accrued and unpaid interest with the redemption price declining each year after 2009 resulting in a redemption price of 100% of the principal amount plus accrued interest beginning October 15, 2010. Using the proceeds from a trust unit offering, 35% of the principal amount of $7^{7/8}$% Senior Notes outstanding at the time may be redeemed at a price of 107.875% plus accrued interest at any time prior to October 15, 2007. Prior to October 15, 2008, the $7^{7/8}$% Senior Notes may be redeemed at a price of 103.938% of the principal amount plus accrued interest if such redemption is necessary to maintain the Trust's status as a "unit trust" or a "mutual fund trust" under the Tax Act. Further if Canadian withholding tax changes were to take place that required Harvest Operations to pay withholding tax on interest payments on the $7^{7/8}$% Senior Notes, the $7^{7/8}$% Senior Notes could be redeemed at 100% of their principal amount plus accrued interest.

Upon a change of control of Harvest (as defined in the note indenture respecting the $7^{7/8}$% Senior Notes), Harvest Operations is required to make an offer to purchase the $7^{7/8}$% Senior Notes at a price of 101% of the principal amount plus accrued interest.

The terms of the $7^{7/8}$% Senior Notes may limit Harvest's ability to incur additional indebtedness; make investments or certain restricted payments; engage in sale-leaseback transactions; enter into transactions with Unitholders or affiliates of Harvest Operations; guarantee debts; sell assets and utilize the proceeds; create liens; issue and sell stock in the Operating Subsidiaries; and, merge or amalgamate with other corporations. The Trust may also be subject to restrictions regarding the amount of distributions paid or the amount of dividends or other payments made to the Operating Subsidiaries. Certain of these covenants may cease to be in effect should Moody's Investor Service and Standard and Poor's Rating Services each assign the $7^{7/8}$% Senior Notes an investment grade credit rating.

Convertible Debentures

Subsequent to the closing of the Viking Arrangement, the Trust has either issued or assumed five series of unsecured subordinated convertible debentures. Each series of debentures has the following common features: interest payable on a semi-annual basis; convertible into fully paid and non-assessable Trust Units at the option of the holder; and redeemable by the Trust at its option in whole or in part two years prior to the maturity date at a price equal to $1,050 per debenture and at a price equal to $1,025 per debenture one year prior to the maturity date. At redemption, the Trust is also required to pay accrued and unpaid interest.

The following table summarized certain terms of each series of debentures including the principal amount outstanding as of March 20, 2006:

Series and Year of Maturity	Interest Rate at Date of Issue	Principal Amount Outstanding	Conversion Price per Trust Unit	Number of Trust Units Reserved
Series 1 due 2009	9%	$1,570,000	$13.85	113,357
Series 2 due 2009	8%	3,209,000	$16.07	199,689
Series 3 due 2010	6.5%	38,738,000	$31.00	1,249,613
Series 4 due 2008	10.5%	33,913,000	$29.00	1,169,414
Series 5 due 2012	6.4%	174,945,000	$46.00	3,803,152
Total		$252,375,000		6,535,225

For a complete description of the terms of the Debentures Series 1, Debentures Series 2 and Debentures Series 3, a copy of the trust indenture and supplemental indentures has been filed on www.sedar.com under the Harvest profile. For a complete description of the terms of the Debentures Series 4 and Debentures Series 5, a copy of the trust indenture and supplemental indenture has been filed on www.sedar.com under the Viking profile.

INDUSTRY CONDITIONS

The oil and natural gas industry is subject to extensive controls and regulations governing its operations (including land tenure, exploration, development, production, refining, transportation and marketing) imposed by legislation enacted by various levels of government and with respect to pricing and taxation of oil and natural gas by agreements among the governments of Canada, Alberta, British Columbia and Saskatchewan, all of which should be carefully considered by investors in the oil and gas industry. It is not expected that any of these controls or regulations will affect Harvest's operations in a manner materially different than they would affect other oil and gas entities of similar size. All current legislation is a matter of public record and we are 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, Natural Gas and Associated Products

In the provinces of Alberta, British Columbia and Saskatchewan oil, natural gas and associated products are generally sold at market index based prices. These indices are generated at various sales points depending on the commodity and are reflective of the current value of the commodity adjusted for quality and locational differentials. While these indices tend to track industry reference prices (ie. price of West Texas Intermediate crude oil at Cushing, Oklahoma or price of natural gas at Henry Hub, Louisiana), some variances can occur due to specific supply-demand imbalances. These differentials can change on a monthly or daily basis depending on the supply-demand fundamental at each location as well as other non-related changes such as the value of the Canadian dollar and the cost of transporting the commodity to the pricing point of the particular index.

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 other contractual terms. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the 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 license from the NEB and the issuance of such license requires the approval of the Governor in Council.

The price of natural gas is determined by negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas exports for a term of less than 2 years or for a term of 2 to 20 years (in quantities of not more than 30,000 m^3/day) must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or a larger quantity requires an exporter to obtain an export license from the NEB and the issuance of such license requires 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.

Pipeline Capacity

Although pipeline expansions are ongoing, pipeline capacity ia an important consideration and may impact the oil and natural gas industry by limiting 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, United States of America and Mexico became effective on January 1, 1994. NAFTA carries forward most of the material energy terms that are contained in the Canada-United States Free Trade Agreement. In the context of energy resources, Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to domestic use (based upon the proportion prevailing in the most recent 36 month period or in such other representative period as the parties may agree); (ii) impose an export price higher than the domestic price subject to an exception with respect to certain measures which only restrict the volume of exports; and (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum or maximum export or import price requirements provided, in the case of export-price requirements, prohibition in any circumstances in which any other form of quantitative restriction is prohibited, and in the case of import-price requirements, such requirements do not apply with respect to enforcement of countervailing and anti-dumping orders and undertakings.

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

Provincial Royalties and Incentives

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

From time to time the governments of the western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays and tax credits, and are generally introduced when commodity prices are low. The programs are designed to encourage exploration and development activity by improving earnings and cash flow within the industry. Royalty holidays and reductions would reduce the amount of Crown royalties paid by oil and gas producers to the provincial governments and would increase the net income and funds from operations of such producers. However, the trend in recent years has been for provincial governments to allow such incentive programs to expire without renewal, and consequently few such incentive programs are currently operative.

On March 3, 2003 the Department of Finance (Canada) released a technical paper entitled "Improving the Income Taxation of the Resource Sector in Canada" (the "Technical Paper"). In November, 2003 the Tax Act was amended to provide the following initiatives applicable to the oil and gas industry (to a maximum of $2,000,000) to be phased in over a five year period: (i) a reduction of the federal statutory corporate income tax rate on income earned from resource activities from 28% to 21%, beginning with a one percentage point reduction effective January 1, 2003, and (ii) a deduction for federal income tax purposes of actual provincial and other Crown royalties and mining taxes paid and the elimination of the 25% resource allowance. In addition, the percentage of Alberta Royalty Tax Credit that Harvest will be required to include in federal taxable income was 12.5% in 2004 and 17.5% in 2005; and will be 32.5% in 2006; 50% in 2007; 60% in 2008; 70% in 2009; 80% in 2010; 90% in 2011, and 100% in 2012 and beyond.

Alberta

Regulations made pursuant to the *Mines and Minerals Act* (Alberta) provide various incentives for exploring and developing oil reserves in Alberta. Oil produced from horizontal extensions commenced at least 5 years after the well was originally spudded may also qualify for a royalty reduction. A 24-month, 8,000 m^3 exemption is available to production from a reactivated well that has not produced for: (i) a 12-month period, if resuming production in October, November or December of 1992 or January, 1993; or (ii) a 24 month period, if resuming production in February 1993 or later. As well, oil production from eligible new field and new pool wildcat wells and deeper pool test wells spudded or deepened after September 30, 1992 is entitled to a 12-month royalty exemption (to a maximum of $1 million). Oil produced from low productivity wells, enhanced recovery schemes (such as injection wells) and experimental projects is also subject to royalty reductions.

Oil royalty rates vary from province to province. In Alberta, oil royalty rates vary between 10% and 35% for oil and 10% and 30% for new oil. New oil is applicable to oil pools discovered after March 31, 1974 and prior to October 1, 1992. The Alberta government introduced the Third Tier Royalty with a base rate of 10% and a rate cap of 25% for oil pools discovered after September 30, 1992.

Effective January 1, 1994, the calculation and payment of natural gas royalties became subject to a simplified process. The royalty reserved to the Crown in respect of natural gas production, subject to various incentives, is between 15% and 30%, in the case of new natural gas, and between 15% and 35%, in the case of old natural gas, depending upon a prescribed or corporate average reference price. Natural gas produced from qualifying exploratory natural gas wells spudded or deepened after July 31, 1985 and before June 1, 1988 continues to be eligible for a royalty exemption for a period of 12 months, or such later time that the value of the exempted royalty quantity equals a prescribed maximum amount. Natural gas produced from qualifying intervals in eligible natural gas wells spudded or deepened to a depth below 2,500 meters is also subject to a royalty exemption, the amount of which depends on the depth of the well.

Alberta’s current royalty system for oil sands, introduced in 1997 and expiring June 30, 2007, is designed to support the development of the oil sands industry. An initial royalty of 1% of the quantity of oil sands product that is recovered and delivered to the royalty calculation point is payable until the project has recovered specified allowed costs, including certain exploration and development costs, operating costs, a return allowance and royalties paid to the Crown. Subsequent to such recovery, the royalty payable is the greater of the aforesaid 1% royalty and 25% of the net revenue from an oil sands project. The foregoing royalty will approximate a 1% royalty on gross revenue before payout and a 25% royalty on net revenue after payout.

In Alberta, a producer of oil or natural gas is entitled to a credit on qualified oil and natural gas production against the royalties payable to the Crown by virtue of the Alberta Royalty Tax Credit ("ARTC") program. The ARTC rate is based on a price sensitive formula and the ARTC rate varies between 75% at prices at and below $100 per m3 and 25% at prices at and above $210 per m3. Crude oil and natural gas royalty programs for specific wells and royalty reductions reduce the amount of Crown royalties paid by Harvest to the provincial governments. In general, the ARTC program provides a rebate on Alberta Crown royalties paid in respect of eligible producing properties. The ARTC rate is applied to a maximum of $2,000,000 of Alberta Crown royalties payable for each producer or associated group of producers. Crown royalties on production from producing properties acquired from a corporation claiming maximum entitlement to ARTC will generally not be eligible for ARTC. The rate will be established quarterly based on the average "par price", as determined by the Alberta Department of Energy for the previous quarterly period.

On December 22, 1997, the Alberta government announced that it was conducting a review of the ARTC program with the objective of setting out better targeted objectives for a smaller program and to deal with administrative difficulties. On August 30, 1999, the Alberta government announced that it would not be reducing the size of the program but that it would introduce new rules to reduce the number of persons who qualify for the program. The new rules will preclude companies that pay less than $10,000 in royalties per year and non-corporate entities from qualifying for the program. Such rules will not presently preclude Harvest from being eligible for the ARTC program.

British Columbia

Producers of oil and natural gas in the Province of British Columbia are also required to pay annual rental payments in respect of the Crown leases and royalties and freehold production taxes in respect of oil and gas produced from Crown and freehold lands, respectively. The amount payable as a royalty in respect of oil depends on the type of oil, the value of the oil, the quantity of oil produced in a month and the vintage of the oil. Generally, 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). Oil produced from newly discovered pools may be exempt from the payment of a royalty for the first 36 months of production. The royalty payable on natural gas is determined by a sliding scale based on a reference price, which is the greater of the amount obtained by the producer, and a prescribed minimum price. As an incentive for the production and marketing of natural gas, which may have been flared, natural gas produced in association with oil has a lower royalty then the royalty payable on non-conservation gas.

On May 30, 2003, the Ministry of Energy and Mines for the province of British Columbia announced an Oil and Gas Development Strategy for the Heartlands ("Strategy"). The Strategy is a comprehensive program to address road infrastructure, targeted royalties, and regulatory reduction and British Columbia service sector opportunities. In addition, the Strategy will result in economic and employment opportunities for communities in British Columbia's heartlands.

Some of the financial incentives in the Strategy include:

- Royalty credits of up to $30 million annually towards the construction, upgrading and maintenance of road infrastructure in support of resource exploration and development. Funding will be contingent upon an equal contribution from industry.

- Changes to provincial royalties: new royalty rates for low productivity natural gas to enhance marginally economic resources plays, royalty credits for deep gas exploration to locate new sources of natural gas, and royalty credits for summer drilling to expand the drilling season.

Saskatchewan

In Saskatchewan, the amount payable as a royalty in respect of oil depends on the vintage of the oil, the type of oil, the quantity of oil produced in a month and the value of the oil. For Crown royalty and freehold production tax purposes, crude oil is considered "heavy oil", "southwest designated oil" or "non-heavy oil other than southwest designated oil". The conventional royalty and production tax classifications ("fourth tier oil" introduced October 1, 2002, "third tier oil", "new oil" or "old oil") of oil production are applicable to each of the three crude oil types. The Crown royalty and freehold production tax structure for crude oil is price sensitive and varies between the base royalty rates of 5% for all "fourth tier oil" to 20% for "old oil". Marginal royalty rates are 30% for all "fourth tier oil" to 45% for "old oil".

The amount payable as a royalty in respect of natural gas is determined by a sliding scale based on a reference price (which is the greater of the amount obtained by the producer and a prescribed minimum price), the quantity produced in a given month, the type of natural gas and the vintage of the natural gas. As an incentive for the production and marketing of natural gas which may have been flared, the royalty rate on natural gas produced in association with oil is less than on non-associated natural gas. The royalty and production tax classifications of gas production are "fourth tier gas" introduced October 1, 2002, "third tier gas", "new gas" and "old gas". The Crown royalty and freehold production tax for gas is price sensitive and varies between the base royalty rate of 5% for "fourth tier gas" and 20% for "old gas". The marginal royalty rates are between 30% for "fourth tier gas" and 45% for "old gas".

On October 1, 2002, the following changes were made to the royalty and tax regime in Saskatchewan:

- A new Crown royalty and freehold production tax regime applicable to associated natural gas (gas produced from oil wells) that is gathered for use or sale. The royalty/tax will be payable on associated natural gas produced from an oil well that exceeds approximately 65 thousand cubic meters in a month.

- A modified system of incentive volumes and maximum royalty/tax rates applicable to the initial production from oil wells and gas wells with a finished drilling date on or after October 1, 2002 was introduced. The incentive volumes are applicable to various well types and are subject to a maximum royalty rate of 2.5% and a freehold production tax rate of zero per cent.

- The elimination of the re-entry and short section horizontal oil well royalty/tax categories. All horizontal oil wells with a finished drilling date on or after October 1, 2002 will receive the "fourth tier" royalty/tax rates and new incentive volumes.

On March 23, 2005, the Government of Saskatchewan passed legislation to subject trusts to their Corporation Capital Tax Resource Surcharge (the “Resource Surcharge”) with an effective date of April 1, 2005. The Resource Surcharge is calculated based on the applicable oil and natural gas revenues earned in Saskatchewan at a rate of 3.6% for wells drilled prior to October 1, 2002 and at a rate of 2% for wells drilled on or after October 1, 2002. Prior to this legislation, the Resource Surcharge did not apply to resource trusts

Land Tenure

Crude oil and natural gas located in western Canada 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 2 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.

Environmental Regulation

The oil and natural gas industry is subject to environmental regulation pursuant to a variety of international conventions and Canadian federal, provincial and municipal laws, regulations, and guidelines. Such regulation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations. In addition, such regulation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such regulation 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.

Environmental legislation in the Province of Alberta has been consolidated into the *Environmental Protection and Enhancement Act* (Alberta) (the "AEPEA"), which came into force on September 1, 1993 and the *Oil and Gas Conservation Act* (Alberta) (the "OGCA"). The AEPEA and OGCA impose stricter environmental standards, requires more stringent compliance, reporting and monitoring obligations and significantly increase penalties. Harvest is committed to meeting its responsibilities to protect the environment wherever it operates and anticipates making increased expenditures of both a capital and an expense nature as a result of the increasingly stringent laws relating to the protection of the environment and will be taking such steps as required to ensure compliance with the AEPEA and similar legislation in other jurisdictions in which it operates. Harvest believes that it is in material compliance with applicable environmental laws and regulations and also believes that it is reasonably likely that the trend towards stricter standards in environmental legislation and regulation will continue.

British Columbia's *Environmental Assessment Act* became effective June 30, 1995. This legislation rolls the previous processes for the review of major energy projects into a single environmental assessment process with public participation in the environmental review process.

In December 2002, the Government of Canada ratified the Kyoto Protocol ("Protocol"). The Protocol calls for Canada to reduce its greenhouse gas emissions to 6% below 1990 "business-as-usual" levels between 2008 and 2012. Given revised estimates of Canada's normal emissions levels, this target translates into an approximately 40% gross reduction in Canada's current emissions. In April 2005, Environment Canada released "Project Green", a working paper giving early indications of how implementation was to be achieved. Large Final Emitters ("LFEs"), being 700 of Canada's largest emitters, will receive a specific reduction target of 45 megatonnes, and will have the opportunity to purchase domestic offset and technology credits. The exact mechanism for operating in the domestic credit market has yet to be revealed, and the prospect of non-LFE enterprise participating in that market to any great extent is uncertain. Various incentive funds have also been established to provide seed funding for the purchase of experimental technologies, encourage investment in alternative energy sources, and acquire credits from the domestic and international markets for re-sale to Canadian enterprise.

Environment Canada, in August 2005, released consultation papers for the management of a system of greenhouse gas offsets in the form of tradable and bankable credits. The credits are created by enterprise, individuals, or municipal government through the implementation of projects registered with the to-be-created offset authority. Standards for quantifying greenhouse gas reductions were also proposed in the consultation paper.

RISK FACTORS

Harvest’s operations are conducted in the same business environment most other petroleum and natural gas operators and the business risks are very similar. However, the Harvest Energy Trust structure is significantly different than that of a traditional corporation with share capital and there are certain unique business risks of Harvest’s structure. Accordingly, Harvest’s business risks have been segregated into those generally applicable to petroleum and natural gas operators and those applicable to royalty trusts as well as those risks particular to Unitholders resident in the United States and other non-residents of Canada.

The following information is a summary 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 Annual Information Form.

Risks Related to Harvest's Petroleum and Natural Gas Operations

Volatility of Commodity Prices and Foreign Exchange Risk

The Trust's results of operations and financial condition are dependent on its cash flow from its net profits interests and the Direct Royalties which are dependent on the prices received for the sale of petroleum, natural gas and natural gas liquids production. Prices for petroleum, natural gas and natural gas liquids have fluctuated widely during recent years and are determined by supply and demand factors, including weather and general economic conditions as well as conditions in other oil producing regions, which are beyond the control of Harvest Operations or the Trust. Oil prices received from production in Canada also reflect changes in the Canadian/U.S. currency exchange rate. A decline in petroleum and/or natural gas prices or an increase in the Canadian/US currency exchange rate could have a material adverse effect on the Trust's operations, financial condition and the amount of cash available for distribution as well as funds available for the development of its Operating Subsidiaries oil and natural gas reserves. From time to time, Harvest Operations may manage the risk of changes in commodity prices and currency exchange rates by entering into commodity price risk management contracts and/or currency exchange contracts. To the extent that Harvest Operations or the Trust engage in risk management activities related to commodity prices and currency exchange rates, it will be subject to counterparty risk. In addition, commodity price risk management contracts may require, from time to time, margin payments to be made which could reduce the Trust's cash available for distribution to Unitholders.

Crude Oil Differentials

At the end of 2005, Harvest's production was approximately 53% light and medium gravity crude oil, 34% heavy oil and 13% natural gas and associated liquids. Processing and refining heavy oil is more expensive than processing and refining light oil and accordingly, producers of heavy oil receive lower prices from refiners or their marketing intermediaries. The differential between light oil and heavy oil has fluctuated widely during recent years and when compounded with the fluctuations in the benchmark prices for light oil, the result is a substantial increase in the volatility of heavy oil prices. An increase in the heavy oil differential usually results in Harvest receiving lower prices for its heavy oil and could have a material adverse effect on the Trust's operations, financial condition and the amount of cash available for distribution as well as funds available for the development of its oil and natural gas reserves. The heavy oil price differential is normally the result of the seasonal supply and demand for heavy oil, pipeline constraints and heavy oil processing capacity of refineries, all of which are beyond the control of Harvest Operations.

Operational Matters

The operation of oil and natural gas wells involves a number of operating and natural hazards which may result in blowouts, environmental damage and other unexpected or dangerous conditions resulting in damage to Harvest Operation's assets and potentially, liability to third parties. Harvest Operations employs prudent risk management practices and maintains liability insurance in amounts consistent with industry standards. Business interruption insurance has been purchased for selected facilities. Operating Subsidiaries may become liable for damages arising from such events against which it cannot insure against or which it may elect not to insure because of high premium costs or other reasons. Costs incurred to repair such damage or pay such liabilities will reduce the Trust's cash flow from its net profits interest.

Continuing production from a property and to some extent, the marketing of production therefrom, are largely dependent upon the capabilities of the operator of the property. To the extent the operator fails to perform its duties properly, production may be reduced and proceeds from the sale of production from properties operated by third parties may be negatively impacted. Although Harvest Operations operates the majority of the Properties, there is no guarantee that it will remain operator of such Properties or that it will operate other Properties that may be acquired.

A significant portion of Harvest's operating expenses are electrical power costs. Since deregulation of the electrical power system in Alberta in recent years, electrical power prices have been set by the market based on supply and demand and recently, electrical power price in Alberta have been volatile. Generally, this volatility has resulted in higher electrical power prices which negatively impact Harvest's operating expenses, and in turn, the Trust's Cash

Available For Distribution. To mitigate its exposure to the volatility in electrical power prices, Harvest Operations has entered into fixed priced forward purchase contracts. In respect of its operations in Saskatchewan, the Saskatchewan power system is regulated and as such, electrical power costs are not subject to significant volatility. However, there can be no certainty that the Saskatchewan power system will not deregulate in the future.

Although satisfactory title reviews will generally be conducted on the Properties in accordance with industry standards, such reviews do not guarantee or certify that a defect in title may not arise to defeat the claim of an Operating Subsidiary to certain Properties. A reduction of cash flow from a net profits interest or income from Direct Royalties payable to the Trust could result from such circumstances.

Harvest's ability to market oil and natural gas from its wells also depends upon numerous other factors beyond its control, including:

- The availability of capacity to refine heavy oil;
- The availability of natural gas processing capacity;
- The availability of pipeline capacity;
- The availability of diluent to blend with heavy oil to enable pipeline transportation;
- The price of oilfield services;
- The accessibility of remote areas to drill and subsequently service wells and facilities; and,
- The effects of inclement weather;

Because of these factors, Harvest may be unable to market all of the oil or natural gas it is capable of producing or to obtain favourable prices for the oil and natural gas it produces.

Reserve Estimates

The reserve and recovery information contained in Harvest's Reserve Reports are only an estimate, such estimates are complex to determine, and the actual production and ultimate reserves recovered from the Properties may differ from the estimates prepared by the Independent Reserve Engineering Evaluators.

Depletion of Reserves (Sustainability)

Harvest's Cash Available For Distribution, absent commodity price increases or cost effective acquisition and development activities, will decline over time in a manner consistent with declining production from typical oil, natural gas and natural gas liquids reserves. Harvest will not be reinvesting to the same extent as other industry participants as it makes cash distribution to its unitholders. Accordingly, absent additional capital investment from other sources, production levels and reserves attributable to the Properties will decline.

