HARVEST ENERGY TRUST

2004 RENEWAL ANNUAL INFORMATION FORM

MARCH 30, 2005

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SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Annual Information Form contains forward-looking statements. These 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 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 2005 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, 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.

The information contained in this Annual Information Form, including the information provided under the heading "Operational and Other Business Risks" identifies additional factors that could affect our operating results and performance. We urge you to carefully consider these factors.

Our forward-looking statements are expressly qualified in their entirety by this cautionary statement. Our forward-looking statements are only made as of the date of this Annual Information Form and we undertake no obligation to publicly update these forward-looking statements to reflect new information, subsequent events or otherwise.

SUPPLEMENTAL DISCLOSURE

Distributable cash and cash available for distribution and cash-on-cash yield are not recognized generally accepted accounting principles. Management believes that in addition to net income and net income per Trust Unit, distributable cash and cash available for distribution are useful supplemental measures as they provide investors with information on cash available for distribution. Cash-on-cash yield is a useful and widely used supplemental measure that provides investors with information on cash actually distributed relative to trading price. Investors are cautioned that distributable cash, cash available for distribution and cash-on-cash yield should not be construed as an alternate to net income as determined by Canadian generally accepted accounting principles. **Investors are also cautioned that cash-on-cash yield represents a blend of return *of* investors' initial investment and a return *on* investors' initial investment and is not comparable to traditional yield on debt instruments where investors are entitled to full return of the principal amount of debt on maturity in addition to a return on investment through interest payments.**

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 the Corporation pursuant to which the Corporation provides certain administrative and advisory services in connection with the Trust. See "Description of the Trust" and "Information Respecting the Corporation".

"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 the Corporation.

"Bridge Agreements" means, collectively, the Bridge Notes and the Equity Bridge Notes.

"Bridge Lenders" means, collectively, Caribou and the Chairman of the Corporation.

"Bridge Notes" means, collectively, the bridge notes dated September 29, 2003 between the Trust and each of the Bridge Lenders providing for advances of up to $30 million to the Trust to assist with the payout of the then existing credit facility and the payment of the Deferred Purchase Price Obligation as a result of the acquisition of the Southeast Saskatchewan Properties.

"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. See "Description of the Trust – Capital Fund".

"Caribou" means Caribou Capital Corp.

"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 "Description of the Trust – 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;

"Corporation" means, as the context requires, the Trust's wholly-owned subsidiary, Harvest Operations Corp., a corporation amalgamated under the *Business Corporations Act* (Alberta) on June 30, 2004 and on January 1, 2004 and, prior to January 1, 2004, a corporation incorporated under the *Business Corporations Act* (Alberta), or its wholly-owned subsidiaries;

"Corporation" means Harvest Operations Corp., a wholly-owned subsidiary of the Trust, and its wholly-owned subsidiaries.

"Current Bank Facility" means the credit facility provided by the Current Lenders as more fully described under "Information Respecting the Corporation – Borrowing by the Corporation".

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

"Debenture Indenture" means the trust indenture dated January 29, 2004 made among the Trust, the Corporation and the Debenture Trustee, as trustee.

"Debenture Trustee" means the trustee of the Debentures Series 1 and Debentures Series 2, 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.

"Deferred Purchase Price Obligation" or "DPPO" means, collectively, the ongoing obligation of the Trust to pay to the Corporation, 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 the Corporation, 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.

"Distributable Cash" means, for any particular period, the Cash Available For Distribution less any amounts retained by the Trust for the Capital Fund.

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

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

"Equity Bridge Notes" means, collectively, the equity bridge notes dated July 28, 2003 and amended September 29, 2003, June 29, 2004, July 7, 2004 and July 9, 2004 between the Trust and each of the Bridge Lenders providing for advances of up to $50 million to the Trust to assist in the payout of the Corporation's then existing credit facility and the payment of the Deferred Purchase Price Obligation as a result of the Southeast Saskatchewan Properties Transaction.

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

"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 Gilbert, Laustsen & Jung Associates 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.

"HBT1" means Harvest Breeze Trust 1, a trust established under the laws of the Province of Alberta, wholly owned by HST.

"HBT2" means Harvest Breeze Trust 2, a trust established under the laws of the Province of Alberta, wholly owned by the Trust.

"HST" 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 PLA, 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, 2004, 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 the Corporation 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 15^{th} 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 by the Operating Subsidiaries to the Trust pursuant to the NPI Agreements.

"NPI Agreements" means, collectively, the amended and restated net profit interest agreement dated September 27, 2002 between the Corporation and the Trust, the royalty agreement dated effective January 17, 2003 between WEI and BNY Trust Company of Canada and the net profit interest agreement dated October 17, 2003 between HST and the Trust and **"NPI Agreement"** means any one of these agreements, as applicable.

"NYMEX" means the New York Mercantile Exchange.

"Operating Subsidiaries" means, collectively, the Corporation, HST, REEI, REP, BRP, HBT1 and HBT2, each a direct or indirect wholly-owned subsidiary of the Trust, and **"Operating Subsidiary"** means any of the Corporation, HST, REEI, REP, BRP, HBT1, and HBT2, 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.

"**Permitted Investments**" means:

(a) loan advances to the Corporation;

(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;

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.

"PLA" means Paddock, Lindstrom & Associates Ltd., independent oil and natural gas reservoir engineers of Calgary, Alberta.

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

"Property Interests" means petroleum and natural gas rights and related tangibles and miscellaneous interests beneficially owned by the Corporation, HST or HBT2.

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

"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 the Corporation.

"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 "Description of the Trust – The NPI and Direct Royalties – Reserve Fund".

"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 the report prepared by the Independent Reserve Engineering Evaluators, dated January 1, 2005 evaluating the crude oil, natural gas liquids and natural gas reserves of the Operating Subsidiaries as at December 31, 2004, 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).

"SE Saskatchewan Properties Acquisition Agreement" means the agreement of purchase and sale between the SE Saskatchewan Properties Vendor and the Corporation dated effective October 1, 2003 for the purchase of the Southeast Saskatchewan Properties.

"SE Saskatchewan Properties Transaction" means the acquisition of the Southeast Saskatchewan Properties by the Corporation pursuant to the SE Saskatchewan Properties Acquisition Agreement.

"SE Saskatchewan Properties Vendor" means a senior oil and natural gas partnership.

"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.

"Southeast Saskatchewan Properties" means various working, royalty, proprietary 3D seismic and other interests acquired pursuant to the SE Saskatchewan Properties Transaction as described under "Acquisition of Southeast Saskatchewan Properties".

"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 the Corporation pursuant to the Deferred Purchase Price Obligations under the NPI Agreement;

(b) making loans to the Corporation 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 created, issued and certified under the Trust Indenture and outstanding and entitled to the benefits thereof.

"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.

"Unit Incentive Plan" means the Trust's unit incentive plan described under "Trust Unit Incentive Plan".

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

"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 the Corporation 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		Natural Gas	
Bbl	Barrel	Mcf	thousand cubic feet
Bbls	Barrels	Mmcf	million cubic feet
Mbbls	thousand barrels	Bcf	billion cubic feet
Bbls/d	barrels per day	Mcf/d	thousand cubic feet per day
Mmbbls	million barrels	Mmcf/d	million cubic feet per day
NGLs	natural gas liquids	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. The conversion factor used to convert natural gas to oil equivalent is not necessarily based upon either energy or price equivalents at this time.
BOE/d	barrels of oil equivalent per day.
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.

DATE OF INFORMATION

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, 2004.

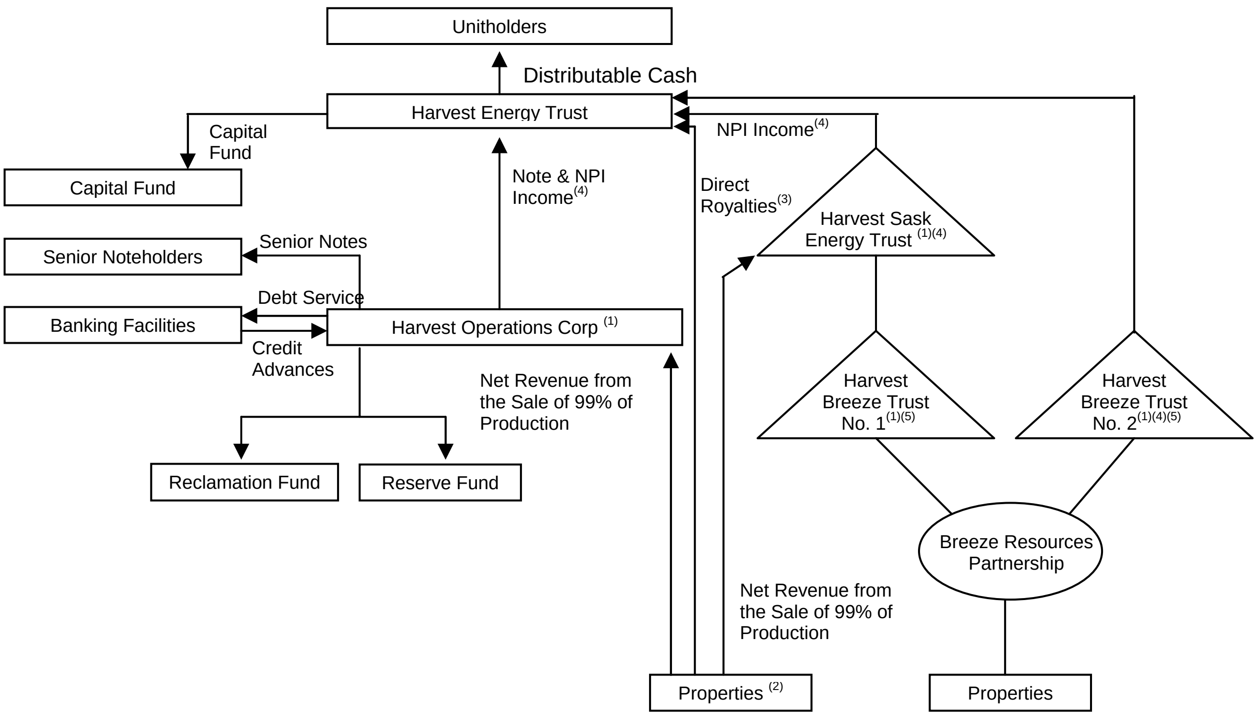
HARVEST ENERGY TRUST

General

The Trust is an open-ended, unincorporated investment trust established under the laws of the Province of Alberta and created pursuant to the Trust Indenture. The head and principal office of the Trust is located at Suite 2100, 330 - 5th Avenue S.W., Calgary, Alberta T2P 0L4. Although the Trust receives income from the NPI from each of the Operating Subsidiaries, all oil and natural gas operations are conducted through the Corporation and the Trust is managed solely by the Corporation pursuant to the Trust Indenture and the Administration Agreement.

Structure of the Trust

The structure of the Trust and the flow of cash from the Properties to the Operating Subsidiaries, from the Operating Subsidiaries to the Trust and from the Trust to Unitholders are set forth below:



Notes:

(1) All operations and management of the Trust and the Operating Subsidiaries are conducted through Harvest Operations Corp. The Trust holds all of the voting securities of Harvest Operations Corp. and of Harvest Sask. Energy Trust.

(2) Harvest Operations Corp. and Harvest Sask. Energy Trust own these properties.

(3) In addition to the NPI, the Trust holds various direct royalties.

(4) The Trust receives regular monthly payments in accordance with the NPI Agreements as well as distributions and interest payments from Harvest Sask. Energy Trust, HBT1 and HBT2.

(5) HBT1 and HBT2 have also issued priority units to Harvest Operations Corp.

GENERAL DEVELOPMENT OF THE BUSINESS

The following is a description of the general development of the business of the Trust.

The Corporation was incorporated on May 14, 2002 to carry on oil and natural gas acquisition, development and production activities. The Board of Directors then reviewed its strategic alternatives and based on such review determined that the formation of an energy royalty trust was the optimal structure. On July 10, 2002, the Trust was formed pursuant to the Trust Indenture. On the same date, the Corporation and the Trust entered into a net profit agreement which has been amended and restated effective September 27, 2002 pursuant to which the Corporation granted to the Trust the right to receive income from the net profit interest created thereby on Properties held by the Corporation from time to time. Pursuant to that NPI Agreement, the Trust paid to the Corporation $12.6 million using the proceeds from an interim loan provided by Caribou to the Trust.

On July 10, 2002 the Corporation acquired certain direct royalties and properties from a major oil and natural gas producer for an aggregate purchase price of $26.1 million. The acquisition consisted of an overriding royalty interest of 7.10688% in the Choice Viking Gas Unit No. 1, and an approximate 99% working interest in oil and natural gas producing properties that are both unitized and non-unitized. The purchase price was funded by an advance under the Corporation's credit facilities and, indirectly, through an interim loan provided by Caribou to the Trust.

On August 1, 2002 the Corporation entered into an Agreement of Purchase and Sale with a major oil and natural gas producer to purchase certain direct royalties and properties effective June 1, 2002 for an aggregate purchase price of $71.8 million. The Corporation completed the acquisition on November 15, 2002 for a closing price of $53.2 million. The acquisition consisted of a direct royalty interest and an interest in oil and natural gas producing properties located in East Central Alberta. The purchase price was funded by an advance under the Corporation's credit facilities and, indirectly, through an interim loan provided by Caribou to the Trust.

On December 5, 2002, the Trust completed the Initial Public Offering, which resulted in the issuance of 3,750,000 Trust Units and aggregate gross proceeds of $30.0 million. Approximately $22.9 million from the net proceeds of the Initial Public Offering was used to repay interim loans which had been provided by Caribou to the Trust (including accrued interest) and approximately $5.4 million from the net proceeds of the Initial Public Offering was used to partially repay bank indebtedness. The balance was used for general working capital purposes.

On December 17, 2002, the Trust issued 562,500 Trust Units to FirstEnergy Capital Corp. and Haywood Securities Inc. as a result of the exercise of an over-allotment option granted to them in connection with the Initial Public Offering. The gross proceeds from the sale of such Trust Units were $4.5 million.

On February 4, 2003, the Trust sold 1,500,000 Special Warrants to a syndicate of underwriters at a price of $10.00 per Special Warrant for net proceeds of $13.7 million. Each Special Warrant entitled the holder to receive on exercise or deemed exercise one Trust Unit for the payment of no additional consideration. On March 7, 2003, the Trust received receipts for a (final) prospectus qualifying the Trust Units issuable on exercise of the Special Warrants and on March 7, 2003, the Trust issued 1,500,000 Trust Units on the deemed exercise of the Special Warrants. The net proceeds were used to partially repay bank indebtedness and for working capital.

During April and May, 2003, the Corporation closed the acquisition of various interests in two properties in the Killarney area of Alberta. The properties were acquired from two major oil and natural gas producers for $13.2 million and the issuance of 200,000 Trust Units respectively. The cash acquisition was financed through the Corporation's credit facilities. Included with the acquisition was an interest in two oil batteries.

At the Annual and Special Meeting of Unitholders of the Trust held on June 12, 2003 (the "2003 Unitholders' Meeting"), Unitholders approved resolutions respecting each of the matters set forth below:

- to amend the Trust Indenture to authorize the creation of an unlimited number of special voting units ("Special Voting Units"). Each Special Voting Unit entitles 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;

- to amend the Trust Indenture to grant the Corporation (through the Board of Directors) the specific authority and responsibility for any and all matters relating to the terms of the NPI Agreement and other material contracts of the Trust (other than as otherwise provided in the Trust Indenture) including any amendments thereto;

- to amend the Trust Indenture to clarify and elaborate upon the responsibility which had previously been delegated to the Corporation in respect of matters relating to an issuance or offering of Trust Units or any other rights, warrants or other securities to purchase, to convert into or to exchange into Trust Units;

- to authorize an amendment of the articles of the Corporation to create a new class of non-voting common shares, issuable in series ("Non-Voting Shares"). Except for the right to notice of and to attend at any meetings of the shareholders of the Corporation, the holder of the Non-Voting Shares will have the same rights as the holders of common shares of the Corporation;

- to increase the number of Trust Units which may be reserved for issuance under the Unit Incentive Plan by 246,000 Trust Units from 875,000 Trust Units to a cumulative maximum number of 1,121,000 Trust Units; and

- approving the issuance by the Trust in one or more private placements during the 12 month period commencing June 12, 2003, of up to 11,210,957 Trust Units, subject to certain restrictions.

