Harvest Energy Trust

2002 Initial Annual Information Form

December 10, 2003

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SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

The Trust is hereby providing cautionary statements identifying important factors that could cause the Trust's actual results to differ materially from those projected in forward-looking statements made in this Annual Information Form. Any statements that express or involve discussions as to expectations, beliefs, plans, objectives, assumptions or future events or performance (often, but not always through use of words or phrases such as "will likely result", "are expected to", "will continue", "is anticipated", "estimated", "intends", "plans", "projection" and "outlook") are not historical facts and may be forward-looking and may involve estimates, assumptions and uncertainties which could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements. Accordingly, any such statements are qualified in their entirety by reference to, and are accompanied by, the factors discussed throughout this Annual Information Form, and particularly in the risk factors set forth herein under "Risk Factors". Because actual results or outcomes could differ materially from those expressed in any forward-looking statements of the Trust made by or on behalf of the Trust, investors should not place undue reliance on any such forward-looking statements. Further, any forward-looking statement speaks only as of the date on which such statement is made, and the Trust undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events, except as required by law including applicable securities laws. New factors emerge from time to time, and it is not possible for management of the Corporation to predict all of such factors and to assess in advance the impact of each such factor on the Trust or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statements.

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 Prior Bank Facility and the payment of the Deferred Purchase Price Obligation as a result of the acquisition of the Carlyle 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.

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

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

"Carlyle Properties Transaction" means the acquisition of the Carlyle Properties by the Corporation pursuant to the Carlyle Properties Acquisition Agreement.

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

"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 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.

"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 Lender as more fully described under "Information Respecting the Corporation – Borrowing by the Corporation".

"Current Lender" means a syndicate of lenders comprised of two Canadian chartered banks and Alberta Treasury Branches.

"Deferred Purchase Price Obligation" means, collectively, the ongoing obligation of the Trust to pay to the Operating Subsidiaries, to the extent of the Trust's available funds, an amount equal to 99% of the cost of, including any amount borrowed to acquire, any Canadian resource property acquired by an Operating Subsidiary, 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 the Trust's Distribution Reinvestment and Optional Unit Purchase Plan.

"Equity Bridge Notes" means, collectively, the equity bridge notes dated July 28, 2003 and amended September 29, 2003 between the Trust and each of the Bridge Lenders providing for advances of up to $40 million to the Trust to assist in the payout of the Prior Credit Facility and the payment of the Deferred Purchase Price Obligation as a result of the Carlyle Properties Transaction.

"Established Reserves" means the sum of 100% of Proved Reserves and 50% of the Probable Reserves.

"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.

"Gross Reserves" means, collectively, the Operating Subsidiaries' interest, or the interest to be acquired by the Operating Subsidiaries, in reserves before the deduction of royalties.

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

"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.

"Interim Bank Facility" means the interim credit facility provided by the Interim Lender as more fully described under "Information Respecting the Corporation – Borrowing by the Corporation", which interim credit facility was replaced with the Current Bank Facility.

"Interim Lender" means the Canadian chartered bank providing the Interim Bank Facility.

"Management Group" means those directors and officers of the Corporation and their family members, close friends and business associates who owned the Management Group Debentures. See "Risk Factors – Public and Insider Ownership".

"Management Group Debentures" means debentures of 990148 Alberta Ltd. previously held by the Management Group. See "Risk Factors – Public and Insider Ownership".

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

"McDaniel Report – Provost Properties" means, collectively, the independent engineering evaluations dated August 5, 2003 of the reserves associated with the Provost Properties and the Direct Royalties as at January 1, 2003 conducted by McDaniel on behalf of the Corporation, based on constant and May 1, 2003 escalating price and cost assumptions.

"McDaniel Report – Carlyle Properties" means the independent engineering evaluation dated September 30, 2003 of the reserves associated with the Carlyle Properties as at January 1, 2003 conducted by McDaniel on behalf of the Corporation, based on constant and May 1, 2003 escalating price and cost assumptions.

"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 15th anniversary of the date of issuance;

(d) being an aggregate principal amount not to exceed $500 million, and

(e) 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 and WEI, each a wholly-owned subsidiary of the Trust, and **"Operating Subsidiary"** means either of the Corporation, HST or WEI, 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.

"Prior Bank Facility" means the credit facility provided by the Prior Lender to the Corporation which was repaid in full on September 30, 2003.

"Prior Lender" means a syndicate of lenders with a U.S. bank as a lender and as administrative agent for all of the lenders.

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

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

"**Properties**" means the working, royalty or other interests of the Operating Subsidiaries in any petroleum and natural gas rights, tangibles and miscellaneous interests, including properties which may be acquired by any of the Operating Subsidiaries from time to time.

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

"Proved Reserves", **"Probable Reserves"**, **"Producing Reserves"**, **"Non-Producing Reserves", "Net Reserves", "Undeveloped Reserves"** and **"Total Proved Reserves"** have the meanings given to those terms under "Oil and Natural Gas Reserves of the Provost Properties and the Direct Royalties" and "Acquisition of Carlyle Properties – Oil and Natural Gas Reserves", as the case may be.

"Provost Properties" means Properties as of the date of this Annual Information Form other than the Carlyle Properties.

"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.

"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 Established Reserves as at January 1, 2003 by the annualized 2003 production of petroleum, natural gas and natural gas liquids from those reserves as projected in the McDaniel Report – Provost Properties or the McDaniel Report – Carlyle Properties, as applicable.

"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 Established Reserves shown in the McDaniel Report – Provost Properties or the McDaniel Report – Carlyle Properties for such property, discounted at 10% and using escalating price and cost assumptions (a common benchmark in the oil and natural gas industry).

"Seaton Jordan Report – Provost Properties" means the independent valuation dated August 8, 2003 of the Undeveloped Lands associated with the Provost Properties effective July 1, 2003.

"Seaton Jordan Report – Carlyle Properties" means the independent valuation dated October 1, 2003 of the Undeveloped Lands associated with the Carlyle Properties effective July 1, 2003.

"Seaton Jordon" means Seaton-Jordon & Associates Ltd., independent land evaluators of Calgary, Alberta.

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

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

"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 to 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 September 27, 2002 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.

"Undeveloped Lands" means those lands included in the Provost Properties or the Carlyle Properties which have not shown definite Proved Reserve or Probable Reserve potential as a result of regional development and/or exploration activities as of the effective date of the McDaniel Report – Provost Properties or the McDaniel Report – Carlyle Properties, respectively.