The Operating Subsidiaries' future oil and natural gas reserves and production, and therefore its cash flows, will be highly dependent on their success in exploiting its resource base and acquiring additional reserves. Without reserve additions through acquisition or development activities, the Operating Subsidiaries' reserves and production will decline over time as reserves are produced.

There is strong competition relating to all aspects of the oil and natural gas industry. Harvest's Operating Subsidiaries will actively compete for acquisitions and skilled industry personnel with a substantial number of other oil and natural gas companies, many of which have significantly greater financial and other resources than the Operating Subsidiaries.

There can be no assurance that the Operating Subsidiaries will be successful in developing or acquiring additional reserves on terms that meet the Operating Subsidiaries' investment objectives.

Debt Service

As of March 20, 2006, Harvest has indebtedness of approximately $200 million under its credit facility. In addition, letters of credit have been issued to third parties totalling approximately $5 million on behalf of Harvest Operations to secure services, primarily electric power, for the Properties. Harvest Operations has also issued U.S.$250 million of $7^{7/8}$% Senior Notes due October 15, 2011 on which semi-annual interest payments are required. See "Information Regarding the Harvest Energy Trust Structure – Borrowings - $7^{7/8}$% Senior Notes".

The Operating Subsidiaries have been provided with security over all of its assets to the providers of its credit facilities. If Harvest commits an event of default or the lenders demand repayment, the lenders may foreclose on and/or sell the Properties free from, or together with, the net profits interest encumbrance.

Certain payments by the Operating Subsidiaries and distributions to the unitholders by the Trust are prohibited upon an event of default or demand for repayment under the Current Bank Facility. Any indebtedness of the Operating Subsidiaries to the Trust pursuant to the net profits interests and amounts payable to the unitholders under the Trust Indenture are subordinate to the Current Bank Facility pursuant to subordination agreements between the Lenders, the Trustee, and the Operating Subsidiaries dated September 1, 2004. These subordination agreements may restrict the ability of the Operating Subsidiaries to pay amounts owing under the net profits interests to the Trust or pay interest or principal on any indebtedness owing to the Trust or other amounts owing to the Trust, and therefore may limit or eliminate the Cash Available For Distribution.

The Corporation must meet certain ongoing financial and other covenants under the Current Bank Facility. The covenants are customary restrictions on the Operating Subsidiaries' operations and activities, including restrictions on the incurring of indebtedness, the granting of security, the issuance of incremental debt and the sale of its assets.

The Corporation is also subject to certain covenants under its $7^{7/8}$% Senior Note indenture, including limitations on the ability of Harvest Operations or the Trust to issue incremental debt, and to pay cash distributions to unitholders.

Failure to Realize an Adequate Rate of Return on Prices Paid for Properties

The prices paid for acquisitions made during the current and prior years were based, in part, on engineering and economic assessments made by independent engineers. These assessments include a number of material assumptions regarding such factors as recoverability and marketability of crude oil, natural gas and natural gas liquids, future prices of oil, natural gas and natural gas liquids and operating costs, future capital expenditures and royalties and other government levies which will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond the control of Harvest. In particular, changes in the prices of and markets for petroleum, natural gas and associated liquids from those anticipated at the time of making such assessments will affect the value of Harvest's Trust Units. In addition, all such assessments involve a measure of geological and engineering uncertainty which could result in lower production and reserves than those currently attributed to the Properties.

Changes in Legislation

There can be no assurance that income and capital tax laws, government incentive programs and regulations relating to the petroleum and natural gas industry, such as environmental and operating regulations, will not be changed in a manner which adversely affects Harvest.

Environmental Concerns

The oil and natural gas industry is subject to environmental regulation pursuant to local, provincial and federal legislation. A breach of such legislation may result in the imposition of fines on the Operating Subsidiaries or the issuance of clean up orders on the Properties. Such legislation may be changed to impose higher standards and potentially more costly obligations on the Corporation. See "Industry Conditions – Environmental Regulation".

Additionally, the potential impact on Harvest's operations and business, including the Trust's Cash Available for Distribution, of the Kyoto Protocol, which has been ratified by Canada, with respect to instituting reductions of greenhouse gases is difficult to quantify at this time.

Debt Repayment

The Operating Subsidiaries and the Trust are permitted to borrow funds to finance the purchase of Properties, capital expenditures, or other financial obligations in respect of the Properties or for working capital purposes. Borrowings of the Operating Subsidiaries to fund the purchase of Canadian resource properties may be repaid with funds received from the Trust. Debt service costs of the Operating Subsidiaries are deducted in computing income from the net profits interest payments and debt service costs of the Trust are deducted in computing Cash Available For Distribution. Variations in interest rates could result in significant changes in the amount required to be applied to debt service before payment of the net profits interest obligations and cash distributions to Unitholders. Interest and principal payable pursuant to the $7^{7/8}$% Senior Notes are payable in U.S. dollars. Harvest is permitted to borrow funds under the credit facilities in U.S. dollars and would be required to settle interest and principal amounts in the same currency. Variations in the Canadian/U.S. currency exchange rate could result in a significant increase in the amount of the interest and principal payments under the Current Bank Facility and the $7^{7/8}$% Senior Note indenture, thereby reducing the Cash Available For Distribution. See "Information Regarding the Harvest Energy Trust Structure – Borrowings".

Variability of Cash Distributions

The Operating Subsidiaries may retain a portion of their cash flows from the Properties to facilitate the development of the Properties. Harvest believes this will assist in maintaining distributions over a longer period than would otherwise be the case if all cash flows from the Properties were paid to the Trust and subsequently distributed to the Unitholders. Future cash flows from such Properties may not be sufficient to fully recover the development costs and may not generate sufficient cash flows to allow the Operating Subsidiaries to maintain their net profits interest payments to the Trust enabling the Trust to maintain its distributions to unitholders over the longer term.

Impact of Future Capital Expenditures

The Reserve Value of the Properties as estimated by Independent Reserve Engineering Evaluators is based in part on cash flows to be generated in future years as a result of future capital expenditures. The Reserve Value of the Properties as estimated by the Independent Reserve Engineering Evaluators will be reduced to the extent that such capital expenditures on the Properties do not achieve the level of success assumed in such engineering reports.

Competition

There is strong competition relating to all aspects of the petroleum and natural gas industry. The Operating Subsidiaries and/or the Trust actively compete for capital, skilled personnel, undeveloped land, reserve acquisitions, access to drilling rigs, service rigs and other equipment, access to processing facilities and pipeline and refining capacity, and in all other aspects of its operations with a substantial number of other petroleum and natural gas organizations, many of which may have greater technical and financial resources than the Operating Subsidiaries and/or the Trust, individually or combined. Some of those organizations not only explore for, develop and produce oil and natural gas but also carry on refining operations and market petroleum and other products on a world-wide basis and as such have greater and more diverse resources on which to draw.

Potential Conflicts of Interest

Circumstances may arise where members of the Board of Directors or officers of Harvest Operations are directors or officers of corporations which are in competition to the interests of Harvest. No assurances can be given that opportunities identified by such board members will be provided to the Operating Subsidiaries and/or the Trust. See "Conflicts of Interest".

Risks Related to Harvest's Structure

Nature of Trust Units

Securities such as the Trust Units are hybrids in that they share certain attributes common to both equity securities and debt instruments. Trust Units are dissimilar to debt instruments in that there is no principal amount owing to Unitholders. The Trust Units do not represent a traditional investment in the oil and natural gas sector and should not be viewed by investors as shares in Harvest Operations or any of the Operating Subsidiaries. The Trust Units represent a fractional interest in the Trust. As holders of Trust Units, 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's sole assets will be Permitted Investments, its net profits interests, the Direct Royalties and related contractual rights and units in other wholly-owned trusts. The market price per Trust Unit will be a function of anticipated Cash Available For Distribution, the value of the Properties acquired by Harvest and the Operating Subsidiaries' ability to effect long-term growth in the value of the Trust. The issue price of each Trust Unit is greater than the per Trust Unit Reserve Value of the Properties. The market price of the Trust Units will be sensitive to a variety of market conditions including, but not limited to, interest rates and the ability of the Trust to acquire suitable oil and natural gas properties. Changes in market conditions may adversely affect the trading price of the Trust Units.

Unitholder Limited Liability

The Trust Indenture provides that no Unitholder, in its capacity as such, shall incur or be subject to any liability in contract or in tort in connection with the Trust Fund or the obligations or 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 the performance or exercise, or purported performance or exercise, of any obligation, power, discretion or authority conferred upon the Trustee or such other person hereunder or with respect to any transaction entered into by the Trustee or by any other person pursuant to the Trust Indenture. 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 also provides that all contracts signed by or on behalf of the Trust, whether by Harvest Operations, the Trustee, or otherwise, must (except as the Trustee or the Corporation may otherwise expressly agree with respect to their own personal liability) 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 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 by the Board of Directors of Harvest Operations in view of the fact that all business operations are carried on by the Operating Subsidiaries.

The activities of the Trust and Operating Subsidiaries are conducted and are intended to 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 Operating Subsidiaries and having contracts signed by or on behalf of the Trust include a provision that such obligations are not binding upon Unitholders personally.

The provinces of Alberta and Ontario have recently passed legislation providing unitholders of mutual fund trusts the same limited liability protections afforded shareholders of corporations.

Investment Eligibility

If the Trust ceases to qualify as a “mutual fund trust” for purposes of the Tax Act, the Trust Units will cease to be qualified investments for registered retirement savings plans ("RRSPs"), registered retirement income funds ("RRIFs"), deferred profit sharing plans ("DPSPs") and registered education savings plans ("RESPs") (collectively, "Exempt Plans"). Where at the end of any month an Exempt Plan holds Trust Units that are not qualified investments, the Exempt Plan must, in respect of that month, pay a tax under Part XI.1 of the Tax Act equal to 1% of the fair market value of the Trust Units at the time such Trust Units were acquired by the Exempt Plan. In addition, where a trust governed by an RRSP holds Trust Units that are not qualified investments, the trust will become taxable on its income attributable to the Trust Units or any gains realized on a disposition of the Trust Units while they are not qualified investments.

Additional Financing

To the extent that external sources of capital, including the issuance of additional Trust Units, becomes limited or unavailable, the Trust's and the Operating Subsidiaries' ability to make the necessary capital investments to maintain or expand its oil and natural gas reserves will be impaired. To the extent the Trust or the Operating Subisdiaries are required to use cash flow to finance capital expenditures or property acquisitions, the level of Cash Available For Distribution will be reduced.

Dilution

The Trust Indenture provides that Trust Units, including rights, warrants and other securities to purchase, to convert into or to exchange into Trust Units, may be created, issued, sold and delivered on such terms and conditions and at such times as the Board of Directors of Harvest Operations may determine. In addition, the Trust may issue additional Trust Units from time to time pursuant to the Trust Unit Rights Incentive Plan, Unit Award Incentive Plan and DRIP Plan. The possible issuance of these Trust Units could result in dilution to holders of Trust Units.

Reliance on Management of Harvest Operations

Unitholders will be dependent on the management of Harvest Operations in respect of the administration and management of all matters relating to the Properties, the various net profits interests, the Direct Royalties, the Operating Subsidiaries, the Trust, and the Trust Units. Investors who are not willing to rely on the management of Harvest Operations should not invest in the Trust Units.

Return of Capital

Trust Units will have no value when reserves from the underlying assets of the Trust can no longer be economically produced and, as a result, cash distributions do not represent a "yield" in the traditional sense as they represent both return of capital and return on investment.

Net Asset Value

The net asset value of the Trust will vary dependent upon a number of factors beyond the control of management, including oil and natural gas prices. The trading prices of the Trust Units is also determined by a number of factors which are beyond the control of management and such trading prices may be greater than or less than the net asset value of the Trust.

Structure of the Trust

From time to time, the Trust may take steps to organize its affairs in a manner that minimizes taxes and other expenses payable with respect to the operation of the Trust and the Operating Subsidiaries and maximizes the amount of cash available for distributions to Unitholders. If the manner in which the Trust structures its affairs is successfully challenged by a taxation or other authority, the amount of cash available for distribution to Unitholders may be affected.

Risks Particular to Unitholders Resident in the United States and Other Non-Resident Unitholders

Unitholders Resident in the United States May be Subject to Passive Foreign Investment Company Rules

The Trust may be a passive foreign investment company for United States federal income tax purposes for the 2005 taxable year and in subsequent taxable years. To date, Harvest has not received advice that the Trust should not be considered a passive foreign investment company for the 2005 taxable year or previous taxable years. If the Trust were classified as a passive foreign investment company, Unitholders resident in the United States (other than most tax-exempt investors) would be subject to adverse tax rules. Under these adverse tax rules, Unitholders resident in the United States generally would be required to allocate any gain or excess distributions, which include any annual distributions other than in the first year the unitholder held the Trust Units, that is greater than 125% of the average annual distributions received by that unitholder in the three preceding taxable years or, if shorter, that unitholder's holding period for Trust Units. The amount allocated to the current taxable year and any year prior to the first year in which Harvest was a passive foreign investment company would be taxed as ordinary income in the current year. The amount allocated to each of the other taxable years would be subject to tax at the highest rate of tax in effect for the applicable class of taxpayer for that year, and an interest charge for the deemed deferral benefit would be imposed with respect to the resulting tax attributable to each of the other taxable years. Holders will not be able to make a "qualifying electing fund" election or, with respect to the Trust's Operating Subsidiaries that were considered to be passive foreign investment companies, a "mark-to-market" election to protect themselves from these adverse consequences if Harvest were ultimately determined to be a passive foreign investment company. Unitholders resident in the United States are strongly urged to consult their own tax advisors regarding the United States federal income tax consequences of Harvest's possible classification as a passive foreign investment company and the consequences of such classification.

Unitholders Resident in the United States and Other Non-Resident Unitholders may be subject to Additional Taxations

The Tax Act and the tax treaties between Canada and other countries may impose additional withholding and other taxes on the cash distributions or other property paid by the Trust to unitholders who are not residents of Canada and these taxes may change from time to time. For instance, since January 1, 2005, a 15% withholding tax is applied to all cash distributions made to all unitholders who are not residents of Canada.

The Ability of Unitholders Resident in the United States and Other Non-Resident Unitholders to Enforce Civil Remedies May be Limited

The Trust is a trust organized under the laws of Alberta, Canada and Harvest's principal place of business is in Canada. The directors and officers of Harvest Operations are residents of Canada and most of the experts who provide services to Harvest are resident of Canada and all or a substantial portion of their assets and Harvest's assets are located within Canada. As a result, it may be difficult for investors in the United States or other non-Canadian jurisdictions (a "Foreign Jurisdiction") to effect service of process within such Foreign Jurisdiction upon such directors, officers and representatives of experts who are not residents of the Foreign Jurisdiction or to enforce against them judgements of courts of the applicable Foreign Jurisdiction based upon civil liability under the securities laws of such Foreign Jurisdiction, including United States federal securities laws or the securities laws of any state within the United States. In particular, there is doubt as to the enforceability in Canada against Harvest or any of its directors, officers or representative of experts who are not residents of the United States, in original actions or in actions for enforcement of judgement of United States courts of liabilities based solely upon the United States federal securities laws or the securities laws of any state within the United States.

DISTRIBUTIONS TO UNITHOLDERS

The following table sets forth the per Trust Unit amount of monthly cash distributions paid by the Trust since the completion of the Initial Public Offering.

	2006	2005	2004	2003
January	$0.35	$0.20	$0.20	$0.20(1)
February	$0.35	$0.20	$0.20	$0.20
March	$0.38	$0.20	$0.20	$0.20
April	$0.38(3)	$0.20(2)	$0.20	$0.20
May		$0.20	$0.20	$0.20
June		$0.20	$0.20	$0.20
July		$0.20	$0.20	$0.20
August		$0.25	$0.20	$0.20
September		$0.35	$0.20	$0.20
October		$0.35	$0.20	$0.20
November		$0.35	$0.20	$0.20
December		$0.35	$0.20	$0.20

Notes:

(1) This distribution was the first cash distribution paid by the Trust following the completion of the Initial Public Offering.

(2) In addition to the regular cash payment to Unitholders on April 15, 2005, the Trust also paid an extra distribution valued at $0.252 in the form of trust units to holders of record on March 31, 2005.

(3) The Trust announced on March 8, 2006 that the next monthly cash distribution of $0.38 per Trust Unit will be paid on April 17, 2006 to Unitholders of record on March 22, 2006.

Unitholders of record on a Record Date are entitled to receive a cash distributions which becomes payable on the 15th day of the month following the Record Date, and if such date of payment is not a Business Day on the next Business Day after the 15th day of the month following the Record Date.

TRUST UNITS AND TRUST INDENTURE

The following is a summary of certain provisions of the Trust Indenture and the Trust Units. For a complete description, reference should be made to the Trust Indenture, as may be subsequently amended and superseded, a copy of which may be viewed at the offices of, or obtained from, the Trustee, and a copy of which has been filed on Harvest's SEDAR profile at www.sedar.com.

General

Harvest was created, and the Trust Units are issued, pursuant to the Trust Indenture. The Trust Indenture, among other things, provides for the administration of Harvest, the investment of Harvest's assets, the calculation and payment of cash distributions to Unitholders, the calling of and conduct of business at meetings of Unitholders, the appointment and removal of the Trustee, redemption of Trust Units and the payment of distributions by Harvest to its Unitholders. Among other things, material amendments to the Trust Indenture, the early termination of Harvest and the sale or transfer of all or substantially all of the property of Harvest require the approval by Special Resolution (ie. 66 2/3% of the votes cast) of the Unitholders.

Types of Securities

Trust Units

Concurrent with the closing of the Viking Arrangement on February 3, 2006, the Trust is authorized to issue two classes of Trust Units, described and designated as Ordinary Trust Units and Special Trust Units, pursuant to its amended Trust Indenture. Each Ordinary Trust Unit entitles the holder or holders thereof to one vote at any meeting of the unitholders and each Special Trust Unit shall entitle the holder or holders thereof to three-sixteenths of one vote at any meeting of the unitholders. The Special Trust Units were created and issued to enable the closing of the Viking Arrangement and all have been subsequently cancelled. Unless otherwise specifically designated as such, all references to Trust Units are deemed to be references to Ordinary Trust Units.

As of March 20, 2006, there were 100,524,074 Trust Units (52,982,567 Trust Units at December 31, 2005) issued and outstanding. Each Trust Unit entitles the holder thereof to one vote at any meeting of the holders of Trust Units and represents an equal 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 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 (see "Redemption Right" below). See "Risk Factors – Nature of Trust Units".

The Trust Indenture also provides that Trust Units, including rights, warrants and other securities to purchase, to convert into or exchange into Trust Units, may be created, issued, sold and delivered on such terms and conditions and at such times as the Harvest Board may determine. The Trust Indenture also provides that Harvest Operations may authorize the creation and issuance of debentures, notes and other evidences of indebtedness of the Trust from time to time on such terms and conditions to such persons and for such consideration as the Corporation may determine.

The Trust Units do not represent a traditional investment and should not be viewed by investors as “shares” in the Trust. Corporate law does not govern the Trust and the rights of Unitholders. As holders of Trust Units in the Trust, the 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 rights of Unitholders are specifically set forth in the Trust Indenture. In addition, trusts are not defined as recognized entities within the definitions of legislation such as the *Bankruptcy and Insolvency Act (Canada)*, the *Companies’ Creditors Arrangement Act (Canada* , and in some cases, the *Winding Up and Restructuring Act (Canada).* As a result, in the event of an insolvency or restructuring, a Unitholder’s position as such may be quite different than that of a shareholder of a corporation.

Exchangeable Shares of Harvest Operations

Exchangeable shares were issued on June 30, 2004 to Canadian-resident former shareholders of Storm Energy Ltd. who elected to receive such shares. The Exchangeable Shares are exchangeable into Trust units at a pre-determined exchange ratio, which is increased for each distribution made by the Trust following June 30, 2004. The Exchangeable Shares have priority over the common shares of Harvest Operations (all of which are held by the Trust) with respect to the payment of dividends and the distribution of assets of Harvest Operations. The Exchangeable Shares are provided equivalent voting rights as those of Unitholders through an agreement (the Exchangeable Share Voting and Exchange Trust Agreement) pursuant to which the holders of Exchangeable Shares can direct the Trustee to vote at meetings of Unitholders. The holders of Exchangeable Shares are further assured of the delivery of Trust Units by the Trust in satisfaction of the obligations of Harvest Operations under the Exchangeable Share terms through the provisions of another agreement (the Exchangeable Share Support Agreement). As of March 20, 2006, there were 26,902 Exchangeable Shares outstanding.

Effective March 16, 2006, Harvest Operations elected to exercise its de minimus redemption right to redeem all of the Exchangeable Shares outstanding on June 20, 2006. Each Exchangeable Share will be purchased for a cash payment at a price per share equal to the amount obtained by multiplying the exchange ratio for the Exchangeable Shares in effect on June 19, 2006 by the weighted average trading price of the Trust Units of Harvest on the Toronto Stock Exchange for the 5 trading days immediately prior to June 19, 2006.

A Notice of Redemption has been mailed to all exchangeable shareholders outlining the terms of this redemption. HOC will also mail a formal Letter of Transmittal to all exchangeable shareholders of record on June 20, 2006 to complete this transaction.

Special Voting Units

At the 2004 Unitholders’ Meeting, the Unitholders approved an amendment to the Trust Indenture to provide for the issuance of an unlimited number of special voting units. Each special voting unit will entitle the holder thereof to such number of votes at meetings of Unitholders as may be prescribed by the Board of Directors of the Corporation in the resolution authorizing the issuance of any such special voting units. Currently, one special voting unit has been issued in connection with the Exchangeable Shares.

Certain Unitholder Rights and Trust Unit Information

Unitholder Limited Liability

The Trust Indenture provides that no Unitholder, in its capacity as such, shall incur or be subject to any liability in contract or in tort in connection with the Trust Fund or the obligations or affairs of the Trust 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 hereunder or with respect to any transaction entered into by the Trustee or by any other person pursuant to the Trust Indenture. 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 provinces of Alberta and Ontario have recently passed legislation providing Unitholders of mutual fund trusts the same protections afforded shareholders of corporations. See "RISK FACTORS – Unitholder Limited Liability".

Redemption Right

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, accompanied by a duly completed and properly executed notice requiring redemption. Upon receipt of the notice to redeem Trust Units 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" (as defined in the Trust Indenture) of the Trust Units on the principal market on which the Trust Units are quoted for trading during the 10 trading day period commencing immediately after the date on which the Trust Units are tendered to the Trust for redemption; and (ii) the closing market price on the principal market on which the Trust Units are quoted for trading on the date that the Trust Units are so tendered for redemption.

The Trust Indenture imposes limitations on the amount of cash consideration the Trust may pay out for the Trust Units tendered for redemption and also provides for the determination of the value of the Market Redemption Price payable if the Trust Units are not listed for trading on the TSX or any other stock exchange. The details of these provisions can be reviewed in further detail in the Trust Indenture filed at www.sedar.com .

It is anticipated that this Redemption Right will not be the primary mechanism for holders of Trust Units to dispose of their Trust Units. Promissory notes of Harvest Operations or the Trust which may be distributed in specie to Unitholders in connection with a redemption will not be listed on any stock exchange and no market is expected to develop in such notes. Such notes may not be qualified investments for trusts governed by registered retirement savings plans, registered retirement income funds, deferred profit sharing plans and registered education savings plans.