On June 27, 2003, the Trust completed the acquisition of all of the common shares of WEI and an NPI in certain producing oil and natural gas properties held by WEI in exchange for total consideration of approximately $10.1 million (consisting of the issuance of 625,000 Trust Units, $3 million in cash and a $850,000 unsecured promissory note) plus the assumption of $2.8 million in bank debt and $2.3 million in working capital deficit. The oil and natural gas producing properties acquired included working interests ranging from 20% to 100% in the fields of Amisk, Czar and Killarney, all of which are operated by the Corporation.

On July 28, 2003, the Trust entered into the Equity Bridge Notes to provide funds to pay the Deferred Purchase Price Obligation associated with the Southeast Saskatchewan Properties Transaction. On July 29, 2003, $11 million was advanced to the Trust pursuant to the Equity Bridge Notes to fund a deposit relating to the purchase of the Southeast Saskatchewan Properties. On September 29, 2003, the Trust amended the Equity Bridge Notes to allow advances to be used to pay out the Corporation's then existing credit facility and entered into the Bridge Notes. On September 29, 2003, the Trust received additional advances under the Equity Bridge Notes in the amount of $22.5 million and also received advances of $25.0 million under the Bridge Notes. These amounts were advanced by the Trust to the Corporation on September 30, 2003 and used to pay out in part the approximately $48.1 million owing under the Corporation's then existing credit facility. On October 1, 2003, the $11 million deposit in connection with the Southeast Saskatchewan Properties Transaction was refunded and the Trust used this amount to repay $11 million of principal in respect of the Bridge Notes.

On July 29, 2003 the Corporation entered into an agreement in respect of the purchase of partnership interests in a New Brunswick limited partnership which held the Southeast Saskatchewan Properties. On September 29, 2003 the Corporation entered into an agreement wherein the interests of the Corporation in the July 29, 2003 agreement referred to above were assigned to the Southeast Saskatchewan Properties Vendor and wherein it was agreed that substantially all of the Southeast Saskatchewan Properties would be conveyed to the Corporation. On October 1, 2003, the Corporation entered into the Southeast Saskatchewan Properties Acquisition Agreement with the Southeast Saskatchewan Properties Vendor to acquire substantially all of the Southeast Saskatchewan Properties effective October 1, 2003 for total consideration of approximately $80 million, prior to adjustments and transaction costs. Closing of the Southeast Saskatchewan Properties Acquisition occurred on October 16, 2003.

Immediately following the completion of the Southeast Saskatchewan Properties Transaction, the Trust completed an internal reorganization pursuant to which substantially all of the Southeast Saskatchewan Properties were conveyed to HST, a trust which is wholly-owned by the Trust.

The Southeast Saskatchewan Properties Acquisition was financed as to $48.65 million through an offering of 4,312,500 Trust Units at a price of $12.00 per Trust Unit for gross proceeds of $51.8 million and as to $31.35 million through advances under the Current Bank Facility.

The Southeast Saskatchewan Properties are located in South East Saskatchewan near the town of Carlyle. The majority of the production is situated between Township 7 Range 32 W1M to Township 13 Range 13 W2M. In 2004, the Southeast Saskatchewan Properties produced an average of 5,447 BOE/d of light (28° to 34° API) oil concentrated in the Mississippian-aged Tiltson subcrop play trend. As evaluated by the Independent Reserve Engineering Evaluators in the Reserve Report, the Southeast Saskatchewan Properties contained, as at December 31, 2004, 18.1 MMBOE of proved plus probable reserves, with an RLI of 9.0 years. The recovery mechanism is bottom water drive supported by an active aquifer affording an efficient recovery of reserves, making operating characteristics of the Southeast Saskatchewan Properties similar to those of the other Properties. The Trust has an average Working Interest of 100% in the Southeast Saskatchewan Properties and operates 100% of the production from the properties. All of the production is concentrated geographically which promotes ease of access and operating synergies. Management identified upside value with the Southeast Saskatchewan Properties, associated with production optimization, development drilling, the undeveloped land holdings and the proprietary seismic database.

On October 16, 2003, the Trust issued 4,312,500 Trust Units at a price of $12.00 per Trust Unit for gross proceeds of $51.8 million. The Trust Units were offered to the public through a syndicate of underwriters, which was led by National Bank Financial Inc. and included CIBC World Markets Inc., FirstEnergy Capital Corp. and Haywood Securities Inc.

On January 29, 2004, the Trust issued $60 million principal amount of 9% convertible unsecured subordinated debentures, maturing on May 31, 2009 and convertible into Trust Units at a price of $14.00 per Trust Unit. The convertible debentures were offered to the public through a syndicate of underwriters which was led by National Bank Financial Inc. and included CIBC World Markets Inc., FirstEnergy Capital Corp., Haywood Securities Inc., TD Securities Inc. and Canaccord Capital Corporation.

On June 30, 2004, Harvest acquired Storm Energy for approximately $192.2 million, including assumed debt of approximately $56.8 million and a working capital deficit of $10.5 million. Harvest paid approximately $75 million in cash and issued approximately $40 million of trust units and approximately $9 million of exchangeable shares of the Corporation to former shareholders of Storm. The acquired properties produced approximately 4,060 boe/d during the six months ended June 30, 2004 and are primarily concentrated in the Red Earth area of North Central Alberta. These properties added high quality light oil to Harvest's product mix, providing diversification benefits, along with low operating costs. Harvest acquired a 60% interest in the Red Earth Partnership when it purchased Storm.

On July 30, 2004, the Trust issued 12,166,666 Subscription Receipts at a price of $14.40 per receipt, each of which entitled the holder to receive one Trust Unit of the Trust on September 2, 2004, and $100 million principal amount of 8% convertible unsecured subordinated debentures, maturing on September 30, 2009 and convertible into Trust Units at a price of $16.25 per Trust Unit. The Subscription Receipts and convertible debentures were offered to the public through a syndicate of underwriters, which was led by National Bank Financial Inc., and included CIBC World Markets Inc., TD Securities Inc., BMO Nesbitt Burns Inc., RBC Dominion Securities Inc., FirstEnergy Capital Corp., Canaccord Capital Corporation, Haywood Securities Inc. and GMP Securities Ltd.

On September 2, 2004, Harvest acquired Breeze Resources Partnership, which held certain assets in East Central Alberta and Southern Alberta acquired from a senior producer, for the purchase price of approximately $526 million before final working capital adjustments. These assets produced approximately 20,481 boe/d for the six months ended June 30, 2004 and are primarily concentrated in the Crossfield area of Alberta, southern Alberta and east central Alberta. The Crossfield and southeast Alberta properties comprise Harvest's new Southern Alberta core area, and the east central Alberta properties supplemented Harvest's existing properties in that core area. The acquisition of these assets added Harvest's first significant natural gas production.

On October 14, 2004 Harvest closed a private placement of US$250 million of senior notes due October 15, 2011, issued in the United States. Net proceeds were used to repay Harvest's bank bridge facility associated with the September 2004 asset acquisition and to partially repay outstanding balances under the Trust's revolving credit facility. The senior notes bear interest at an annual rate of 7⅞% and were sold at a price of 99.3392% of their principal amount.

Significant Acquisitions and Significant Dispositions

There were no significant acquisitions or significant dispositions by the Trust or any significant probable acquisitions by the Trust within or since the completion of the most recently completed financial year of the Trust other than as described above in "- General Development of the Business" and as described in "Recent Developments – Acquisitions".

RECENT DEVELOPMENTS

Acquisitions

On June 30, 2004, Harvest Operations Corp. amalgamated with Storm Energy Ltd. immediately after acquiring its shares under a Plan of Arrangement. The amalgamated corporation continued under the name "Harvest Operations Corp.".

On September 2, 2004, Harvest acquired the Breeze Resources Partnership which held certain producing assets acquired from a senior producer. This acquisition closed for a purchase price of $526 million, before closing adjustments. This acquisition was financed partially with bank debt, which was mostly repaid with the proceeds of a US$250 million senior note offering closed in October 2004.

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 other than as described above. The Trust cannot predict whether any current or future opportunities will result in one or more acquisitions for the Trust.

STATEMENT OF RESERVES DATA

The statement of reserves data and other oil and natural gas information set forth below (the "Statement") is dated December 31, 2004. The effective date of the Statement is December 31, 2004 and the preparation date of the Statement is February 17, 2005.

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, 2004. Harvest’s reserves were evaluated by McDaniel (who evaluated 77% of Harvest’s total reserves), GLJ (who evaluated 17% of Harvest’s total reserves) and PLA (who evaluated 6% of Harvest’s total reserves).

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, 2004
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	26,722.0	23,942.0	29,163.3	26,766.4	56,899.6	50,471.5
Developed Non-Producing	355.6	329.1	-	-	5,648.7	5,425.4
Undeveloped	2,691.6	2,396.4	3,374.5	3,093.8	1,949.6	1,325.7
TOTAL PROVED	29,769.2	26,667.5	32,537.8	29,860.2	64,497.9	57,222.6
PROBABLE	8,205.9	7,488.8	14,950.3	13,819.7	18,512.3	16,360.0
TOTAL PROVED PLUS PROBABLE	37,975.1	34,156.3	47,488.1	43,679.9	83,010.2	73,582.6

	RESERVES			
	NATURAL GAS LIQUIDS		TOTAL OIL EQUIVALENT (BOE)	
RESERVES CATEGORY	Gross (Mbbl)	Net (Mbbl)	Gross (Mboe)	Net (Mboe)
PROVED				
Developed Producing	1,981.1	1,755.8	67,349.7	60,876.1
Developed Non-Producing	82.2	72.0	1,379.3	1,305.3
Undeveloped	62.5	60.0	6,453.5	5,771.2
TOTAL PROVED	2,125.8	1,887.8	75,182.5	67,952.6
PROBABLE	509.2	460.1	26,750.8	24,495.3
TOTAL PROVED PLUS PROBABLE	2,635.0	2,347.9	101,933.2	92,447.9

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	998,514.7	806,481.2	684,174.1	599,096.0	536,200.3
Developed Non-Producing	41,029.0	29,407.2	22,871.7	18,695.7	15,790.2
Undeveloped	93,379.0	66,294.0	49,224.5	37,705.4	29,512.0
TOTAL PROVED	1,132,922.7	902,182.4	756,270.3	655,497.1	581,502.5
PROBABLE	372,454.7	254,713.9	188,850.9	147,266.4	118,838.8
TOTAL PROVED PLUS PROBABLE	1,505,377.4	1,156,896.3	945,121.2	802,763.5	700,341.3

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
as of December 31, 2004
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	2,392,609	273,263	842,770	76,407	67,246	1,132,923
Proved Plus Probable Reserves	3,152,293	347,123	1,094,278	135,818	69,697	1,505,377

FUTURE NET REVENUE
BY PRODUCTION GROUP
as of December 31, 2004
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	410,994
	Heavy Crude Oil	178,211
	Natural Gas (including by-products)	167,065
Proved Plus Probable Reserves	Light and Medium Crude Oil	489,163
	Heavy Crude Oil	242,344
	Natural Gas (including by-products)	213,614

Reserves Data (Forecast Prices and Costs) – December 31, 2004

SUMMARY OF OIL AND NATURAL GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
as of December 31, 2004
FORECAST 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	26,385.8	23,679.3	29,355.3	26,635.9	56,887.4	50,464.8
Developed Non-Producing	356.6	331.9	0	0	5,649.7	5,426.4
Undeveloped	2,698.6	2,416.3	3,374.5	2,923.7	1,953.6	1,328.7
TOTAL PROVED	29,441.0	26,427.5	32,729.8	29,559.6	64,490.7	57,219.9
PROBABLE	8,397.7	7,679.9	15,446.9	13,849.4	18,660.2	16,474.6
TOTAL PROVED PLUS PROBABLE	37,838.7	34,107.4	48,176.7	43,409.0	83,150.9	73,694.5

	RESERVES			
	NATURAL GAS LIQUIDS		TOTAL OIL EQUIVALENT	
RESERVES CATEGORY	Gross (Mbbl)	Net (Mbbl)	Gross (Mboe)	Net (Mboe)
PROVED				
Developed Producing	1,979.5	1,755.4	67,201.8	60,481.4
Developed Non-Producing	82.2	72.0	1,380.4	1,308.3
Undeveloped	63.5	60.0	6,462.2	5,621.5
TOTAL PROVED	2,125.2	1,887.4	75,044.5	67,411.1
PROBABLE	512.8	463.0	27,467.4	24,738.1
TOTAL PROVED PLUS PROBABLE	2,638.0	2,350.4	102,511.9	92,149.2

	NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAXES DISCOUNTED AT (%/year) [1]				
RESERVES CATEGORY	0% ($000)	5% ($000)	10% ($000)	15% ($000)	20% ($000)
PROVED					
Developed Producing	1,145,401.6	948,487.3	820,000.6	728,640.9	659,768.4
Developed Non-Producing	35,851.3	25,399.5	19,697.4	16,136.0	13,691.1
Undeveloped	103,879.8	77,550.3	60,364.4	48,400.8	39,649.2
TOTAL PROVED	1,285,132.7	1,051,437.1	900,062.4	793,177.7	713,108.7
PROBABLE	447,590.0	310,111.9	232,424.1	183,027.1	149,083.9
TOTAL PROVED PLUS PROBABLE	1,732,722.7	1,361,549.0	1,132,486.5	976,204.8	862,192.6

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
as of December 31, 2004
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	2,732,967	310,515	965,391	83,341	88,587	1,285,133
Proved Plus Probable Reserves	3,672,879	408,354	1,291,284	146,272	94,246	1,732,723

FUTURE NET REVENUE
BY PRODUCTION GROUP
as of December 31, 2004
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	405,447
	Heavy Crude Oil	331,702
	Natural Gas (including by-products)	162,913
Proved Plus Probable Reserves	Light and Medium Crude Oil	481,776
	Heavy Crude Oil	458,081
	Natural Gas (including by-products)	192,630

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.

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 (see the discussion of "Economic Assumptions" below).

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

(a) **Proved reserves** are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

(b) **Probable reserves** are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

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

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

(c) **Developed reserves** are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

(i) **Developed producing reserves** are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainly.

(ii) **Developed non-producing reserves** are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

(d) **Undeveloped reserves** are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned.

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

Levels of Certainty for Reported Reserves

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

(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.

Forecast Prices and Costs – January 1, 2005

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, 2005
FORECAST PRICES AND COSTS

	OIL								
Year Forecast	WTI Crude Oil ($US/ bbl)	Edmonton Light Crude Oil ($Cdn/ bbl)	Alberta Heavy Crude Oil ($Cdn/ bbl)	Alberta Bow River Medium Crude Oil ($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)
2005	42.00	49.60	29.40	37.00	43.50	6.45	50.40	2.0	0.830
2006	39.50	46.60	29.90	37.10	40.90	6.20	47.40	2.0	0.830
2007	37.00	43.50	27.90	34.60	38.20	6.05	44.30	2.0	0.830
2008	35.00	41.10	26.30	32.70	36.00	5.80	41.90	2.0	0.830
2009	34.50	40.50	25.90	32.20	35.50	5.70	41.30	2.0	0.830
2010	34.30	40.20	25.80	32.00	35.30	5.60	41.00	2.0	0.830
2011	35.00	41.00	26.30	32.60	36.00	5.80	41.80	2.0	0.830
2012	35.70	41.90	26.80	33.30	36.70	5.90	42.80	2.0	0.830
2013	36.40	42.70	27.30	33.90	37.40	5.95	43.60	2.0	0.830
2014	37.10	43.50	27.90	34.60	38.10	6.05	44.40	2.0	0.830
2015	37.80	44.30	28.40	35.20	38.90	6.20	45.20	2.0	0.830
2016	38.60	45.30	29.00	36.00	39.70	6.35	46.20	2.0	0.830
2017	39.40	46.20	29.60	36.70	40.50	6.45	47.20	2.0	0.830
2018	40.20	47.10	30.20	37.50	41.30	6.65	48.10	2.0	0.830
2019	41.00	48.10	30.80	38.20	42.20	6.75	49.10	2.0	0.830
2020	41.80	49.00	31.40	38.90	43.00	6.85	50.00	2.0	0.830
2021	42.60	50.00	32.00	39.70	43.80	6.95	51.00	2.0	0.830
2022	43.50	51.00	32.70	40.50	44.70	7.15	52.10	2.0	0.830
2023	44.40	52.10	33.30	41.40	45.60	7.30	53.20	2.0	0.830
2024	45.30	53.10	34.00	42.20	46.60	7.50	54.20	2.0	0.830
There-after	45.30	53.10	34.00	42.20	46.60	7.50	54.20	0.0	0.830

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, 2004, were $6.30/mcf for natural gas, $41.10/bbl for natural gas liquids and $31.11/bbl for heavy oil.