"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 Westcastle Energy Inc., a wholly-owned subsidiary of the Trust, a corporation incorporated under the *Business Corporations Act* (Alberta).

"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.

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	means barrel of oil equivalent, using the conversion factor of 6 Mcf of natural gas being equivalent to one Bbl of oil, unless otherwise specified. The conversion factor used to convert natural gas to oil equivalent is not necessarily based upon either energy or price equivalents at this time.
BOE/d	barrels of oil equivalent per day.
MBOE	means thousand barrels of oil equivalent.
MMBOE	means million barrels of oil equivalent.
OOIP	means original oil in place.
WTI	means West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade.
ºAPI	means the measure of the density or gravity of liquid petroleum products derived from a specific gravity.
MW	megawatts of electrical power.
3D	three dimensional.
Darcies	means the measure of permeability (being the ease with which a single fluid will flow through connected pore space when a pressure gradient is applied).
porosity	means the measure of the fraction of pore space of a reservoir.

CONVERSIONS

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

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.

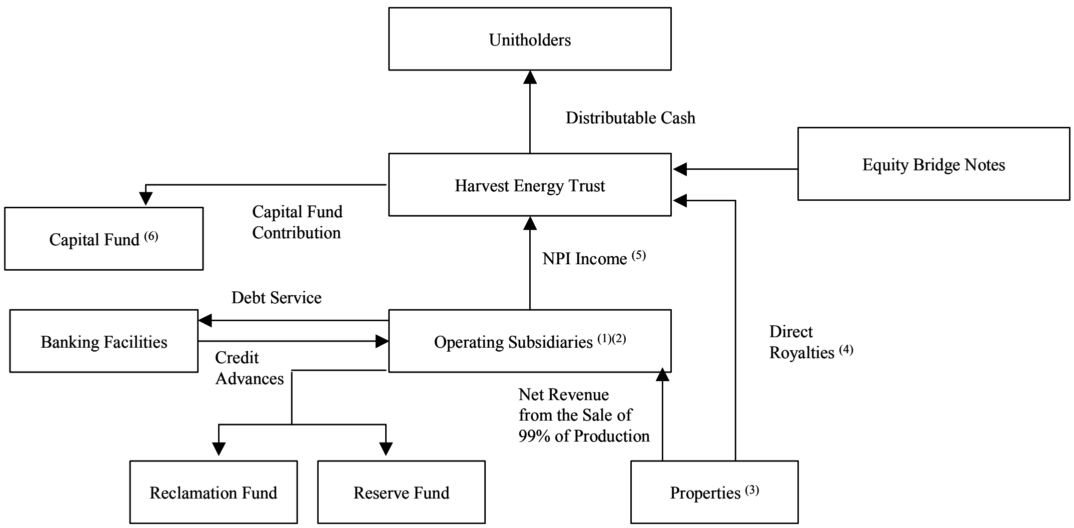
HARVEST ENERGY TRUST

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 1900, 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) The Operating Subsidiaries consist of Harvest Operations Corp. and Westcastle Energy Inc., each of which is a wholly-owned subsidiary of the Trust.
(2) Although the Trust receives NPI income from each of the Operating Subsidiaries, all operations and management of the Trust are conducted through the Corporation.
(3) The Operating Subsidiaries own the Properties.
(4) In addition to the NPI, the Trust holds various Direct Royalties.
(5) The Trust receives regular monthly payments in accordance with the NPI Agreements. See "Description of the Trust – The NPI and Direct Royalties".
(6) The Trust may retain up to 50% of the Cash Available For Distribution in its Capital Fund to finance future acquisitions and development of the Properties.

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

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. Effective August 1, 2002, McDaniel assigned 4,573 MBOE of Established Reserves to these properties, before deduction of royalties. These properties are located in a relatively small area from Townships 39 to 43 and Ranges 3 to 12 W4M in East Central Alberta. These properties include interests in the following major oilfields: Thompson Lake, David North, Bellshill Lake and Metiskow, all of which are described in more detail below. 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. Following the completion of the acquisition, the Corporation then sold to the Trust the Direct Royalties which the Corporation had acquired pursuant to the acquisition.

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. The acquisition consisted of a direct royalty interest and an interest in oil and natural gas producing properties located in East Central Alberta. The direct royalty interest consisted of a minor gross overriding royalty interest in ¼ of a section of land in the Hayter area. The oil and natural gas producing properties consisted of the major fields of Hayter and West Provost, both of which are operated by the Corporation. Effective August 1, 2002, McDaniel assigned 8,155 MBOE of Established Reserves to these properties, before deduction of royalties. 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. Following the completion of the acquisition, the Corporation then sold to the Trust the direct royalty interest which the Corporation had acquired pursuant to the acquisition.

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 $4.2 million in net proceeds from the sale of such Trust Units were used to partially repay bank indebtedness. These amounts are included in the aggregate gross proceeds of the Initial Public Offering above.

On February 4, 2003, the Trust sold 1,500,000 special trust unit purchase warrants ("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 are located in Township 41 Range 1 W4M and 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. The properties acquired in the Killarney field are operated by the Corporation. The McDaniel Report – Provost Properties assigned 2,177 MBOE of Established Reserves before deduction of royalties to the Corporation's interest in this area.

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. The McDaniel Report – Provost Properties assigned 1,454 MBOE of Established Reserves to the properties acquired, before deduction of royalties. The effective date of the transaction was February 5, 2003.

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.

Further information in respect of each of the above resolutions which were approved at the 2003 Unitholders' Meeting is contained in the Information Circular – Proxy Statement of the Trust relating thereto dated April 30, 2003.

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 Carlyle 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 Carlyle Properties Vendor and wherein it was agreed that substantially all of the Carlyle Properties would be conveyed to the Corporation. On October 1, 2003, the Corporation entered into the Carlyle Properties Acquisition Agreement with the Carlyle Properties Vendor to acquire substantially all of the Carlyle Properties effective October 1, 2003 for total consideration of approximately $80 million, prior to adjustments and transaction costs. Closing of the Carlyle Properties Acquisition occurred on October 16, 2003. See "Acquisition of Carlyle Properties".