Non-Resident Unitholders

It is in the best interests of Unitholders that the Trust qualify as a "unit trust" and a "mutual fund trust" under the Tax Act. Pursuant to the Tax Act, for the Trust to qualify as a “mutual fund trust” for the purposes of The Act, it is required that, amoung other things, (i) the Trust not be considered to be a trust established or maintained primarily for the benefit of non-residents of Canada; or (ii) the Trust satisfies certain conditions as to the nature of the assets of the Trust as specified in the Tax Act (the “Asset Test”). The Trust Indenture provides that it is intended that the Trust comply with the requirements of the Tax Act for mutual fund trusts at all relevant times such that the Trust maintains the status of a “mutual fund trust” for purposes of the Tax Act. Harvest believes that the Trust has at all material times satisfied the Asset Test and accordingly, for purposes of the Tax Act, the Trust should qualify as a "mutual fund trust".

Governance of the Trust

Trustee

Valiant Trust Company is the trustee of the Trust. All of the administrative and management powers of the Trustee relating to the Trust and the operations of the Trust have been delegated to Harvest Operations pursuant to the Trust Indenture and the Administration Agreement. Notwithstanding this general delegation, pursuant to the Administration Agreement, the Trustee has agreed not to delegate any authority to manage the following affairs of the Trust:

(a) the issue, certification, countersigning, transfer, exchange and cancellation of certificates representing Trust Units;

(b) the maintenance of a register of Unitholders;

(c) the cash distributions paid to Unitholders, although the calculation of the amount of the distribution shall be made by Harvest Operations and approved by the Harvest Board;

(d) the mailing of notices, financial statements and reports to Unitholders pursuant to the Trust Indenture, although Harvest Operations shall be responsible for the preparation or causing the preparation of such notices, financial statements and reports;

(e) the provision of a basic list of registered Unitholders to Unitholders in accordance with the procedures outlined in the Trust Indenture;

(f) the amendment or waiver of the performance or breach of any term or provision of the Trust Indenture on behalf of the Trust;

(g) the renewal or termination of the Administration Agreement on behalf of the Trust; and

(h) any matter which requires the approval of the Unitholders under the terms of the Trust Indenture.

The Trustee is required under the Trust Indenture to exercise its powers and carry out its functions thereunder as Trustee honestly, in good faith and in the best interests of the Trust and the Unitholders and, in connection therewith, shall exercise that degree of care, diligence and skill that a reasonably prudent trustee would exercise in comparable circumstances.

At each annual meeting, the Unitholders shall reappoint or appoint a successor to the Trustee at the annual meeting of Unitholders. The Trustee may also be removed by the Corporation upon delivery of a notice in writing by the Corporation to the Trustee in limited circumstances. Such resignation or removal becomes effective only upon the approval of the Unitholders by Special Resolution, the acceptance or appointment of a successor trustee and the assumption by the successor trustee of all obligations of the Trustee and in the same capacity.

Liability of the Trustee

The Trustee, its directors, officers, employees, shareholders and agents shall not be liable to any Unitholder or any other person, in tort, contract or otherwise, in connection with any matter pertaining to the Trust or the Trust Fund, arising from the exercise by the Trustee of any powers, authorities or discretion conferred under the Trust Indenture, including, without limitation, any action taken or not taken in good faith in reliance on any documents that are, *prima facie*, properly executed, any depreciation of, or loss to, the Trust Fund incurred by reason of the sale of any asset, any inaccuracy in any valuation provided by any other appropriately qualified person, any reliance on any such evaluation, any action or failure to act of Harvest Operations, or any other person to whom the Trustee has, with the consent of Harvest Operations, delegated any of its duties under the Trust Indenture, or any other action or failure to act (including failure to compel in any way any former trustee to redress any breach of trust or any failure by Harvest Operations to perform its duties under or delegated to it under the Trust Indenture or any other contract), unless such liabilities arise out of the gross negligence, willful default or fraud of the Trustee or any of its directors, officers, employees or shareholders. If the Trustee has retained an appropriate expert, adviser or legal counsel with respect to any matter connected with its duties under the Trust Indenture or any other contract, the Trustee may act or refuse to act based on the advice of such expert, adviser or legal counsel, and the Trustee shall not be liable for and shall be fully protected from any loss or liability occasioned by any action or refusal to act based on the advice of any such expert, adviser or legal counsel. In the exercise of the powers, authorities or discretion conferred upon the Trustee under the Trust Indenture, the Trustee is and shall be conclusively deemed to be acting as Trustee of the assets of the Trust and shall not be subject to any personal liability for any debts, liabilities, obligations, claims, demands, judgments, costs, charges or expenses against or with respect to the Trust or the Trust Fund. In addition, the Trust Indenture contains other customary provisions limiting the liability of the Trustee.

Delegation of Authority, Administration and Governance

Harvest Operations (and, accordingly, the Board of Directors of Harvest Operations) has generally been delegated the significant management decisions of the Trust. In particular, the Trustee has delegated to Harvest Operations responsibility for any and all matters relating to the following: (i) an offering of securities; (ii) ensuring compliance with all applicable laws, including in relation to an offering; (iii) all matters relating to the content of any offering documents, the accuracy of the disclosure contained therein, and the certification thereof; (iv) all matters concerning the terms of, and amendment from time to time of the material contracts of the Trust; (v) all matters concerning any underwriting or agency agreement providing for the sale of Trust Units or rights to Trust Units; (vi) all matters relating to the redemption of Trust Units; (vii) all matters relating to the voting rights on any investments in the Trust Fund or any Subsequent Investments; (viii) all matters relating to the specific powers and authorities as set forth in the Trust Indenture.

Harvest Operations currently has a board of directors consisting of 9 individuals, and has presented a slate of 9 directors to the Unitholders at the 2006 Annual and Special Meeting. Pursuant to the Trust Indenture, Unitholders are entitled to elect the Board of Directors annually. Prior to all annual meetings, Harvest Operations will deliver an information circular and form of proxy to Unitholders with respect to the election of the directors of Harvest Operations at any such meeting.

Under the net profits interest agreements, the Operating Subsidiaries have the exclusive control and authority over development of, and recovery of petroleum, natural gas and natural gas liquids from, the Properties and lands pooled or unitized therewith, including, without limitation, making all decisions respecting whether, when and how to drill, complete, equip, produce, suspend, abandon and shut-in wells and whether to elect to convert royalties to working interests. The Harvest Board has determined that all significant operational decisions and all decisions relating to: (i) the acquisition and disposition of properties for a purchase price or proceeds in excess of $5 million; (ii) the approval of capital expenditure budgets; (iii) the approval of risk management policies and activities proposed to be undertaken, and (iv) the establishment of credit facilities, shall be made by the Board of Directors.

In exercising its powers and discharging its duties, Harvest Operations must act honestly and in good faith and exercise the degree of care, diligence and skill that a reasonably prudent oil and natural gas industry advisor and administrator would exercise in comparable circumstances. Harvest Operations' objective in exercising its powers and discharging its duties is to maximize the income distributable to the Unitholders to the extent consistent with long-term growth in the value of the Trust. In pursuing such an objective, Harvest Operations employs and will continue to employ prudent oil and natural gas business practices. All of Harvest Operations' business is and will continue to be conducted in accordance with applicable laws with a view to the best interests of the Unitholders and the Trust.

The Harvest Board reviews on an ongoing basis both the nature and extent of the services required of Harvest Operations by the Trust and the costs of providing such services.

General and administrative costs are deducted from production revenues in computing income from the net profits interest to the extent not paid from the residual income of Harvest Operations or deducted by the Trust in computing

Cash Available For Distribution. General and administrative costs are generally charged to the Trust by Harvest Operations based on direct costs incurred in fulfilling the obligations of Harvest Operations to the Trust pursuant to the Trust Indenture and the Administration Agreement. Harvest Operations is entitled to reimbursement for all of its direct and indirect expenses, costs and expenditures in connection with the creation, start-up, set-up and organization of the Trust.

Meetings of Unitholders

The Trust Indenture provides that meetings of Unitholders must be called and held for, among other matters, the election or removal of the Trustee, the appointment or removal of the auditors of the Trust, the approval of amendments to the Trust Indenture, the sale of the property of the Trust as an entirety or substantially as an entirety, and the commencement of winding-up the affairs of the Trust. Meetings of Unitholders will be called and held annually for, among other things, the election of the directors of the Corporation and the appointment of the auditors of the Trust.

A meeting of Unitholders may be convened at any time and for any purpose by Harvest Operations and must be convened, except in certain circumstances, if requisitioned by the holders of not less than 20% of the Trust Units then outstanding by a written requisition. A requisition must, among other things, state in reasonable detail the business purpose for which the meeting is to be called.

Unitholders may attend and vote at all meetings of Unitholders either in person or by proxy and a proxyholder need not be a Unitholder. Two persons present in person or represented by proxy and representing in the aggregate at least 10% of the votes attaching to all outstanding Trust Units shall constitute a quorum for the transaction of business at all such meetings.

The Trust Indenture contains provisions as to the notice required and other procedures with respect to the calling and holding of meetings of Unitholders in accordance with the requirements of applicable laws.

Take-Over Bid

The Trust Indenture contains provisions to the effect that if a take-over bid is made for the Trust Units and not less than 90% of the Trust Units (other than Trust Units held at the date of the takeover bid by or on behalf of the offeror or associates or affiliates of the offeror) are taken up and paid for by the offeror, the offeror will be entitled to acquire the Trust Units held by Unitholders who did not accept the takeover bid on the terms offered.

Termination of the Trust

Unitholders may vote to terminate the Trust at any meeting of the Unitholders duly called for that purpose, subject to the following: (a) a vote may only be held if requested in writing by the holders of not less than 20% of the outstanding Trust Units; (b) a quorum of 50% of the issued and outstanding Trust Units is present in person or by proxy; and (c) the termination must be approved by Special Resolution of Unitholders.

Unless the Trust is earlier terminated or extended by vote of the Unitholders, the Trustee shall commence to wind-up the affairs of the Trust on December 31, 2099. In the event that the Trust is wound-up, the Trustee will sell and convert into cash the Direct Royalties and other assets comprising the Trust Fund in one transaction or in a series of transactions at public or private sale and do all other acts appropriate to liquidate the Trust Fund, and shall in all respects act in accordance with the directions, if any, of the Unitholders in respect of termination authorized pursuant to the Special Resolution authorizing the termination of the Trust. However, in no event shall the Trust be wound-up until the Direct Royalties have been disposed of. After paying, retiring or discharging, or making provision for the payment, retirement, or discharge of all known liabilities and obligations of the Trust and after providing for indemnity against any other outstanding liabilities and obligations, the Trustee shall distribute the remaining part of the proceeds of the sale of the assets together with any cash forming part of the property of the Trust among the Unitholders in accordance with their Pro Rata Share.

Reporting to Unitholders

The consolidated financial statements of the Trust will be audited annually by an independent recognized firm of chartered accountants. The audited consolidated financial statements of the Trust, together with the report of such chartered accountants, will be mailed by the Trust to registered Unitholders and the unaudited interim consolidated financial statements of the Trust will be mailed to registered Unitholders within the periods prescribed by securities legislation. The year end of the Trust is December 31. The Trust is subject to the continuous disclosure obligations under the applicable securities legislation of each of the provinces and certain of the territories of Canada.

Borrowing By the Trust

Pursuant to the Trust Indenture, the Trustee is permitted to, directly or indirectly, borrow money from or incur indebtedness to any person and in connection therewith, to guarantee, indemnify or act as a surety with respect to payment or performance of any indebtedness, liabilities or obligation of any kind of any person, including, without limitation, the Corporation and any subsidiary of the Trust; to enter into any other obligations on behalf of the Trust; or enter into any subordination agreement on behalf of the Trust or any other person, and to assign, charge, pledge, hypothecate, convey, transfer, mortgage, subordinate, and grant any security interest, mortgage or encumbrance over or with respect to all or any of the Trust Fund or to subordinate the interests of the Trust in the Trust Fund to any other person. Debt service costs incurred by the Trust are deducted in computing the Cash Available For Distribution.

Premium Distribution™, Distribution Reinvestment and Optional Trust Units Purchase Plan ("DRIP Plan")

The Trust has adopted the DRIP Plan which is available to eligible Unitholders (the DRIP Plan is not available to residents of the United States). The DRIP Plan provides eligible holders of Trust Units the means of accumulating additional Trust Units by reinvesting cash distributions. At the discretion of Harvest Operations, Trust Units will be issued from treasury at 95% of the market price of the Trust Units (calculated as the weighted average trading price of the Trust Units on the TSX for the period commencing on the second Business Day following the record date applicable to such distribution payment, and the second Business Day immediately prior to the distribution payment date on which at least a board lot of Trust Units is traded).

Effective August 23, 2005, the DRIP Plan includes a unique feature which allows eligible Unitholders to elect, under the Premium Distribution™ component of the DRIP Plan, to deliver Trust Units which have been received pursuant to the distribution reinvestment component of the DRIP Plan to a designated broker in exchange for a premium cash distribution equal to 102% of the cash distribution that such Unitholders would have otherwise been entitled to receive on the applicable distribution date (subject to a proration in certain events under the DRIP Plan). Canaccord Capital Corporation has been designated as the plan broker under the Premium Distribution™ component of the DRIP Plan.

Participants in the DRIP Plan are also permitted to purchase additional Trust Units at 100% of the market price (as described above) of the Trust Units by investing additional sums to a maximum of up to $100,000 aggregate amount of remittances by a Unitholder in any calendar month and a minimum of $5,000 per remittance; provided that the total number of Trust Units that may be issued each fiscal year pursuant to optional cash payments is restricted to not more than 2% of the number of issued and outstanding Trust units at the commencement of that year. As at March 20, 2006, 3,777,305 Trust Units have been issued from treasury since February 15, 2003 as a result of Unitholder participation in the DRIP Plan with proceeds of approximately $89 million.

Stability Ratings

The following agency has provided a rating for the Trust. It should be noted that a stability rating is not a recommendation to buy, sell or hold securities and may be subject to revision or withdrawal at any time by the rating organization.

Dominion Bond Rating Services Limited

Dominion Bond Rating Services Limited ("DBRS") has assigned a stability rating of STA-6 (high) to the Units and has placed such stability rating "Under Review" with "positive implications" following the announcement by the Trust of the Viking Arrangement. Income funds rated as STA-6 are considered by DBRS to have very weak distributions per unit in terms of stability and sustainability. STA-1 is the highest DBRS rating available to units of income funds and STA-7 is the lowest DBRS rating available to units of income funds. Each of the Canadian energy trusts currently rated by DBRS falls within the range of STA-5 (high) to STA-6 (middle). In addition, DBRS further separates the ratings into "high", "middle" and "low" subcategories to indicate where they fall within the rating category. Ratings take into consideration the seven main factors of: (1) operating and industry characteristics; (2) asset quality; (3) financial flexibility; (4) diversification; (5) size and market position; (6) sponsorship/governance; and (7) growth. In addition, consideration is given to specific structural or contractual elements that may eliminate or mitigate risks or other potentially negative factors.

MARKET FOR SECURITIES

The Trust Units are listed and traded on the TSX and the New York Stock Exchange ("NYSE"). The trading symbol on the TSX for the Trust Units is "HTE.UN", and on the NYSE is "HTE". The Trust has issued three series of unsecured subordinated debentures which trade on the TSX under the symbols "HTE.DB" for the 9% series, "HTE.DB.A" for the 8% series, and "HTE.DB.B" for the 6.5% series. For more information on the details of these debentures see "ADDITIONAL INFORMATION REGARDING THE TRUST AND CORPORATION – Borrowing – Convertible Debentures". In addition, pursuant to the Viking Arrangement, the Trust assumed the two outstanding series of convertible debentures that Viking had outstanding as of February 3, 2006. These debentures trade on the TSX under the symbols "HTE.DB.C" ("VKR.DB" prior to the Viking Arrangement) for the 10.5% series and "HTE.DB.D" ("VKR.DB.A" prior to the Viking Arrangement) for the 6.4% debentures. The trading history for each of the series of debentures is presented below.

The following sets forth the price range and trading volume of the Trust Units on the TSX and the NYSE for the periods indicated.

	TSX Price Range			NYSE Price Range		
	High	Low	Volume	High	Low	Volume
2005						
January	$24.00	$22.10	2,987,380	-	-	-
February	$25.97	$23.75	3,533,047	-	-	-
March	$26.45	$23.01	5,125,832	-	-	-
April	$25.75	$22.15	3,085,512	-	-	-
May	$23.00	$21.02	2,926,658	-	-	-
June	$28.26	$22.60	4,025,580	-	-	-
July (1)	$30.40	$27.01	4,848,268	$24.65	$23.85	725,500
August	$37.40	$29.16	8,002,371	$31.35	$24.04	4,155,200
September	$39.36	$33.85	6,871,029	$33.69	$29.19	5,885,000
October	$38.75	$29.65	7,619,136	$33.39	$25.25	8,600,900
November	$36.98	$32.51	3,899,092	$31.45	$27.57	3,885,300
December	$38.60	$35.17	3,075,044	$33.57	$30.17	3,352,000
2006						
January	$38.51	$36.51	4,284,479	$33.50	$31.73	3,275,300
February	$37.99	$32.06	9,809,410	$33.17	$27.75	8,056,800
March (1-20)	$34.83	$32.10	9,430,006	$30.13	$28.00	4,822,500

Note:
[1] *Harvest trust units commenced trading on the NYSE on July 21, 2005*

Our Debentures Series 1 are listed for trading on the TSX under the symbol "HTE.DB". The following table sets forth the high, low and closing trading prices and the aggregate trading volume of the Debentures Series 1 as reported by the TSX for the periods indicated.

Harvest Energy Trust Series I Debentures
TSX: HTE.DB (Canadian $)

Month	High	Low	Close
January	170.00	159.55	170.00
February	183.00	171.00	176.50
March	186.00	165.00	170.13
April	185.00	177.00	177.00
May	165.50	160.08	165.00
June	200.00	160.00	194.00
July	219.22	195.00	214.25
August	265.27	208.00	265.27
September	273.05	230.00	273.05
October	277.00	226.00	247.25
November	265.00	254.26	265.00
December	265.18	265.18	265.18

Our Debentures Series 2 are listed for trading on the TSX under the symbol "HTE.DB.A". The following table sets forth the high, low and closing trading prices and the aggregate trading volume of the Debentures Series 2 as reported by the TSX for the periods indicated.

Harvest Energy Trust Series II Debentures
TSX: HTE.DB.A (Canadian $)

Month	High	Low	Close
January	146.00	138.00	145.00
February	159.00	145.00	153.00
March	160.00	142.00	152.00
April	160.00	138.25	138.77
May	145.00	131.32	143.00
June	169.46	141.51	167.21
July	190.00	169.73	190.00
August	228.65	186.00	228.49
September	242.88	220.00	235.76
October	224.50	196.13	212.32
November	218.65	207.62	218.65
December	240.00	225.00	230.00

Our Debentures Series 3 are listed for trading on the TSX under the symbol "HTE.DB.B". The following table sets forth the high, low and closing trading prices and the aggregate trading volume of the Debentures Series 3 as reported by the TSX for the periods indicated.

Harvest Energy Trust Series III Debentures (issued Aug, 2, 2006)
TSX: HTE.DB.B (Canadian $)

Month	High	Low	Close
August	120.00	102.95	118.21
September	126.56	110.00	122.36
October	125.00	103.00	108.64
November	119.14	108.00	111.42
December	125.00	116.00	120.00

The tables below reflect the trading history of the Debentures Series 4 and Debenture Series 5 assumed February 3, 2006 pursuant to the Viking Arrangement.

The Debentures Series 4 are listed for trading on the TSX under the symbol "HTE.DB.C". The following table sets forth the high, low and closing trading prices and the aggregate trading volume of the Debentures Series 4 as reported by the TSX for the periods indicated.

Harvest Energy Trust Series IV Debentures
TSX: HTE.DB.C (Canadian $)

Month	High	Low	Close
January	112.00	109.76	110.05
February	113.34	110.00	113.00
March	113.00	106.50	109.99
April	110.75	108.00	108.51
May	112.50	108.51	110.00
June	111.05	109.41	110.00
July	112.00	109.50	111.25
August	114.99	110.01	111.00
September	138.03	112.25	135.98
October	137.21	120.01	128.06
November	130.00	118.50	122.00
December	130.00	122.19	126.32

The Debentures Series 5 are listed for trading on the TSX under the symbol "HTE.DB.D". The following table sets forth the high, low and closing trading prices and the aggregate trading volume of the Debentures Series 5 as reported by the TSX for the periods indicated.

Harvest Energy Trust Series V Debentures (issued October 2005)
TSX: HTE.DB.D (Canadian $)

Month	High	Low	Close
October	101.00	98.01	100.00
November	100.98	99.50	100.35
December	105.85	100.35	105.25

ESCROWED SECURITIES

To the knowledge of the Corporation, no securities of the Trust are held in escrow.

DIRECTORS AND OFFICERS OF HARVEST OPERATIONS CORP.

The names, municipalities of residence, present positions with the Corporation and principal occupations during the past five years of the directors and officers of the Corporation are set out in the table below.

Name and Municipality of Residence	Position with the Corporation	No. of Trust Units Held [(1)]	Principal Occupation
Kevin A. Bennett[(4)] Calgary, Alberta	Director	505,489	Professional engineer; independent businessman involved in founding and the directorship of several oil and gas, and energy services companies. Co-founded Harvest Energy Trust in 2002 with Mr. Chernoff. From Sept. 1998 to Sept. 2001, was President, Chief Operating Officer and a director of Ventus Energy Ltd. (a public oil and gas company).
John A. Brussa [(3)(5)] Calgary, Alberta	Director	254,528	Barrister and Solicitor; Partner of Burnet, Duckworth & Palmer LLP (a law firm).
M. Bruce Chernoff [(3)(5)] Calgary, Alberta	Director, Chairman	6,251,496[(7)]	Professional Engineer; Chairman of the Corporation; President and Director of Caribou (a private investment management company) since June 1999; from April 2000 to October 2001, Executive Vice President and Chief Financial Officer of Petrobank Energy and Resources Ltd. (a public oil and natural gas company).
Hank B. Swartout[(4)] Calgary, Alberta	Director	915,637[(8)]	Chairman and Chief Executive Officer of Precision Drilling Corporation (a public oil and natural gas drilling and services company) since July 1987.
Verne G. Johnson[(2)] Calgary, Alberta	Director	60,381	President of KristErin Resources Inc. (a private family company) since January 2000; Senior Vice President, Funds Management of Enerplus Resources Group (a public oil and natural gas trust) from 2000 to 2002.
Hector J. McFadyen[(2)] Calgary, Alberta	Director	55,329	Independent businessman and Director of Hunting PLC (a UK based public oil and natural gas company); Director of Computershare Trust Company of Canada (a private Canadian company that manages the administration of shareholder and employee records from public and private companies throughout North America); formerly, President, Midstream Division, Alberta Energy Company Ltd. (now EnCana Ltd., a public oil and natural gas company) until 1992.
Dale Blue[(2)(14)] Mississauga, Ontario	Director	20,373	Independent consultant; until 2001, Chairman, President & Chief Executive Officer of Chase Manhattan Bank of Canada (a financial services company), and Managing Director of Chase Manhattan Bank in New York (a financial services company); over thirty years experience in financial services, has served on numerous domestic and international Boards.
David J. Boone[(4) (14)] Calgary, Alberta	Director	15,316	Professional Engineer; President, Escavar Energy Inc. (a private oil and natural gas company); prior thereto, Executive Vice President of EnCana Corporation (a public oil and natural gas company) and President of EnCana's Offshore and International Operations division, 2002 – 2003; prior thereto, Executive Vice-President and Chief Operating Officer of PanCanadian Petroleum (a public oil and natural gas company), 2000 – 2002; prior therero, various positions with Imperial Oil (a public oil and natural gas company); also Vice-Chair, Canadian National Committee of the World Petroleum Congress.