Constant Prices and Costs

Constant prices and costs are:

(c) 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

(d) 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, 2004
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[2] ($Cdn/bbl)	Hardisty Heavy[3] ($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] ($Cdn/bbl)	EXCHANGE RATE[1] ($US/$Cdn)
2004	43.45	48.79	24.58	17.61	39.70	6.62	37.30	0.8308

Notes:
(1) December 31, 2004 NYMEX close
(2) Average of Shell, Imperial, PetroCanada pricing at December 31, 2004
(3) Based on historical price differentials and adjustments
(4) Estimated from AECO December 31, 2004 price of $6.44/GJ

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.

Year	Forecast Prices and Costs ($000) Proved Reserves	Forecast Prices and Costs ($000) Proved Plus Probable Reserves	Constant Prices and Costs ($000) Proved Reserves	Constant Prices and Costs ($000) Proved Plus Probable Reserves
2005	23,796	42,304	23,426	41,641
2006	29,346	67,280	28,242	64,715
2007	4,294	4,690	4,070	4,443
Thereafter	25,905	31,998	20,669	25,019
Total Undiscounted	83,341	146,272	76,407	135,818
Total Discounted at 10%	60,304	111,654	57,425	107,061

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.

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

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, 2003	**17,512.1**	**4,279.7**	**21,791.8**	**6,307.2**	**895.6**	**7,202.8**	**1,700.4**	**564.1**	**2,264.5**
Extensions/ Improved Recovery	860.3	528.0	1,388.3	23.0	26.6	49.6	52.0	12.0	64.0
Technical Revisions	963.7	113.5	1,077.2	450.4	169.3	619.7	234.7	133.7	368.4
Discoveries	325.6	109.4	435.0	0.0	0.0	0.0	0.0	0.0	0.0
Acquisitions	8,580.1	2,420.4	11,000.5	24,478.4	12,418.9	36,897.3	57,974.1	15,479.2	73,453.3
Dispositions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Economic Factors	1,929.3	228.9	2,158.2	899.9	338.0	1,238.9	594.8	285.6	880.4
Production	(3,743.6)	0.0	(3,743.6)	(2,599.3)	0.0	(2,599.3)	(3,336.1)	0.0	(3,336.1)
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**

FACTORS	NATURAL GAS LIQUIDS Net Proved (Mbbl)	Net Probable (Mbbl)	Net Proved Plus Probable (Mbbl)	TOTAL (BOE) Net Proved (MBOE)	Net Probable (MBOE)	Net Proved Plus Probable (MBOE)
December 31, 2003	**101.8**	**27.2**	**129.0**	**24,204.5**	**5,296.5**	**29,501.0**
Extensions/ Improved Recovery	0.0	0.0	0.0	891.9	556.6	1,448.5
Technical Revisions	72.9	17.4	90.3	1,526.1	322.5	1,848.6
Discoveries	0.0	0.0	0.0	325.6	109.4	435.0
Acquisitions	1,710.2	383.6	2,093.8	44,431.1	17,802.8	62,233.8
Dispositions	0.0	0.0	0.0	0.0	0.0	0.0
Economic Factors	146.5	34.8	181.3	3,074.80	650.3	3,725.20
Production	(144.0)	0.0	(144.0)	(7,042.9)	0.0	(7,042.9)
December 31, 2004	**1,887.4**	**463.0**	**2,350.4**	**67,411.1**	**24,738.1**	**92,149.2**

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	2004 ($000)
Estimated Future Net Revenue at Beginning of Year	$ 244,263
Oil and Gas Sales During the Period Net of Royalties and Production Costs	(203,653)
Changes due to Prices	21,431
Actual Development Costs During the Period	42,662
Changes in Future Development Costs	(85,871)
Changes Resulting from Extensions, Infill Drilling and Improved Recovery	30,616
Changes Resulting from Discoveries	7,960
Changes Resulting from Acquisitions of Reserves	502,785
Changes Resulting from Dispositions of Reserves	-
Accretion of Discount	24,426
Other Significant Factors	-
Net Changes in Income Taxes	-
Changes Resulting from Technical Reserves Revisions Plus Effects of Timing	171,651
Estimated Future Net Revenue at End of Year	$ 756,270

Note: Table includes values from all Independent Reserve Engineering Evaluators

Additional Information Relating to Reserves Data

Undeveloped Reserves

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 2005 and the remainder in 2006 and 2007.

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.

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.

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 16, 2005.

OTHER OIL AND NATURAL GAS INFORMATION

Oil and Natural Gas Properties

The Operating Subsidiaries' portfolio of Properties is discussed below. Although the Trust receives income from the NPI from each of the Operating Subsidiaries, 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. 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. Harvest is actively engaged in cost reduction, production and reserve replacement optimization efforts directed at reserve addition through extending the economic life of these properties and developing new proven reserves previously not evaluated by Harvest's Independent Reserve Engineering Evaluators.

2004 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)
Southern Alberta				
Suffield(1)	2,334	538	-	2,424
Crossfield(1)	-	4,703	186	970
Cavalier(1)	304	2,708	15	770
Badger(1)	248	196	6	287
Other(1)	6	46	-	14
Total Southern Alberta	2,892	8,191	207	4,465
East Central Alberta				
Hayter	4,587	347	13	4,658
Wainwright/Viking Kinsella(1)	999	43	-	1,006
Killarney	1,083	95	3	1,102
Thompson Lake	1,019	286	25	1,092
Amisk/Czar	978	74	6	996
Halkirk/Leahurst(1)	201	414	6	276
Other(1)	1,802	1,116	23	2,012
Total East Central Alberta	10,669	2,375	76	11,142
North Central Alberta				
Evi 1(2)	683	-	92	775
Evi 3 / Kitty(2)	125	-	-	125
Loon Lake(2)	324	-	-	324
Red Earth(2)	208	-	-	208
Other(2)	93	34	5	103
Total North Central Alberta	1,433	34	97	1,535
Saskatchewan				
Hazelwood	2,454	-	91	2,544
Moose Valley	1,063	-	-	1,063
Big Marsh / White Bear	873	287	-	921
Flinton/Corning	827	-	-	827
Other	520	16	-	523
Total Saskatchewan	5,736	303	91	5,877
2004 Production Total	20,730	10,903	471	23,019

(1) Properties acquired as part of the Property Acquisition completed on September 2, 2004. Production only reflects annual historical contribution from September 2, 2004.

(2) Properties acquired as part of the Storm acquisition completed June 30, 2004. Production only reflects annual historical contribution from June 30, 2004.

East Central Alberta

The properties within the East Central Alberta core area are located between T35-R1-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)	27,338.2
NGL (mbbl)	183.5
Natural gas (mmcf)	4,697.0
Total (mboe)	28,304.5
PV10 ($000)	281,072.2
Current Production (boe/d)	13,956
Producing wells	1,360
Ownership	85-90%
Operatorship	90%
Average area operating expenses ($/boe)	$9.09

Viking-Kinsella/Wainwright

Harvest acquired the Viking-Kinsella/Wainwright property from EnCana in September 2004. Current production from these pools averages approximately 3,180 boe/d of 20° API oil, producing from the Cretaceous Upper Mannville Sparky Formation. Harvest has an average 96% working interest in these operated properties. Original oil in place (OOIP) at Viking-Kinsella/Wainwright is estimated at 133 mmbbls on Harvest's working interest acreage.

Future development opportunities at this property may include 16 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.

Hayter

Harvest acquired the Hayter property in November 2002. Current production at Hayter averages approximately 4,500 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. OOIP at Hayter is estimated at 138 mmbbls of oil on Harvest's working interest acreage.

Future development at Hayter may include infill and step-out drilling at up to 13 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. Current production from the property is 1,105 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. OOIP at Killarney is estimated at 51 mmbbls on Harvest's working interest acreage.

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.

Thompson Lake

Thompson Lake was one of the first properties acquired by Harvest in July 2002. Current production from this property is 887 boe/d of 27° API oil, producing from the Glauconite A pool. Harvest has an average 99% working interest in this operated property. OOIP at Thompson Lake is estimated at 50 mmbbls on Harvest's working interest acreage.

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

Amisk
The Amisk property was acquired by Harvest in June 2003. Current production from the property averages approximately 550 boe/d of 20° API oil. Harvest has an average 75% working interest in this operated property.

Future development at Amisk will primarily be focused on reducing operating expenses through power reduction resulting from low pressure water disposal.

Czar
Harvest's Czar property was acquired in June 2003. Current production from Czar averages approximately 367 boe/d of 16° API oil, producing from the Dina formation. Harvest has an average 100% working interest in this operated property.

Future development at Czar may include some sweet gas production in the latter half of 2005.

Halkirk / Leahurst
The Halkirk/Leahurst properties are located near Stettler, Alberta and were acquired by Harvest in September 2004. Current production from these properties averages approximately 805 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 waterfloods and reactivation of shut-in wells. Some infill drilling is planned for later in 2005.

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 from EnCana in September 2004, and formed a new core area. The following table summarizes the key characteristics of this core operating area:

Proved Reserves:	
Oil (mbbl)	12,864.2
NGL (mbbl)	1,376.7
Natural gas (mmcf)	52,688.8
Total (mboe)	23,022.4
PV10 ($000)	323,223.3
Current Production (boe/d)	12,723
Producing wells	295
Ownership	85%
Operatorship	100%
Average area operating expenses ($/boe)	$5.21

Suffield
Current production from this region is 6,900 boe/d of heavy oil, averaging 11-18° API from the Upper Mannville Glauconitic formation. Harvest has an average 99% working interest in this operated property. OOIP at Suffield is estimated at 170 mmbbls of oil on Harvest's working interest acreage.

Future development at Suffield may include step-out, extension and infill drilling at up to 65 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
Current production from this region is primarily natural gas with some liquids, and averages approximately 2,730 boe/d from the Lower Cretaceous Basal Quartz formation. Harvest has an average 75% working interest in this operated property. Original Gas In Place (OGIP) at Crossfield is estimated at 400 bcf of natural gas on Harvest's working interest acreage, with another 150-180 bcf not exposed. Future development at Crossfield will include infill

and step-out drilling at up to 12 identified locations and field compression to increase the recovery factor and accelerate production.

Cavalier

Current production from this region is 2,190 boe/d of primarily light crude oil averaging 30-36° API. 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

Current production from this region is 800 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. OOIP at Badger is estimated at 14 mmbbls and OGIP is estimated at 6 bcf on Harvest's working interest acreage.

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

Southeast Saskatchewan

The properties within the southeast Saskatchewan core area are located from T5-R31-W1M to T13-R9-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)	14,675.7
NGL (mbbl)	229.2
Natural gas (mmcf)	1,307.7
Total (mboe)	15,122.9
PV10 ($000)	161,904.3
Current Production (boe/d)	5,619
Producing wells	448
Ownership	98%
Operatorship	99%
Average area operating expenses ($/boe)	$10.08

Hazelwood

Current production from Hazelwood is 2,840 boe/d of average 33° API crude oil produced from the Tilston Formation. Harvest has an average 99% working interest in this operated property. OOIP at Hazelwood is estimated at 160 mmbbls on Harvest's working interest acreage.

Future development at Hazelwood may include step-out and horizontal infill drilling at up to 45 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.

Whitebear/Big Marsh

Current production from Whitebear/Big Marsh is 710 boe/d of average 34° API crude oil produced from the Tilston Formation. Harvest has an average 100% working interest in this operated property. OOIP at Whitebear/Big Marsh is estimated at 85 mmbbls on Harvest's working interest acreage.

Future development at Whitebear/Big Marsh may include infill drilling at three identified locations, 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 drilling.

Flinton/ Corning

Current production from the Flinton / Corning area is 780 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%. OOIP at Flinton is estimated at 80 mmbbl on Harvest's working interest acreage.

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

Moose Valley

Current production from Moose Valley is 815 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%. OOIP at Moose Valley is estimated at over 47 mmbbl on Harvest's working interest acreage.

Future development in this area may include downspaced infill drilling.

North Central Alberta

The properties within the North Central Alberta core area are located from T83-R7-W5M to T89-R15-W5M and produce primarily light gravity crude oil and natural gas. Harvest acquired all North Central Alberta properties when it acquired Storm in June 2004, and formed a new core area. The following table summarizes the key characteristics of this core operating area:

Proved Reserves:	
Oil (mbbl)	7,288.3
NGL (mbbl)	336.7
Natural gas (mmcf)	5,818.0
Total (mboe)	8,594.7
PV10 ($000)	133,862.1
Current Production (boe/d)	3,443
Producing wells	156
Ownership	50%
Operatorship	75%
Average area operating expenses ($/boe)	$5.08

Evi 1

Evi 1 was acquired by Harvest in June of 2004 and current production averages 1,420 BOE/d of 39° API from the Slave Point / Granite Wash Formations. Harvest has an average 58% working interest in this operated property. Potential development may include new completions and step-out drilling.

Evi 3 / Kitty

Evi 3 and Kitty were acquired in June, 2004 and current production averages 510 BOE/d of 39° API also from the Slave Point / Granite Wash 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

Current production from Loon Lake is approximately 670 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. OOIP at Loon Lake Slave Point and Granite Wash is estimated at over 55 mmbbls on Harvest's working interest acreage.

Future development at Loon Lake may include downspace drilling in the Slave Point at up to 32 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 15 locations, as well as production optimization opportunities.

Red Earth

Current production in Red Earth proper as well as miscellaneous other Red Earth properties averages approximately 440 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 3rd party Reserve Reporting. 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 have a working interest as at December 31, 2004.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	1,733	1,417	265	240	78	22	4	3
Saskatchewan	440	416	208	196	8	8	4	4
Total	2,173	1,833	473	436	86	30	8	7

Properties with no Attributable Reserves

The following table sets out the Operating Subsidiaries' undeveloped land holdings as at January 1, 2005.

	Undeveloped Acres	
	Gross	Net
Alberta	307,722	235,002
British Columbia	35,882	8,660
Saskatchewan	118,368	115,457
Total	461,972	359,119

	Undeveloped Acres for which rights expire within one year	
	Gross	Net
Alberta	54,789	49,185
British Columbia	3,199	799
Saskatchewan	19,167	11,894
Total	77,155	61,878

Forward Contracts

For details of material commitments to sell natural gas and crude oil which were outstanding at December 31, 2004 – see note 16 to the Consolidated Financial Statements contained on pages 59 to 62 in the Trust's annual report, which pages 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, 2004	88,591	25,139
Anticipated to be paid in 2005	307	292
Anticipated to be paid in 2006	436	378
Anticipated to be paid in 2007	628	495

The number of net wells for which the Independent Reserve Engineering Evaluators estimated that the Operating Subsidiaries would incur abandonment and reclamation costs is 1,741.6 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. 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 $168.1 million ($45.5 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 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, 2004 ($000):

Property acquisition costs	
Proved properties	689.8
Undeveloped properties	16.2
Total acquisition costs	706.0
Exploration costs	-
Development costs	42.7
Total Capital Expenditures	748.7

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, 2004:

	Exploratory Wells		Development Wells	
	Gross	Net	Gross	Net
Light Oil	-	-	17	17
Heavy Oil	-	-	10	9.54
Natural Gas	-	-	-	-
Service	-	-	4	3.96
Dry	-	-	-	-
Total:	-	-	31	30.5

During 2005, the Operating Subsidiaries plan to drill 70 net wells (83 gross). The Operating Subsidiaries will continue the development drilling program in Southeast Saskatchewan started in 2004, and are targeting to drill 15 net wells for Tilston oil production. The Operating Subsidiaries have commenced a development drilling program in Southern Alberta, with approximately 25 net wells targeted, and plan to undertake projects such as battery optimization and consolidation to reduce operating costs. The Operating Subsidiaries will continue development drilling with approximately 5 locations targeted in Hayter, although the area has become less of a focal point for the Operating Subsidiaries. The Operating Subsidiaries are also 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, 2005 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.