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 Carlyle 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 Carlyle Properties. On September 29, 2003, the Trust amended the Equity Bridge Notes to allow advances to be used to pay out the Prior Bank Facility and executed 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 $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 Prior Bank Facility. On October 1, 2003, the Trust made interest payments in the amount of approximately $219,000 under the Bridge Agreements. In addition, on October 1, 2003, the $11 million deposit in connection with the Carlyle Properties Transaction was refunded and the Trust used this amount to repay $11 million of principal in respect of the prior advance made under the Bridge Notes. See "Description of the Trust – Borrowing by the Trust".

On October 1, 2003 the Corporation entered into an agreement with the Interim Lender to provide the $15 million Interim Bank Facility to be used to pay out WEI's credit facility and to fund working capital requirements. On October 3, 2003, the Corporation paid out approximately $3.8 million in respect of the borrowings plus accrued interest under WEI's credit facility. Upon closing of the Carlyle Properties Transaction on October 16, 2003, the Interim Bank Facility was paid out and replaced with the Current Bank Facility. See "Information Respecting the Corporation – Borrowing by the Corporation".

Significant Acquisitions and Significant Dispositions

There were no significant acquisitions or significant dispositions by the Trust or any significant probable acquisition 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 under "Acquisition of Carlyle Properties".

Trends

There are a number of trends in the oil and natural gas industry that are shaping the near term future of the business. The first trend is the ongoing consolidation phase that the industry has been going through which has affected companies of all sizes from the small emerging companies to the senior integrated organizations. Although consolidation is nothing new for the industry, the pace at which it has occurred during the past 30 months and the nature of the companies involved are unique. The companies which have been consolidated include the traditional small to medium size companies as well as a number of large, well established companies. The most active acquirors have been royalty trusts and large U.S. based independents and one large Canadian oil and natural gas producer, which is a new trend.

Another continuing trend has been small to medium sized exploration and production companies converting to royalty trusts. These new trusts have become active in the consolidation of the industry thereby increasing competition for the previously existing trusts.

Including recently announced conversions of several exploration and production companies to trusts, approximately half of the top 30 publicly listed oil and natural gas issuers on the TSX are now trusts. Annual production declines from the trusts will likely result in a continued high level of competition for available oil and natural gas properties and companies. This increased competition within the trust sector, as well as the influence of U.S. based companies, has resulted in higher valuation parameters for corporate and asset acquisitions. Those trusts with substantial opportunities for production replacement through internal development drilling should be in an advantaged position relative to those more exposed to production replacement through acquisitions.

A direct consequence of the consolidation which has occurred is asset rationalization by the acquiring companies. As a result, significant asset acquisition opportunities have developed. The Trust expects this trend of asset dispositions to continue, thereby providing new acquisition opportunities for the Trust.

Another ongoing trend is the continued volatility of oil and natural gas prices with oil and natural gas company capital budgets highly responsive to commodity prices. As the supply/demand balance for both natural gas and crude oil tightens, commodity prices increase and drilling activity rises reflecting increased capital spending by oil and natural gas companies. Conversely, as commodity prices decline, capital budgets are reduced and drilling activity declines. In tight markets such as those the Trust is currently encountering, the supply response resulting from changing drilling activity has a material impact on prices. In addition, oil prices have been stronger due to higher demand associated with recovering world economies. This has been supported by the influence of both

OPEC production cuts and the political instability in the Middle East. Price volatility is expected to be an ongoing characteristic of the oil and natural gas industry.

The Canadian/U.S. exchange rate also influences commodity prices received by Canadian producers as oil and natural gas production is priced in U.S. dollars. The recent strengthening of the Canadian dollar has had and will continue to have a negative impact on Canadian oil and natural gas production revenue.

DESCRIPTION OF THE PROVOST PROPERTIES

The Operating Subsidiaries' portfolio of key Provost Properties are 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 Provost 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 McDaniel Report – Provost Properties and developing new proven reserves previously not evaluated by McDaniel. In respect of the Provost 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 Provost Properties.

Principal Provost Properties

The following is a description of the principal oil and natural gas properties of the Operating Subsidiaries which constitute the Provost Properties. The term "net", when used to describe the Operating Subsidiaries' share of production, means the total of the Operating Subsidiaries' Working Interest share before deducting royalties owned by others. Reserve volume amounts are stated, before deduction of royalties, at January 1, 2003, based on escalated cost and price assumptions as evaluated in the McDaniel Report – Provost Properties (see "Oil and natural gas Reserves of the Provost Properties and the Direct Royalties"). Information in respect of gross and net acres, well counts and production are as at September 30, 2003, except where indicated otherwise. Unless otherwise indicated, all information set forth below is net to the Operating Subsidiaries. OOIP numbers are published values from the Alberta Government.

Hayter

The Corporation has an average 93.1% Working Interest in this operated property, which produces approximately 5,500 net BOE/d of 15° API oil from the Dina "B" Pool located in Sections 24, 25, 34 and 35-40-1 W4M. The McDaniel Report – Provost Properties has assigned 7,845 MBOE of Established Reserves to this area. The Hayter pool contains 176 gross (167 net) producing wells. OOIP is estimated at 138 Mmbbls of oil on the Corporation's Working Interest acreage.

The Hayter fluid production is gathered into one of two central batteries located at 8-35-40-1 W4M or 1-34-40-1 W4M in which the Corporation has a 95% Working Interest and is the operator. The batteries have a combined capacity of approximately 200,000 Bbls/d of fluid. Oil from the Hayter area is blended with condensate and shipped from the battery via the Gibson Provost pipeline to the Hardisty terminal. Solution natural gas is conserved and utilized as fuel gas at the batteries, with the remainder processed at the Husky North Hansman Gas Plant located at 8-14-39-03 W4M. Future development of this pool will include additional in-fill drilling on closer spacing, pool extensions through the identification of by-passed reserves and re-completion of existing wells by isolating portions of the horizontal wells that are experiencing higher water production. There is also an opportunity to employ cost reduction practices to improve netbacks and ultimate recovery, employing inclined free-water knockouts and additional disposal. Initial low pressure water disposal results are encouraging for continuing reduction of operating costs and increase in disposal volumes.

Thompson Lake

The Corporation operates the Thompson Lake properties with approximately a 99% Working Interest. Production from the properties is approximately 1,380 BOE/d of 27° API oil, at a 99% water cut, from the Provost Glauconite "A" Pool located in Township 40 and 41 and Range 10 and 11 W4M. The McDaniel Report – Provost Properties assigned 2,107 MBOE of Established Reserves to this area. The field contains 192 gross producing wells. OOIP is estimated at 50 Mmbbls of oil.