Name and Municipality of Residence	Position with the Corporation	No. of Trust Units Held [1]	Principal Occupation
William Friley[3][5] [14] Calgary, Alberta	Director	12,686	President and Chief Executive Officer of Telluride Oil and Gas Ltd. (a private oil and natural gas company), President of Skyeland Oils Ltd. (a private oil and natural gas company), Director of Mustang Resources Inc. (a public oil and natural gas company), and Chairman of TimberRock Energy Corporation (a private oil and natural gas company); Prior thereto, President and Chief Executive Officer of Triumph Energy Corporation (a public oil and natural gas company).
John Zahary[15] Calgary, Alberta	President & CEO	64,572[13]	Professional Engineer, President and Chief Executive Officer of Harvest Energy Trust since February 2006. Prior thereto, President and Chief Executive Officer of VHI (a public oil and natural gas trust) since May 11, 2004; President of Petrovera Resources (a private oil and natural gas company) from June 1999 to March 2004.
Robert Fotheringham[15] Calgary, Alberta	Vice President, Finance & CFO	23,393	Chartered Accountant, Vice President and Chief Financial Officer of Harvest Energy Trust since February 2006. Prior thereto was Vice President, Finance and Chief Financial Officer of VHI (a public oil and natural gas trust) since June, 2004; Chief Financial Officer of Inter Pipeline Fund (a public pipeline limited partnership) from February 2003 to April 2004; Chief Financial Officer of True North Energy Corporation (a private oil sands development company) from November 2001 to January 2003; Chief Financial Officer of Canadian Oil Sands Trust (a public oil sands trust) from July 1997 to November 2001.
Rob Morgan[15] Calgary, Alberta	Vice President, Engineering & COO	26,131	Professional Engineer, Vice President Engineering and Chief Operating Officer since February, 2006. Prior thereto was Vice President, Operations and Corporate Development of VHI since June, 2004; Manager, Planning at Canadian Natural Resources Limited (a public oil and natural gas company) from March 2004 to June 2004; Vice President Corporate Development, and Vice President Engineering of Petrovera Resources (a private oil and natural gas company) from May 1999 to March 2004.
Jacob Roorda[15] Calgary, Alberta	Vice President, Corporate	272,851[9]	Professional Engineer, Vice President, Corporate of Harvest Energy Trust since February 2006. Prior thereto was President of Harvest since August 2002; from June 1999 to July 2002, Managing Director, Research Capital (a mid-sized investment banking dealer).

Name and Municipality of Residence	Position with the Corporation	No. of Trust Units Held [1]	Principal Occupation
David J. Rain[15] Calgary, Alberta	Corporate Secretary	100,710[10]	Chartered Accountant; Corporate Secretary of Harvest Energy Trust since February 2006 and since July 2004 to February 2006, Vice President Finance and Chief Financial Officer and Vice President and Director of Caribou Capital Corp. (an investment management company) since June 1999. Previously was Vice President and Chief Financial Officer of Harvest since July 2004; prior thereto Vice President, Finance and Chief Financial Officer of Petrobank (a public oil and natural gas company) from October 2001 to March 2004; from April 2000 to September 2001, Director, Corporate Finance of Petrobank.
J.A. Ralston[15] Calgary, Alberta	Vice President, Production	76,852[11]	Vice President, Production of Harvest Energy Trust since February 2006; previously was Vice President, Operations and Chief Operating Officer of Harvest from July 2002; from 1996 to 2002, Manager, Production of Penn West Petroleum (a public oil and natural gas company).
James A. Campbell Calgary, Alberta	Vice President, Geosciences	55,478[12]	Vice President, Geosciences of Harvest Energy Trust since May 2004; prior thereto, Manager, Geosciences of Harvest from August 2002 to May 2004. From August 1997 to July, 2002, Vice President Exploration with Navigo Energy Inc. (a public oil and natural gas company).
Steven Saunders[15] Calgary, Alberta	Treasurer and Director of Taxation	2,731	Treasurer since February 2006 and Director of Taxation of Harvest Energy Trust since November 2004; Prior thereto was International Tax Analyst with EnCana Corporation (a public oil and natural gas company) from April 2002 to September 2004 and from 2000 to 2002 was Senior Tax Planner with PanCanadian Petroleum Ltd. (a predecessor to EnCana).

Notes:

(1) Represents all Trust Units held directly or indirectly or over which such person exercises control or direction as at March 20, 2006. Based upon information provided by the director or officer to the Trust.
(2) Member of the Audit Committee.
(3) Member of the Corporate Governance Committee.
(4) Member of the Reserves, Safety and Environment Committee.
(5) Member of the Compensation Committee.
(6) The terms of office of all of the directors will expire at the next annual unitholders' meeting of the Trust.
(7) Includes Trust Units held by entities controlled by Mr. Chernoff, and Trust Units held in RESP accounts for the benefit of Mr. Chernoff's children.
(8) Includes 164,647 Trust Units held by Mr. Swartout’s spouse.
(9) Includes 70,645 Trust Units held by Mr. Roorda's spouse.
(10) Includes 30,700 Trust Units held by Mr. Rain's spouse.
(11) Includes 37,406 Trust Units held by Mr. Ralston’s spouse.
(12) Includes 9,098 Trust Units held by Mr. Campbell’s spouse.
(13) Includes 2,450 Trust Units held by Mr. Zahary’s spouse.
(14) Appointed as a director on February 3, 2006 following the completion of the Viking Arrangement
(15) Effective February 3, 2006 the following changes were made to Harvest Operations’ Officers: John Zahary, former President & Chief Executive Officer of Viking became President & Chief Executive Officer of Harvest Operations; Robert Fotheringham, former Vice President, Finance & Chief Financial Officer of Viking became Vice President, Finance & Chief Financial Officer of Harvest Operations; Rob Morgan, former Vice President, Operations & Chief Operating Officer of Viking became Vice President, Engineering and Chief Operating Officer of Harvest Operations;

Jacob Roorda, former President of Harvest Operations became Vice President, Corporate; David Rain, former Vice President, Finance & Chief Financial Officer of Harvest Operations became Corporate Secretary; J. A. Ralston, former Vice President, Operations & Chief Operating Officer of Harvest Operations became Vice President, Production; Steve Saunders became Treasurer and Director of Taxation.

As at March 20, 2006, the directors, nominated directors and officers of the Corporation and their associates and affiliates, as a group, held, directly or indirectly, or exercise control or direction over, approximately 8,713,953 Trust Units or approximately 8.7% of the outstanding Trust Units and Exchangeable Shares.

Corporate Cease Trade Orders or Bankruptcies

Mr. John Brussa was a director of Imperial Metals Limited, a corporation engaged in both oil and gas and mining operations, in the year prior to that corporation implementing a plan of arrangement under the Company Act (British Columbia) and under the Companies' Creditors Arrangement Act (Canada) which resulted in the separation of its two businesses and the creation of two public corporations: Imperial Metals Corporation and IEI Energy Inc. (now Rider Resources Ltd.).

Other than the item referenced above, no director, executive officer or unitholder holding a sufficient number of Trust Units to affect materially the control of the Trust has, within the last 10 years, been a director or executive officer of any company that, while such person was acting in that capacity: was the subject of a cease trade or similar order or an order that denied the company access to any exemption under securities legislation for a period of more than 30 consecutive days; was subject to an event that resulted, after the director or executive officer ceased to be a director or executive officer, in the company being the subject of a cease trade order or similar order or an order that denied the company access to any exemption under securities legislation for a period of more than 30 consecutive days; or within a year of ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver-manager or trustee appointed to hold the assets of that person.

Personal Bankruptcies

No director, executive officer or Unitholder holding a sufficient number of Trust Units to affect materially the control of the Trust has, within the last 10 years, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or being subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold the assets of the individual.

Penalties or Sanctions

No director, executive officer or Unitholder holding a sufficient number of Trust Units to affect materially the control of the Trust has, within the last 10 years, has been subject to any penalties or sanctions imposed by a court or securities regulatory authority relating to trading in securities, promotion or management of a publicly traded issuer or theft or fraud.

Conflicts of Interest

Directors and officers of the Corporation may, from 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". Properties will not be acquired from officers or directors of the Corporation or persons not at arm's length with such persons at prices which are greater than fair market value, nor will Properties be sold to officers or directors of the Corporation or persons not at arm's length with such persons at prices which are less than fair market value in each case as established by an opinion of an independent financial advisor and approved by the independent members of the Harvest Board. There may be circumstances where certain transactions may also require the preparation of a formal valuation and the affirmative vote of Unitholders in accordance with the requirements of Ontario Securities Commission Rule 61-501.

Circumstances may arise where members of the Harvest Board serve as directors or officers of corporations which are in competition with the interests of the Corporation and the Trust. No assurances can be given that opportunities identified by such board members will be provided to the Corporation and the Trust.

PROMOTERS

Kevin A. Bennett and M. Bruce Chernoff may be considered to be the promoters of the Trust by reason of their initiative in organizing the business and affairs of the Trust. The following table sets forth the number of securities owned, directly or indirectly, by Messrs. Bennett and Chernoff.

Name and Municipality of Residence of Promoter	Type of Ownership	Number of Trust Units Owned	Percentage of Trust Units
Kevin A. Bennett Calgary, Alberta	Direct and Beneficial	505,489[(1)]	0.5%
M. Bruce Chernoff Calgary, Alberta	Direct and Beneficial	6,251,496[(2)]	6.2%

Notes:
(1) Does not include units held by Mr. Bennett's spouse.

(2) Includes Trust Units held by entities controlled by Mr. Chernoff, and Trust Units held in RESP accounts for the benefit of Mr. Chernoff's children.

LEGAL PROCEEDINGS

There are no legal proceedings which the Trust or any subsidiary of the Trust is a party or of which any of their property is subject which are material to the Trust and the Corporation is not aware of any such proceedings that are contemplated or pending.

INTERESTS OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There were no material interests, direct or indirect, of directors and executive officers of the Trust, any person or company that is the direct or indirect beneficial owner, or who exercises control or direction over more than 10% of the outstanding Trust Units, or any known associate or affiliate of such persons or company, in any transaction within the three most recently completed financial years or during the current financial year.

TRANSFER AGENT AND REGISTRAR

Valiant Trust Company, at its principal offices in Calgary, Alberta, is the transfer agent and registrar of the Trust Units, Exchangeable Shares, Debentures Series 1, Debentures Series 2 and Debentures Series 3. The transfer agent and registrar of the Debentures Series 4 and Debentures Series 5 is Computershare Trust Company of Canada at its principal offices in Calgary, Alberta and Toronto, Ontario.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, the only material contracts entered into by the Trust within the most recently completed financial year, or before the most recently completed financial year but still in effect, are the following:

1. the Trust Indenture between Harvest Operations Corp. and Valiant Trust Company described in "Trust Indenture";

2. the Indenture between Harvest Energy Trust, Harvest Operations Corp. and Valiant Trust Company in connection with the Debentures Series 1, Debentures Series 2 and Debentures Series 3 described in

"ADDITIONAL INFORMATION REGARDING THE HARVEST ENERGY TRUST STRUCTURE – Borrowing – Convertible Debentures";

3. the Indenture between Harvest Operations Corp., the Subsidiary Guarantors, Harvest Energy Trust and U.S. Bank National Association in connection with the $7^{7/8}$% Senior Notes as described in "ADDITIONAL INFORMATION REGARDING THE TRUST AND CORPORATION – Borrowing – $7^{7/8}$% Senior Notes"; and,

4. The Trust's Unit Incentive Plan and Unit Award Incentive Plan as described in "GENERAL BUSINESS DESCRIPTION – Unit Based Compensation.

Copies of each of these documents have been filed on SEDAR at www.sedar.com.

INTERESTS OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a statement, report or valuation described or included in a filing, or referred to in a filing, made under National Instrument 51-102 by the Trust during, or related to, the Trust's most recently completed financial year other than McDaniel, GLJ and Sproule, the Trust's Independent Reserve Engineering Evaluators and KPMG LLP, the Trust's auditors. As at the date hereof, none of the principals of McDaniel, GLJ, and Sproule as a group, directly or indirectly, owned more than 1% of the Units and KMPG LLP has advised Harvest's Audit Committee that they are independent with respect to the Trust within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

In addition, none of the aforementioned persons or companies, nor any director, officer or employee of any of the aforementioned persons or companies, is or is expected to be elected, appointed or employed as a director, officer or employee of the Trust or of any associate or affiliate of the Trust except for John A. Brussa, a director of Harvest Operations, who is a partner at Burnett, Duckworth and Palmer LLP which law firm renders legal services to Harvest.

DISCLOSURE PURSUANT TO THE REQUIREMENTS OF THE NEW YORK STOCK EXCHANGE

As a Canadian issuer listed on the New York Stock Exchange (the "NYSE"), we are not required to comply with most of the NYSE rules and listing standards and instead may comply with domestic requirements. As a foreign private issuer, we are only required to comply with three of the NYSE Rules (i) have an audit committee that satisfies the requirements of the United States Securities Exchange Act of 1934; (ii) the Chief Executive Officer must promptly notify the NYSE in writing after an executive officer becomes aware of any material non-compliance with the applicable NYSE Rules; and (iii) provide a brief description of any significant differences between our corporate governance practices and those followed by U.S. companies listed under the NYSE. The Trust has disclosed in the corporate governance section of its website at www.harvestenergy.ca that it does not have an internal audit function. Except as described, the Trust is in compliance with the NYSE corporate governance standards in all other significant respects.

ADDITIONAL INFORMATION

Additional information, including directors' and officers' remuneration and indebtedness, principal holders of securities and interests of insiders in material transactions, where applicable, is contained in our information circular for the most recent annual meeting of shareholders that involved the election of directors. Additional financial information is provided in our financial statements and management's discussion and analysis for the year ended December 31, 2005. Documents affecting the rights of securityholders, along with additional information relating to Harvest, may be found on SEDAR at www.sedar.com.

APPENDIX A-1
REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

Management of Harvest Operations Corp. (the "Company") on behalf of Harvest Energy Trust (the "Trust") are responsible for the preparation and disclosure of information with respect to the Company's and the Trust's other subsidiaries' oil and natural gas activities in accordance with securities regulatory requirements. This information includes reserves data, which consist of the following:

(a) (i) proved and proved plus probable oil and natural gas reserves estimated as at December 31, 2005 using forecast prices and costs; and

(ii) the related estimated future net revenue; and

(b) (i) proved oil and natural gas reserves estimated as at December 31, 2005 using constant prices and costs; and

(ii) the related estimated future net revenue.

An independent qualified reserves evaluator has evaluated the Company's and the Trust's other subsidiaries' reserves data. The report of the independent qualified reserves evaluator is presented below.

The Reserves, Safety & Environment Committee (the "RSE Committee") of the board of directors of the Company has

(c) reviewed the Company's procedures for providing information to the independent qualified reserves evaluators;

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

(e) reviewed the reserves data with management and the independent qualified reserves evaluators.

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

(f) the content and filing with securities regulatory authorities of the reserves data and other oil and natural gas information;

(g) the filing of the report of the independent qualified reserves evaluators on the reserves data; and

(h) 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.

(signed) "John Zahary"
John Zahary
President & CEO

(signed) "Rob Morgan"
Rob Morgan
Vice President, Engineering & COO

(signed) "Verne Johnson"
Verne Johnson
Director and Chairman of the RSE Committee

(signed) "Hank B. Swartout"
Hank B. Swartout
Director and Member of the RSE Committee

February 8, 2006

APPENDIX A-2

Report on Reserves Data by Independent Qualified Reserves Evaluators

To the Board of directors of Harvest Operations Corp. (the "Corporation"):

1) We have evaluated the Corporation's and Harvest Energy Trust's other subsidiaries' reserves data as at December 31, 2005. The reserves data consist of the following:

   (a) (i) Proved and proved plus probable oil and gas reserves estimated as at December 31, 2005 using forecast prices and costs; and

   (ii) The related estimated future net revenue; and

   (b) (i) Proved and proved plus probable oil and gas reserves estimated as at December 31, 2005 using constant prices and costs; and

   (ii) The related estimated future net revenue; and

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

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

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

4) The following table sets forth the estimated future net revenue (before deductions of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs, and calculated using a discount rate of 10 percent, included in the reserves data of the Corporation evaluated by us for the year ended December 31, 2005. This table also identifies the respective portions thereof that we have evaluated and reported on to the Corporation's Management and Board of directors.

Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of Evaluation Report	Location of Reserves	Net Present Value of Future Net Revenue (Before Income Taxes, 10% Discount Rate)($M) Audited	Evaluated	Reviewed	Total
McDaniel and Associates Consultants Ltd.	February 17, 2006	Canada	-	1,269,313	,	1,269,313
GLJ Petroleum Consultants Ltd.	February 27, 2006	Canada	-	226,011	,	226,011
Sproule Associates Ltd.	January 31, 2006	Canada	-	264,002	,	264,002
Totals				1,759,325		1,759,325

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 did not evaluate.

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

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

Executed as to our report referred to above:

(Signed) McDaniel & Associates Consultants Ltd.

Calgary, Alberta, Canada

(Signed) GLJ Petroleum Consultants Ltd.

Calgary, Alberta, Canada

(Signed) Sproule Associates Ltd.

Calgary, Alberta, Canada

APPENDIX A-3

HARVEST ENERGY TRUST STATEMENT OF RESERVES DATA

The statement of reserves data and other oil and natural gas information set forth below (the "Statement") is dated March 20, 2006. The effective date of the Statement is December 31, 2005 and the preparation date of the Statement is March 20, 2006.

Disclosure of Reserves Data

Harvest retained the qualified, Independent Reserves Engineering Evaluators to evaluate and prepare reports on 100% of Harvest's crude oil and natural gas reserves as of December 31, 2005. Harvest's reserves were evaluated by McDaniel (who evaluated 66% of Harvest's total proved reserves), GLJ (who evaluated 16% of Harvest's total proved reserves) and Sproule (who evaluated 18% of Harvest's total proved reserves). All of Harvest's reserves were evaluated using the price and cost assumptions of McDaniel.

The Reserves Data summarizes the crude oil, natural gas liquids and natural gas reserves of the Operating Subsidiaries and the net present values of future net revenue for these reserves using constant prices and costs and forecast prices and costs. The Reserve Report has been prepared by the Independent Reserve Engineering Evaluators in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101. Additional information not required by NI 51-101 has been presented to provide continuity and additional information which we believe is important to the readers of this information. The Operating Subsidiaries engaged the Independent Reserve Engineering Evaluators to provide an evaluation of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

All of the Operating Subsidiaries' reserves are in Canada and, specifically, in the provinces of Alberta, British Columbia and Saskatchewan.

Disclosure provided herein in respect of BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the constant prices and costs assumptions and forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserve estimates of the Operating Subsidiaries' crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquid reserves may be greater than or less than the estimates provided herein.

Reserves Data (Constant Prices and Costs)

SUMMARY OF OIL AND NATURAL GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
as of December 31, 2005
CONSTANT PRICES AND COSTS

	RESERVES					
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS	
RESERVES CATEGORY	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (Mmcf)	Net (Mmcf)
PROVED						
Developed Producing	39,963.9	35,561.4	28,554.6	25,988.7	49,572.8	42,813.4
Developed Non-Producing	333.6	305.4	0.0	0.0	10,757.6	9,037.9
Undeveloped	5,231.1	4,266.3	3,316.8	2,862.4	1,850.5	1,395.1
TOTAL PROVED	45,528.6	40,133.1	31,871.4	28,851.1	62,180.9	53,246.4
PROBABLE	15,639.9	13,549.9	14,287.6	12,816.1	17,936.3	15,561.6
TOTAL PROVED PLUS PROBABLE	61,168.5	53,683.0	46,159.0	41,667.2	80,117.2	68,808.0

	RESERVES			
	NATURAL GAS LIQUIDS		TOTAL OIL EQUIVALENT (BOE)	
RESERVES CATEGORY	Gross (Mbbl)	Net (Mbbl)	Gross (Mboe)	Net (Mboe)
PROVED				
Developed Producing	1,810.4	1,526.6	78,591.0	70,212.3
Developed Non-Producing	47.2	41.5	2,173.7	1,853.2
Undeveloped	44.2	33.0	8,900.5	7,394.2
TOTAL PROVED	1,901.8	1,601.1	89,665.3	79,459.7
PROBABLE	482.3	416.1	33,399.2	29,375.7
TOTAL PROVED PLUS PROBABLE	2,384.1	2,017.2	123,064.5	108,835.4

Note:

(1) The reserves attributable to Harvest's Hay River property, which is an area that produces medium gravity crude oil (average 24° API), are subject to a heavy oil royalty regime in British Columbia and would be required, under NI 51-101, to be classified as heavy oil for that reason. We have presented Hay River reserves as medium gravity crude in this and the following reserve tables, in respect of reserves determined using constant price and cost assumptions as they would otherwise be classified in this fashion were it not for the lower rate royalty regime applied in British Columbia. If the Hay River reserves were included in the heavy crude oil category, it would increase the gross heavy oil reserves and reduce the light/medium oil reserves by the following amounts: Proved Developed Producing: 11,550.0 Mboe, Proved Undeveloped: 3,410.0 Mboe, Total Proved: 14,960.0 Mboe, Probable: 3,860.0 Mboe and Total Proved plus Probable: 18,820.0 Mboe, and would increase the net heavy oil reserves and reduce the light/medium oil reserves by the following amounts: Proved Developed Producing: 10,180.0 Mboe, Proved Undeveloped: 2,770.0 Mboe, Total Proved: 12,950.0 Mboe, Probable: 3,230.0 Mboe, and Total Proved plus Probable: 16,180.0 Mboe.