	Light and Medium Oil (bbls/d)	Heavy Oil (bbls/d)	Natural Gas (mcf/d)	Natural Gas Liquids (bbls/d)	BOE (BOE/d)
Proved Producing	12,731	14,007	27,989	852	32,254
Proved Developed Non-Producing	78	0	1,361	10	315
Proved Undeveloped	521	158	651	23	810
Total Proved	13,330	14,164	30,001	884	33,379
Total Probable	933	879	2,455	53	2,274
Total Proved Plus Probable	14,263	15,043	32,456	937	35,653

Suffield is the Operating Subsidiaries' largest producing property representing 18% of forecast 2005 production. It is forecast by the Reserve Evaluators to produce 6,527 Bbl/d of the estimated total 35,653 Bbl/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:

	2004				
Average Daily Production Volumes (before the deduction of royalties)	Q1	Q2	Q3	Q4	Total
Light Oil (bopd)	5,053	5,216	9,087	12,228	7,911
Medium Oil (bopd)	4,150	4,082	5,416	3,644	4,324
Heavy Oil (bopd)	5,423	5,477	7,894	15,120	8,495
Total Oil (bopd)	14,626	14,775	22,397	30,992	20,730
NGL (blpd)	50	141	377	1,309	471
Natural Gas(mcfd)	915	2,249	11,909	28,338	10,903
Total Daily Production (BOE/d)	**14,829**	**15,291**	**24,759**	**37,024**	**23,019**
Total Sales Production:					
Light Oil (bbl)	459,823	474,656	836,004	1,124,976	2,895,426
Medium Oil (bbl)	377,650	371,462	498,272	335,248	1,582,584
Heavy Oil (bbl)	493,493	498,407	726,248	1,391,040	3,109,170
Total Oil (bbl)	1,330,966	1,344,525	2,060,524	2,851,264	7,587,180
NGL (bbl)	4,550	12,831	34,684	120,428	172,386
Natural Gas (mcf)	83,265	204,659	1,095,628	2,607,096	3,990,498
Total Production (BOE)	**1,349,439**	**1,391,481**	**2,277,828**	**3,406,208**	**8,424,954**

Average Sales Prices Received:

	2004 Q1	2004 Q2	2004 Q3	2004 Q4	2004 Total
Natural Gas (mcf)	$ 5.46	$ 5.91	$ 6.22	$ 5.68	$ 6.30
Heavy Oil ($/bbl)	28.79	33.53	37.64	28.73	31.11
Medium Oil ($/bbl)	36.44	36.95	43.54	35.55	38.78
Light Oil ($/bbl)	41.09	44.28	53.46	53.64	48.70
Total Oil ($/bbl)	34.89	38.42	45.84	38.52	39.42
NGL ($bbl)	35.00	30.39	45.69	33.19	41.10
BOE – 6:1	$ 35.20	$ 38.13	$ 44.83	$ 37.77	$ 39.33

Royalties Paid

	2004 Q1	2004 Q2	2004 Q3	2004 Q4	2004 Total
Heavy Oil ($000)	2,463	2,375	4,674	6,449	15,962
Medium & Light Oil ($000)	5,391	5,780	10,357	12,908	34,436
Natural gas & NGL's ($000)	172	150	1,669	1,848	3,838
Total BOE ($000)	8,026	8,305	16,700	21,205	54,236
Heavy Oil ($/bbl)	4.99	4.77	6.44	4.64	5.13
Medium & Light Oil ($/bbl)	6.44	6.83	7.76	8.84	7.69
Natural gas & NGL's ($/boe)	9.34	3.19	7.68	3.33	4.58
Total BOE ($/boe)	$ 5.95	$ 5.97	$ 7.33	$ 6.23	$ 6.44

Operating Expenses[(1)]

	2004 Q1	2004 Q2	2004 Q3	2004 Q4	2004 Total
Heavy Oil ($000)	4,814	4,213	4,906	8,268	22,989
Medium & Light Oil ($000)	8,828	9,143	13,148	15,548	45,921
Natural gas & NGL's ($000)	32	244	939	3,359	4,532
Total BOE ($000)	13,674	13,600	18,993	27,175	73,442
Heavy Oil ($/bbl)	9.76	8.45	6.76	5.70	7.03
Medium & Light Oil ($/bbl)	10.54	10.81	9.85	9.39	10.01
Natural gas & NGL's ($/BOE)	1.71	5.19	4.32	6.07	5.47
Total BOE ($/BOE)	$ 10.13	$ 9.77	$ 8.34	$ 7.37	$ 8.48

(1) *Includes impact of power hedge gains and losses*

Netback Received[(2)]

	2004 Q1	2004 Q2	2004 Q3	2004 Q4	2004 Total
Heavy Oil ($/bbl)	14.04	20.31	24.45	18.39	18.94
Medium & Light Oil ($/bbl)	22.01	23.42	32.14	31.26	27.49
Natural gas & NGL's ($/BOE)	22.26	25.69	26.66	24.49	28.43
Total BOE ($/BOE)	$ 19.12	$ 22.39	$ 29.16	$ 24.17	$ 24.41

(2) *Before gains or losses on commodity derivatives*

DESCRIPTION OF THE TRUST

General

The Trust is an open-ended, unincorporated investment trust established under the laws of the Province of Alberta. The Trust is not managed by a third party manager. Instead, the Trust is managed by the Corporation, its wholly-owned subsidiary, pursuant to the Trust Indenture and the Administration Agreement.

The Trust was established for the purposes of:

(a) acquiring the NPI and similar interests from the Corporation and similar interests and acquiring Direct Royalties;

(b) making payments to the Corporation, to the extent of the Trust's available funds, for 99% of the Corporation's cost of (including any amount borrowed to acquire) any Canadian resource property acquired by the Corporation, and the cost of (including any amount borrowed to fund) certain designated capital expenditures in relation to the Properties;

(c) acquiring or investing in securities of the Corporation and in the securities of any other entity including, without limitation, bodies corporate, partnerships or trusts that are Permitted Investments, and borrowing funds or otherwise obtaining credit for that purpose;

(d) disposing of any part of the Trust Fund, including, without limitation, any securities of the Corporation;

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

(f) paying costs, fees and expenses associated with the foregoing purposes or incidental thereto.

See "Description of the Trust – Cash Available For Distribution" and "Description of the Trust – Distributable Cash".

The NPI and Direct Royalties

Overview

The NPI consists of the right to receive a monthly payment from the Operating Subsidiaries pursuant to the terms of the NPI 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 NPI is retained by the Operating Subsidiaries, together with any income derived from Properties that are not Working Interests in Canadian resource properties (including the Corporation's 1% share of income from the royalty interests from which the Direct Royalties are derived). This residual revenue is used to defray certain expenses and capital expenditures of the Operating Subsidiaries.

In calculating the NPI, 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 the Corporation's Properties. The Operating Subsidiaries are entitled to set off the right to be so reimbursed against the obligation to pay the NPI.

Pursuant to the NPI 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 NPI on any Properties are paid to the Corporation. 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 NPI 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 NPI Agreements is for so long as there are petroleum and natural gas rights to which the NPI Agreement applies.

In addition to the NPI, 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 NPI 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 Corporation of such indebtedness.

To satisfy the Deferred Purchase Price Obligation, the Trust is required to pay over to the Corporation the net proceeds of any issue of the Trust Units or the proceeds from the disposition of the NPI of any Properties held by the Corporation. 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 Corporation designates an expenditure as a Deferred Purchase Price Obligation:

(a) 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 income from the NPI, and therefore will not reduce payments of income from the NPI to the Trust or distributions to Unitholders;

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

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

(d) the additional revenue generated from the Properties acquired by the designated expenditure will be added to the revenues used to calculate income from the NPI, thereby potentially increasing the amount payable to the Trust under the NPI Agreements.

Reserve Fund

Under the NPI Agreements, the Operating Subsidiaries are entitled to pay such amounts of the revenues received from Production and other income received by the Corporation in respect of the Properties into the Reserve Fund if, as and when the Corporation 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 the Corporation 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 Corporation in the Reserve Fund are required to be used by the Corporation 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 NPI.

Reclamation Fund

Each of the Operating Subsidiaries are liable for their share of ongoing environmental obligations and for the ultimate reclamation of the Properties upon abandonment. Pursuant to the NPI 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 NPI.

Ongoing environmental obligations are expected to be funded out of debt and cash flow. Those obligations will reduce the amount of income from the NPI payable to the Trust. At this time, the Operating Subsidiaries have not established either a separate bank or investment account to segregate funds to finance these obligations.

In addition to the identified producing wells and wells capable of production, the Properties include interests in approximately 519 gross (495 net) active injection, disposal or service wells and 738 gross (640 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 NPI 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, the Corporation calculates income from the NPI for each calendar month and arranges for payment of certain direct expenses of the Trust from the NPI.

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 the Corporation determines not to use those proceeds to acquire additional Properties.

Delay in Cash Available For Distribution

In addition to the usual delays in payment by purchasers of oil and natural gas to the operator of the Properties, and by the operator to the Operating Subsidiaries or the Trust, payments between any of such parties may also be delayed by restrictions imposed by lenders, delays in the sale or delivery of products, delays in the connection of wells to a gathering system, blowouts or other accidents, recovery by the operator of expenses incurred in the operation of Properties, or the establishment by the operator of reserves for such expenses.

Capital Fund

The Trust retains up to 50% of the Cash Available For Distribution to finance future acquisitions and development of Properties with the intent that it will be able to continue to provide or maintain the Cash Available For Distribution over a longer period of time than would otherwise be the case. The Trust does not maintain a separate bank or investment account in which it maintains such amounts. To the extent Cash Available for Distribution is not distributed to unitholders, it is invested in acquisitions and development of Properties or used to repay debt of the Trust or the Operating Subsidiaries.

Distributable Cash

Distributable Cash consists of the balance of the Cash Available For Distribution after the retention of funds by the Trust for the Capital Fund, which is distributed to Unitholders.

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

Income Tax Treatment

Any amounts paid by the Trust in respect of acquisition costs and the Deferred Purchase Price Obligation is COGPE of the Trust in the year incurred. The Trust's share of any proceeds of disposition of Canadian resource properties which are receivable as a result of the release of the NPI will reduce the Trust's cumulative COGPE. In determining the portion of Distributable Cash that is taxable to a Unitholder, the Trust is entitled to an annual deduction in respect of its cumulative COGPE account, resource allowance, general and administrative and capitalized issue expenses in accordance with the provisions of the Tax Act. Any portion of Distributable Cash to Unitholders that is not taxable in the Trust is treated as a return of capital and reduces the adjusted cost base of Trust Units held as capital property by a Unitholder. In this respect, the taxation of capital distributions is deferred until an actual or deemed disposition of Trust Units occurs or a holder's Trust Units have an adjusted cost base which is less than zero. See "Canadian Federal Income Tax Considerations".

Board of Directors

The Corporation currently has a board of directors consisting of 5 individuals, and has presented a slate of 6 directors to the unitholders at the 2005 Annual General Meeting. Pursuant to the Trust Indenture, Unitholders are entitled to elect the Board of Directors annually. Prior to all annual meetings, the Corporation will deliver an information circular and form of proxy to Unitholders with respect to the election of the directors of the Corporation at any such meeting. See "Information Respecting the Corporation – Directors and Officers of the Corporation".

Delegation of Authority, Administration and Trust Governance

The Corporation (and, accordingly, the Board of Directors of the Corporation) has generally been delegated the significant management decisions of the Trust. In particular, the Trustee has delegated to the Corporation 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.

Under the NPI 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, the Corporation 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. The Corporation's 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, the Corporation employs and will continue to employ prudent oil and natural gas business practices. All of the Corporation's 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 the Corporation by the Trust and the costs of providing such services.

General and administrative costs are deducted from production revenues in computing income from the NPI to the extent not paid from the residual income of the Corporation or deducted by the Trust in computing Cash Available For Distribution. General and administrative costs are generally charged to the Trust by the Corporation based on direct costs incurred in fulfilling the obligations of the Corporation to the Trust pursuant to the Trust Indenture and the Administration Agreement. The Corporation 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.

Borrowing by the Trust

Equity Bridge Notes

On July 28, 2003, the Trust entered into the Equity Bridge Notes with the Bridge Lenders which provide for advances of up to $40 million to the Trust to assist with the payment of the Deferred Purchase Price Obligation in connection with the acquisition of certain oil and natural gas properties. On July 29, 2003, Harvest received $11 million in advances pursuant to the Equity Bridge Notes to fund the deposit relating to the purchase of such properties. On September 29, 2003, the Equity Bridge Notes were amended to permit advances to be used to pay out the Prior Bank Facility and the Trust entered into the Bridge Notes. The Bridge Notes provided for advances of up to $30 million to the Trust to assist with the payment of the Deferred Purchase Price Obligations as a result of the acquisition of the Southeast Saskatchewan Properties and to repay outstanding bank debt. No commitment or arrangement fee was earned by the Bridge Lenders through the provision of the Bridge Agreements.

The terms of the Bridge Agreements call for quarterly interest payments to be made to the Bridge Lenders in arrears due on the first business day following a calendar quarter. The payments are calculated daily at a fixed rate of 10% per annum using a 365 or 366 (as the case may be) year. Under the Equity Bridge Notes, the Trust has the option to settle the quarterly interest payments with cash or, subject to receipt or applicable regulatory approval, the issue of Trust Units. If the Trust elects to issue Trust Units the Trust is required to give the Bridge Lenders at least 5 business days notice. The number of Trust Units to be issued to the Bridge Lenders to settle a quarterly payment shall be equivalent to the quarterly payment amount divided by 90% of the ten-day weighted average trading price of the Trust Units on TSX over the last 10 trading days of the calendar quarter.

The Trust also has the option to repay the principal amounts outstanding at any time. The Trust is required to give the Bridge Lenders ten business days written notice prior to the Trust's repayment of principal. If the Trust chooses to partially repay the outstanding principal amount, such payment is to be made in cash. Under the Equity Bridge Notes, if the Trust elects to repay the full principal amount plus the accrued quarterly payment at maturity, the Trust then has the option to settle its obligation with cash or, subject to receipt of applicable regulatory approvals, the issue of Trust Units. If the Trust elects to issue Trust Units, the Trust is required to give the Bridge Lenders at least five business days notice. The number of Trust Units to be issued to the Bridge Lenders to settle the principal amount and accrued quarterly payment amount shall be equivalent to the sum of the principal and accrued quarterly payment amounts divided by 90% of the ten-day weighted average trading price of the Trust Units on TSX over the last ten trading days immediately prior to the date that the obligation will be settled.

The equity bridge lenders have agreed to subordinate their interests to any claims of the Bank Lenders. Security has been provided in the form of second-priority fixed and floating debentures on all of Harvest Energy Trust's assets. The equity bridge lenders may demand payment of the full amount if specified events of default under the equity bridge note agreements occur, including cross default to any other indebtedness of Harvest, an unacceptable change in Harvest management or trustee, a change in control of Harvest, suspension or cease trading of the trust units of Harvest on any stock exchange or if the lender believes there has been a material adverse change or that repayment or the collateral security has been impaired or is in jeopardy. Covenants include a negative covenant not to make distributions during an event of default or if it would materially limit its ability to meet obligations under the equity bridge notes. The Trust does not have the option to issue Trust Units to satisfy its repayment obligations if an event of default occurs.

On October 16, 2003, the Corporation repaid $8.5 million of the Equity Bridge Notes (resulting in $25 million being outstanding thereunder) and $25 million of the Bridge Notes resulting in no amount being outstanding thereunder through drawings under the Current Bank Facility.

On January 2, 2004 Harvest paid $0.665 million in accrued interest in respect of equity bridge principal outstanding during the fourth quarter of 2003. On January 26 and 29, 2004, Harvest repaid the remaining $25 million of equity bridge principal amounts outstanding and paid $0.185 million of interest accrued since December 31, 2003. The Equity Bridge Notes were amended on June 29, 2004, July 7, 2004, and July 9, 2004 to assist with the acquisition by Harvest Operations of Storm and the acquisition of the EnCana assets. These notes were drawn by $30 million and repaid as to $20 million on August 11, 2004 and $10 million on December 30, 2004.

Convertible Debentures

On January 29, 2004, the Trust issued $60 million of 9% convertible unsecured subordinated debentures due May 31, 2009. Interest on the debentures is payable semi-annually in arrears in equal installments on May 31 and November 30 in each year, commencing May 31, 2004. The debentures are convertible into fully paid and non-assessable trust units at the option of the holder at any time prior to the close of business on the earlier of May 31, 2009 and the business day immediately preceding the date specified by the Trust for redemption of the Debentures, at a conversion price of $14.00 per trust unit plus a cash payment for accrued interest and in lieu of any fractional trust units resulting on the conversion. The debentures may be redeemed by the Trust at its option in whole or in part subsequent to May 31, 2007, at a price equal to $1,050 per debenture between June 1, 2007 and May 31, 2008 and at $1,025 per debenture between June 1, 2008 and May 31, 2009. Any redemption will include accrued and unpaid interest at such time when completed. Under both redemption options, the Trust may elect to pay both the principal and accrued interest in the form of trust units at a price equal to 95% of the weighted average trading price for the preceding 20 consecutive trading days, 5 days prior to settlement date.