The Thompson Lake fluid production is gathered at a central battery located at 4-2-41-11 W4M in which the Corporation has a 100% Working Interest. The battery has a capacity of approximately 210,000 Bbls/d of fluid. Oil is shipped from the battery via the Gibson Pipeline to the Hardisty terminal. Solution natural gas is conserved and processed at the Husky Provost Gas Plant at 13-30-40-10 W4M.

A primary operating tactic to enhance the future performance of the Thompson Lake field is to improve overall fluid handling efficiency and by reducing the electrical power requirements associated with water handling. Additional low pressure water disposal capacity will allow production optimization through total fluid increases at the wells, that could have a favourable impact on production rates, reserve recoveries and production costs. Additionally, production prioritization is expected to optimize total fluids handling by focusing operational efforts on the most prolific wells.

Killarney

The Operating Subsidiaries collectively own a 93% average Working Interest and the Corporation operates the Killarney field, which was acquired by the Corporation and by the Trust, through the acquisition of certain properties in Killarney directly and through the acquisition of WEI, in the second quarter of 2003. The Killarney field is a Cummings/Dina oil pool within 3.5 miles of Harvest's existing Hayter field. Production is approximately 1,195 BOE/d of 20.4° API oil. The McDaniel Report – Provost Properties assigned 2,623 MBOE of Established Reserves to this area. The Killarney pool contains 123 gross (114 net) producing oil wells. OOIP is estimated at 51 Mmbbls of oil.

The Killarney fluid production is gathered at two central batteries located at 6-29-41-1 W4M and 10-20-41-1 W4M. The batteries have a total maximum capacity of approximately 175,000 Bbls/d of fluid. Upside may be realized by increasing water disposal capacity for this field.

David North

The Corporation has a 100% Working Interest in this operated property, which produces approximately 785 BOE/d of primarily 23° API oil, at a 98% water cut, from the Lloydminster (which is under waterflood) and Dina sands located in Sections 26 and 27-40-3 W4M. The McDaniel Report – Provost Properties assigned 978 MBOE of Established Reserves to this area. The field contains 54 gross (54 net) producing wells. OOIP is estimated at 18 Mmbbls of oil for the two producing zones.

The fluid production is gathered to the central battery located at 15-26-40-3 W4M in which the Corporation has a 100% Working Interest. The battery has a capacity of approximately 40,000 Bbls/d of fluid. Oil is shipped from the battery via the Gibson Pipeline to the Hardisty terminal. Solution natural gas is conserved and processed at the Husky North Hansman Gas Plant 8-14-39-3 W4M.

Selected well speed-ups and expanded use of inclined free-water knockouts could result in increased efficiency, lower operating costs and increased fluid handling capacity. The Corporation is also considering targeting re-completions for wells that have produced in the Lloydminster and/or Dina zones to be converted to Cummings or Sparky oil producers. Numerous wells have been identified by the Corporation for re-completion.

West Provost

The Corporation holds an average 43.1% Working Interest in this area. Production from the area is approximately 625 BOE/d of primarily 26° API oil, at a 98% water cut, primarily from the Mannville "L" Pool located in Townships 37, 38 and 39-3 W4M. Natural gas production is approximately 200 Mcf/d. The McDaniel Report – Provost Properties has assigned 1,038 MBOE of Established Reserves to this area. The West Provost pool contains 114 gross (43 net) producing oil wells and 15 gross (6 net) producing natural gas wells. OOIP is estimated at 35 Mmbbls of oil.

The majority of the West Provost fluid production in the area is gathered at a central battery located at 3-15-38-03 W4M, in which the Corporation has a 37.5% Working Interest. The battery has a capacity of approximately 115,000 Bbls/d of fluid. Oil is shipped from the battery via the Gibson Provost pipeline to the Hardisty terminal. Solution and non-associated natural gas is conserved and processed at the Husky North, Hansman Lake Gas Plant at 8-14-39-03 W4M. The West Provost area also produces natural gas from 15 gross wells, primarily from the Viking and Colony Formations.

There is an opportunity to employ cost reduction practices to improve netbacks and ultimate recovery employing inclined free-water knockouts and increased water disposal capacity.

Amisk

WEI owns a 75% average Working Interest in the Amisk field and the Corporation operates all production, which was acquired by the Trust through the acquisition of WEI on June 27, 2003. The Amisk field is located on the producing trend which includes Thompson Lake, Hayter, Killarney and West Provost. Amisk is located 15 miles east of Thompson Lake, produces from the same formation and has similar production characteristics. Production from the field is 603 BOE/d of 22° API oil. The McDaniel Report – Provost Properties assigned 1,037 MBOE of Established Reserves to this field. The Amisk pool contains 88 gross (66 net) producing oil wells. OOIP is estimated at 62 Mmbbls oil for the entire Amisk pool area.

The Amisk fluid production is gathered at an operated central battery located at 12-15-40-08W4M. The Corporation has identified an opportunity to improve netbacks and ultimate recovery by reducing operating costs, suspending marginal wells and increasing water disposal capacity for the field.

Czar

WEI owns an average 100% Working Interest in this area and the Corporation operates all production, which was acquired by the Trust through the acquisition of WEI on June 27, 2003. The Czar field is located 8 miles due east of Amisk on the same producing trend. Production is 525 BOE/d of 16° API oil. The McDaniel Report – Provost Properties assigned 278 MBOE of Established Reserves to the field. The Czar pool contains 67 gross (67 net) producing oil wells. OOIP is estimated at 34 Mmbbls of oil.

The Czar fluid production is gathered at an operated central battery located at 2-19-40-06W4M. The Corporation has identified an opportunity to improve netbacks and ultimate recovery by reducing operating costs and increasing water disposal capacity for the field.

Bellshill Lake

The Corporation has a 100% Working Interest in 1,120 acres of land in Sections 5 and 6-41-12 W4M which is in proximity to the Bellshill Blairmore Unit. Production from this operated property is approximately 410 BOE/d of primarily 18° API oil, at a 98% water cut, from the Ellerslie "A" Pool and natural gas from the Glauconite "A" Pool. The McDaniel Report – Provost Properties assigned 740 MBOE of Established Reserves to this area. The field contains 20 gross (20 net) producing wells. OOIP is estimated at 27 Mmbbls of oil.