RESERVES CATEGORY	NET PRESENT VALUES OF FUTURE NET REVENUE DISCOUNTED BEFORE INCOME TAXES (1) 0% ($000)	5% ($000)	10% ($000)	15% ($000)	20% ($000)
PROVED					
Developed Producing	1,880,398.8	1,506,883.4	1,269,817.7	1,106,028.9	985,731.6
Developed Non-Producing	93,554.6	55,753.8	38,194.1	28,887.0	23,244.7
Undeveloped	168,352.6	130,191.2	102,695.5	81,920.5	65,713.1
TOTAL PROVED	2,142,306.0	1,692,828.4	1,410,707.3	1,216,836.4	1,074,689.4
PROBABLE	841,463.7	545,789.4	394,001.3	303,493.4	243,967.2
TOTAL PROVED PLUS PROBABLE	2,983,769.7	2,238,617.8	1,804,708.6	1,520,329.8	1,318,656.6

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
as of December 31, 2005
CONSTANT PRICES AND COSTS

RESERVES CATEGORY	REVENUE ($000)	ROYALTIES ($000)	OPERATING COSTS ($000)	DEVELOPMENT COSTS ($000)	WELL ABANDONMENT COSTS ($000)	FUTURE NET REVENUE BEFORE INCOME TAXES(1) ($000)
Proved Reserves	4,197,078	579,833	1,244,755	170,758	59,426	2,142,306
Proved Plus Probable Reserves	5,702,517	791,018	1,625,355	240,383	61,991	2,983,770

FUTURE NET REVENUE
BY PRODUCTION GROUP
as of December 31, 2005
CONSTANT PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) ($000)
Proved Reserves	Light and Medium Crude Oil	764,388
	Heavy Crude Oil	335,746
	Natural Gas (including by-products)	310,573
Proved Plus Probable Reserves	Light and Medium Crude Oil	960,652
	Heavy Crude Oil	464,513
	Natural Gas (including by-products)	379,544

Reserves Data (Forecast Prices and Costs) – December 31, 2005

SUMMARY OF OIL AND NATURAL GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
as of December 31, 2005
FORECAST PRICES AND COSTS

	RESERVES					
	LIGHT AND MEDIUM OIL(1)		HEAVY OIL(1)		NATURAL GAS	
RESERVES CATEGORY	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (Mmcf)	Net (Mmcf)
PROVED						
Developed Producing	38,319.2	34,013.8	28,413.3	25,786.7	49,089.3	42,415.5
Developed Non-Producing	324.7	296.8	0.0	0.0	10,753.1	9,034.8
Undeveloped	5,197.7	4,245.7	3,317.4	2,832.7	1,843.3	1,391.0
TOTAL PROVED	43,841.6	38,556.3	31,730.7	28,619.4	61,685.7	52,841.3
PROBABLE	14,657.4	12,612.3	13,917.2	12,442.4	17,481.9	15,190.7
TOTAL PROVED PLUS PROBABLE	58,499.0	51,168.6	45,647.9	41,061.8	79,167.6	68,032.0

	RESERVES			
	NATURAL GAS LIQUIDS		TOTAL OIL EQUIVALENT	
RESERVES CATEGORY	Gross (Mbbl)	Net (Mbbl)	Gross (Mboe)	Net (Mboe)
PROVED				
Developed Producing	1,780.5	1,504.6	76,694.6	68,374.4
Developed Non-Producing	47.2	41.5	2,164.1	1,844.1
Undeveloped	49.9	37.8	8,872.2	7,348.0
TOTAL PROVED	1,877.6	1,583.9	87,730.9	77,566.5
PROBABLE	457.9	397.9	31,946.2	27,983.8
TOTAL PROVED PLUS PROBABLE	2,335.5	1,981.8	119,677.0	105,550.3

Note:

(1) The reserves attributable to Harvest's Hay River property, which is an area that produces medium gravity crude oil (average 24° API), are subject to a heavy oil royalty regime in British Columbia and would be required, under NI 51-101, to be classified as heavy oil for that reason. We have presented Hay River reserves as medium gravity crude in the following reserve tables, in respect of reserves determined using forecast price and cost assumptions as they would otherwise be classified in this fashion were it not for the lower rate royalty regime applied in British Columbia. If the Hay River reserves were included in the heavy crude oil category, it would increase the gross heavy oil reserves and reduce the light/medium oil reserves by the following amounts: Proved Developed Producing: 11,445.0 Mboe, Proved Undeveloped: 3,407.1 Mboe, Total Proved: 14,852.1 Mboe, Probable: 3,874.3 Mboe and Total Proved plus Probable: 18,726.4 Mboe, and would increase the net heavy oil reserves and reduce the light/medium oil reserves by the following amounts: Proved Developed Producing: 10,100.7 Mboe, Proved Undeveloped: 2,778.6 Mboe, Total Proved: 12,879.3 Mboe, Probable: 3,247.6 Mboe, and Total Proved plus Probable: 16,126.9 Mboe.

RESERVES CATEGORY	NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAXES DISCOUNTED AT (%/year) (1) 0% ($000)	5% ($000)	10% ($000)	15% ($000)	20% ($000)
PROVED					
Developed Producing	1,759,661.3	1,446,113.8	1,242,837.9	1,100,017.5	994,884.2
Developed Non-Producing	76,218.3	43,489.8	28,955.7	21,579.7	17,323.7
Undeveloped	147,147.2	120,785.8	98,540.5	80,358.8	64,229.1
TOTAL PROVED	1,983,026.8	1,610,389.4	1,370,334.1	1,201,956.0	1,076,437.0
PROBABLE	826,022.2	537,387.6	388,991.3	300,971.3	243,314.2
TOTAL PROVED PLUS PROBABLE	2,809,049.0	2,147,777.0	1,759,325.4	1,502,927.3	1,319,751.2

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
as of December 31, 2005
FORECAST PRICES AND COSTS

RESERVES CATEGORY	REVENUE ($000)	ROYALTIES ($000)	OPERATING COSTS ($000)	DEVELOPMENT COSTS ($000)	WELL ABANDONMENT COSTS ($000)	FUTURE NET REVENUE BEFORE INCOME TAXES(1) ($000)
Proved Reserves	4,260,523	575,810	1,410,330	183,543	107,813	1,983,027
Proved Plus Probable Reserves	5,853,501	794,475	1,871,359	261,587	117,031	2,809,049

FUTURE NET REVENUE
BY PRODUCTION GROUP
as of December 31, 2005
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) ($000)
Proved Reserves	Light and Medium Crude Oil	693,169
	Heavy Crude Oil	427,085
	Natural Gas (including by-products)	250,080
Proved Plus Probable Reserves	Light and Medium Crude Oil	872,763
	Heavy Crude Oil	583,490
	Natural Gas (including by-products)	303,072

Notes to Reserves Data Tables:

1. The Trust is entitled to deduct from its income all amounts which are paid or payable by it to Unitholders in a given financial year. As a result of amounts paid to Unitholders in the course of the most recent financial year, the Trust is not liable for any material amount of income tax on income. The net present values of

future net revenue after income taxes are, therefore, the same as the net present values of future net revenue before income taxes.

2. Columns may not add due to rounding.

3. The crude oil, natural gas liquids and natural gas reserve estimates presented in the Reserve Report are based on the definitions and guidelines contained in the COGE Handbook. A summary of those definitions are set forth below.

4. The crude oil, natural gas liquids and natural gas reserve estimates presented in the Reserve Report are based on the definitions and guidelines contained in the COGE Handbook. A summary of these 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.

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.

(d) **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 certainly.

(e) **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.

(f) **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:

(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 sum of 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.

5. Forecast Prices and Costs – January 1, 2006

Forecast prices and costs are those:

(a) generally acceptable as being a reasonable outlook of the future; and

(b) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which the Operating Subsidiaries is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

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 in the Reserve Report, based on McDaniel's then current forecasts at the date of the Report, were as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
as of January 1, 2006
FORECAST PRICES AND COSTS[5]

	OIL								
Year Forecast	WTI Crude Oil ($US/ bbl)	Edmonton Light Crude Oil ($Cdn/ bbl)	Alberta Heavy Crude Oil ($Cdn/ bbl)	Alberta Bow River Hardisty Crude Oil ($Cdn/ bbl)	Sask Cromer Medium Crude Oil ($Cdn/ bbl)	NATURAL GAS Alberta AECO Spot Price ($Cdn/ GJ)	NATURAL GAS LIQUIDS Edmonton Cond. and Natural Gasolines ($Cdn/ bbl)	INFLATION RATES [1] (%/Year)	U.S./ CAN EXCHANGE RATE[2] ($US/$Cdn)
2006	57.50	66.60	35.50	45.70	58.50	10.05	68.10	2.5	0.850
2007	55.40	64.20	36.10	45.30	56.30	9.05	65.70	2.5	0.850
2008	52.50	60.70	36.00	44.00	53.30	8.05	62.30	2.5	0.850
2009	49.50	57.20	35.30	42.60	50.20	7.00	58.80	2.5	0.850
2010	46.90	54.10	33.40	40.30	47.50	6.55	55.80	2.5	0.850
2011	48.10	55.50	34.20	41.30	48.70	6.75	57.20	2.5	0.850
2012	49.30	56.80	35.10	42.30	49.90	6.90	58.50	2.5	0.850
2013	50.50	58.20	35.90	43.40	51.10	7.05	60.00	2.5	0.850
2014	51.80	59.70	36.90	44.50	52.40	7.25	61.50	2.5	0.850
2015	53.10	61.20	37.80	45.60	53.70	7.45	63.10	2.5	0.850
2016	54.40	62.70	38.70	46.70	55.00	7.60	64.60	2.5	0.850
2017	55.80	64.30	39.70	47.90	56.50	7.80	66.30	2.5	0.850
2018	57.20	65.90	40.70	49.10	57.90	8.00	67.90	2.5	0.850
2019	58.60	67.60	41.70	50.30	59.30	8.20	69.70	2.5	0.850
2020	60.10	69.30	42.80	51.60	60.80	8.40	71.40	2.5	0.850
There-after	+2.5%/yr	+2.5%/yr	+2.5%/yr	+2.5%/yr	+2.5%/yr	+2.5%/yr	+2.5%/yr	2.5	0.850

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 prices realized by the Operating Subsidiaries for the year ended December 31, 2005, were $9.05/mcf for natural gas, $52.40/bbl for natural gas liquids, $57.07/bbl for light/medium oil, and $39.43/bbl for heavy oil.

6. Constant Prices and Costs

Constant prices and costs are:

(a) the Operating Subsidiaries' prices and costs as at the effective date of the estimation, held constant throughout the estimated lives of the properties to which the estimate applies; and

(b) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which the Operating Subsidiaries is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

For the purposes of paragraph (a), the Operating Subsidiaries' prices are the posted prices for oil and the spot price for natural gas, after historical adjustments for transportation, gravity and other factors.

The constant crude oil and natural gas benchmark references pricing and the exchange rate utilized in the Reserve Report were as follows:

SUMMARY OF PRICING ASSUMPTIONS
as of December 31, 2005
CONSTANT PRICES AND COSTS

	OIL				NATURAL GAS	NATURAL GAS LIQUIDS	
Year	West Texas Intermediate (WTI)[1] ($US/bbl)	Edmonton Light Crude[2] ($Cdn/bbl)	Bow River Medium Crude at Hardisty[2] ($Cdn/bbl)	Cromer Medium Crude[2] ($Cdn/bbl)	Alberta Spot Natural Gas Price at Field Gate[4] ($Cdn/MMBtu)	Edmonton Reference Price NGL Mix[3] ($Cdn/bbl)	EXCHANGE RATE ($US/$Cdn)
2005	61.04	68.46	36.71	51.65	9.80	56.30	0.850

Notes:
(1) December 31, 2005 NYMEX close
(2) Based on Shell, Imperial, PetroCanada, EnCana, Suncor pricing at December 30, 2005.
(3) Based on historical price differentials and adjustments.
(4) Estimated from AECO December 31, 2005 price of $9.47/GJ.

7. Future Development Costs

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

	Forecast Prices and Costs ($000)		Constant Prices and Costs ($000)	
Year	Proved Reserves	Proved Plus Probable Reserves	Proved Reserves	Proved Plus Probable Reserves
2006	88,339	112,748	85,991	109,355
2007	31,344	67,299	30,574	64,667
2008	9,262	11,603	8,840	10,961
2009	2,849	4,868	2,650	4,434
2010	2,449	2,449	2,244	2,244
Thereafter	49,300	62,620	40,459	48,722
Total Undiscounted	183,543	261,587	170,758	240,383
Total Discounted at 10%	139,373	198,628	133,170	188,919

Future development costs will be funded through cash flow and the Trust's credit facilities currently available.

8. Estimated future abandonment and reclamation costs related to a property have been taken into account by the Independent Reserve Engineering Evaluators 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 and reclamation of any facilities.

9. Both the constant and forecast price and cost assumptions assume the continuance of current laws and regulations.

10. The extent and character of all factual data supplied to the Independent Reserve Engineering Evaluators were accepted by the Independent Reserve Engineering Evaluators as represented. No field inspection was conducted.

Reconciliations of Changes in Reserves and Future Net Revenue

RECONCILIATION OF
OPERATING SUBSIDIARIES NET RESERVES (After royalties)
BY PRINCIPAL PRODUCT TYPE
FORECAST PRICES AND COSTS

	LIGHT AND MEDIUM OIL			HEAVY OIL			ASSOCIATED AND NON-ASSOCIATED NATURAL GAS		
FACTORS	Net Proved (Mbbl)	Net Probable (Mbbl)	Net Proved Plus Probable (Mbbl)	Net Proved (Mbbl)	Net Probable (Mbbl)	Net Proved Plus Probable (Mbbl)	Net Proved (Mmcf)	Net Probable (Mmcf)	Net Proved Plus Probable (Mmcf)
December 31, 2004	**26,427.5**	**7,679.9**	**34,107.4**	**29,559.6**	**13,849.4**	**43,409.0**	**57,219.9**	**16,474.6**	**73,694.5**
Extensions/ Improved Recovery	1,113.0	1,006.0	2,120.0	1,179.0	945.0	2,124.0	1,460.0	998.0	2,458.0
Technical Revisions	468.0	484.0	951.0	2,211.0	(2,444.0)	(232.0)	(3,353.0)	(3,253.0)	(6,605.0)
Discoveries	552.0	688.0	1,240.0	0.0	0.0	0.0	0.0	0.0	0.0
Acquisitions	13,086.0	2,766.0	15,852.0	0.0	0.0	0.0	5,310.0	900.0	6,210.0
Dispositions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Economic Factors	1,314.0	(23.0)	1,291.0	804.0	93.0	897.0	1,115.0	71.0	1,186.0
Production	(4,402.0)	0.0	(4,402.0)	(5,136.0)	0.0	(5,136.0)	(8,911.0)	0.0	(8,911.0)
December 31, 2005	**38,556.3**	**12,612.3**	**51,168.6**	**28,619.6**	**12,442.4**	**41,061.8**	**52,841.3**	**15,190.7**	**68,032.0**

	NATURAL GAS LIQUIDS			TOTAL (BOE)		
FACTORS	Net Proved (Mbbl)	Net Probable (Mbbl)	Net Proved Plus Probable (Mbbl)	Net Proved (MBOE)	Net Probable (MBOE)	Net Proved Plus Probable (MBOE)
December 31, 2004	**1,887.4**	**463.0**	**2,350.4**	**67,411.1**	**24,738.1**	**92,149.2**
Extensions/ Improved Recovery	23.0	8.0	31.0	2,558.3	2,125.3	4,684.7
Technical Revisions	(139.0)	(82.0)	(220.0)	1,982.2	(2,584.8)	(602.7)
Discoveries	0.0	0.0	0.0	552.0	688.0	1,240.0
Acquisitions	0.0	0.0	0.0	13,971.0	2,916.0	16,887.0
Dispositions	0.0	0.0	0.0	0.0	0.0	0.0
Economic Factors	91.0	9.0	100.0	2394.7	91.2	2,485.8
Production	(278.0)	0.0	(278.0)	(11,300.8)	0.0	(11,300.8)
December 31, 2005	**1,583.9**	**397.9**	**1,981.8**	**77,566.5**	**27,983.8**	**105,550.3**

Note: Columns may not add due to rounding

RECONCILIATION OF CHANGES IN
NET PRESENT VALUES OF FUTURE NET REVENUE
DISCOUNTED AT 10% PER YEAR
PROVED RESERVES
CONSTANT PRICES AND COSTS

PERIOD AND FACTOR		2005 ($000)
Estimated Future Net Revenue at Beginning of Year	**$**	**756,269**
Oil and Gas Sales During the Period Net of Royalties and Production Costs		(427,236)
Changes due to Prices		562,133
Actual Development Costs During the Period		120,508
Changes in Future Development Costs		(135,106)
Changes Resulting from Extensions, Infill Drilling and Improved Recovery		49,887
Changes Resulting from Discoveries		13,880
Changes Resulting from Acquisitions of Reserves		258,120
Changes Resulting from Dispositions of Reserves		-
Accretion of Discount		75,627
Other Significant Factors		-
Net Changes in Income Taxes		-
Changes Resulting from Technical Reserves Revisions Plus Effects of Timing		136,625
Estimated Future Net Revenue at End of Year	**$**	**1,410,706**

Note: Table includes values from all Independent Reserve Engineering Evaluators

Additional Information Relating to Reserves Data

Undeveloped Reserves

Proved and probable undeveloped reserves have been estimated in accordance with procedures and standards contained in the COGE Handbook.

The Operating Subsidiaries carry a relatively minor amount of undeveloped reserves. These reserves are infill wells primarily located in undrilled spacing units. A portion of these infill wells are projected to be upgraded to producing status in 2006 and the remainder in 2007 and 2008.

The Operating Subsidiaries do not see a major uncertainty related to the upgrading of undeveloped reserves. Nevertheless, a catastrophic drop in oil prices might delay infill drilling activity.

Significant Factors or Uncertainties

Information in this Annual Information Form contains forward-looking information and estimates with respect to Harvest. This information addresses future events and conditions, and as such involves risks and uncertainties that could cause actual results to differ materially from those contemplated by the information provided. These risks and uncertainties include but are not limited to factors intrinsic in domestic and international politics and economics, general industry conditions including the impact of environmental laws and regulations, imprecision of reserves estimates, fluctuations in commodity prices, interest rates or foreign exchange rates and stock market volatility. The information and opinions concerning the Trust's future outlook are based on information available at March 20, 2006.

Important economic factors that should be taken into consideration that may affect particular components of the reserve data include: oil pricing, power costs and operating expenses.

OTHER OIL AND NATURAL GAS INFORMATION

Oil and Natural Gas Properties

The Operating Subsidiaries' portfolio of Properties is discussed below. Reserve amounts discussed are gross reserves and are stated at December 31, 2005 based on forecast prices and cost assumptions. Although the Trust receives income from each of the Operating Subsidiaries pursuant to the NPI, interest and principal payments and trust and partnership distributions, all oil and natural gas operations and the management of the Trust are conducted by the Corporation.

In general, the Properties include major oil accumulations which benefit from active pressure support due to an underlying regional aquifer. Generally, the properties have predictable decline rates with costs of production and oil price key to determining the economic limits of production. The Corporation is actively engaged in cost reduction, production and reserve replacement optimization efforts directed at reserve addition through extending the economic life of these producing properties beyond the limits used in the Reserve Report and developing new proven reserves previously not evaluated by the Independent Reserve Engineering Evaluators. In respect of the Properties, the Corporation has entered into a number of electrical power swaps to manage a portion of the risk associated with electrical power cost volatility, which is a significant portion of the production costs associated with the Properties.

Harvest's portfolio of significant properties is discussed below. The estimates of reserves and future net revenue for individual properties may not reflect the same confidence levels as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

2005 Historical Production by Material Property

Core Area and Material Property	Light, Medium and Heavy Crude Oil (bbl/d)	Natural gas (mcf/d)	NGL (bbl/d)	Average Daily Production (BOE/d)
Central Alberta				
Wainwright/Viking Kinsella	2,933	171	-	2,961
Thompson Lake	770	65	20	801
Amisk/Czar	834	197	3	870
Halkirk/Leahurst	548	792	12	692
Bellshill	405	153	6	437
Berrymore	2	981	19	185
Other	301	130	17	340
Total Central Alberta	5,793	2,489	77	6,286
Southern Alberta				
Suffield	6,435	1,522	-	6,689
Crossfield	-	12,560	451	2,544
Cavalier	750	6,280	50	1,847
Badger	755	655	15	879
Other	234	778	15	379
Total Southern Alberta	8,174	21,795	531	12,338

Core Area and Material Property	Light, Medium and Heavy Crude Oil (bbl/d)	Natural gas (mcf/d)	NGL (bbl/d)	Average Daily Production (BOE/d)
Eastern Alberta				
Hayter	4,181	299	13	4,244
Killarney	1,059	72	4	1,075
Chauvin	578	43	1	586
Provost	480	152	5	510
Bodo	-	151	-	25
North David	449	116	6	474
Other	12	142	1	37
Total Eastern Alberta	6,759	975	30	6,951
Northern				
Hay River	2,078	-	-	2,078
Evi 1	1,109	27	90	1,203
Loon Lake	788	-	-	788
Evi 3/Kitty	451	-	-	451
Red Earth	376	-	-	376
Parkland	3	874	4	153
Other	43	97	1	60
Total Northern Alberta	4,848	998	95	5,109
Saskatchewan				
Hazelwood	3,036	-	93	3,129
Moose Valley	807	-	-	807
White Bear/Big Marsh	694	188	-	725
Flinton/Corning	730	-	-	730
Other	494	12	-	496
Total Saskatchewan	5,761	200	93	5,887
2005 Production Total	31,335	26,457	826	36,571

Eastern Alberta

The properties within the Eastern Alberta core area are located between T35-R1-W4 to T44-R5-W4M and produce primarily crude oil. The following summarizes the key characteristics of this core operating area:

Proved Reserves:	
Oil (mbbl)	13,164.4
NGL (mbbl)	50.4
Natural gas (mmcf)	1,370.6
Total (mboe)	13,443.2
PV10 ($000)	$ 172,228
2005 Production (boe/d)	6,951
Average 2005 area operating expenses ($/boe)	$8.85

Hayter

Harvest acquired the Hayter property in November 2002. Production in 2005 at Hayter averaged approximately 4,244 boe/d of 14.8° API oil, producing from the Lower Cretaceous Cummings/Dina formation. Harvest has an average 94% working interest in this operated property.

Future development at Hayter may include infill and step-out drilling at up to 14 identified locations. Operating expense reduction projects such as low pressure water disposal wells, horizontal disposal wells, and battery optimization are ongoing. In addition to cost reduction initiatives, Harvest believes it can capitalize on condensate blending opportunities to increase oil price realizations.

Killarney

The Killarney property was acquired by Harvest in two transactions in April and June 2003. Production in 2005 from the property was 1,075 boe/d of 20° API oil, producing from the Lower Cretaceous Cummings/Dina formation. Harvest has an average 91% working interest in this operated property.

Future development at Killarney will primarily be focused on low pressure water disposal to increase operating cost efficiencies through power reduction as well as increased fluid handling leading to increased oil production.

Chauvin

The Chauvin property was acquired by Harvest in July, 2004. Production in 2005 from the property was 586 boe/d of 20° API oil, producing from the Sparky formation. Harvest has a 100% working interest in this operated property.

Future development at Chauvin will primarily be focused on low pressure water disposal to increase operating cost efficiencies through power reduction as well as increased fluid handling leading to increased oil production. Enhancing the existing water flood through pattern balancing will be a primary focus as well.

Central Alberta

The properties within the Central Alberta core area are located between T37-R6-W4 to T49-R2-W5M and produce primarily crude oil. The following summarizes the key characteristics of this core operating area:

Proved Reserves:	
Oil (mbbl)	15,929.0
NGL (mbbl)	101.0
Natural gas (mmcf)	4,248.6
Total (mboe)	16,738.1
PV10 ($000)	$ 233,825
2005 Production (boe/d)	6,286
Average 2005 area operating expenses ($/boe)	$12.95

Viking-Kinsella/Wainwright

Harvest acquired the Viking Kinsella / Wainwright properties in September, 2004. Production in 2005 from these pools averaged approximately 2,961 boe/d of 20° API oil, produced from the Cretaceous Upper Mannville Sparky Formation. Harvest has an average 96% working interest in these operated properties.

Development opportunities in 2006 at this property may include up to 25 infill and step-out drilling locations, as well as field optimization in fluid handling and debottlenecking the water injection system, which Harvest believes will contribute to reduced operating expenses. Numerous fracture stimulation opportunities also have been identified.

Bellshill

Harvest acquired the Bellshill properties in July, 2002. Production in 2005 from these pools averaged approximately 437 boe/d of 27° API oil, producing from the Glauconitic Formation. Harvest has an average 100% working interest in these operated properties.