On August 10, 2004, the Trust issued $100 million of 8% convertible unsecured subordinated debentures due September 30, 2009. Interest on the debentures is payable semi-annually in arrears in equal installments on March 31 and September 30 in each year, commencing March 31, 2005. The debentures are convertible into fully paid and non-assessable trust units at the option of the holder at any time prior to the close of business on the earlier of September 30, 2009 and the business day immediately preceding the date specified by the Trust for redemption of the Debentures, at a conversion price of $16.25 per trust unit plus a cash payment for accrued interest and in lieu of any fractional trust units resulting on the conversion. The debentures may be redeemed by the Trust at its option in whole or in part subsequent to September 30, 2007, at a price equal to $1,050 per debenture between October 1, 2007 and September 30, 2008 and at $1,025 per debenture between October 1, 2008 and September 30, 2009. Any redemption will include accrued and unpaid interest at such time when completed. Under both redemption options, the Trust may elect to pay both the principal and accrued interest in the form of trust units at a price equal to 95% of the weighted average trading price for the preceding 20 consecutive trading days, 5 days prior to settlement date. This series of convertible debentures ranks pari-passu with the outstanding debentures issued on January 29, 2004.

Debt of the Corporation

The Corporation has issued senior notes (see "Borrowing by the Corporation – Senior Notes") which are guaranteed by the Trust, along with the Trust's other wholly-owned subsidiaries.

INFORMATION RESPECTING THE CORPORATION

The Corporation was incorporated under the *Business Corporations Act* (Alberta) on May 14, 2002 as 989131 Alberta Ltd. On May 17, 2002, the Corporation amended its Articles of Incorporation to change its name to Coyote Energy Inc. and on September 17, 2002, the Corporation changed its name to "Harvest Operations Corp.". On January 1, 2004, the Corporation amalgamated with WEI and the amalgamated corporation continued under the name "Harvest Operations Corp.". The head and principal office of the Corporation is located at Suite 2100, 330 - 5th Avenue S.W., Calgary, Alberta, T2P 0L4 and its registered office is located at Suite 1400, 350 – 7th Avenue S.W., Calgary, Alberta T2P 3N9. All of the issued and outstanding shares of the Corporation are held in the name of the Trustee for the benefit of, and on behalf of, the Trust.

Business

The Corporation manages and administers the Trust and the other Operating Subsidiaries on behalf of the Trust and is responsible for the oil and natural gas technical, investment, engineering, geological, land management, financial and administrative services and commodity marketing services relating to the Properties and the Trust. Each of the directors and senior management of the Corporation have been involved in the oil and natural gas industry for, on average, in excess of 20 years. At March 16, 2005, the Corporation has a staff made up of 84 head office employees and 95 field employees dedicated to the Properties, with key personnel having extensive experience in all technical, operating and financial aspects of the oil and natural gas industry including:

- organizing, operating, managing, developing and optimizing petroleum and natural gas properties;
- evaluating, acquiring and disposing of petroleum and natural gas properties; and
- marketing petroleum, natural gas and natural gas liquids.

Management Policies and Strategies

As a result of management's past experience, the members of the management team have established proven track records in acquiring, developing and operating oil and natural gas resources. Management of the Corporation believes that the success derived from these experiences can be attributed to several management principles, including:

(a) a focused and rigorous evaluation and acquisition strategy having an objective of acquiring operated oil and natural gas reserves at low costs;

(b) employing operating and management strategies and controls to increase production rates and enhance production netbacks, primarily through production cost reduction;

(c) identifying and exploiting upside opportunities in acquired Properties to increase production and reserve recovery;

(d) acquiring other assets within existing operating areas to achieve operating and development efficiencies; and

(e) managing risk effectively through prudent insurance and commodity hedging programs and hands-on property management.

Activities undertaken by the management of the Corporation on behalf of the Trust are intended to be directed towards:

- optimizing consistent levels of Cash Available For Distribution and ultimately, the Distributable Cash paid to Unitholders;

- capturing the maximum cash flow, production and reserve recovery from the Properties; and

- striving for long-term growth in the value of the Properties and consequently the value of the NPI and the Direct Royalties held by the Trust by improving recovery levels from the Properties and acquiring additional Properties.

Borrowing by the Corporation

The Operating Subsidiaries and the Trust are permitted to incur indebtedness to purchase Property Interests, effect 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. The Harvest Board 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 by the Board of Directors. The Operating Subsidiaries are entitled to grant security in priority to the NPI and the Trust is permitted to grant security on the NPI 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. The borrowings of the Trust require approval by the Board of Directors.

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. Debt repayment by the Operating Subsidiaries is scheduled to minimize, to the extent possible, any income tax payable by the Operating Subsidiaries.

Senior Credit Facility

On September 1, 2004, in connection with the closing of the acquisition of the Southern Alberta and East Central Alberta Properties, Harvest Operations entered into an amended credit agreement with a syndicate of lenders. This credit facility consists of a $310 million production loan, a $15 million operating loan, and a U.S. $21.3 million mark to market credit to be used for financial instrument hedging. The term of the facility is to June 29, 2005. Availability under the facility is subject to a borrowing base calculation performed by the lenders at least on a semi-annual basis. The facility permits drawings in Canadian or U.S. dollars, and includes banker's acceptances, LIBOR loans and letters of credit. Outstanding balances bear interest at rates ranging from 0% to 2.25% above the applicable Canadian or U.S. prime rate depending upon the type of borrowing and the debt to annualized cash flow ratio. The debt is secured by a $750 million debenture with a fixed and floating charge over all of the assets of the Corporation, and a guarantee by the Trust and its subsidiaries.

Under the terms of this credit agreement, a bridge facility of $70 million was provided to assist in the closing of the EnCana asset acquisition. This facility was due to mature on June 1, 2005, and outstanding balances under this facility accrued interest at progressive rates of 3% to 8% above the applicable Canadian prime rate. The bridge facility was repaid in full with the net proceeds of the senior note issuance. As at December 31, 2004 the Trust was in compliance with all covenants.

The Corporation is subject to a standby fee equal to 0.125% per annum on the undrawn amount of the Current Bank Facility.

Events of default under the Current Bank Facility include: failure to pay interest or principal when due; failure to meet security or covenants; material misrepresentation; material adverse change in the financial condition of operations of the Corporation; uncontested proceedings initiated to enforce encumbrances on the Corporation's assets that have an aggregate value of $500,000; liquidation, winding-up or dissolution of the Corporation; ceasing to carry on business; and appointment of receiver or trustee appointed by judicial body or pursuant to another agreement.

As of March 16, 2005, approximately $90 million is outstanding under the Current Bank Facility.

Senior Notes

On October 14, 2004, Harvest Operations closed an agreement to sell, on a private placement basis in the United States, US$250 million of senior notes due October 15, 2011. The senior notes are unsecured and bear interest at an annual rate of 7 7/8% and were sold at a price of 99.3392% of their principal amount. Interest is payable semi-annually on April 15 and October 15. The senior notes are unconditionally guaranteed by the Trust and all of its wholly-owned subsidiaries. The Trust used the net proceeds of the offering to repay in full Harvest's bank bridge facility and partially repay outstanding balances under Harvest's senior credit facility. The fair value of the senior notes at December 31, 2004 was US$250.6 million (Cdn$301.2 million).

The terms of the notes limit the amount of secured and unsecured debt the Corporation may issue, and also place certain restrictions on the amount of distributions which may be paid in certain circumstances.

Commodity Risk Management

The following is a summary of the oil sales price derivative contracts as at December 31, 2004, that have fixed future sales prices:

Oil price swap contracts based on West Texas Intermediate			
Daily Quantity	Term	Price per Barrel	Mark to Market Gain (Loss)
500 Bbls/d	January through December 2005	U.S. $24.00	$ (4,107)
1,100 Bbls/d	January through March 2005	U.S. $22.38	(2,535)
1,030 Bbls/d	April through June 2005	U.S. $22.18	(2,358)
	50% Participating swap contracts based on West Texas Intermediate		
8,750 Bbls/d	Jan – Dec 2006	U.S. $38.16[b]	$ 3,710

Oil price collar contracts based on West Texas Intermediate				
2,500 Bbls/d	January through June 2005	U.S. $28.40 – 32.25 ($21.80)	$ (6,032)	(a)
1,500 Bbls/d	July through December 2005	U.S. $28.17 – 32.10 ($22.33)	(3,296)	(a)
2,000 Bbls/d	January through December 2005	U.S. $28.00 – 42.00	(529)	

Note: (a) Harvest has sold put options at the average price denoted in parenthesis, for the same volumes as the associated commodity contracts. The counterparty may exercise these options if the respective index falls below the specified price on a monthly settlement basis.

(b) This price is a floor. The Trust realizes this price plus 50% of the difference between spot price and this price.

Indexed put options based on West Texas Intermediate

Daily Quantity	Term	Type	Price per Bbl (U.S.$)	Mark to Market Gain (Loss)
4,000 bbls/d	Jan - Dec 2005	Long Put	$30.00	$ 937
1,972 bbls/d	Jan - Dec 2005	Short Call	$30.00	(11,261)
1,972 bbl/d	Jan - Dec 2005	Long Call	$40.00	4,642
7,000 bbl/d	Jan - Dec 2005	Long Put	$35.00	4,050
2,380 bbl/d	Jan - Dec 2005	Short Call	$35.00	(9,239)
2,380 bbl/d	Jan - Dec 2005	Long Call	$45.00	3,090
7,500 bbl/d	Jan - Dec 2005	Long Put	$40.00	9,142
3,675 bbl/d	Jan - Dec 2005	Short Call	$40.00	(8,651)
3,675 bbl/d	Jan - Dec 2005	Long Call	$50.00	2,678
7,500 bbl/d	Jan - June 2006	Long Put	$34.00	2,989
3,750 bbl/d	Jan - June 2006	Short Call	$34.00	(7,252)
3,750 bbl/d	Jan - June 2006	Long Call	$44.00	3,170

The following is a summary of electricity price physical and financial swap contracts entered into by Harvest Operations to fix the cost of future electricity usage as at December 31, 2004:

Swap contracts based on electricity prices

Weighted Average Quantity	Term	Average Price per Megawatt	Mark to Market Gain (Loss)
24.8 MWH	January through December 2005	Cdn $47.43	$ 1,272
29.9 MWH	January through December 2006	Cdn $47.51	(196)

Swap contracts based on electricity heat rate

Quantity	Term	Heat Rate	Mark to Market (Loss)
5 MW	January through December 2005	8.40 GJ/MWh	$ (80)

Foreign currency contracts

Monthly Contract Amount	Term	Contract Rate	Mark to Market Gain
U.S. $8.33 million	January through December 2005	1.20 Cdn / U.S.	$ 4,500[1]

(1) Represents the premium paid on this contract.

DIRECTORS AND OFFICERS OF THE CORPORATION

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

Name and Municipality of Residence	Position with the Corporation	No. of Trust Units Held (1)	Principal Occupation
Kevin A. Bennett Calgary, Alberta	Nominated Director	500,000	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, C.O.O. and a director of Ventus Energy Ltd.
John A. Brussa (2)(3)(5) Calgary, Alberta	Director	298,305	Barrister and Solicitor; Partner of Burnet, Duckworth & Palmer LLP (a law firm).
M. Bruce Chernoff (4)(5) Calgary, Alberta	Director, Chairman	7,645,130(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. ("Petrobank") (a public oil and natural gas company); from February to June 1999, Executive Vice President and Chief Financial Officer of Pacalta Resources Ltd. ("Pacalta") (a public oil and natural gas company); prior thereto, Executive Vice President of Pacalta.
Hank B. Swartout(4) Calgary, Alberta	Director	905,690(8)	Chairman, President and Chief Executive Officer of Precision Drilling Corporation since July, 1987.
Verne G. Johnson(2)(3)(4) Calgary, Alberta	Director	35,000	President of KristErin Resources Inc., a private family company since January 2000; Senior Vice President, Funds Management of Enerplus Resources Group from 2000 to 2002; prior thereto, President and Chief Executive Officer of AltaQuest Energy Corporation from 1999 to 2000; prior thereto, President of Ziff Energy Group (an energy consulting company) from 1997 to 1999; prior thereto, President and Chief Executive Officer of ELAN Energy Inc. (a public oil and natural gas company) from 1989 to 1997.
Hector J. McFadyen(2)(3)(5) Calgary, Alberta	Director	30,000	Independent businessman and Director of Hunting PLC (a UK based public international oil services company); director of Computershare Trust Company of Canada (a private Canadian company that manages various trust related activities for public and private companies throughout North America); director of Aluma Systems (a private Canadian company providing industrial and concrete construction services); formerly, President, Midstream Division, Alberta Energy Company Ltd. (a public oil and natural gas company) from 1995 to 2002.

Name and Municipality of Residence	Position with the Corporation	No. of Trust Units Held [1]	Principal Occupation
Jacob Roorda Calgary, Alberta	President	219,625[9]	Professional Engineer, President of the Corporation; from June 1999 to July 2002, Managing Director, Research Capital (a mid-sized investment banking dealer); from January 1996 to March 1999, Vice President, Corporate, Director and co-founder of PrimeWest Energy Trust ("PrimeWest") (a public energy trust); from May 1991 to January 1996, Manager, Business Development, Fletcher Challenge (a private oil and natural gas company).
David J. Rain Calgary, Alberta	Vice President, Corporate Secretary and Chief Financial Officer	108,000[10]	Chartered Accountant; Vice President, CFO and Corporate Secretary of the Corporation; Vice President, Finance and Chief Financial Officer of Petrobank from October 2001 to March 2004; Vice President and Director of Caribou since June 1999; from April 2000 to September 2001, Director, Corporate Finance of Petrobank; from May 1997 to June 1999, Corporate Controller and Treasurer of Pacalta.
J.A. Ralston Calgary, Alberta	Vice President, Operations	76,083[11]	Vice President, Operations of the Corporation; from 1996 to 2002, Manager, Production of Penn West Petroleum ("PennWest") (a public oil and natural gas company).
James A. Campbell Calgary, Alberta	Vice President, Geosciences	31,950[12]	Vice President, Geosciences of the Corporation from 2004; prior thereto, Manager, Geosciences since August 2002. From August 1997 to July, 2002, Vice President Exploration with Navigo Energy (and predecessor public oil and natural gas companies).

Notes:

(1) Represents all Trust Units held directly or indirectly or over which such person exercises control or direction as at March 16, 2005. 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 companies controlled by Mr. Chernoff, and Trust Units held in RESP accounts for the benefit of Mr. Chernoff's children.
(8) Includes 162,857 Trust Units held by Mr. Swartout’s spouse.
(9) Includes 64,243 Trust Units held in Mr. Roorda's spouse's account which is controlled by Mr. Roorda.
(10) Includes 30,700 Trust Units held by Mr. Rain's spouse.
(11) Includes 37,066 Trust Units held by Mr. Ralston’s spouse.
(12) Includes 9,000 Trust Units held by Mr. Campbell’s spouse.

As at March 16, 2005, the directors, nominated directors and officers of the Corporation and their associates and affiliates, as a group, hold, directly or indirectly, or exercise control or direction over, approximately 9,849,783 Trust Units or 23.0% of the outstanding Trust Units and exchangeable shares.

The following is a brief description of the background of each of the senior officers, nominated directors and directors of the Corporation. The past performance of each of the individuals indicated below is not necessarily indicative of future performance.

Jacob Roorda, President

Mr. Roorda is a Professional Engineer and holds a Bachelor of Applied Science (Eng.) degree from Queen's University and an MBA from the University of Calgary.

Following university, Mr. Roorda held a number of senior engineering positions with Dome Petroleum Ltd. From 1987 to 1991, Mr. Roorda was a Vice President in the equity research group and was a ranked oil and natural gas analyst at BZW Canada Ltd., in Toronto.

From 1991 to 1996, Mr. Roorda was Manager, Business Development at Fletcher Challenge. In January 1996, Mr. Roorda co-founded PrimeWest (a public energy trust) and served as Vice President, Corporate and Director of PrimeWest. Mr. Roorda was responsible for overseeing the acquisition strategies of PrimeWest. While at Fletcher and PrimeWest, Mr. Roorda was responsible for closing in excess of $650 million of oil and natural gas property acquisitions.

From June 1999 to July 2002, Mr. Roorda was a Managing Director of Research Capital, an investment-banking firm. At Research Capital, Mr. Roorda was responsible for the overall direction and operations of the Calgary investment banking office of the firm.