The Bellshill Lake fluid production is gathered at a central battery located at 11-5-41-12 W4M in which the Corporation has a 100% Working Interest. The battery has a capacity of approximately 40,000 Bbls/d of fluid. Oil is shipped from the battery via the Gibson Bellshill Pipeline to the Hardisty terminal. Solution natural gas is conserved and processed at the Husky Hastings Coulee Gas Plant at 1-14-41-15 W4M. Water is re-injected back into the lower Cretaceous aquifer. Development upside includes an additional horizontal drilling location and increases to water injection capacity.

Metiskow

The Corporation has a 100% Working Interest in this operated property, which produces approximately 144 BOE/d of 16° API oil from the Provost Dina "E" Pool located in Sections 22 and 23-39-6 W4M. The field has been developed exclusively with horizontal wells. The McDaniel Report – Provost Properties assigned 138 MBOE of Established Reserves to this area. The pool contains 9 gross (9 net) producing wells. OOIP is estimated at 3.0 Mmbbls of oil.

The Metiskow fluid production is gathered at a central battery located at 5-22-39-6 W4M in which the Corporation has a 100% Working Interest. The battery has a capacity of approximately 13,500 Bbls/d of fluid. Oil is trucked from the battery to the Hardisty terminal. Upside may be realized by increasing water disposal capacity for this field.

OIL AND NATURAL GAS RESERVES OF THE PROVOST PROPERTIES AND THE DIRECT ROYALTIES

McDaniel has prepared the McDaniel Report – Provost Properties evaluating as at January 1, 2003 the crude oil, natural gas and natural gas liquids reserves attributable to the Provost Properties and the Direct Royalties. **The McDaniel Report – Provost Properties evaluates the crude oil, natural gas and natural gas liquids reserves attributable to the Provost Properties and the Direct Royalties prior to provision for income taxes, interest and debt service costs, general and administrative expenses, facility site restoration, well abandonment, well site restoration costs and salvage recovery, but after providing for estimated royalties, operating costs and future capital expenditures. The probable reserves and the present worth value of such reserves as set forth in the tables below have been reduced by 50% to reflect the degree of risk associated with recovery of such reserves. It should not be assumed that the discounted future net production revenues estimated by McDaniel represent the fair market value of the reserves.** Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized in the notes following the tables.

Petroleum and Natural Gas Reserves and Pre-Tax Net Cash Flows
Escalating Cost and Price Case (1) (9)

	Crude Oil and Natural Gas Liquids (Mbbls)		Natural Gas (6) (Mmcf)		Estimated Present Worth of Future Pre-Tax Net Cash Flows ($000's) (2)(7)(8)(11) Discounted at			
	Gross (4)	Net (3)	Gross (4)	Net (3)	0%	10%	15%	20%
Proved Reserves (4)								
Producing Reserves (4) (12)	13,323	11,911	1,406	1,126	145,433	124,059	115,863	108,857
Non-Producing Reserves (4)	346	323	336	259	5,517	4,238	3,774	3,390
Undeveloped Reserves (4)	1,824	1,504	95	79	18,795	13,720	11,857	10,310
Total Proved Reserves (4)	15,493	13,738	1,837	1,464	169,744	142,018	131,494	122,558
Risked Probable Reserves (5)	1,077	946	155	125	12,484	8,485	7,180	6,166
Established Reserves (4)	16,570	14,683	1,992	1,589	182,228	150,502	138,674	128,724

Petroleum and Natural Gas Reserves and Pre-Tax Net Cash Flows
Constant Cost and Price Case (1) (9)

	Crude Oil and Natural Gas Liquids (Mbbls)		Natural Gas (6) (Mmcf)		Estimated Present Worth of Future Pre-Tax Net Cash Flows ($000's) (2)(7)(8)(10) Discounted at			
	Gross (4)	Net (3)	Gross (4)	Net (3)	0%	10%	15%	20%
Proved Reserves (4)								
Producing Reserves (4) (12)	13,354	11,910	1,408	1,128	167,140	138,240	127,512	118,509
Non-Producing Reserves (4)	346	322	336	259	6630	5,056	4,488	4,020
Undeveloped Reserves (4)	1,824	1,503	95	79	21,226	15,544	13,464	11,739
Total Proved Reserves (4)	15,524	13,735	1,839	1,466	194,996	158,840	145,464	134,268
Risked Probable Reserves (5)	1,072	940	154	124	15,249	10,095	8,442	7,169
Established Reserves (4)	16,596	14,675	1,993	1,590	210,245	168,935	153,906	141,437

Notes:

(1) Columns may not add due to rounding.

(2) Does not include the value of the Undeveloped Lands.

(3) Represents the Operating Subsidiaries' interest (and includes the Direct Royalties) after deduction of royalty encumbrances payable to others (excluding the Trust).

(4) The following definitions have been used in the McDaniel Report – Provost Properties:

(a) "Gross Reserves" represents the Operating Subsidiaries' interest (and includes the Direct Royalties of the Trust) before deduction of royalty encumbrances payable to others (excluding the Trust).

(b) "Proved Reserves" means those reserves estimated as recoverable under current technology and existing economic conditions from that portion of a reservoir which can be reasonably evaluated as economically productive on the basis of analysis of drilling, geological, geophysical and engineering data, including the reserves to be obtained by enhanced recovery processes demonstrated to be economic and technically successful in the subject reservoir.

(c) "Probable Reserves" means those reserves which analysis of drilling, geological, geophysical and engineering data does not demonstrate to be Proved under current technology and existing or anticipated economic conditions but where such analysis suggests the likelihood of their existence and future recovery. Probable additional reserves to be obtained by the application of enhanced recovery processes will be the increased recovery over and above that estimated in the proved category which can be realistically estimated for the pool on the basis of enhanced recovery processes which can be reasonably expected to be instituted in the future.

(d) "Established Reserves" means the sum of 50% of Probable Reserves and 100% of Proved Reserves.

(e) "Producing Reserves" means those reserves that are actually on production, or if not producing, that could be recovered from existing wells or facilities and where the reason for the current non-producing status is the choice of the owner.

(f) "Non-Producing Reserves" means those proved reserves that are not currently producing either due to lack of facilities and/or markets.

(g) "Undeveloped Reserves" means those proved reserves expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major capital expenditure will be required.

(h) "Total Proved Reserves" means the sum of Proved Producing, Proved Non-Producing, and Proved Undeveloped Reserves.

(5) The present worth values and quantities of Probable Reserves have been risked by reducing those values by 50% to reflect the degree of risk associated with the recovery of such reserves.