Development opportunities in 2006 at this property may include an infill drilling location, as well as field optimization in fluid handling and debottlenecking the water injection system, which Harvest believes will contribute to reduced operating expenses.

Thompson Lake

Thompson Lake was one of the first properties acquired by Harvest in July 2002. Production in 2005 from this property was 801 boe/d of 27° API oil, producing from the Glauconite A pool. Harvest has an average 99% working interest in this operated property.

Future development at Thompson Lake will be focused on ongoing operating expense reduction as well as increased fluid handling leading to increase oil production.

Amisk / Czar

The Amisk / Czar properties were acquired by Harvest in June 2003. Production in 2005 from the properties averaged approximately 870 boe/d ranging from 16 - 20° API oil. Harvest has an average 85% working interest in these operated properties.

Future development at Amisk/Czar will primarily be focused on reducing operating expenses through power reduction resulting from low pressure water disposal, and reducing water production and operating expenses through recompletions and water shutoff projects.

Halkirk / Leahurst

The Halkirk/Leahurst properties are located near Stettler, Alberta and were acquired by Harvest in September 2004. Production in 2005 from these properties averaged approximately 692 boe/d of 36° API oil, producing from the Glauconite formation. A small amount of slightly sour gas is produced from this area as well. Harvest has 70% working interest in Leahurst and 96% in Halkirk.

Future development at Halkirk/Leahurst will primarily be focused on gas recompletions for the Viking zone, and waterflood optimization and reactivation of shut-in oil wells.

Southern Alberta

The properties within the Southern Alberta core area are located from T13-R6-W4M to T29-R29-W4M and produce both crude oil and natural gas. Harvest acquired all Southern Alberta properties in September 2004. The following table summarizes the key characteristics of this core operating area:

Proved Reserves:	
Oil (mbbl)	11,918.7
NGL (mbbl)	1,849.9
Natural gas (mmcf)	42,702.8
Total (mboe)	20,885.7
PV10 ($000)	$ 392,144
2005 Production (boe/d)	12,338
Average 2005 area operating expenses ($/boe)	$6.27

Suffield
Production from this region averaged 6,689 boe/d of primarily heavy oil in 2005, averaging 11-18° API from the Upper Mannville Glauconitic formation. Harvest has an average 99% working interest in this operated property.

Future development at Suffield may include step-out, extension and infill drilling at up to 22 identified locations, as well as increased fluid handling capacities. Pool optimization projects may target increased production and generate economic oil production with increased water cuts to outperform engineering reserve estimates.

Crossfield
Production in 2005 from this region was primarily natural gas with some liquids, and averaged approximately 2,544 boe/d from the Lower Cretaceous Basal Quartz formation. Harvest has an average 75% working interest in this operated property. Future development at Crossfield will include infill and step-out drilling and field compression to increase the recovery factor and accelerate production.

Cavalier
Production from this region in 2005 averaged 1,847 boe/d of primarily light crude oil averaging 30-36° API and natural gas. Production is from the Upper Mannville Glauconitic formation. Harvest has an average 96% working interest in this operated property.

Future development at Cavalier may include waterflood/reservoir management and optimization, and infill drilling to increase the recovery factor and accelerate production.

Badger
Production in 2005 from this region averaged 879 boe/d of medium crude oil averaging 21° API and natural gas produced from the Upper Mannville Glauconitic Formation. Harvest has an average 100% working interest in this operated property.

Future development at Badger may include infill drilling, waterflood optimization, and reservoir management to increase the recovery factor.

Saskatchewan
The properties within the southeast Saskatchewan core area are located from T7-R32-W1M to T12-R8-W2M and produce primarily light gravity crude oil. Harvest acquired the properties in October 2003. The following table summarizes the key characteristics of this core operating area:

Proved Reserves:	
Oil (mbbl)	13,780.2
NGL (mbbl)	244.9
Natural gas (mmcf)	1649.8
Total (mboe)	14,300.1
PV10 ($000)	$ 204,055
2005 Production (boe/d)	5,887
Average 2005 area operating expenses ($/boe)	$11.21

Hazelwood
Production from Hazelwood averaged 3,129 boe/d of average 33° API crude oil in 2005, primarily produced from the Tilston Formation. Harvest has an average 99% working interest in this operated property.

Future development at Hazelwood may include step-out and horizontal infill drilling at up to 28 locations to increase the recovery factor and accelerate production. Harvest believes further drilling opportunities are possible through the continued pooling of landowner interests to drill under-exploited areas. Harvest's extensive proprietary 3D seismic coverage offers control of the opportunity. An extensive workover program is available to increase oil production.

Big Marsh
Production from Big Marsh in 2005 was 725 boe/d of average 34° API crude oil produced from the Tilston Formation. Harvest has an average 100% working interest in this operated property.

Future development at Whitebear/Big Marsh may include infill drilling, stepout drilling, water handling upgrades and water control measures to increase the recovery factor. Harvest's extensive proprietary 3D seismic coverage offers control of the opportunity to increase oil production through horizontal infill, and stepout drilling.

Flinton/ Corning
Production in 2005 from the Flinton / Corning area was 730 boe/d of average 28.4° API crude oil produced from the Tilston Formation. Harvest's average working interest in this operated property is 100%.

Future development in this area may include infill drilling at 2 identified locations.

Moose Valley
Production in 2005 from Moose Valley was 807 boe/d of average 27.8° API crude oil produced from the Tilston Formation. Harvest's average working interest in this operated property is 95%.

Future development in this area may include downspaced infill drilling and pool extension drilling at 2 identified locations.

Northern

The properties within the Northern core area are located from T83-R7-W5M to just within the British Columbia border T111-R12-W6M and produce primarily light gravity crude oil and natural gas. Harvest acquired its interests in northern Alberta properties when it acquired Storm in June 2004 which formed a new core area and then subsequently added to this area with its acquisition of Hay River in August 2005. The following table summarizes the key characteristics of this core operating area:

Proved Reserves:	
Oil (mbbl)	20,811.8
NGL (mbbl)	241.4
Natural gas (mmcf)	12,565.0
Total (mboe)	23,147.4
PV10 ($000)	$ 373,037
2005 Production (boe/d)[1]	5,109
Average 2005 area operating expenses ($/boe)	$6.93

[1] Annual 2005 production only includes the Hay River production from August 2, 2005, and as a result, full year 2005 production in the Northern area is not reflective of current production or 2006 anticipated production.

Hay River

Hay River was acquired by Harvest on August 2, 2005 and produced 2,078 BOE/d (March 2006 production estimated at 4,400 BOE/d) of medium gravity (24° API) crude oil in 2005. The Hay River medium production is priced at a discount to the Edmonton Light oil benchmark, contributing to stronger netbacks in this area. Harvest has an average 100% working interest in this operated property.

Evi 1

Evi 1 was acquired by Harvest in June of 2004 and current production in 2005 averaged 1,203 BOE/d of 39° API from the Slave Point / Granite Wash Formations. Harvest has an average 60% working interest in this operated property. Potential development in this area may include new completions, recompletions and step-out drilling.

Evi 3 / Kitty

Evi 3 and Kitty were acquired in June, 2004 and production in 2005 averaged 451 BOE/d of 39° API from the Slave Point / Gilwood Formations. Harvest has an average 67% working interest in this operated property.

Future development in these areas may include production optimization opportunities, efficiency improvements, step-out drilling and waterflood implementation.

Loon Lake

Production in 2005 from Loon Lake averaged 788 boe/d of oil averaging 39° API from the Devonian Slave Point and Granite Wash Formations. Harvest has an average 45% working interest in this operated property.

Future development at Loon Lake may include downspace drilling in the Slave Point at up to 25 locations, as well as potential waterflood to increase the recovery factor and flatten production profiles. Future development in the Granite Wash may include utilization of Harvest's extensive 3D seismic inventory to identify future drilling locations, step-out and infill drilling up to 5 locations, as well as production optimization opportunities.

Red Earth

Production in 2005 from Red Earth proper as well as miscellaneous other Red Earth properties averaged approximately 376 boe/d of 39° API gravity crude oil from the Slave Point / Granite Wash Formations. Harvest has an average 68% working interest in this operated property.

Incremental Exploitation and Development Potential

Management of the Corporation has identified numerous development opportunities, many of which provide the potential for capital investment and incremental production beyond that identified in the Reserve Report. Opportunities being considered include:

- Implementation or optimization of waterfloods in selected pools resulting in increased production and recovery;
- Increasing water handling and water disposal capacity at key fields to add incremental oil volumes. This includes additional use of free water knock-outs and additional disposal wells;
- Debottlenecking existing fluid handling facilities and surface infrastructure;
- Optimizing field oil cut management through the shut-in of select wells and increased total fluid from offset higher oil cut wells. Shut-in wells would be available for restart as oil cuts vary;
- Uphole completions of bypassed or untested reserves in existing wellbores, including recompletion of existing shut-in wells to access undrained reserves;
- Selected infill and step-out development drilling opportunities for various proven targets generally defined by 3D seismic; and
- Numerous exploratory opportunities defined by seismic from which value might be extracted by sale, farmout or joint venture.

Oil And Natural Gas Wells

The following table sets forth the number and status of wells in which the Operating Subsidiaries had a working interest as at December 31, 2005.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	2,000	1,771	313	218	185	150	15	14
British Columbia	109	109	11	10	86	81	6	6
Saskatchewan	467	430	243	230	32	18	-	-
Total	2,576	2,310	567	458	303	249	21	20

Properties with no Attributable Reserves

The following table sets out the Operating Subsidiaries' undeveloped land holdings as at December 31, 2005.

	Undeveloped Acres	
	Gross	Net
Alberta	270,963	244,844
British Columbia	35,255	7,794
Saskatchewan	172,223	160,614
Total	478,441	413,252

	Undeveloped Acres for which rights expire within one year	
	Gross	Net
Alberta	42,878	25,714
British Columbia	26,126	13,582
Saskatchewan	22,096	12,993
Total	91,100	52,289

Marketing Arrangements and Forward Contracts

Crude Oil and NGLs
Harvest's crude oil and NGLs production is marketed to a diverse portfolio of intermediaries and end users on 30 day continuously renewing contracts whose terms fluctuate with monthly spot market prices. Harvest received an average sales price, excluding the effects of commodity price risk contracts, of $57.07/bbl for its light and medium crude oil, $39.43/bbl for its heavy crude oil and $52.40/bbl for its NGLs for the year ended December 31, 2005 compared to $44.95/bbl for its light and medium crude oil, $31.13/bbl for its heavy crude oil and $40.95/bbl for its NGLs for the year ended December 31, 2004.

Natural Gas
Harvest's natural gas production is sold primarily at it's the prevailing spot market price in Alberta with only 9% of its production dedicated to aggregator contracts which are contracted for the economic life of the reserves. Accordingly, Harvest's average sales price for natural gas will closely follow the benchmark prices for natural gas deliver to the Alberta spot market. Harvest received an average sales price, excluding the effects of commodity price risk contracts, of $9.05/mcf for its natural gas for the year ended December 31, 2005 compared to $6.32/mcf in 2004.

Forward Contracts
Harvest may use a variety of financial instruments and fixed price physical sales contracts to reduce its exposure to fluctuations in commodity prices and as a result, may be exposed to losses in the event of default by the counterparties to these contracts. This risk is managed by diversifying its contracts among a number of financially sound counterparties. Harvest has entered into fixed price physical sales contracts for heavy oil which include a fixed heavy oil differential of approximately 30% of the West Texas Intermediate benchmark price on 10,000 bbls/d in 2006 and fixed price purchase contracts for the purchase of approximately 45 MWH of electrical power on the Alberta power grid for 2006 at an average price of approximately $49.15 and a further 35 MWH in each of 2007 and 2008 at price of $56.69.

A complete summary of Harvest's fixed price sales and purchase contracts along with its financial instruments use to manage commodity price risks can be found in Note 16 "Financial Instruments and Risk Management Contracts" to our audited consolidated financial statements for the year ended December 31, 2005 and under the heading "Risk Management Contracts" in our management discussion and analysis and results of operations for the year ended December 31, 2005 which have been filed on SEDAR at www.sedar.com. Both Note 16 of the audited consolidated financial statements for the year ended December 31, 2005 and the "Risk Management Contracts" section of our 2005 management's discussion and analysis are incorporated herein by reference.

Additional Information Concerning Abandonment and Reclamation Costs

The following table sets forth information respecting future abandonment and reclamation costs for surface leases, wells, facilities and pipelines which are expected to be incurred by the Operating Subsidiaries and for the periods indicated:

Period	Abandonment & Reclamation costs net of salvage value (undiscounted and using a 2% inflation rate) ($000)	Abandonment & Reclamation costs net of salvage value (discounted at 10% using a 2% inflation rate) ($000)
Total as at Dec. 31, 2005	406,650	103,519
Anticipated to be paid in 2006	4,376	3,979
Anticipated to be paid in 2007	3,960	3,273
Anticipated to be paid in 2008	4,645	3,490

The number of net wells for which the Independent Reserve Engineering Evaluators estimated that the Operating Subsidiaries would incur abandonment and reclamation costs is 2,024 wells (Proved plus Probable).

Abandonment costs (excluding salvage values) associated only with wells for which reserves were assigned are deducted by the Independent Reserve Engineering Evaluators in estimating future net revenue in the Reserve Report. When abandonment costs associated with facilities, pipelines and no reserve addition ("NRA") wells are excluded from the table above, the estimated future undiscounted expense related to facilities, pipelines and NRA wells is $288 million ($63 million discounted at 10%). The nature of these expenses are not expected to change the anticipated costs for the next three years as they will not be incurred until the end of a field's reserve life profile.

Tax Horizon

In our structure, taxable income from the Operating Subsidiaries is transferred to the Trust on an annual basis and taxable income of the Trust is transferred to our Unitholders with the payment of taxable distributions. The transfer of taxable income from the Operating Subsidiaries is primarily accomplished with the payment of the various net profits interests and the interest on the unsecured debt obligations owing to the Trust which are both deductible by the Operating Subsidiaries for income tax purposes. Accordingly, Harvest anticipates that there will be no corporate income tax liability payable by the Operating Subsidiaries for the foreseeable future. Further, the Trust Indenture currently requires the Trust to distribute its taxable income to Unitholders by December 31 in each fiscal year which ensures the Trust will not become liable for income taxes on undistributed income.

Capital Expenditures

The following tables summarize capital expenditures (net of incentives and net of certain proceeds and including capitalized general and administrative expenses) related to the Operating Subsidiaries' activities for the year ended December 31, 2005 ($000):

Property acquisition costs	
Proved properties	240,817
Undeveloped properties	1,018
Total acquisition costs	241,835
Exploration costs	-
Cash development costs	120,508
Total Capital Expenditures	362,343

Potential Acquisitions

The Trust continues to evaluate potential acquisitions of all types of petroleum and natural gas and other energy-related assets as part of its ongoing acquisition program. The Trust is normally in the process of evaluating several potential acquisitions at any one time which individually or together could be material. As of the date hereof, the

Trust has not reached agreement on the price or terms of any potential material acquisitions. The Trust cannot predict whether any current or future opportunities will result in one or more acquisitions for the Trust.

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells in which the Operating Subsidiaries participated during the year ended December 31, 2005:

	Exploratory Wells		Development Wells	
	Gross	Net	Gross	Net
Light & Medium Oil	-	-	37	34
Heavy Oil	-	-	49	45
Natural Gas	-	-	3	1
Service	-	-	1	1
Dry	-	-	5	3
Total:	-	-	95	84

During 2006, the Operating Subsidiaries plan to drill between 240 and 280 gross wells. The Operating Subsidiaries plan to actively drill in the Northern area, with 34 wells budgeted for the Hay River property and 19 wells planned in Red Earth. The Operating Subsidiaries plan to continue the development drilling program in Southeast Saskatchewan started in 2004, with 25 wells planned for primarily Tilston oil production. The Operating Subsidiaries have also budgeted for a development drilling program targeting approximately 45 wells in the Edmonton Sands and Pekisko Formations in Markerville, approximately 25 wells at the Suffield property in Southern Alberta and plan to continue undertaking projects such as battery optimization and consolidation to reduce operating costs. The Operating Subsidiaries will also continue development drilling with approximately 82 locations targeted in the Wainwright / Provost region. The Operating Subsidiaries are continuing with a program to add low pressure water disposal to reduce operating costs by reducing consumption of electricity.

Production Estimates

The following table sets out the volume of the Operating Subsidiaries' net production estimated for the year ended December 31, 2006 which is reflected in the estimate of future net revenue disclosed in the tables contained under "Disclosure of Reserves Data" and forecast by the Independent Reserve Engineering Evaluators.

	2006 Production Forecast				
	Light and Medium Oil (bbl/d)	Heavy Oil (bbl/d)	Natural Gas (mcf/d)	Natural Gas Liquids (bbl/d)	BOE (boe/d)
Proved Producing	16,517	14,147	22,591	733	35,163
Proved Developed Non-Producing	50	0	393	4	120
Proved Undeveloped	1,992	2,024	1,596	30	4,312
Total Proved	18,493	16,171	23,816	761	39,395
Total Probable	1,489	1,004	2,862	63	3,032
Total Proved Plus Probable	19,982	17,175	26,678	824	42,427

Suffield is the Operating Subsidiaries' largest producing property representing approximately 18% of forecast 2006 production. It is forecast by the Reserve Evaluators to produce 7,633 Bbl/d of the estimated total 42,427 BOE/d.

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:

Average Daily Production Volumes (before the deduction of royalties)	2005 Q1	Q2	Q3	Q4	Total
Light & Medium Oil (bbl/d) (1)	15,614	15,336	18,868	20,471	17,590
Heavy Oil (bbl/d)	14,473	13,519	13,735	13,273	13,747
Total Oil (bbl/d)	30,087	28,855	32,603	33,744	31,337
NGL (bbl/d)	780	798	850	867	824
Natural Gas(mcf/d)	27,114	28,857	24,574	25,339	26,461
Total Daily Production (BOE/d)	**35,386**	**34,463**	**37,549**	**38,834**	**36,571**
Total Sales Production:					
Light and Medium Oil (bbl) (1)	1,405,260	1,395,576	1,735,856	1,883,332	6,420,350
Heavy Oil (bbl)	1,302,570	1,230,229	1,263,620	1,221,116	5,017,655
Total Oil (bbl)	2,707,830	2,625,805	2,999,476	3,104,448	11,438,005
NGL (bbl)	70,200	72,618	78,200	79,764	300,760
Natural Gas (mcf)	2,440,260	2,626,260	2,260,992	2,331,096	9,657,900
Total Production (BOE)	**3,184,740**	**3,136,133**	**3,454,508**	**3,572,728**	**13,348,415**

Average Sales Prices Received:	2005 Q1	Q2	Q3	Q4	Total
Natural Gas (mcf)	$ 6.53	$ 7.92	$ 10.69	$ 11.39	$ 9.05
Light & Medium oil ($/bbl) (1)	49.88	53.49	65.71	57.62	57.07
Heavy Oil ($/bbl)	31.67	36.04	52.37	37.75	39.43
Total Oil ($/bbl)	41.12	45.31	60.09	49.80	49.34
NGL ($bbl)	36.00	47.31	54.23	58.37	52.40
BOE – 6:1	$ 40.76	$ 45.67	$ 60.39	$ 52.01	$ 50.01

Royalties Paid

	2005 Q1	Q2	Q3	Q4	Total
Light & Medium Oil ($000) [(1)]	9,029	12,910	25,072	19,778	66,789
Heavy Oil ($000)	8,216	7,965	11,611	9,183	36,975
Natural gas & NGL's ($000)	2,650	2,080	2,291	2,217	9,238
Total BOE ($000)	19,895	22,955	38,974	31,178	113,002
Light & Medium Oil ($/bbl) [(1)]	6.93	10.49	19.84	16.20	13.31
Heavy Oil ($/bbl)	5.85	5.71	6.69	4.88	5.76
Natural gas & NGL's ($/boe)	5.56	4.08	5.03	4.73	4.84
Total BOE ($/boe)	$ 6.25	$ 7.32	$ 11.28	$ 8.73	$ 8.47

Operating Expenses[(2)]

	2005 Q1	Q2	Q3	Q4	Total
Light & Medium Oil ($000) [(1)]	14,871	15,087	18,111	19,637	67,706
Heavy Oil ($000)	8,930	9,678	10,284	10,775	39,667
Natural gas & NGL's ($000)	3,381	3,723	2,576	3,915	13,595
Total BOE ($000)	27,182	28,488	30,971	34,327	120,968
Light & Medium Oil ($/bbl) [(1)]	11.42	12.26	14.33	16.08	13.49
Heavy Oil ($/bbl)	6.35	6.93	5.92	5.72	6.18
Natural gas & NGL's ($/BOE)	7.09	7.30	5.66	8.36	7.12
Total BOE ($/BOE)	$ 8.54	$ 9.08	$ 8.96	$ 9.60	$ 9.07

Netback Received[(3)]

	2005 Q1	Q2	Q3	Q4	Total
Light & Medium Oil ($/bbl) [(1)]	31.53	30.73	31.54	25.34	30.27
Heavy Oil ($/bbl)	19.47	23.40	39.76	27.15	27.49
Natural gas & NGL's ($/BOE)	29.88	43.86	54.22	56.67	49.50
Total BOE ($/BOE)	$ 25.97	$ 29.27	$ 40.15	$ 33.68	$ 32.47

Notes:

(1) Medium oil production includes production from our Hay River property. The crude oil from this property has an average API of 24^{o} (medium grade); however, it benefits from a heavy oil royalty regime and therefore, would be classified as heavy oil according to NI 51-101.

(2) Includes impact of power hedge gains and losses

(3) Before gains or losses on commodity derivatives

SCHEDULE B-1

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

Management of Harvest Operations Corp., on behalf of Viking Energy Royalty Trust (the "Trust"), are responsible for the preparation and disclosure of information with respect to the Trust's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which consist of the following:

(a) (i) proved and proved plus probable oil and natural gas reserves estimated as at December 31, 2005 using forecast prices and costs; and

(ii) the related estimated future net revenue; and

(b) (i) proved oil and natural gas reserves estimated as at December 31, 2005 using constant prices and costs; and

(ii) the related estimated future net revenue.

An independent qualified reserves evaluator has evaluated the Trust's and its subsidiaries' reserves data. The report of the independent qualified reserves evaluator is presented below.

The Reserves, Safety & Environment Committee (the "RSE Committee") of the board of directors of Harvest Operations Corp. has

(c) reviewed the Trust's procedures for providing information to the independent qualified reserves evaluators;

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

(e) reviewed the reserves data with management and the independent qualified reserves evaluators.

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

(f) the content and filing with securities regulatory authorities of the reserves data and other oil and natural gas information;

(g) the filing of the report of the independent qualified reserves evaluators on the reserves data; and

(h) 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.

(signed) "John Zahary"
John Zahary
President & CEO

(signed) "Rob Morgan"
Rob Morgan
Vice President, Engineering & COO

(signed) "Verne Johnson"
Verne Johnson
Director and Chairman of the RSE Committee

(signed) "Hank B. Swartout"
Hank B. Swartout
Director and Member of the RSE Committee

February 8, 2006

SCHEDULE B-2

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

To the board of directors of Harvest Operations Corp. on behalf of Viking Energy Royalty Trust (the "Trust")":

1. We have prepared an evaluation of the Trust's and its subsidiaries' reserves data as at December 31, 2005. The reserves data consist of the following:

   (a) (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2005, using forecast prices and costs; and
   (ii) the related estimated future net revenue; and

   (b) (i) proved oil and gas reserves estimated at December 31, 2005, using constant prices and costs; and
   (ii) the related estimated future net revenue.