David J. Rain, Vice President, Chief Financial Officer and Corporate Secretary

Mr. Rain is a Chartered Accountant and holds a Bachelor of Commerce degree from the University of Saskatchewan.

Mr. Rain articled at KPMG LLP Chartered Accountants and was a Manager in their audit group when he departed in 1992. Mr. Rain served in senior financial positions at Nowsco Well Service Ltd., an oilfield service company with worldwide operations, from 1992 through August 1996. Mr. Rain was the Chief Financial Officer of Trican Well Service Ltd, an oilfield service company with operations in Alberta and Saskatchewan, from October 1996 through April 1997. Mr. Rain joined Pacalta in May 1997 as Corporate Controller. Pacalta was an oil and natural gas exploration and production company with operations primarily in Ecuador. When AEC acquired Pacalta in 1999, Mr. Rain joined Mr. Chernoff at Caribou, and became Director, Corporate Finance at Petrobank in March 2000. Mr. Rain assumed the position of Vice President, Finance and Chief Financial Officer of Petrobank in October 2001 and resigned in March 2004. Mr. Rain also serves as a Director and Chief Financial Officer of Caribou.

J.A. Ralston, Vice President, Operations

Mr. Ralston completed the Management Development Program at the University of Calgary in 1994.

Mr. Ralston was employed with Petro-Canada from 1980 through June 1994 in a broad range of field operating positions of increasing responsibility. During his tenure at Petro-Canada, Mr. Ralston was responsible for construction of field facilities and pipelines, natural gas plant and field operations, procurement, reservoir management, drilling and workovers.

Mr. Ralston commenced employment with Penn West in July 1994 where he worked until June 2002. Since 1997, Mr. Ralston served as Production Manager, responsible for overseeing all of Penn West's 100,000 BOE/d production operations, 270 field staff and an annual budget of $200 million. Mr. Ralston was responsible for all areas of operations including engineering, exploitation, production optimization, capital management, planning, construction and budgeting.

James A. Campbell, Vice President, Geosciences

Mr. Campbell has primary responsibility for all Geological and Geophysical activities, and provides leadership from a technical/operational and organizational perspective. With over 25 years in the oil and gas sector at senior management levels, Mr. Campbell will also play an expanded role in planning Harvest’s strategic direction.

Mr. Campbell has been with Harvest since inception of the Corporation. Prior to joining Harvest, Mr. Campbell held the Vice President, Exploration role at Conoco Canada Ltd. and later Navigo Energy Inc. Mr. Campbell holds a B.Sc. degree from McMaster University.

Kevin A. Bennett, Nominated Director

Mr. Bennett is a professional engineer with a Bachelor of Engineering Science degree in Chemical Engineering from the University of Western Ontario (1981).

Since September, 2001 Mr. Bennett has been an independent businessman involved in founding and the directorship of several oil and gas, and energy services companies. Mr. Bennett was a co-founder of Harvest Energy Trust with Mr. Chernoff in 2002.

Prior to Sept. 2001, Mr. Bennett was the President, C.O.O. and a director of Ventus Energy Ltd. from Sept. 1998.

John A. Brussa, Director

Mr. Brussa is a barrister and solicitor and has been a partner at Burnet, Duckworth & Palmer LLP in Calgary since 1987. Mr. Brussa is recognized as a leading tax practitioner in Canada and sits on the board of directors of several Canadian public companies.

M. Bruce Chernoff, Director and Chairman

Mr. Chernoff is a Professional Engineer with a Bachelor of Applied Science degree in Chemical Engineering from Queen's University. Mr. Chernoff commenced employment with Pacalta in 1988. Pacalta was a public junior oil and natural gas company with operations in Canada until 1996 when it acquired an oil property in Ecuador. Mr. Chernoff held various senior positions with Pacalta including Executive Vice-President and Chief Financial Officer. Mr. Chernoff was a director of Pacalta from 1992 until Pacalta was purchased by Alberta Energy Company in May 1999.

Mr. Chernoff initiated the formation of Caribou, of which he is the President and a Director, in June 1999, to carry out investments in oil and natural gas among other sectors. Mr. Chernoff became a Director, and the Executive Vice President and Chief Financial Officer of Petrobank in March 2000. Mr. Chernoff resigned that position in October 2001 to focus on his other business interests. Mr. Chernoff initiated the formation of the Corporation in June 2002 to pursue oil and natural gas development and acquisition opportunities.

Hank B. Swartout, Director

Since 1987, Mr. Swartout has been the Chairman of the Board, President and Chief Executive Officer of Precision Drilling Corporation, the largest Canadian integrated oilfield and industrial services contractor and a global provider of products and services to the energy industry.

Verne G. Johnson, Director

Mr. Johnson received a Bachelor of Science degree in Mechanical Engineering from the University of Manitoba in 1966. He immediately commenced employment with Imperial Oil Limited, which continued until 1981 (including two years with Exxon Corporation in New York from 1977 to 1979). In 1981, Mr. Johnson joined Liberty Petroleum Ltd. as President and Chief Executive Officer. In 1982, he joined Roxy Petroleum Ltd. as Vice President, Production, remaining until 1987 when he joined Paragon Petroleum Ltd. as President. In 1989, Mr. Johnson joined ELAN Energy Inc. (then Lasmo Canada Inc.) as President and a Director. Following the sale of ELAN in 1997, he became President of Ziff Energy Group until 1999, then President of AltaQuest Energy Corporation and he then joined the Enerplus Resources Group in 2000, becoming Senior Vice President of Funds Management. In February 2002, he departed from the Enerplus Resources Group and remains as President of his private family company, KristErin Resources Inc.

Hector J. McFadyen, Director

Mr. McFadyen holds a Master of Arts (Econ.) degree from the University of Calgary and a Bachelor of Arts (Econ.) degree from Sir George Williams University.

Mr. McFadyen was employed at the Alberta Energy and Utilities Board (formerly the Oil and Natural Gas Conservation Board) between 1969 and 1976, primarily within its Economics Department.

Mr. McFadyen began work for Alberta Energy Company Ltd. ("AEC"), now EnCana Corporation ("EnCana"), in 1976. EnCana is one of the largest independent oil and natural gas producers in North America. Mr. McFadyen developed a number of significant business units within AEC, developing experience in a broad range of businesses and disciplines. Such experience included project development and investments across North America, Latin America, Asia and Europe. At AEC, Mr. McFadyen served as a member of the senior executive team involved in recommending and implementing the strategic plan for the company. As President of the Forest Products Division, he assumed responsibility for development and implementation of the business strategy for an Alberta based forest products business. Mr. McFadyen also served as the President of the Midstream Division of AEC since 1995, having responsibility for the company's pipelines and natural gas storage businesses. Mr. McFadyen retired from EnCana in 2002.

Mr. McFadyen is a member of the board of directors of Hunting PLC ("Hunting"), a UK-based public corporation engaged in oil services, and oil and natural gas marketing and distribution activities internationally. Hunting carries on its oil and natural gas marketing and distribution activities in North America through its wholly-owned subsidiary, Gibson Energy Ltd. Mr. McFadyen is also a member of the Board of Directors of Computershare Trust Company of Canada, a private Canadian company that manages various trust related activities for public and private companies throughout North America. Mr. McFadyen is also a director of Aluma Systems, a private Canadian company providing industrial and concrete construction services.

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, officer or promoter of the Corporation has, within the last 10 years, been a director, officer or promoter of any reporting issuer 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 statutory exemption for a period of more than 30 consecutive days or was declared a bankrupt or made a voluntary assignment in bankruptcy, made a proposal under any legislation relating to bankruptcy or been 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 that person.

Penalties or Sanctions

No director, officer or promoter of the Corporation, 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.

Personal Bankruptcies

No director, officer or promoter of the Corporation, or a shareholder holding sufficient securities of the Corporation to affect materially the control of the Corporation, or a personal holding company of any such persons, 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.

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".

SHARE CAPITAL OF THE CORPORATION

The share capital of the Corporation currently consists of an unlimited number of common shares and an unlimited number of first preferred shares. As at the date hereof, one hundred common shares of the Corporation are outstanding. Such shares are held by the Trustee for and on behalf of the Trust. The voting of such shares is governed by the provisions of the Trust Indenture and the Trust is not entitled, without the direction of Unitholders, to exercise its rights as a shareholder of the Corporation except as permitted by the Trust Indenture. See "Trust Indenture – Exercise of Voting Rights Attached to Shares of the Corporation".

DESCRIPTION OF CAPITAL STRUCTURE

Trust Units

For a description of the Trust Units, see below under the section titled “Trust Indenture”.

Common Shares of the Corporation

Subject to the provisions of the ABCA, the holders of Common Shares are entitled to receive notice of, to attend and vote at all meetings of the shareholders of The Corporation and are entitled to one vote, in person or by proxy, for each Common Share held.

As at the date hereof, one hundred common shares of the Corporation are outstanding. Such shares are held by the Trustee for and on behalf of the Trust. The voting of such shares is governed by the provisions of the Trust Indenture and the Trust is not entitled, without the direction of Unitholders, to exercise its rights as a shareholder of the Corporation except as permitted by the Trust Indenture.

The holders of Common Shares are entitled to receive, if, as and when declared by the directors of The Corporation, non-cumulative dividends at such rate and payable on such date as may be determined from time to time by the directors of The Corporation. Distributions may be made only where such distribution does not result in the Corporation having insufficient net assets to redeem or purchase the First Preferred Shares (see below).

On the liquidation, dissolution or winding-up of The Corporation, or any other distribution of the assets of The Corporation among its shareholders for the purpose of winding-up its affairs, the holders of the Common Shares shall be entitled to receive the remaining property and assets of The Corporation after property and assets have been distributed to holders of First Preferred Shares.

Exchangeable Shares of the Corporation

Exchangeable shares were issued pursuant to the Plan of Arrangement 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 the Plan of Arrangement. The exchangeable shares rank above Common Shares with respect to the payment of dividends and the distribution of assets of the Corporation.

The Corporation may redeem up to 20% of the exchangeable shares on an annual basis. Once the number of exchangeable shares outstanding is less than 500,000, the Corporation may redeem all outstanding exchangeable shares. The Corporation may also redeem all remaining outstanding exchangeable shares at its option beginning on June 30, 2006. Any exchangeable shares outstanding on June 30, 2009 will be automatically redeemed by the Corporation.

First Preferred Shares of the Corporation

First Preferred Shares are redeemable and retractable, with the holder entitled to receive notice of, to attend and vote at all meetings of the shareholders of The Corporation and to one vote for each First Preferred Share held. As at the date hereof, no First Preferred Shares of the Corporation are outstanding.

Holders of First Preferred Shares are entitled to receive, if, as and when declared by the directors of the Corporation, non-cumulative dividends at such rate and payable on such date as may be determined from time to time by the directors of the Corporation.

On the liquidation, dissolution or winding-up of the Corporation, or any other distribution of the assets of the Corporation among its shareholders for the purpose of winding-up its affairs, the holders of the First Preferred Shares shall be entitled to receive the remaining property and assets of the Corporation before any property or assets are distributed to holders of Common Shares.

TRUST INDENTURE

The following is a summary of the Trust Indenture and other matters regarding the structure and operations of the Trust.

Trust Units

An unlimited number of Trust Units may be created and issued pursuant to the Trust Indenture. As of March 16, 2005, there were 42,585,278 Trust Units 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 outstanding from time to time shall be entitled to equal shares of any distributions by the Trust, and in the event of termination or winding-up of the Trust, in any net assets of the Trust. All Trust Units 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) and to one vote at all meetings of Unitholders for each Trust Unit held. See "Risk Factors – Nature of Trust Units".

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.

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".

Issuance Of Trust Units

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 Harvest Board may determine. The Trust Indenture also provides that the Corporation 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.

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.

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" 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.

For the purposes of this calculation, "market price" will be an amount equal to the simple average of the closing price of the Trust Units for each of the trading days on which there was a closing price; provided that, if the applicable exchange or market does not provide a closing price but only provides the highest and lowest prices of the Trust Units traded on a particular day, the market price shall be an amount equal to the simple average of the average of the highest and lowest prices for each of the trading days on which there was a trade; and provided further that if there was trading on the applicable exchange or market for fewer than 5 of the 10 trading days, the market price shall be the simple average of the following prices established for each of the 10 trading days: the average of the last bid and last ask prices for each day on which there was no trading; the closing price of the Trust Units for each day that there was trading if the exchange or market provides a closing price; and the average of the highest and lowest prices of the Trust Units for each day that there was trading, if the market provides only the highest and lowest prices of Trust Units traded on a particular day.

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

The aggregate Market Redemption Price payable by the Trust in respect of any Trust Units surrendered for redemption during any calendar month shall be satisfied by way of a cheque drawn on a Canadian chartered bank or trust company in Canadian money payable on the last day of the following month. The entitlement of Unitholders to receive cash upon the redemption of their Trust Units is subject to the limitation that the total amount payable by the Trust in respect of such Trust Units and all other Trust Units tendered for redemption in the same calendar month and in any preceding calendar month during the same year shall not exceed $100,000; provided that, the Corporation may, in its sole discretion, waive such limitation in respect of any calendar month. If this limitation is not so waived, the Market Redemption Price payable by the Trust in respect of Trust Units tendered for redemption in such calendar month shall be paid on the last day of the following month as follows: (i) firstly, by the Trust distributing Notes having an aggregate principal amount equal to the aggregate Market Redemption Price of the Trust Units tendered for redemption, and (ii) secondly, to the extent that the Trust does not hold Notes having a sufficient principal amount outstanding to effect such payment, by the Trust issuing its own promissory notes (herein referred to as "Redemption Notes") to the Unitholders who exercised the right of redemption having an aggregate principal amount equal to any such shortfall.

If, at the time Trust Units are tendered for redemption by a Unitholder, the outstanding Trust Units are not listed for trading on the TSX and are not traded or quoted on any other stock exchange or market which the Corporation considers, in its sole discretion, to represent fair market value for the Trust Units or the normal trading of the outstanding Trust Units is suspended or halted on any stock exchange on which the Trust Units are listed for trading or, if not so listed, on any market on which the Trust Units are quoted for trading, on the date such Trust Units are tendered for redemption or for more than five trading days during the 10 trading day period, commencing immediately after the date such Trust Units were tendered for redemption then such Unitholder shall, instead of the Market Redemption Price, be entitled to receive a price per Trust Unit (the "Appraised Redemption Price") equal to 90% of the fair market value thereof as determined by the Corporation as at the date on which such Trust Units were tendered for redemption. The aggregate Appraised Redemption Price payable by the Trust in respect of Trust Units tendered for redemption in any calendar month shall be paid on the last day of the third following month by, at the option of the Trust: (i) a cash payment; or (ii) a distribution of Notes and/or Redemption Notes as described above.

It is anticipated that this Redemption Right will not be the primary mechanism for holders of Trust Units to dispose of their Trust Units. Redemption Notes 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 Redemption Notes. Redemption 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. Certain provisions of the Tax Act require that the Trust not be established nor maintained primarily for the benefit of Non-Residents. Accordingly, in order to comply with such provisions, the Trust Indenture contains restrictions on the ownership of Trust Units by Unitholders who are Non-Residents. In this regard, the Trust shall, among other things, take all necessary steps to monitor the ownership of the Trust Units. If at any time the Trust becomes aware that the beneficial owners of 49% or more of the outstanding Trust Units are or may be Non-Residents or that such a situation is imminent, the Trust, by or through the Corporation on the Trust's behalf, shall take such action as may be necessary to carry out the intentions evidenced herein. For the purposes of this Section, "Non-Residents" means non-residents of Canada within the meaning of the Tax Act.

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 (except as described under "– 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 the Corporation 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.

Exercise of Voting Rights Attached to Shares of the Corporation

The Trust Indenture prohibits the Trustee from voting the shares of the Corporation with respect to (i) the election of directors of the Corporation, (ii) the appointment of auditors of the Corporation or (iii) the approval of the Corporation's financial statements, except in accordance with an Ordinary Resolution adopted at an annual meeting of Unitholders. The Trust Indenture also provides that the Trustee shall not vote the shares to authorize:

(a) any sale, lease or other disposition of, or any interest in, all or substantially all of the assets of the Corporation, except in conjunction with an internal reorganization of the direct or indirect assets of the Corporation as a result of which either the Corporation or the Trust has the same, or substantially similar, interest, whether direct or indirect, in the assets as the interest, whether direct or indirect, that it had prior to the reorganization;

(b) any statutory amalgamation of the Corporation with any other corporation, except in conjunction with an internal reorganization as referred to in paragraph (a) above;

(c) any statutory arrangement involving the Corporation except in conjunction with an internal reorganization as referred to in paragraph (a) above;

(d) any amendment to the articles of the Corporation to increase or decrease the minimum or maximum number of directors; or

(e) any material amendment to the articles of the Corporation to change the authorized share capital or amend the rights, privileges, restrictions and conditions attaching to any class of the Corporation's shares in a manner which may be prejudicial to the Trust;

without the approval of the Unitholders by Special Resolution at a meeting of Unitholders called for that purpose.