(6) All natural gas reserves are reserves remaining after deducting surface losses due to processing shrinkage and raw natural gas used as lease fuel.

(7) The $U.S./$Cdn. exchange rate used in the McDaniel Report – Provost Properties was $0.69 in 2003, $0.69 in 2004; $0.68 in 2005 and $0.68 thereafter.

(8) The McDaniel Report – Provost Properties estimates total capital expenditures (net to the Operating Subsidiaries) to achieve the estimated future pre-tax net cash flows from the Established Reserves, based on escalating cost and price assumptions to be $10,740,600 ($9,700,500 if discounted by 15% per annum) with $8,155,100, $2,580,200 and $5,300 of those capital expenditures estimated for the calendar years 2003, 2004 and 2005 respectively. The corresponding capital expenditures to achieve the estimated future pre-tax net cash flows from the Established Reserves, based on constant cost and price assumptions are $10,481,800 ($9,778,140 if discounted by 15% per annum) with $7,996,800, $2,480,000 and $5,000 of those capital expenditures estimated for the calendar years 2003, 2004 and 2005.

(9) The extent and character of the interests evaluated in the McDaniel Report – Provost Properties and all factual data was supplied by the Corporation to McDaniel and were accepted by McDaniel as represented. The crude oil and natural gas

reserve calculations and any projections on which the McDaniel Report – Provost Properties is based were determined with generally accepted petroleum engineering evaluation practices.

(10) The constant cost and price evaluation was based on the average yearly general product prices for 2002 as forecast in the escalated cost and price valuation (see note 11) adjusted for transportation and quality differentials to wellhead prices as set forth below:

Crude oil (WTI)	U.S. $28.14/Bbl
Heavy oil	$24.15/Bbl
Propane	$25.90/Bbl
Butane	$28.30/Bbl
Pentanes Plus	$30.32/Bbl
Natural Gas	$6.35/MMBTU

Operating and capital costs were not escalated in the constant cost and price evaluation.

(11) In respect of the escalated cost and price valuation, the average yearly general product prices utilized in the McDaniel Report – Provost Properties for natural gas, crude oil and natural gas liquids, are outlined in the following table.

		Light Crude Oil		Natural gas Liquids at Edmonton		
Year	Heavy Crude Oil $/Bbl	WTI Cushing Oklahoma* $U.S./Bbl	Edmonton Par 40° API $/Bbl	Propane $/Bbl	Butane $/Bbl	Edmonton NGL Mix $/Bbl
2003	26.54	28.23	40.28	28.72	29.19	31.23
2004	23.47	25.00	35.20	24.70	23.20	26.30
2005	23.38	24.00	34.30	23.10	22.60	25.20
2006	21.66	23.00	32.80	22.00	21.60	24.00
2007	21.83	23.30	33.20	21.80	21.90	24.10
2008	22.31	23.80	33.90	22.20	22.40	24.60
2009	22.78	24.30	34.60	22.70	22.80	25.10
2010	23.24	24.80	35.30	23.10	23.30	25.60
2011	23.70	25.30	36.00	23.60	23.70	26.10
2012	24.15	25.80	36.70	24.10	24.20	26.70
2013	24.70	26.30	37.50	24.60	24.70	27.20
2014	25.14	26.80	38.20	25.00	25.20	27.70
2015	25.58	27.30	38.90	25.50	25.60	28.20
2016	26.02	27.80	39.60	25.90	26.10	28.70
2017	26.55	28.40	40.40	26.40	26.60	29.30
2018	27.17	29.00	41.30	27.00	27.20	29.90
2019	27.79	29.60	42.20	27.60	27.80	30.60
2020	28.30	30.20	43.00	28.10	28.40	31.20
2021	28.90	30.80	43.90	28.80	28.90	31.90
2022	29.40	31.40	44.70	29.30	29.50	32.50
Thereafter	29.40	31.40	44.70	29.30	29.50	32.50

* 40 degree API, 0.4% sulphur.

Year	Henry Hub $U.S./MMBTU	AECO Spot $/GJ	Alberta Spot $/MMBTU
2003	5.79	7.04	7.13
2004	4.56	5.51	5.65
2005	4.00	4.95	5.05
2006	3.75	4.71	4.80
2007	3.66	4.57	5.65
2008	3.69	4.61	4.70
2009	3.77	4.71	5.80
2010	3.85	4.81	4.90
2011	3.93	4.90	5.00
2012	4.00	5.00	5.10
2013	4.08	5.10	5.20
2014	4.16	5.19	5.30
2015	4.24	5.29	5.40
2016	4.31	5.38	5.50
2017	4.41	5.50	5.60
2018	4.50	5.62	5.70
2019	4.59	5.73	5.85
2020	4.69	5.85	5.95
2021	4.78	5.97	6.10
2022	4.87	6.08	6.20
Thereafter	4.87	6.08	6.20

Operating and capital costs have been escalated at 2% annually.

(12) All of the Proved Producing Reserves are currently on production.

Summary of Selected Reserve Information

The following table sets forth the Working Interest, Gross Reserves and Reserve Value information respecting the Provost Properties as at January 1, 2003, the effective date of the McDaniel Report – Provost Properties.

Property	% Working Interest (1)(2)	Gross Reserves (MBOE) (2)(3)	Reserve Value (2)(3)(4)(5) ($000's)	Reserve Value %
Hayter	93.1	7,845	66,966	44.50
Killarney	93.8	2,623	20,291	13.50
Thompson Lake	99.1	2,107	21,583	14.30
Amisk	75.0	1,037	9,193	6.10
West Provost	43.1	1,038	9,735	6.50
David North	100.0	978	12,204	8.10
Bellshill Lake	99.5	740	5,506	3.70
Czar	100.0	278	2,262	1.50
Mestikow	100.0	138	1,471	0.98
Hayter West	100.0	34	128	0.09
Provost	58.6	13	179	0.12
Black Creek(6)	100.0	59	691	0.46
Choice(7)	6.4	11	294	0.20
TOTAL (8)		16,901	150,502	100.00

Notes:

(1) The Operating Subsidiaries' weighted average Working Interest of Established Reserves before the deduction of royalties payable to others (excluding the Trust).
(2) Based on Established Reserves as derived from the McDaniel Report – Provost Properties.
(3) Utilizing escalating cost and price assumptions.
(4) Discounted at 10%, before general and administrative expenses, interest costs, taxes, site restoration and abandonment costs.
(5) Net of capital expenditures. Does not include the value of Undeveloped Lands.
(6) Non-producing reserves.