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

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

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

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Trust evaluated by us for the year ended December 31, 2005, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to Board of Directors of Harvest Operations Corp.:

Description and Preparation Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate)			
		Audited	Evaluated	Reviewed	Total
February 8, 2006	Canada	-	$1,244,262		$1,244,262

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.

6. We have no responsibility to update this evaluation for events and circumstances occurring after the preparation dates.

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

Executed as to our report referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada Dated February 8, 2006

[ORIGINALLY SIGNED BY]
Myron J. Hladyshevsky, P. Eng.
Vice-President

APPENDIX B-3

VIKING ENERGY ROYALTY TRUST STATEMENT OF RESERVES DATA

The following is a summary of the oil and natural gas reserves and the value of future net revenue of Viking as evaluated by GLJ as at December 31, 2005 (the "GLJ Report"). The pricing used in the forecast and constant price evaluations is set forth in the notes to the tables.

All evaluations of future revenue are after the deduction of future income tax expenses, unless otherwise noted in the tables, royalties, development costs, production costs and well abandonment costs but before consideration of indirect costs such as administrative, overhead and other miscellaneous expenses. The estimated future net revenue contained in the following tables does not necessarily represent the fair market value of Viking's reserves. There is no assurance that the forecast price and cost assumptions contained in the GLJ Report will be attained and variances could be material. Other assumptions and qualifications relating to costs and other matters are included in the GLJ Report. The recovery and reserves estimates on the Viking's properties described herein are estimates only. The actual reserves on the Viking's properties may be greater or less than those calculated.

Oil and Gas Production and Reserves Data Disclosure

Where any disclosure of reserves data is made in this AIF that does not reflect all reserves of Viking, the reader should note that the estimates of reserves and future net revenue for individual properties or groups of properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties.

OIL AND GAS RESERVES
BASED ON CONSTANT PRICES AND COSTS [9]

As of December 31, 2005

RESERVES CATEGORY	LIGHT AND MEDIUM OIL Gross (Mbbl)	LIGHT AND MEDIUM OIL Net (Mbbl)	HEAVY OIL Gross (Mbbl)	HEAVY OIL Net (Mbbl)	NATURAL GAS Gross (MMcf)	NATURAL GAS Net (MMcf)
PROVED						
Developed Producing	24,254.0	22,082.0	3,868.0	3,428.0	142,372.0	115,785.0
Developed Non-Producing	831.0	738.0	1,823.0	1,538.0	16,570.0	13,457.0
Undeveloped	1,110.0	950.0	1,247.0	1,037.0	6,128.0	4,980.0
TOTAL PROVED	26,195.0	23,770.0	6,938.0	6,003.0	165,070.0	134,222.0
PROBABLE	8,602.0	7,713.0	4,049.0	3,471.0	54,109.0	44,020.0
TOTAL PROVED PLUS PROBABLE	34,797.0	31,483.0	10,987.0	9,474.0	219,179.0	178,242.0

RESERVES CATEGORY	NATURAL GAS LIQUIDS Gross (Mbbl)	NATURAL GAS LIQUIDS Net (Mbbl)	TOTAL OIL EQUIVALENT (BOE) Gross (Mbbl)	TOTAL OIL EQUIVALENT (BOE) Net (Mbbl)
PROVED				
Developed Producing	3,325.0	2,427.0	55,176.0	47,235.0
Developed Non-Producing	296.0	213.0	5,712.0	4,732.0
Undeveloped	186.0	133.0	3,564.0	2,950.0
TOTAL PROVED	3,807.0	2,773.0	64,452.0	54,917.0
PROBABLE	1,242.0	890.0	22,911.0	19,411.0
TOTAL PROVED PLUS PROBABLE	5,049.0	3,663.0	87,363.0	74,328.0

NET PRESENT VALUES OF FUTURE NET REVENUE
BASED ON CONSTANT PRICES AND COSTS(9)

RESERVES CATEGORY	0% ($000)	5% ($000)	10% ($000)	15% ($000)	20% ($000)
PROVED					
Developed Producing	1,609,098.0	1,226,975.0	1,006,905.0	862,298.0	759,385.0
Developed Non-Producing	168,884.0	131,330.0	108,054.0	92,005.0	80,186.0
Undeveloped	87,511.0	64,978.0	50,000.0	39,592.0	32,006.0
TOTAL PROVED	1,865,493.0	1,423,283.0	1,164,959.0	993,895.0	871,577.0
PROBABLE	653,839.0	407,344.0	288,118.0	219,852.0	176,155.0
TOTAL PROVED PLUS PROBABLE	2,519,332.0	1,830,627.0	1,453,077.0	1,213,747.0	1,047,732.0

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
BASED ON CONSTANT PRICES AND COSTS(9)

RESERVES CATEGORY	REVENUE ($000)	ROYALTIES ($000)	OPERATING COSTS ($000)	DEVELOPMENT COSTS ($000)	WELL ABANDONMENT COSTS ($000)	FUTURE NET REVENUE BEFORE INCOME TAXES ($000)
Proved Reserves	3,437,372	541,607	929,987	59,708	40,577	1,865,493
Proved Plus Probable Reserves	4,604,752	734,250	1,215,586	93,464	42,121	2,519,332

FUTURE NET REVENUE BY PRODUCTION GROUP
BASED ON CONSTANT PRICES AND COSTS(9)

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) ($000)
Proved Reserves	Light and Medium Crude Oil	416,541
	Heavy Crude Oil	87,612
	Natural Gas (including by-products)	660,806
Proved Plus Probable Reserves	Light and Medium Crude Oil	506,719
	Heavy Crude Oil	127,896
	Natural Gas (including by-products)	818,462

OIL AND GAS RESERVES
BASED ON FORECAST PRICES AND COSTS[10]

RESERVES CATEGORY	LIGHT AND MEDIUM OIL Gross (Mbbl)	LIGHT AND MEDIUM OIL Net (Mbbl)	HEAVY OIL Gross (Mbbl)	HEAVY OIL Net (Mbbl)	NATURAL GAS Gross (MMcf)	NATURAL GAS Net (MMcf)
PROVED						
Developed Producing	23,947.0	21,798.0	3,867.0	3,399.0	140,292.0	114,023.0
Developed Non-Producing	832.0	738.0	1,825.0	1,527.0	16,569.0	13,455.0
Undeveloped	1,084.0	924.0	1,247.0	1,024.0	6,118.0	4,991.0
TOTAL PROVED	25,863.0	23,460.0	6,939.0	5,950.0	162,979.0	132,469.0
PROBABLE	8,435.0	7,563.0	4,049.0	3,436.0	53,350.0	43,366.0
TOTAL PROVED PLUS PROBABLE	34,298.0	31,023.0	10,988.0	9,386.0	216,329.0	175,835.0

RESERVES CATEGORY	NATURAL GAS LIQUIDS Gross (Mbbl)	NATURAL GAS LIQUIDS Net (Mbbl)	TOTAL OIL EQUIVALENT (BOE) Gross (Mbbl)	TOTAL OIL EQUIVALENT (BOE) Net (Mbbl)
PROVED				
Developed Producing	3,298.0	2,413.0	54,495.0	46,614.0
Developed Non-Producing	296.0	214.0	5,715.0	4,721.0
Undeveloped	185.0	133.0	3,536.0	2,914.0
TOTAL PROVED	3,779.0	2,760.0	63,746.0	54,249.0
PROBABLE	1,229.0	883.0	22,606.0	19,109.0
TOTAL PROVED PLUS PROBABLE	5,008.0	3,643.0	86,352.0	73,358.0

NET PRESENT VALUES OF FUTURE NET REVENUE
BASED ON FORECAST PRICES AND COSTS(10)

RESERVES CATEGORY	0% ($000)	5% ($000)	10% ($000)	15% ($000)	20% ($000)
PROVED					
Developed Producing	1,276,710.0	1,013,035.0	860,530.0	757,944.0	682,952.0
Developed Non-Producing	149,128.0	117,746.0	98,176.0	84,585.0	74,501.0
Undeveloped	73,852.0	56,126.0	43,938.0	35,297.0	28,905.0
TOTAL PROVED	1,499,690.0	1,186,907.0	1,002,644.0	877,826.0	786,358.0
PROBABLE	534,748.0	337,366.0	241,619.0	186,715.0	151,470.0
TOTAL PROVED PLUS PROBABLE	2,034,438.0	1,524,273.0	1,244,263.0	1,064,541.0	937,828.0

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
BASED ON FORECAST PRICES AND COSTS(10)

RESERVES CATEGORY	REVENUE ($000)	ROYALTIES ($000)	OPERATING COSTS ($000)	DEVELOPMENT COSTS ($000)	WELL ABANDONMENT COSTS ($000)	FUTURE NET REVENUE BEFORE INCOME TAXES (1) ($000)
Proved Reserves	3,158,496	484,737	1,058,202	63,080	52,787	1,499,690
Proved Plus Probable Reserves	4,285,329	661,605	1,432,806	98,345	58,135	2,034,438

FUTURE NET REVENUE BY PRODUCTION GROUP BASED ON FORECAST PRICES AND COSTS(9)

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) ($000)
Proved Reserves	Light and Medium Crude Oil	354,174
	Heavy Crude Oil	97,737
	Natural Gas (including by-products)	550,732
Proved Plus Probable Reserves	Light and Medium Crude Oil	430,270
	Heavy Crude Oil	142,797
	Natural Gas (including by-products)	671,195

RECONCILIATION OF COMPANY NET RESERVES BY PRINCIPAL PRODUCT TYPE BASED ON FORECAST PRICES AND COSTS (10)

The following table sets forth a reconciliation of the changes in Viking's light and medium crude oil, heavy oil and associated and non-associated gas (combined) reserves as at January 1, 2006 against such reserves as at January 1, 2005 based on the price and cost assumptions set forth in note 10:

	Light and Medium Oil			Heavy Oil			Natural Gas Liquids		
	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable
FACTORS	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)
December 31, 2004	**24,318**	**7,289**	**31,607**	**1,646**	**586**	**2,232**	**948**	**266**	**1,214**
Discoveries	0	0	0	0	0	0	7	5	13
Extensions	91	37	128	478	-51	427	145	36	181
Infill Drilling	150	77	227	337	51	388	46	44	90
Improved Recovery	286	-204	83	123	78	202	3	-2	1
Technical Revisions	-371	-28	-398	61	203	264	-1	-6	-7
Acquisitions	2,285	778	3,063	3,879	2,568	6,447	1,911	538	2,448
Dispositions	-1,341	-474	-1,814	0	0	0	-4	-1	-4
Economic Factors	693	87	780	12	0	12	8	3	11
Production	-2,651	0	-2,651	-585	0	-585	-303	0	-303
December 31, 2005	**23,460**	**7,563**	**31,023**	**5,950**	**3,436**	**9,386**	**2,760**	**883**	**3,643**

FACTORS	Associated and Non-Associated Natural Gas Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)	BOE Proved (Mboe)	Probable (Mboe)	Proved Plus Probable (Mboe)
December 31, 2004	**50,590**	**11,580**	**62,170**	**35,344**	**10,071**	**45,415**
Discoveries	730	498	1,228	129	88	217
Extensions	8,914	2,497	11,411	2,199	438	2,637
Infill Drilling	2,477	1,647	4,124	946	446	1,392
Improved Recovery	88	-27	61	426	-131	295
Technical Revisions	1,175	294	1,469	-115	218	103
Acquisitions	87,682	26,918	114,600	22,688	8,370	31,058
Dispositions	-748	-210	-958	-1,469	-509	-1,978
Economic Factors	632	167	799	817	119	936
Production	-19,070	0	-19,070	-6,717	0	-6,717
December 31, 2005	**132,469**	**43,365**	**175,834**	**54,248**	**19,110**	**73,358**

The following table sets forth changes between future net revenue estimates attributable to net proved reserves as at January 1, 2006 against such reserves as at January 1, 2005.

RECONCILIATION OF CHANGES IN NET PRESENT VALUES OF FUTURE NET REVENUE DISCOUNTED AT 10%
BASED ON PROVED RESERVES AND CONSTANT PRICES AND COSTS [9]

Period and Factor	**Before Tax 2005 (M$)**
Estimated Net Present Value at December 31, 2004	**383,367**
Oil and Gas Sales During the Period Net of Production Costs and Royalties [a]	(295,197)
Changes due to Prices, Production Costs and Royalties Related to Forecast Production [b]	379,940
Development Costs During the Period [c]	93,663
Changes In Forecast Development Costs [d]	(94,793)
Changes Resulting from Extensions and Improved Recovery [e]	85,056
Changes Resulting from Discoveries [e]	4,247
Changes Resulting from Acquisitions of Reserves [e]	573,902
Changes Resulting from Dispositions of Reserves [e]	(34534)
Accretion of Discount [f]	38,337
Net Change in Income Taxes [g]	-
Changes Resulting from Technical Reserves Revisions	14,337
All Other Changes	16,633
Estimated Net Present Value at End of Period December 31, 2005	**1,164,959**

(a) Company actual before income taxes, excluding G&A.
(b) The impact of changes in prices and other economic factors on future net revenue.
(c) Actual capital expenditures relating to the exploration, development and production of oil and gas reserves.
(d) The change in forecast development costs for the properties evaluated at the beginning of the period.
(e) End of period net present value of the related reserves.
(f) Estimated as 10% of the beginning of period net present value.
(g) The difference between forecast income taxes at beginning of period and the actual taxes for the period plus forecast income taxes at the end of period.

Notes:

1. "Gross Reserves" are Viking's working interest (operating or non-operating) share before deducting of royalties and without including any royalty interests of Viking. "Net Reserves" are Viking's working interest (operating or non-operating) share after deduction of royalty obligations, plus Viking's royalty interests in reserves.
2. "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.
3. "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.
4. "Possible" reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.
5. "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 (e.g. when compared to the cost of drilling a well) to put the reserves on production.
6. "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.
7. "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.
8. "Undeveloped" reserves are those reserves expected to be recovered from know 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, possible) to which they are assigned.
9. The product prices used in the constant price and cost evaluations in the GLJ Report were as follows:

Product	December 31, 2005
West Texas Intermediate Crude Oil ($US/bbl)	61.04
Exchange Rate ($US/$CDN)	0.8577
Light, Sweet Crude Oil at Edmonton (estimated)	68.27
Natural Gas Liquids – Ethane Edmonton reference price ($Cdn/bbl)	32.92
Natural Gas Liquids – Propane Edmonton reference price ($Cdn/bbl)	43.69
Natural Gas Liquids – Butane Edmonton reference price ($Cdn/bbl)	50.52
Natural Gas Liquids – Pentanes Edmonton reference price ($Cdn/bbl)	71.67
AECO C-spot ($CDN/GJ)	9.71
Bow River Medium Crude at Hardisty ($CDN/bbl)	39.00

10. The pricing assumptions used in the GLJ Report with respect to net values of future net revenue (forecast) as well as the inflation rates used for operating and capital costs are set forth below. GLJ is an independent qualified reserves evaluator appointed pursuant to NI 51-101

	Light and Medium Crude Oil		Natural Gas	Alberta Natural Gas Liquids (Then Current Dollars)			Inflation Rate	Exchange Rate
	WTI Cushing Oklahoma ($US/bbl)	Edmonton Par Price 40° API ($Cdn/bbl)	AECO Gas price ($Cdn/mmBTU)	Edmonton Propane ($Cdn/bbl)	Edmonton Butane ($Cdn/bbl)	Edmonton Pentanes Plus ($Cdn/bbl)	%/year	$US/$Cdn
Year Forecast								
2006	57.00	66.25	10.60	42.50	49.00	67.00	2	0.85
2007	55.00	64.00	9.25	41.00	47.25	65.25	2	0.85
2008	51.00	59.25	8.00	38.00	43.75	60.50	2	0.85
2009	48.00	55.75	7.50	35.75	41.25	56.75	2	0.85
2010	46.50	54.00	7.20	34.50	40.00	55.00	2	0.85
2011	45.00	52.25	6.90	33.50	38.75	53.25	2	0.85
2012	45.00	52.25	6.90	33.50	38.75	53.25	2	0.85
2013	46.00	53.25	7.05	34.00	39.50	54.25	2	0.85
2014	46.75	54.25	7.20	34.75	40.25	55.25	2	0.85
2015	47.75	55.50	7.40	35.50	41.00	56.50	2	0.85
Thereafter	+2.0%/year	+2.0%/year	+2.0%/year	+2.0%/year	+2.0%/year	+2.0%/year		0.85

11. Viking's entity structure has been set up so that the annual tax liability is shifted to its Unitholders. Internal tax forecasting models show there is no cash taxes payable in the future by Viking or its subsidiaries. This result is attributable to the following inter-corporate agreements:

- Royalty agreements that are in place between Viking and two of its subsidiaries (Viking Holdings Inc. and Viking Holdings Trust) which between them hold the majority of Viking's oil and gas working interests. These royalty agreements facilitate the tax effective movement of the cash flow generated by the properties to Viking, which is then required to be distributed to Unitholders.

- Inter-company notes with fixed forms and fixed interest rates that have been entered into between the subsidiaries and Viking, which again shifts taxable income from corporate entities to Viking which in turn shifts the tax burden to Unitholders; and
- Corporate entities that have debt with external parties have sufficient accumulated tax pools to shelter pre-tax cash flow in a sufficient amount in order to fund a repayment of such indebtedness.

The cash flow paid to Viking is a deduction for tax purposes for Viking Holdings Inc. and Viking Holdings Trust, eliminating any tax liability at the subsidiary level. Therefore, the cash flow as per the reserve report would have not resulted in any cash tax expense to the unitholders. The contractual obligation of the subsidiaries is to pay the excess cash flow to Viking, even on a blow-down scenario.

Undeveloped Reserves

Proved and probable undeveloped reserves have been estimated in accordance with procedures and standards contained in the COGE Handbook.

As at January 1, 2006, Viking has a total of 9.3 MMBOE of company interest reserves that are classified as proved non-producing. Of these non-producing reserves approximately 38% are undeveloped reserves. The balance are developed non-producing reserves which would be wells that are not currently producing and are eligible to be brought back on production given current economics and production information. Substantially all of the undeveloped reserves are based on Viking's current 2006 budget and long range development plans for the major assets noted above. Approximately 70% of these reserves are expected to be developed within the next two years. The remaining undeveloped reserves will be developed over the next five years, in most cases due to processing facility capacity restrictions. The capital cost has been taken into account for these programs in the estimated future net revenue.

Future Development Costs

	Forecast Prices and Costs ($000)		Constant Prices and Costs ($000)	
Year	Proved Reserves	Proved Plus Probable Reserves	Proved Reserves	Proved Plus Probable Reserves
2006	38,817	62,096	38,817	62,096
2007	5,283	13,991	5,179	13,716
2008	3,530	3,862	3,393	3,712
2009	1,973	2,080	1,859	1,960
2010	830	999	767	923
Thereafter	12,647	15,317	9,693	11,057
Total Undiscounted	63,080	98,345	59,708	93,464
Total Discounted at 10%	50,141	80,502	49,144	79,267

Future development costs will be funded through cash flow and the Trust's credit facilities currently available.

Significant Factors or Uncertainties

There are several risk factors and uncertainties in estimating reserves. To estimate the economically recoverable oil and natural gas reserves and related future net cash flows, Viking incorporates many factors and assumptions including:

- expected reservoir characteristics based on geological, geophysical and engineering assessments;
- future production rates based on historical performance and expected future operating and investment activities;
- future oil and gas prices and quality differentials;
- assumed effects of regulation by governmental agencies; and
- future development and operating costs.

Viking believes these factors and assumptions are reasonable, based on the information available to it at the time the estimates are prepared. However, actual results could vary considerably, which could cause material variances in:

- estimated quantities of proved oil and natural gas reserves in aggregate and for any particular group of properties;
- reserve classification based on risk of recovery;
- future net revenues, including production, revenues, taxes and development and operating expenditures;
- financial results including the annual rate of depletion and recognition of property impairments;
- assessing, when necessary, our oil and gas assets for impairment. Estimated future undiscounted cash flows are determined using proved reserves. The critical estimates used to assess impairment, including the impact of changes in reserve estimates, are discussed below.

As circumstances change and additional data becomes available, our reserve estimates also change, possibly materially impacting net income. Estimates made by our engineers 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 we make every reasonable effort to ensure that our 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 our reserve estimates can arise from changes in year-end oil and gas prices, and reservoir performance. Such revisions can be either positive or negative.

Oil and Gas Properties and Wells

The following table sets forth the number of wells in which Viking held a working interest as at December 31, 2005:

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	1,336	947	1242	750	1597	658	345	151
Saskatchewan	552	419	186	141	0	0	1	1
Total	1,888	1,366	1,428	891	1,597	658	346	152

Notes:

1. "Gross Wells" are wells in which Viking has an interest (operating or non-operating). "Net Wells" are Viking's interest share of the gross wells (operating or non-operating).

Exploration and Development Activities

The following table sets forth the number of exploratory and development wells which Viking completed during its 2005 financial year:

	Exploratory Wells		**Development Wells**	
	Gross(1)	**Net(1)**	**Gross(1)**	**Net(1)**
Oil Wells	0.0	0.0	71.0	51.4
Gas Wells	10.0	4.6	117.0	51.4
Service Wells	0.0	0.0	1.0	1.0
Dry Holes	1.0	1.0	4.0	4.0
Total Wells	11.0	5.6	193.0	107.7

Note:

1. "Gross Wells" are wells in which Viking has an interest (operating or non-operating). "Net Wells" are Viking's interest share of the gross wells (operating or non-operating).

For a discussion of Viking's exploration and development activities refer to the "2006 Capital Expenditures Plan" section later in this Appendix.

Properties with No Attributed Reserves

The following table sets out Viking's undeveloped land holdings as at December 31, 2005.

	Undeveloped Acres	
	Gross	Net
Alberta	481,896	324,622
Saskatchewan	6,256	5,840
Total	488,152	330,462

	Undeveloped Acres for which rights expire within one year	
	Gross	Net
Alberta	93,179	61,245
Saskatchewan	252	252
Total	93,431	61,497

Production Estimates

The following table sets forth the volume of company working interest production estimated for 2006 as found in the GLJ report:

	2006 Production Forecast				
	Light and Medium Oil (bbl/d)	Heavy Oil (bbl/d)	Natural Gas (mcf/d)	Natural Gas Liquids (bbl/d)	BOE (boe/d)
Proved Producing	7,262	2,949	66,113	1,203	22,432
Proved Developed Non-Producing	193	315	7,992	94	1,933
Proved Undeveloped	387	281	2,019	51	1,056
Total Proved	7,842	3,544	76,124	1,348	25,421
Total Probable	460	814	6,404	109	2,450
Total Proved Plus Probable	8,302	4,358	82,527	1,456	27,871

Production History by Material Property

The following table provides average annual production by each material property:

Material Property	Light, Medium and Heavy Crude Oil (bbl/d)	Natural Gas (Mcf/d)	NGL (bbl/d)	2005 Average Daily Production (boe/d)
Markerville	118	21,024	561	4,183
Bellshill Lake	2,946	1,433	86	3,271
Bashaw	1,270	1,628	88	1,629
Kindersley	1,139	779	39	1,308
Channel Lake	-	7,458	-	1,243
Chin Coulee	994	-	-	994
Alexis	498	2,228	-	870
Tweedie/Wappau	-	5,091	-	848
Greater Richdale	24	3,911	34	710
Bassano	533	540	6	629
Pouce Coupe	5	3,655	12	626
Lindbergh	557	-	-	557
Wildmere	322	11	-	324
Other	1,799	18,856	285	5,227
Totals	**10,206**	**66,613**	**1,110**	**22,418**

Principal Viking Producing Properties at December 31, 2005

Reserve amounts discussed are gross reserves and are stated at December 31, 2005 based on forecast prices and cost assumptions.