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 the Corporation pursuant to the Trust Indenture and the Administration Agreement. See "Description of the Trust – Delegation of Authority, Administration and Trust Governance". 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 distribution of Distributable Cash to Unitholders, although the calculation of the amount of the distribution shall be made by the Corporation and approved by the Harvest Board and submitted by the Corporation to the Trustee for distribution to the Unitholders;

(d) the mailing of notices, financial statements and reports to Unitholders pursuant to the Trust Indenture, although the Corporation 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 the Corporation, or any other person to whom the Trustee has, with the consent of the Corporation, 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 the Corporation 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, wilful 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.

Amendments to the Trust Indenture

The Trust Indenture may be amended or altered from time to time by Special Resolution. The Trustee may, without the consent, approval or ratification of any of the Unitholders, amend the Trust Indenture for the purpose of:

- ensuring the Trust's continuing compliance with applicable laws or requirements of any governmental agency or authority of Canada or of any province;
- ensuring that the Trust will satisfy the provisions of each of subsections 108(2) and 132(6) of the Tax Act as from time to time amended or replaced;
- ensuring that such additional protection is provided for the interests of Unitholders as the Trustee may consider expedient;
- removing or curing any conflicts or inconsistencies between the provisions of the Trust Indenture or any supplemental indenture, any Direct Royalties Sale Agreement, and any other agreement of the Trust or any Offering Document pursuant to which securities of the Trust are issued with respect to the Trust, or any applicable law or regulation of any jurisdiction, provided that in the opinion of the Trustee the rights of the Trustee and of the Trust Unitholders are not prejudiced thereby;
- providing for the electronic delivery by the Trust to Unitholders of documents relating to the Trust (including annual and quarterly reports, including financial statements, notices of Unitholder meetings and information circulars and proxy related materials) once applicable securities laws have been amended to permit such electronic delivery in place of normal delivery procedures, provided that such amendments to the Trust Indenture are not contrary to or do not conflict with such laws;
- curing, correcting or rectifying any ambiguities, defective or inconsistent provisions, errors, mistakes or omissions, provided that in the opinion of the Trustee the rights of the Trustee and of the Unitholders are not prejudiced thereby; and
- making any modification in the form of the Trust Unit certificates to conform with the provisions of the Trust Indenture, or any other modifications provided the rights of the Trustee and the Unitholder are not prejudiced thereby.

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 Corporation to Unitholders and the unaudited interim consolidated financial statements of the Trust will be mailed to 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 all applicable securities legislation.

TRUST UNIT INCENTIVE PLAN

The Trust has adopted the Unit Incentive Plan which permits the Harvest Board to grant non-transferable rights to purchase Trust Units ("Incentive Rights") to the directors, officers, consultants, employees and other ongoing service providers of the Trust and its subsidiaries, including the Corporation. The purpose of the Unit Incentive Plan is to provide an effective long term incentive to eligible participants and to reward them on the basis of long term performance and distributions. Effective June 22, 2004 the total number of Trust Units issuable under the Unit Incentive Plan was increased from 1,121,000 Trust Units to a cumulative maximum number of 1,487,250 Trust Units. The total number of Trust Units outstanding under the Unit Incentive Plan as at March 16, 2005 was 1,189,000.

The Harvest Board administers the Unit Incentive Plan and determines participants in the Unit Incentive Plan, numbers of Incentive Rights granted, and the terms of vesting of Incentive Rights. The grant price of the Incentive Rights (the "Grant Price") shall be equal to the per Trust Unit closing price on the trading date immediately preceding the date of grant, unless otherwise permitted. Management has proposed in its Information Circular – Proxy dated March 30, 2005 that the grant price be revised in connection with changes to the TSX rules. Under these new rules, grant price cannot exceed market price, which is based on the volume weighted average trading price of the trust units for the 5 trading days prior to the date of grant The exercise price ("Exercise Price") per Right shall be calculated by deducting from the Grant Price in respect of each distribution made by the Trust after the Grant Date (on a per Unit basis) an amount that will in no case exceed the amount of the distribution, provided the Trust's net operating cash flow for that month in which the distribution was made exceeds 0.833% of the Trust's recorded cost of capital assets less all debt, working capital deficiency (surplus) or debt equivalent instruments, depletion, depreciation and amortization charges, asset retirement obligations and any future income tax liability associated with such capital assets at the end of each month. When Incentive Rights are exercised, the amount by which distributions since the grant date exceed the cumulative reduction in the exercise price is paid to the holder in cash on a semi-annual basis.

Incentive Rights are exercisable for a maximum of five years from the date of the grant thereof and are subject to early termination upon the holder ceasing to be an eligible participant, or upon the death of the holder. In the case of early termination, a holder is entitled, from the date the holder ceased to be an eligible participant to the earlier of 30 days and the end of the exercise period, to exercise vested Incentive Rights. In the case of death, the estate of the holder is entitled, from the date of death to the earlier of 6 months and the end of the exercise period, to exercise vested Incentive Rights at the Exercise Price in effect at the date of death. Incentive Rights not vested at the date of termination of the holder or at date of the holder's death are immediately null and void. The holder has the option to settle outstanding Incentive Rights with Trust Units and/or cash. The number of Trust Units to be issued to settle outstanding Incentive Rights shall equal the amount determined by multiplying the number of Incentive Rights by the quotient obtained by dividing the difference between the current market price of a Trust Unit and the Exercise Price by the current market price of a Trust Unit. Cash paid to settle outstanding Incentive Rights will equal the difference between the current market price of a Trust Unit less the Exercise Price multiplied by the number of Incentive Rights to be settled.

The following table sets forth information with respect to the Incentive Rights outstanding under the Unit Incentive Plan as at March 16, 2005:

Group	Range of Incentive Rights Grant Dates	Trust Units Under Option	Weighted Average Grant Price	Weighted Average Exercise Price as at March 16, 2005(1)	Market Value of Incentive Right (2)
Executive Officers (4)	November 25, 2002 to July 14, 2004	406,050	$9.61	$5.05	$8,291,541
Directors (5)	November 25, 2002 to February 14, 2003	100,000	$8.69	$3.39	$2,208,000
Employees and Consultants (92)	November 25, 2002 to March 16, 2005	682,950	$15.11	$12.64	$8,762,249

Notes:

(1) Includes the value accrued to holders to the extent that distributions since the grant date exceed cumulative exercise price reductions.

(2) Based on the difference between the closing price of $25.47 per Trust Unit on the TSX on March 16, 2005 and the exercise price of the Incentive Right multiplied by the number of Trust Units under the Incentive Right.

DRIP PLAN

The Trust has received all applicable regulatory approvals and has implemented a DRIP Plan. **The DRIP Plan is not available to Unitholders who are residents of the United States.** The DRIP Plan provides eligible holders of Trust Units the means of accumulating additional Trust Units by reinvesting any Distributable Cash received. At the discretion of the Corporation, Trust Units will either be acquired at prevailing market rates (not exceeding 115% of the volume weighted average trading price of the Trust Units on the TSX for the 10 trading days immediately preceding the date the Trust Units are purchased) or 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 distribution record date and ending on the second Business Day immediately prior to the distribution payment date on which at least a board lot of Trust Units is traded). 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 $5,000 per month and a minimum of $1,000 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 16, 2005, 1,913,686 Trust Units have been issued from treasury since February 15, 2003 for proceeds of approximately $27,233,179 million due to DRIP Plan participation associated with cash distributions by the Trust.

CONFLICTS OF INTEREST

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.

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 "D". The members of the Audit Committee are John Brussa, Verne Johnson and Hector McFadyen. Mr. Brussa is deemed to be the financial expert. By May 4, 2005, the date of Harvest's next annual general and special meeting of unitholders, Mr. Brussa will no longer sit on the Audit Committee as he is a Related Director given that his law firm provides services to the Trust. The Board will be required to appoint another Director to the Audit Committee in his place.

Composition of the Audit Committee

The members of the Audit Committee are independent (in accordance with National Instrument 52-110) except as noted above and are financially literate.

Relevant Education and Experience

The financial expert, Mr. Brussa, has been a partner of his law firm for a number of years and is considered a leading tax practitioner in Canada. Mr. Brussa sits on the boards and audit committees of several other public companies.

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 Corporation'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 $377,634 in 2004 and $238,500 in 2003.

Audit and Related Fees

The aggregate fees billed in each of the last two fiscal years for assurance related services by the Corporation's external auditor that are reasonably related to the performance of the audit or review of the Corporation's financial statements that are not reported under "Audit Fees" above were $83,510 in 2004 and $42,500 in 2003. 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 Corporation's external auditor for regular tax compliance, tax advice and tax planning were $111,275 in 2004 and $65,820 in 2003.

All Other Fees

The aggregate fees billed in each of the last two fiscal years for products and services provided by the Corporation's auditors other than services reported above were nil in 2004 and in 2003.

PROMOTERS

Kevin A. Bennett and M. Bruce Chernoff may be considered to be the promoters of the Corporation by reason of their initiative in organizing the business and affairs of the Corporation. 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	500,000[(1)]	1.2%
M. Bruce Chernoff Calgary, Alberta	Direct and Beneficial	7,645,130[(2)]	18.0%

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

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

Mr. Chernoff has from time to time, directly or indirectly, provided various loans to the Trust. The terms of such loans are described in "Description of the Trust – Borrowing by the Trust – Equity Bridge Notes".

LEGAL PROCEEDINGS

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

RECORD OF CASH DISTRIBUTIONS

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.

2003	**Distribution Per Trust Unit**
January [(1)]	$0.20
February	$0.20
March	$0.20
April	$0.20
May	$0.20
June	$0.20
July	$0.20
August	$0.20
September	$0.20
October	$0.20
November	$0.20
December	$0.20
2004	
January	$0.20
February	$0.20
March	$0.20
April	$0.20
May	$0.20

June	$0.20
July	$0.20
August	$0.20
September	$0.20
October	$0.20
November	$0.20
December	$0.20
2005	
January	$0.20
February(2)	$0.20
March	$0.20
April(3)	$0.20
	$5.60

Notes:

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

(2) The Trust announced on February 28, 2005 that it would pay 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 14, 2005 that the next monthly cash distribution of $0.20 per Trust Unit will be paid on April 15, 2005 to Unitholders of record on March 31, 2005.

Unitholders of record on a Record Date will be 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.

ESCROWED SECURITIES

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

INTERESTS OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There were no material interests, direct or indirect, of directors and senior officers of the Corporation, any shareholder who beneficially owns more than 10% of the outstanding Common Shares, or any known associate or affiliate of such persons, in any transaction within the last fiscal year and in any proposed transaction which has materially affected or would materially affect the Corporation other than the transactions described under "Description of the Trust – Borrowing by the Trust – Equity Bridge Notes".

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, and Convertible Debentures of the Corporation.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, the only material contracts entered into by the Corporation 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 convertible debentures described in "Description of the Trust – Borrowing by the Trust – 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 senior notes as described in "Information Respecting the Corporation – Borrowing by the Corporation – Senior Notes";

4. the Exchangeable Share provisions referred to under "Description of Capital Structure – Exchangeable Shares of the Corporation";

5. the Support Agreement between Harvest Energy Trust, Harvest Operations Corp., Harvest Exchangeco Ltd. and Valiant Trust Company referred to under "Description of Capital Structure – Exchangeable Shares of the Corporation";

6. the Voting and Exchange Trust Agreement between Harvest Energy Trust, Harvest Operations Corp., Harvest Exchangeco Ltd. and Valiant Trust Company referred to under "Description of Capital Structure – Exchangeable Shares of the Corporation"; and,

7. the Trust's Trust Unit Rights Incentive Plan and Unit Award Incentive Plan.

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 Corporation during, or related to, the Corporation's most recently completed financial year other than McDaniel, GLJ and PLA, the Corporation's Independent Reserve Engineering Evaluators. As at the date hereof, none of the principals of McDaniel and Associates Ltd., Gilbert Laustsen Jung Associates Ltd., and Paddock Lindstrom and Associates Ltd., as a group, directly or indirectly, owned more than 1% of the Units.

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 Corporation or of any associate or affiliate of the Corporation.

MARKET FOR SECURITIES

The Trust Units and convertible debentures are listed and traded on the TSX. The trading symbol for the Trust Units is "HTE.UN", and for the convertible debentures is "HTE.DB" and "HTE.DB.A".

The following sets forth the price range and trading volume of the Trust Units on the TSX (as reported by the TSX) for the periods indicated.

	Price Range		
	High	Low	Volume
2004			
January	$14.40	$12.65	1,091,793
February	$13.99	$12.15	1,061,991
March	$15.18	$13.60	1,316,461
April	$15.49	$14.55	1,397,530
May	$15.45	$14.60	1,862,143
June	$15.07	$13.80	959,139
July	$17.53	$14.75	3,526,288
August	$18.10	$16.00	8,758,948
September	$20.79	$16.85	7,023,949
October	$24.03	$20.56	12,071,497
November	$23.64	$19.82	5,978,590
December	$23.50	$21.40	3,544,495

	Price Range		
	High	Low	Volume
2005			
January	$24.00	$22.10	2,987,380
February	$25.97	$23.75	3,533,047
March (1-16)	$26.14	$24.80	2,595,887

RISK FACTORS

The following are certain factors relating to the business of the Trust. The following information is a summary only of certain risk factors and is qualified in its entirety by reference to, and must be read in conjunction with, the detailed information appearing elsewhere in this Annual Information Form.

Volatility of Commodity Prices and Foreign Exchange Risk

The Trust's results of operations and financial condition, and therefore the NPI and the Direct Royalties, will be dependent on the prices received for 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 the Corporation or the Trust. Oil prices received from production in Canada also reflect changes in the Canadian/U.S. currency exchange rate. Any decline in petroleum oil and natural gas prices or increases in differentials could have a material adverse effect on the Trust's operations, financial condition and the level of funds available for the development of its oil and natural gas reserves. The Corporation may manage the risk associated with changes in commodity prices and foreign exchange rates by entering, or causing the Trust to enter, from time to time, into crude oil and natural gas price hedges and foreign exchange contracts. To the extent that the Corporation or the Trust engages in risk management activities related to commodity prices and foreign exchange rates, it will be subject to counterparty risk. In addition, commodity hedge contracts may require, from time to time, margin payments to be made which could impact negatively on the Trust's ability to make distributions to Unitholders. To the extent that commodity prices increase significantly, Cash Available for Distribution could be negatively affected.

Crude Oil Differentials

In the fourth quarter of 2004, the Corporation's crude oil production from the Properties was approximately 33% light oil, 51% medium and heavy oil, 13% natural gas, and 3% natural gas liquids. Processing medium oil and heavy oil is more expensive than processing conventional light oil, and such processing yields less valuable products compared to refining light oil; accordingly, producers of heavy oil or medium oil receive lower wellhead prices. The differential between light oil and heavy oil or medium oil has fluctuated widely during recent years and when considered with the fluctuating prices of light oil, substantially increases the volatility of prices for heavy oil and medium oil. Any increase in the differentials could result in lower prices being received for petroleum, natural gas and natural gas liquids and could have a material adverse effect on the Trust's operations, financial condition and the level of funds available for the development of its oil and natural gas reserves. Volatility in the differential is a result of an availability of supply, seasonal demand, pipeline constraints and conversion capacity of refineries, which are beyond the control of the Trust or the Corporation.

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 the Corporation’s assets and possible liability to third parties. The Corporation will employ prudent risk management practices and maintain liability insurance, where available, in amounts consistent with industry standards. Business interruption insurance may also be purchased for selected facilities, to the extent that such insurance is available. The Corporation may become liable for damages arising from such events against which it cannot insure or against 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 income from the NPI.

Continuing production from a property and to some extent, the marketing of production therefrom, are largely dependent upon the ability of the operator of the property. To the extent the operator fails to perform these functions properly, revenue may be reduced. Payments from production generally flow through the operator and there is a risk of delay and additional expense in receiving such revenues if the operator becomes insolvent. Although the Corporation operates the majority of its Properties, there is no guarantee that it will remain operator of such Properties or that the Corporation will operate other Properties it may acquire.