(7) Royalty interest only.
(8) Columns may not add due to rounding.

OTHER INFORMATION ABOUT THE PROVOST PROPERTIES

Undeveloped Lands

The following table sets out the Operating Subsidiaries' Undeveloped Land holdings included in the Provost Properties as at July 1, 2003.

	Gross (1)	Net (2)
	(acres)	
Alberta	27,030	17,745
Total	27,030	17,745

Notes:
(1) "Gross" refers to the total acres in which the Operating Subsidiaries have an interest.
(2) "Net" refers to the total acres in which the Operating Subsidiaries have an interest, multiplied by the percentage Working Interest therein owned by the Operating Subsidiaries.

The Seaton Jordan Report – Provost Properties has estimated the market value of the Undeveloped Land holdings associated with the Provost Properties as at July 1, 2003 at $704,232. For purposes of the Seaton Jordan Report – Provost Properties, "market value" is defined as the price which Seaton Jordan feels could reasonably be expected to receive for the properties. In order to determine market value, Seaton Jordan analyzed the most current price paid at land sales for properties in the immediate vicinity of each of the properties evaluated. In areas where current prices were not available in the immediate vicinity, Seaton Jordan used its best judgement.

Oil and Natural Gas Wells

The following table sets forth the number and status of wells located on the Provost Properties as at August 1, 2003 in which the Operating Subsidiaries have an interest, and which are producing or which are considered by the Corporation to be capable of producing.

	Producing (4) (5)				Shut-in (1)			
	Oil		Natural Gas		Oil		Natural Gas	
	Gross Wells (2)	Net Wells (3)	Gross Wells (2)	Net Wells (3)	Gross Wells (2)	Net Wells (3)	Gross Wells (2)	Net Wells (3)
Alberta	871	757	9	3.3	305	290	2	1.4
TOTAL	871	757	9	3.3	305	290	2	1.4

Notes:
(1) "Shut-in" wells are wells which are not producing but which are considered by the Corporation to be capable of producing. Shut-in wells in which the Operating Subsidiaries have a Working Interest are located within a reasonable distance from or are already tied into gathering systems, pipelines or other means of transportation.
(2) "Gross" wells are the total number of wells in which the Operating Subsidiaries have a Working Interest.
(3) "Net" wells means the aggregate of the numbers obtained by multiplying each gross well by the Operating Subsidiaries' percentage Working Interest acquired therein.
(4) Royalty interest wells have been assigned a net number of zero.
(5) Not all wells in which the Operating Subsidiaries have an interest have been assigned reserves in the McDaniel Report – Provost Properties or are included in this table. See "Description of the Trust – The NPI and Direct Royalties – Reclamation Fund".

Production History

The sales volumes of crude oil, natural gas and natural gas liquids attributable to the Provost Properties, before deduction of royalties, for the periods indicated is summarized below.

	2003			Year Ended December 31[1][2]		
	Third Quarter	Second Quarter	First Quarter [1][2]	2002	2001	2000
Crude Oil (Bbls/d)	11,054	9,371	8,034	9,336	7,872	6,527
Natural Gas (Mcf/d)	1,453	1,161	875	1,181	596	246
Natural Gas Liquids (Bbls/d)	77	67	43	5	–	–
Total (BOE/d 6:1)	11,373	9,632	8,223	9,538	7,971	6,568

Notes:
(1) Based on information provided to the Corporation by the Provost Properties Vendors for periods where the applicable Provost Properties were not held by the Operating Subsidiaries and the Corporation's accounting records for all other periods.
(2) Does not include production from the Killarney, Amisk and Czar properties.

The mix of the Operating Subsidiaries' production of crude oil, natural gas and natural gas liquids from the Provost Properties for the nine month period ended September 30, 2003 was approximately 53% heavy quality crude oil (less than 20° API), 44% medium quality crude oil (20° API to 27° API), 2% natural gas and 1% natural gas liquids.

Approximately 98% of the Operating Subsidiaries' gross revenue is derived from the production of crude oil and natural gas liquids with the remainder from natural gas.

Drilling History

The following table sets forth the gross and net development wells in respect of the Provost Properties in which the Operating Subsidiaries and the Provost Properties Vendors participated during the periods indicated.

	Year Ended December 31,			
	2002		2001	
	Gross [1]	Net [2]	Gross [1]	Net [2]
Crude Oil	10	9.5	33	31.6
Natural Gas	–	–	–	–
Dry	–	–	1	1.0
Service	–	–	1	0.9
Total	10	9.5	35	33.5

Notes:
(1) "Gross Wells" means the total number of wells in which the Operating Subsidiaries have a Working Interest.
(2) "Net Wells" means the aggregate of the numbers obtained by multiplying each gross well by the Operating Subsidiaries' percentage Working Interest therein.
(3) Royalty interest wells have been assigned a net number of zero.

Capital Expenditures

The following table summarizes capital expenditures made by the Operating Subsidiaries and the Provost Properties Vendors on acquisitions, exploration and development drilling and production facilities and other equipment in respect of the Provost Properties for the periods indicated.

	2003(1)			Year Ended December 31,(1)(2)		
	Third Quarter	Second Quarter	First Quarter (2)	2002	2001	2000
	(unaudited) ($000's)	(unaudited) ($000's)	(unaudited) ($000's)	(unaudited) ($000's)	(unaudited) ($000's)	(unaudited) ($000's)
Property acquisitions (3)	1,022	24,003	–	76,153	–	54
Development expenditures (4)	5,070	3,706	1,473	–	12,373	14,941
Production equipment (5)	4,007	4,798	4,420	770	4,518	3,915
TOTAL	10,099	32,507	5,893	76,923	16,891	18,910

Notes:

(1) Based on information provided to the Corporation by the Provost Properties Vendors for periods where the applicable Provost Properties were not held by the Operating Subsidiaries' and the Corporation's accounting records for all other periods.

(2) Does not include capital expenditures of the Provost Properties Vendors associated with the Killarney, Amisk and Czar properties.

(3) Property acquisitions include production lease and production royalty purchases and property exchanges of lease and royalty interests.

(4) Development expenditures includes development drilling and miscellaneous intangible expenditures.

(5) Production equipment includes production and facility equipment, pipelines and miscellaneous tangible assets.