Southern Alberta

Viking's principle operated properties in Southern Alberta, are Bassano, Chin Coulee and non-operated property Channel Lake.

Bassano: Viking has a 100% working interest in a majority of the Upper Mannville oil zone at Bassano and a 50% working interest in a majority of the Belly River gas zone. Average production was approximately 629 BOE per day, 85% of which is attributable to oil. There are 109 gross wells at Bassano with 62 producers, 8 service and injection wells and 39 non-producing wells.

Chin Coulee: This area is an oil property in which Viking holds a 100% interest in 46 producing wells with production from the Sawtooth zone. The total well count of 69 includes 12 injection and service wells, and 11 non-producing wells. Production in 2005 was approximately 994 BOE per day of 24 degree medium gravity oil. One well was drilled and water injector optimization was undertaken during the year for total capital expenditures of $0.7 million.

Channel Lake: Viking has non-operated interests at Channel Lake and Channel Lake South in which Viking holds 50% and 25% working interests, respectively. The properties produce dry gas from the Milk River and Medicine Hat formations. Production from this area averaged 7,458 mmcf/d (1,243 BOE/d) for 2005. Viking also has an interest in the gathering and sales lines in the area.

Northern Alberta

Viking's Northern Alberta core area consists of operated property Tweedie/Wappau, operated and non-operated property Alexis, and non-operated property Pouce Coupe.

Alexis: The Alexis area is a combination of operated and non-operated lands with the largest single asset being the operated Alexis Banff Unit in which Viking has a 49% working interest. Lands located outside the unit are non-operated, with Viking having working interests varying between 30% and 70%. Primary producing formations are the Banff and Nordegg, located at a depth of 1350m. In 2005, production from this property averaged 870 BOE/d, of which 57% is oil on a boe basis. Alexis was an active oil development area for Viking with a total net capital investment of $8.7 million. This included the drilling of 23 gross (10.4 net) wells, facility modifications, and workover and optimization projects. The identification of further delineation and infill locations will continue the development program into 2006.

Tweedie/Wappau: The Tweedie/Wappau core area is located just north of Lac La Biche approximately 110 miles northeast of Edmonton. The Trust has an average working interest of approximately 64% in 212 gross wells in the area. Net production from Tweedie/Wappau in 2005 averaged 5,091 mmcf per day (848 BOE per day) from the Viking formation as well as a number of shallow Mannvile horizons – Grand Rapids, Wabiskaw and McMurray.

The Trust owns and operates 100% of the facilities and infrastructure in the area. Both the Tweedie and Wappau gas facilities have excess capacity that can be used for Viking's own additional production or to process third party gas from the area. On average about 50% of the gas throughput at the facilities is from third party production. A majority of the undeveloped land was farmed out late in 2004, which resulted in a total of 11 gross (0 net) wells being drilled during 2005. Viking receives a royalty on the production, as well as processing fees as the gas is processed through the Viking owned facilities as noted above.

Pouce Coupe: Viking owns an average working interest of 41% in this non-operated field, which is located approximately 100 kilometres northwest of Grande Prairie, near the Alberta-British Columbia border. Production in Pouce Coupe averaged 626 boe/day (97% gas) for the 12 months ending December 31, 2005. (The property was acquired through the acquisition of Calpine Natural Gas Trust, which occurred on February 1, 2005). Viking has a working interest varying from 20 to 50% in 47 gross wells. During 2005, Viking participated in the drilling of 1 (0.25 net) gas well, and various recompletion and tie-in projects for a total capital expenditure of $2.3 million

The wells in this area produce primarily from the Kiskatinaw formation which has a well depth of approximately 2,200 metres. Other producing zones in the area include Baldonnel and Halfway formations. Other contributing formations include the Montney, Doig, Halfway, Charlie Lake, Baldonnel and Gething zones ranging in depth from 1,150 metres to 1,800 metres.

East Central Alberta

Viking's East Central Alberta core area consists of significant operated properties Bellshill Lake, Bashaw, Lindbergh and Wildmere.

Bellshill Lake: Viking holds a 98.96% working interest in the Bellshill Lake Ellerslie Unit, as well as working interests ranging from 6.5% to 100% in non-unit leases located next to the unit. Production consists of 26° API to 28° API oil produced from the Ellerslie and Dina formations, and averaged 3,271 BOE/d net to Viking in 2005 weighted 93% towards oil and liquids. During 2005 Viking purchased an additional 8% of the unit interests, as well as non-unit interest wells for a net expenditure of $3.0 million

The Unit and area comprises 707 gross wells of which 580 are producing oil wells. There are 32 injection and service wells, and 95 suspended oil wells. The majority of these wells are tied-in to one central facility consisting of an oil processing facility, a water injection plant and a gas processing facility. Oil is transported to market via Gibson's pipeline and the gas is sold on the spot market.

In 2005 Viking drilled 17 gross (16 net) infill horizontal wells in the unit. The cost of this drilling program net to Viking was $11.5 million, including some minor facility modifications and capital workovers.

Bashaw: Viking has a 93.3% working interest in the operated Bashaw D2G pool, a 90.6% working interest in the operated Bashaw D2L pool, and a 24.9% working interest in the non-operated D3A pool. This area produces oil and gas from the Nisku/Leduc formation at an average depth of 1,700m. Average production for 2005 was 1,629 boe/d with 83% weighted to oil and liquids on a boe basis.

Oil and gas production is collected at central processing facilities for pre-processing, then transported via pipeline to third party facilities for final processing and transportation to market. The units and non-unit areas have a total of 80 gross wells of which 45 are producers, 9 are injection or service wells, and 26 non-producing. Development in the Bashaw area for 2005 consisted of the drilling of 2 gross (1.9 net) wells along with workovers and pumping equipment upgrades on existing wells to stimulate production, for a net capital cost of $4.2 million

Lindbergh: Viking has a 100% working interest in the operated Lindbergh area. This area produces 12 degree API oil from the McLaren/Sparky and GP formations at an average depth of 600m. Average production from the 26 gross wells in the area was 557 boe/d with 99% weighted to oil on a boe basis for the 12 month period ending December 31, 2005. (Viking acquired this asset with the acquisition of Krang Energy effective July 1, 2005). Production is gathered at single well field batteries and then trucked to Viking’s Bellshill Lake battery for cleaning and sales. During 2005, Viking drilled 2 gross (2 net) wells for a total capital expenditure of $0.9 million.

Wildmere: Viking has a 100% working interest in the operated Wildmere area. This area produces 12 degree API oil primarily from the Lloydminster formations at an average depth of 650m. Average production from the 23 gross wells in the area was 324 boe/d with 99% weighted to oil on a boe basis for 12 month period ending December 31, 2005. (Viking acquired this asset with the acquisition of Krang Energy effective July 1, 2005). Production is gathered at single well field batteries and then trucked to Viking’s Bellshill Lake battery for cleaning and sales. During 2005, Viking drilled 7 gross (7 net) wells for a total capital expenditure of $3.1 million.

Saskatchewan

Viking’s largest Saskatchewan asset is the Kindersley Viking units which represent over 90% of the company’s Saskatchewan production. The units are located approximately 10 miles east of the town of Kindersley Saskatchewan.

Viking's Kindersley, Saskatchewan operated core area includes the Eagle Lake Unit, North Dodsland Viking Unit No. 1, Smiley Dewar Unit, Whiteside Unit, and Whiteside East Unit in which Viking holds working interests ranging from 11.2 to 100%. Production consists of 36° API crude oil from the Viking formation and, in 2005 averaged 1,308 BOE/d, (90% weighted to oil on a boe basis) of which the Eagle Lake Unit is the single largest contributor accounting for 66%. The crude oil is marketed via the Mid-Sask pipeline system. Solution gas is conserved and sold in the open market.

In 2005, Viking drilled 12 gross (9.4 net) wells into the Eagle Lake Unit with an average working interest of 78.7% as well as continued with fracture stimulation of existing wells, for a net capital expenditure of $3.8 million

Western Alberta

Viking’s most substantial producing asset in the Western Aberta core area is Markerville. Markerville is also Viking’s most significant single asset representing 19% of the company’s total production on a boe basis.

The Markerville field is located approximately 35 kilometres southwest of Red Deer, Alberta. Viking operates the majority of the field and has a working interest varying from 50-90% in the majority of the areas 277 gross wells.

Markerville averaged 4,183 boe/day (84% natural gas) for the 12 months ending December 31, 2005. (The property was acquired through the acquisition of Calpine Natural Gas Trust which occurred on February 1, 2005).

There are two main producing horizons in this area. The Pekisko formation, at a well depth of approximately 2,200 metres contains sweet natural gas along with associated liquids. The formation is developed using both vertical and horizontal wells. In 2005, the company drilled or participated in 5 gross (3.8 net) wells for a total capital expenditure of $7.1 million including incremental tie-in and compression facilitites. The second formation is the Edmonton Sands located at a depth of approx. 800m. The Edmonton sands is a tight gas reservoir that contains sweet natural gas that is developed exclusively with vertical wells. In 2005, Viking participated in 60 gross / 24.9 net wells for a total capital expenditure of $15.1 million including minor facility modifications. Other minor zones of interest in this area are the Viking, Glauconitic and Ellerslie formations.

2006 Capital Expenditure Plan

Prior to the merger with Harvest Energy Trust, Viking expected total capital spending for 2006 to be approximately $100 million. The primary areas of focus for Viking's capital program during 2006 was the following:

Bellshill Lake – drill 14 gross (13.8 net) horizontal infill wells and facility modifications for a net expenditure of $9 million.

Alexis – drill 6 gross (3 net) wells and facility modifications for a net expenditure of $2.8 million.

Bashaw – drill 7 gross (6.5 net) wells and conduct workovers on existing wells for a net expenditure of $6.7 million.

Kindersley Viking Units – drill 30 gross (23 net) infill wells and conduct workover stimulations on 32 gross wells for a net expenditure of $8.6 million.

Markerville/Innisfail – drill 5 (4.0 net) Pekisko wells and 36 (18 net) Edmonton Sands wells for a net expenditure of $18.6 million

Lindbergh/Wildmere/Lloydminster – drill 20 (20 net) heavy oil wells for a net expenditure of $9.5 million.

Forward Contracts

At December 31, 2005, Viking had the following fixed price forward sales contracts outstanding:

Type of Contract	Quantity	Period	Price/Rate	Fair Value (Deficiency) at December 31, 2005
Natural Gas – fixed price	76 GJ/d	May 31/03 – October 31/08	$2.00/GJ(1)	($623,000)
Natural Gas – fixed price	5,000 GJ/d	November 1/05 – March 31/06	$6.83/GJ	($1,670,852)
Natural Gas – fixed price	5,000 GJ/d	November 1/05 – March 31/06	$7.33/GJ	($1,445,852)

(1) The contract provides for an annual price increase of $0.05/GJ until its expiry in 2008.

Additional Information Concerning Abandonment and Reclamation Costs

The following table sets forth information respecting future abandonment and reclamation costs for surface leases, wells, facilities and pipelines which are expected to be incurred by Viking and for the periods indicated:

Period	Abandonment & Reclamation costs (undiscounted and using a 2% inflation rate) ($000)	Abandonment & Reclamation costs (discounted at 10% using a 2% inflation rate) ($000)
Total as at Dec. 31, 2005	209,069	44,880
Anticipated to be paid in 2006	2,141	1,946
Anticipated to be paid in 2007	277	229
Anticipated to be paid in 2008	1,386	1,041

The number of net wells for which the Independent Reserve Engineering Evaluators estimated that Viking would incur abandonment and reclamation costs is 1,884 wells (Proved plus Probable).

Abandonment costs (excluding salvage values) associated only with wells were deducted by the Independent Reserve Engineering Evaluators in estimating future net revenue in the Reserve Report. The estimated future undiscounted expense related to facilities, pipelines and no reserve addition wells is $150.9 million ($29.0 million discounted at 10%). The nature of these expenses are not expected to change the anticipated costs for the next three years as they will not be incurred until the end of a field's reserve life profile.

Capital Expenditures

The following table summarizes capital expenditures (net of incentives and net of certain proceeds and including capitalized general and administrative expenses) related to Viking's activities for the year ended December 31, 2005 ($000):

Property acquisition costs	
Proved properties	549.1
Undeveloped properties	20.0
Total acquisition costs	569.1
Exploration costs	5.7
Development costs	79.1
Total Capital Expenditures	653.9

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:

	2005				
Average Daily Production Volumes (before the deduction of royalties)	Q1	Q2	Q3	Q4	Total
Light & Medium Oil (bbl/d)	10,091	9,112	8,902	8,438	9,130
Heavy Oil (bbl/d)	-	-	2,275	1,993	1,076
Total Oil (bbl/d)	10,091	9,112	11,177	10,431	10,206
NGL (bbl/d)	915	717	1,455	1,343	1,110
Natural Gas(mcf/d)	53,709	62,734	76,357	73,330	66,613
Total Daily Production (BOE/d)	**19,957**	**20,285**	**25,358**	**23,996**	**22,418**
Total Sales Production:					
Light and Medium Oil (bbl)	908,145	829,198	818,959	776,313	3,332,615
Heavy Oil (bbl)	-	-	209,262	183,282	392,544
Total Oil (bbl)	908,145	829,198	1,028,221	959,595	3,725,159
NGL (bbl)	82,338	65,254	133,884	123,600	405,076
Natural Gas (mcf)	4,833,841	5,708,780	7,024,858	6,746,386	24,313,866
Total Production (BOE)	**1,796,123**	**1,845,915**	**2,332,915**	**2,207,593**	**8,182,546**

Average Sales Prices Received:	2005				
	Q1	Q2	Q3	Q4	Total
Natural Gas (mcf)	$ 7.08	$ 7.52	$ 8.47	$ 12.66	$ 9.14
Light & Medium oil ($/bbl)	48.95	51.94	65.15	54.74	55.02
Heavy Oil ($/bbl)	-	-	47.12	30.19	39.21
Total Oil ($/bbl)	48.95	51.94	61.48	50.04	53.36
NGL ($bbl)	44.45	58.41	48.13	58.52	52.21
BOE – 6:1	$ 45.84	$ 48.65	$ 55.38	$ 63.73	$ 54.02

Royalties Paid

	2005				
	Q1	Q2	Q3	Q4	Total
Heavy Oil ($000)	-	-	1,335	1,740	3,075
Medium & Light Oil ($000)	6,584	6,294	7,477	5,917	26,272
Natural gas & NGL's ($000)	8,133	9,839	14,160	18,816	50,898
Total BOE ($000)	14,717	16,133	22,922	26,473	80,245
Heavy Oil ($/bbl)	-	-	6.38	9.49	7.83
Medium & Light Oil ($/bbl)	7.25	7.59	9.13	7.62	7.88
Natural gas & NGL's ($/boe)	9.15	9.68	10.81	15.08	11.41
Total BOE ($/boe)	$ 8.19	$ 8.74	$ 9.83	$ 11.99	$ 9.81

Operating Expenses

	2005				
	Q1	Q2	Q3	Q4	Total
Heavy Oil ($000) [1]	-	-	2,364	2,589	4,9538
Medium & Light Oil ($000)	11,537	10,403	15,564	16,658	54,162
Natural gas & NGL's ($000) [2]	4,296	4,358	9,352	12,814	30,820
Total BOE ($000)	15,833	14,761	27,280	32,061	89,935
Heavy Oil ($/bbl) [1]	-	-	11.30	14.12	12.61
Medium & Light Oil ($/bbl)	12.70	12.55	19.00	21.45	16.25
Natural gas & NGL's ($/BOE) [2]	4.84	4.29	7.17	10.27	6.91
Total BOE ($/BOE)	$ 8.81	$ 8.00	$ 11.69	$ 14.52	$ 10.99

Netback Received[3]

	2005				
	Q1	Q2	Q3	Q4	Total
Heavy Oil ($/bbl)	-	-	29.44	6.58	18.77
Medium & Light Oil ($/bbl)	29.00	31.80	37.02	25.67	30.89
Natural gas & NGL's ($/BOE)	28.67	32.00	32.59	48.90	36.26
Total BOE ($/BOE)	$ 28.84	$ 31.91	$ 33.86	$ 37.22	$ 33.22

(1) Includes transportation expense of $146,000 ($0.70/bbl) and $842,000 ($4.59/bbl) in the third and fourth quarters, respectively.

(2) Includes transportation expense of $733,000 ($0.83/BOE) for the first quarter, $947,000 ($0.93/BOE) for the second quarter, $1.7 million ($1.28/BOE) for the third quarter and $1.8 million ($1.46/BOE) for the fourth quarter.

(3) Before gains or losses on commodity derivatives.

APPENDIX C-1

HARVEST OPERATIONS CORP. 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 Appendix "C-2". The members of the Audit Committee are Dale Blue, Verne Johnson and Hector McFadyen.

Composition of the Audit Committee

The Board of Directors has determined that each member of the Audit Committee is an "independent" director and "financially literate" in accordance with National Instrument 52-110. In considering criteria for the determination of financial literacy, the Board of Directors looked at the ability to read and understand a balance sheet, an income statement and cash flow statement of a public company as well as the director's past experience in reviewing or overseeing the preparation of financial statements.

Relevant Education and Experience

Name (Director Since)	Principal Occupation & Biography
Mr. Dale Blue (February 2006) <u>Other Canadian Public Board of Director Memberships</u> None	Mr. Blue received a Bachelor of Arts degree in economics from the University of Manitoba and has over thirty years experience in the financial services industry and has held senior positions with Chase Manhattan Bank of Canada and Chase Manhattan Bank in New York. He has also served on the Board of Directors of numerous Canadian public companies and various private companies.
Mr. Verne Johnson (December, 2002) <u>Other Canadian Public Board of Director Memberships</u> • Fort Chicago Energy Partners, LP • Builders Energy Services Trust • Blue Mountain Energy • Mystique Energy • Gran Tierra Energy	Mr. Johnson received a Bachelor of Science degree in in Mechanical Engineering from the University of Manitoba and has accumulated over 35 years of experience in the oil and natural gas industry with the multinational majors as well as has served in senior management positions on a number of Alberta based junior and intermediate exploration and production companies. He also serves on several other Boards, including the Boards of other trusts.
Mr. Hector McFadyen (December, 2002) <u>Other Canadian Public Board of Director Memberships</u> None	Mr. McFadyen has a Masters of Arts degree in economics from the University of Calgary and a Bachelor of Arts degree in economics from George Williams University and has accumulated over 35 years of oil and natural gas industry experience with primarily with a senior producer based in Alberta with significant international business interests where he served as a member of the senior management team. He currently serves as a Director of Hunting PLC (a UK based public oil and natural gas company) and privately-held Computershare Trust Company of Canada.

Pre-Approval of Policies and Procedures

All non-audit or special services performed by any independent accountants must be first approved by the Audit Committee. All remuneration provided to the Trust's auditor and any independent accountants are also approved by the Audit Committee. The Trust's auditor meets with the Audit Committee, without management present, at least annually and more often at the request of either the Audit Committee or the auditor.

External Auditor Service Fees

Audit Fees

The aggregate fees billed by the Trust's external auditor in each of the last two fiscal years for audit services (audit and review of Harvest's annual financial statements and review of quarterly financial statements), were $292,000 in 2005 and $377,634 in 2004.

Audit and Related Fees

The aggregate fees billed in each of the last two fiscal years for assurance related services by the Trust's external auditor that are reasonably related to the performance of the audit or review of the Trust's financial statements that are not reported under "Audit Fees" above were $33,000 in 2005 and $83,510 in 2004. These fees are primarily related to French translation fees.

Tax Fees

The aggregate fees billed in each of the last two fiscal years for professional services rendered by the Trust's external auditor for regular tax compliance, tax advice and tax planning were $69,430 in 2005 and $111,275 in 2004.

All Other Fees

The aggregate fees billed in each of the last two fiscal years for products and services provided by the Trust's auditors other than services reported above were nil in 2005 and in 2004.

APPENDIX C-2

HARVEST OPERATIONS CORP. AUDIT COMMITTEE MANDATE AND TERMS OF REFERENCE

Role and Objective

The Audit Committee (the "Committee") is a committee of the board of directors (the "Board") of Harvest Operations Corp. ("HOC") to which the Board has delegated its responsibility for oversight of the nature and scope of the annual audit, management's reporting on internal accounting standards and practices, financial information and accounting systems and procedures, financial reporting and statements and recommending, for approval of the Board, the audited financial statements, interim financial statements and other mandatory disclosure releases containing financial information. The primary objectives of the Committee are as follows:

1. to assist directors to meet their responsibilities (especially for accountability) in respect of the preparation and disclosure of the financial statements of Harvest and related matters;

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

3. to enhance the external auditor's independence;

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

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

Membership of Committee

1. The Committee shall be comprised of at least three (3) directors of HOC, none of whom are members of management of HOC and all of whom are "independent" (as such term is used in Multilateral Instrument 52-110 — Audit Committees ("MI 52-110") unless the Board shall have determined that the exemption contained in Section 3.6 of MI 52-110 is available and has determined to rely thereon.

2. The Board shall appoint the Committee Chair, who shall be an unrelated director.

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

Mandate and Responsibilities of Committee

1. It is the responsibility of the Committee to oversee the work of the external auditors, including resolution of disagreements between management and the external auditors regarding financial reporting.

2. It is the responsibility of the Committee to satisfy itself on behalf of the Board with respect to Harvest's Internal Control Systems:

   - identifying, monitoring and mitigating business risks; and

   - ensuring compliance with legal, ethical and regulatory requirements.

3. It is a primary responsibility of the Committee to review the annual and interim financial statements of Harvest and related management's discussion and analysis ("MD&A") prior to their submission to the Board for approval. The process should include but not be limited to:

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

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

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

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

6. Review with external auditors (and internal auditor if one is appointed by Harvest) their assessment of the internal controls of Harvest, their written reports containing recommendations for improvement, and management's response and follow-up to any identified weaknesses. The Committee shall also review annually with the external auditors their plan for their audit and, upon completion of the audit, their reports upon the financial statements of Harvest and its subsidiaries.

7. The Committee shall review risk management policies and procedures of Harvest (i.e. hedging, litigation and insurance).

8. The Committee shall establish a procedure for:

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

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

9. The Committee shall review and approve Harvest's hiring policies regarding partners and employees and former partners and employees of the present and former external auditors of Harvest.

10. The Committee shall have the authority to investigate any financial activity of Harvest. All employees of Harvest are to cooperate as requested by the Committee.

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

Meetings and Administrative Matters

1. At all meetings of the Committee every question shall be decided by a majority of the votes cast. In case of an equality of votes, the Chairman of the meeting shall not be entitled to a second or casting vote.

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

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

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

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

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

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

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

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

10. Any members of the Committee may be removed or replaced at any time by the Board and shall cease to be a member of the Committee as soon as such member ceases to be a director. The Board may fill vacancies on the Committee by appointment from among its members. If and whenever a vacancy shall exist on the

Committee, the remaining members may exercise all its powers so long as a quorum remains. Subject to the foregoing, each member of the Committee shall hold such office until the close of the next annual meeting of unitholders following appointment as a member of the Committee.

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