A significant portion of the operating expenses at the East Central Alberta Properties, Southern Alberta Properties and to a lesser degree, the Southeast Saskatchewan Properties, is attributable to electrical power costs. Since deregulation of the electrical power system in Alberta in recent years, the unit cost of electrical power has been set by a market driven mechanism based upon supply and demand. As a result, the prices for electrical power have become volatile. This volatility in electrical power pricing can impact the Corporation's operating expenses, and in turn, the Cash Available For Distribution. The Corporation has implemented an electrical power hedging program to mitigate its exposure to electrical power cost volatility. In respect of the Southeast Saskatchewan Properties, 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 the Corporation to certain Properties. A reduction of income from the NPI or income from Direct Royalties could result in 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 transportation;
- The price of oilfield services
- the effects of inclement weather;

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

Reserve Estimates

The reserve and recovery information contained in the Reserve Report is 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)

The Trust has certain unique attributes which differentiate it from other oil and natural gas industry participants. Cash Available For Distribution in respect of Properties, 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. The Trust and the Corporation will not be reinvesting cash flow in the same manner as other industry participants as it makes cash distribution payments to unitholders. Accordingly, absent additional capital investment in Properties through the use of the Capital Fund or otherwise, initial production levels and reserves attributable to the Properties will decline.

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

Trust Units will have no value when reserves from the Properties can no longer be economically produced and, as a result, subscribers for Trust Units will need to obtain a return of capital invested during the period when reserves can be economically recovered.

There is strong competition relating to all aspects of the oil and natural gas industry. The Corporation will actively compete for reserve 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 Corporation.

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

Debt Service

As at the date hereof, the Trust had indebtedness of approximately $90 million under the Current Bank Facility. In addition, the New Lender has issued letters of credit to third parties of approximately $5 million on behalf of the Corporation to secure services on the Properties. The Corporation issued U.S.$250 million of senior notes due October 15, 2011 on which semi-annual interest payments are due. See "Information Respecting the Corporation – Borrowing by the Corporation".

The Current Lenders have been provided with security over all of the assets of the Operating Subsidiaries. If the Corporation experiences an unremedied borrowing base shortfall or default, commits an event of default or the Current Lenders demand repayment, the Current Lenders may foreclose on or sell the Properties free from, or together with, the NPI.

Dividends and other distributions by the Corporation are prohibited in certain circumstances upon a borrowing base shortfall or default, or upon an event of default or demand for repayment under the Current Bank Facility. The NPI, any indebtedness of the Corporation or other Operating Subsidiaries to the Trust, and amounts payable to the Trustee under the Trust Indenture are subordinate to the Current Bank Facility pursuant to subordination agreements between the Current Lenders, the Trustee, and the Operating Subsidiaries dated September 1, 2004. These subordination agreements may restrict the ability of the Corporation or the Operating Subsidiaries to pay the NPI to the Trust or pay interest or principal on any indebtedness 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 Corporation's 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 senior note indenture, including limitations on the ability of the Corporation or the Trust to issue incremental debt, and to pay cash distributions to unitholders in certain circumstances.

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 Harvest Board may determine. In addition, the Trust may issue additional Trust Units from time to time pursuant to the Unit Incentive Plan and the DRIP Plan. The possible issuance of these Trust Units could result in dilution to holders of Trust Units. See "Trust Indenture – Issuance of Trust Units", "Trust Unit Incentive Plan" and "DRIP Plan".

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

The prices paid for the purchase of 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 the Corporation and the Trust. In particular, changes in the prices of and markets for petroleum, natural gas and natural gas liquids from those anticipated at the time of making such assessments will affect the return on the value of the 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 oil and natural gas industry, such as the status of mutual fund trusts, the resource allowance and environmental and operating regulations, will not be changed in a manner which adversely affects Unitholders.

Investment Eligibility

If the Trust ceases to qualify as a mutual fund trust, 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.

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 or the issuance of clean up orders in respect of the Corporation or the Properties. Such legislation may be changed to impose higher standards and potentially more costly obligations on the Corporation. See "Industry Conditions – Environmental Regulation".

In December 2002, the Government of Canada ratified the Kyoto Protocol (the "Protocol"). The Protocol calls for Canada to reduce its greenhouse gas emissions to 6 percent below 1990 levels during the period between 2008 and 2012. The Protocol was subsequently ratified and became legally binding, and is expected to affect the operation of all industries in Canada, including the oil and natural gas industry. As details of the implementation of this Protocol have yet to be announced, it is difficult to determine what, if any, the impact the Protocol may have on the Corporation's ongoing environmental liabilities, on prices for oil and natural gas or on other general economic factors, which may affect the Trust's Cash Available For Distribution.

Debt Repayment

The Corporation 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 Corporation 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 NPI 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 NPI and Cash Available For Distribution. Interest and principal payable pursuant to the senior notes is payable in U.S. dollars. The Corporation is permitted to borrow funds under the Current Credit Facility in U.S. dollars and would be required to settle interest and principal amounts in the same currency. Variations in the Canadian/U.S. dollar exchange could result in a significant increase in the amount of the interest paid under the Current Bank Facility and the Senior Notes, thereby reducing the Cash Available For Distribution. See "Information Respecting the Corporation – Borrowing by the Corporation".

Delay in Cash Distributions

In addition to the usual delays in payment by purchasers of oil and natural gas to the operators of the Properties, and by the operator to the Corporation, payments between any of such parties may also be delayed by restrictions imposed by lenders, delays in the sale or delivery of products, delays in the connection of wells to a gathering system, blowouts or other accidents, recovery by the operator of expenses incurred in the operation of Properties or the establishment by the operator of reserves for such expenses.

Variability of Cash Distributions

The Operating Subsidiaries retain a portion of the cash flows from the Properties in their Reserve Fund to facilitate future acquisitions and development of the Properties. Management of the Corporation believes this will assist in maintaining distributions for 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 generated by such additional Properties may not be similar to those of the existing Properties and may not generate sufficient cash flows to allow the Operating Subsidiaries to generate sufficient income to allow the Trust to maintain consistent distributions from the Trust over a long period of time.

Reliance on Management of the Corporation

Unitholders will be dependent on the management of the Corporation in respect of the administration and management of all matters relating to the Properties, the NPI, the Direct Royalties, the Trust, and the Trust Units. Investors who are not willing to rely on the management of the Corporation 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.

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 Corporation's 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 Corporation is required to use cash flow to finance capital expenditures or property acquisitions, the level of Cash Available For Distribution will be reduced.

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 oil and natural gas industry. The Corporation and the Trust will 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 organizations, many of which may have greater technical and financial resources than the Corporation and the Trust. 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 the Corporation are directors or officers of corporations which are in competition to 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. See "Conflicts of Interest".

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 the Corporation. 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, the NPI, 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 the Corporation and the Corporation's 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 the Corporation, 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 Harvest Board in view of the fact that all business operations are carried on by the Corporation.

The activities of the Trust and the Corporation, its wholly-owned subsidiary, 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 Corporation 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.

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.

Change in the Trust's Status Under Tax Laws

Harvest presently qualifies as a mutual fund trust for purposes of the Tax Act and it is intended that the Trust continue to qualify as a mutual fund trust for such purposes; however, should the status of the Trust as a mutual fund trust be lost or successfully challenged by a relevant tax authority, certain adverse consequences may arise. The material consequences of losing mutual fund trust status are as follows: (i) Trust Units would not constitute qualified investments for Exempt Plans upon the Trust ceasing to be a mutual fund trust. 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 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. An RRSP or RRIF holding Trust Units that are not qualified investments would become taxable income attributable to the Trust Units while they are not qualified investments. RESPs which hold Trust Units that are not qualified investments may have their registration revoked by the Canada Customs and Revenue Agency; (ii) the Trust would be required to pay a tax under Part XII.2 of the Tax Act on certain types of income distributed to unitholders including income generated by oil and natural gas royalties held by the Trust. The payment of the Part XII.2 tax by the Trust may have adverse income tax consequences for certain Unitholders, since the amount of cash available for distribution would be reduced by the amount of the tax; (iii) the Trust would cease being eligible for the capital gains refund mechanism available under the Tax Act upon ceasing to be a mutual fund trust; (iv) Trust Units held by Unitholders that are not residents of Canada would become taxable Canadian property upon the Trust ceasing to be a mutual fund trust. Such Unitholders would be subject to Canadian income tax on any gains realized on a disposition of Trust Units constituting taxable Canadian property; and (v) the Trust would be subject to alternative minimum tax under Part I of the Tax Act.

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.

Change to Non-Resident Taxation

In 2004, the Department of Finance introduced legislation that changes the Trust’s obligation to withhold tax on payments of distributions to non-residents. Previously, the portion of a distribution that was considered a return of capital was not subject to withholding tax. As a result of these proposals being passed into law, 100% of the distribution will be subject to withholding tax beginning in 2005, regardless of the nature of its components.

ADDITIONAL INFORMATION

Additional information including remuneration of directors and officers of the Corporation, principal holders of the Trust Units, is contained in the Information Circular - Proxy Statement of the Trust dated March 16, 2005 which relates to the Annual and Special Meeting of Unitholders to be held on May 4, 2005, and additional financial information is provided in the consolidated financial statements of the Trust for the year ended December 31, 2004.

The Trust shall provide to any person, upon request to the Secretary of the Corporation on behalf of the Trust:

(a) a prospectus filed in respect of a distribution of its securities or debt;

(b) one copy of the Annual Information Form of the Trust, together with one copy of any document, or the pertinent pages of any document, incorporated by reference in the Annual Information Form;

(c) one copy of the consolidated financial statements of the Trust for the most recently completed fiscal year together with the accompanying report of the auditor and one copy of any subsequent interim financial statements;

(d) one copy of the Information Circular - Proxy Statement of the Trust dated March 16, 2005; and

(e) one copy of any other documents that are incorporated by reference into a prospectus and are not required to be provided under (a) to (d) above; or

(f) at any other time, one copy of any other documents referred to above, provided the Trust may require the payment of a reasonable charge if the request is made by a person who is not a security holder of the Trust.

For additional copies of the Annual Information Form and the materials listed in the preceding paragraphs please contact:

Harvest Energy Trust
c/o Harvest Operations Corp.
2100, 330 – 5th Avenue S.W.
Calgary, Alberta T2P 0L4
Toll free in Canada: 1-866-666-1178
Fax: (403) 265-3940

APPENDIX A
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, 2004 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, 2004 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) r 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 Audit 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) "Jacob Roorda"
Jacob Roorda
President

(signed) "J. A. Ralston"
J. A. Ralston
Vice President, Operations

(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 3, 2005

APPENDIX B

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 reserves data as at December 31, 2004. The reserves data consist of the following:
   (a) (i) Proved and proved plus probable oil and gas reserves estimated as at December 31, 2004 using forecast prices and costs; and

   (ii) The related future net revenue; and

   (b) (i) Proved oil and gas reserves estimated as at December 31, 2004 using constant prices and costs; and

   (ii) +Proved oil and gas reserves estimated as at December 31, 2004 using constant prices and costs; and

2) The reserves data are the responsibility of the Corporation's management. Our responsibility is to express and opinion on the reserves data base 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 reserve, estimate 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, 2004 and identifies the respective portions thereof that we have evaluated and reported on to the Corporation's Management.

			Net Present Value of Future Net Revenue (Before income taxes, 10% discount rate)			
Independent Qualified Reserves Evaluator or Auditor	**Description and Preparation Date of Evaluation Report**	**Location of Reserves**	**Audited**	**Evaluated**	**Reviewed**	**Total**
McDaniel and Associates Consultants Ltd.	December 31, 2004	Canada	-	889,738	-	889,738
Gilbert Laustsen Jung and Associates Ltd.	December 31, 2004	Canada	-	150,375	-	150,375
Paddock Lindstrom and Associates Ltd.	December 31, 2004	Canada	-	92,374	-	92,374
Totals				1,132,487		1,132,487

5) In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

6) We have no responsibility to update our 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) Gilbert Laustsen Jung Associates Ltd.

Calgary, Alberta, Canada

(signed) Paddock, Lindstrom and Associates Ltd.

Calgary, Alberta, Canada

APPENDIX C
FINANCIAL STATEMENTS

1. Schedule of Revenues, Royalties and Expenses for the New Properties Acquired from EnCana Corporation – Years Ended December 31, 2003 and 2002 and Three Months Ended March 31, 2004 and 2003.

NEW PROPERTIES

SCHEDULE OF REVENUES, ROYALTIES AND OPERATING EXPENSES

Years Ended December 31, 2003 and 2002
and the Three Months Ended March 31, 2004 and 2003 (unaudited)

($ thousands)

AUDITORS' REPORT
To the Trustee of Harvest Energy Trust and Directors of Harvest Operations Corp.

At the request of Harvest Energy Trust and Harvest Operations Corp., we have audited the Schedule of Revenues, Royalties and Operating Expenses for the two years ended December 31, 2003 and 2002 for the New Properties that Harvest Energy Trust and Harvest Operations Corp. have entered into an agreement to acquire dated July 15, 2004. This financial information is the responsibility of management. Our responsibility is to express an opinion on this financial information based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial information is free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial information. An audit also includes assessing the accounting principles used and significant estimates made by management as well as evaluating the overall financial information presentation.

In our opinion, the Schedule of Revenues, Royalties and Operating Expenses presents fairly, in all material respects, the revenues, royalties and operating expenses for the New Properties for each of the years ended December 31, 2003 and 2002 in accordance with the basis of accounting disclosed in note 1.

(Signed)
''PRICEWATERHOUSECOOPERS LLP''
Chartered Accountants

Calgary, Canada
July 16, 2004

NEW PROPERTIES

SCHEDULE OF REVENUES, ROYALTIES AND OPERATING EXPENSES ($ thousands)

	Three Months Ended March 31		Year Ended December 31	
	2004	2003	2003	2002
	(unaudited)			
Revenues	$62,794	$83,982	$274,617	$228,573
Royalties	7,597	10,102	34,250	27,072
	55,197	73,880	240,367	201,501
Operating expenses	10,498	11,715	45,397	44,854
Excess of revenues over operating expenses	$44,699	$62,165	$194,970	$156,647

See accompanying Notes to Schedule

NEW PROPERTIES

NOTES TO SCHEDULE OF REVENUES, ROYALTIES AND OPERATING EXPENSES

For the Years Ended December 31, 2003 and 2002
and the Three Months Ended March 31, 2004 and 2003
(unaudited) ($ thousands)

1. BASIS OF PRESENTATION

The Schedule of Revenues, Royalties and Operating Expenses includes the operating results relating to the New Properties that Harvest Energy Trust and Harvest Operations Corp. have entered into an agreement to acquire dated July 15, 2004. Under the terms of the agreement, Harvest Breeze Trust No. 1 and No. 2 will acquire Breeze Resources Partnership which owns these New Properties (‘‘the Properties’’).

The Properties consist of crude oil and natural gas assets located in the Crossfield area of Alberta, in southeast Alberta and in east central Alberta.

The Schedule of Revenues, Royalties and Operating Expenses for the Properties does not include any provision for the depletion, depreciation and amortization, asset retirement costs, future capital costs, impairment of unevaluated properties, administrative costs and income taxes for the Properties as these amounts are based on the consolidated operations of the vendor of which the Properties form only a part.

2. SIGNIFICANT ACCOUNTING POLICIES

(A) Joint Venture Operations

Substantially all of the Properties are operated through joint ventures therefore the schedule reflects only the vendor’s proportionate interest.

(B) Revenue Recognition

Revenues are recorded net of related transportation costs when the product is delivered. Gas revenues are recorded based on AECO reference pricing used for sales between operating divisions of EnCana Corporation and do not reflect ultimate marketing related activities. Oil revenues are recorded based on blended prices established between operating divisions of EnCana Corporation for similar quality product delivered to a common carrier.

(C) Royalties

Royalties are recorded at the time the product is produced and sold. Royalties are calculated in accordance with the applicable regulations and/or the terms of individual royalty agreements. Crown royalties for natural gas are based on the Alberta Government posted reference price. Crown royalties for crude oil are taken in kind by the Alberta Petroleum Marketing Commission.

(D) Operating Expenses

Operating expenses include amounts incurred on extraction of product to the surface, gathering, field processing, treating and field storage.

APPENDIX D

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 "unrelated directors" (as such term is used in the Report of the Toronto Stock Exchange on Corporate Governance in Canada) and "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.