Direct Revenue and Operating Expenses

The following table sets forth revenue and operating expenses directly attributable to the Provost Properties for the periods indicated.

	2003			Year Ended December 31, (1)(2)		
	Third Quarter	Second Quarter	First Quarter(2)	2002	2001	2000
	($000's) (unaudited)	($000's) (unaudited)	($000's) (unaudited)	($000's)	($000's)	($000's)
Revenue:						
Petroleum and natural gas sales (1)(2)	21,181	17,623	14,738	86,178	74,159	99,550
Operating expenses	9,661	6,596	6,804	26,637	24,420	18,133
Operating Income	11,520	11,027	7,934	59,541	49,739	81,417

Notes:

(1) Does not include revenue and operating expenses of the Provost Properties Vendors associated with the Killarney, Amisk and Czar properties.

(2) See "Schedule of Revenue and Expenses for the Initial Properties Acquired from Devon Canada Corporation – Years Ended December 31, 2001, 2000 and 1999 and Six Months Ended June 30, 2002 and 2001" and "Schedule of Revenue and Expenses for the Additional Properties Acquired from Anadarko Canada Corporation – Years Ended December 31, 2001, 2000 and 1999 and Nine Months Ended September 30, 2002 and 2001" included in this Annual Information Form.

(3) Including royalties.

(4) Average product prices received: three months ended September 30, 2003 - $23.90/BOE; three months ended June 30, 2003 - $24.35/BOE; three months ended March 31, 2003 - $23.86/BOE; 2002 - $22.07/BOE; 2001 - $19.89/BOE; and 2000 - $29.77/BOE; based on information provided to the Corporation by the Provost Properties Vendors.

Netback History

The following table sets forth information respecting average net product prices received, royalties paid, operating expenses and netbacks received by the Operating Subsidiaries in respect of production of crude oil, natural gas liquids and natural gas from the Provost Properties (but only when such properties were held by the Operating Subsidiaries) for the periods indicated.

	2003			For the period from July 10, 2002 to December 31, 2002
	Third Quarter	Second Quarter	First Quarter	
Average Net Production (BOE/D) [(1)]	11,373	9,632	8,223	4,307
Prices Received				
Crude Oil ($/Bbl)	23.85	23.42	23.15	28.65
Oil Equivalent ($/BOE 6:1)	23.90	24.35	23.86	28.79
Royalties Paid				
Crude Oil ($/Bbl)	3.56	3.85	3.85	3.76
Oil Equivalent ($/BOE 6:1)	3.66	3.96	3.95	3.80
Operating Expenses [(2)]				
Crude Oil ($/Bbl)	9.23	7.68	9.19	8.49
Oil Equivalent ($/BOE 6:1)	9.23	7.68	9.19	8.49
Netback Received				
Crude Oil ($/Bbl)	11.06	11.89	10.11	16.40
Oil Equivalent ($/BOE 6:1)	11.01	12.71	10.72	16.50

Notes:

(1) The Operating Subsidiaries' production was comprised of approximately 97% crude oil, 2% natural gas and 1% natural gas liquids for both the first, second and third quarters.

(2) Operating expenses are composed of direct costs incurred to operate both oil and natural gas wells. A number of assumptions have been made in allocating these costs between oil, natural gas and natural gas liquids production.

Future Commitments

The Operating Subsidiaries are exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates, interest rates and electrical power prices in the normal course of operations. A variety of derivative instruments are used by the Operating Subsidiaries to reduce their exposure to fluctuations in commodity prices, foreign exchange rates and electrical power prices. The Operating Subsidiaries are exposed to losses in the event of default by the counterparties to these derivative instruments. The Corporation manages this risk by diversifying its derivative portfolio amongst a number of financially sound counterparties. See "Information Respecting the Corporation – Commodity Hedging".

Marketing Arrangements

Approximately 55% of the oil production is committed under longer-term contracts to the end of 2004. The balance of the oil is sold under shorter-term commitments not extending beyond the second quarter of 2004.

David North and Thompson Lake natural gas is sold on a spot basis. Natural gas production at Mestikow is flared.

All of the oil production from the Hayter and West Provost properties is shipped on the Gibson Provost Pipeline system. Oil production from Hayter is delivered into the LLG stream and oil production from West Provost is delivered into the Bow River stream. Gibson Energy Ltd. supplies condensate required for blending of Hayter and Bellshill production sold into the Provost system and invoices the shipper. The percentage of condensate required ranges from 15% to 25% of the oil depending on the season, with more condensate required in the winter months.

Solution natural gas produced is conserved, and then processed at a third party sour gas plant. Non-associated natural gas is sold under two different contracts. The first is an aggregator natural gas purchase contract with Cargill Gas Marketing Ltd. for the life of the reserves and the second is a 30-day evergreen contract using AECO spot pricing.

ACQUISITION OF CARLYLE PROPERTIES

On October 1, 2003, the Trust entered into the Carlyle Properties Acquisition Agreement with the Carlyle Properties Vendor to acquire the Carlyle Properties effective October 1, 2003 for total consideration of approximately $80 million, prior to adjustments and transaction costs. Closing of the Carlyle Properties Transaction occurred on October 16, 2003.

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

The Carlyle 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 Carlyle 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. For the month of September 2003, the Carlyle Properties produced approximately 5,200 BOE/d of light (28° to 34° API) oil concentrated in the Mississippian-aged Tilson subcrop play trend. As evaluated in the McDaniel Report – Carlyle Properties, the Carlyle Properties contain 16.85 MMBOE of Established Reserves, with an RLI of 8.3 years based on 2003 annual production. The recovery mechanism is bottom water drive supported by an active aquifer affording an efficient recovery of reserves, making operating characteristics of the Carlyle Properties similar to those of the Provost Properties. The Trust acquired an average 98% Working Interest in the Carlyle Properties and assumed operatorship of over approximately 95% of the total production from the properties. All the production is concentrated geographically which promotes ease of access and operating synergies. To support ongoing growth of the properties, management has identified upside value associated with production optimization, development drilling, the undeveloped land holdings and the proprietary seismic database, which are part of the assets associated with the Carlyle Properties.

All references in this section "Acquisition of Carlyle Properties" including as set forth under the various subheadings below to the interests of the Carlyle Properties Vendor or the interests of the prior owners of the Carlyle Properties are references to the interests in the Carlyle Properties which were acquired by the Carlyle Properties Vendor and then conveyed by the Carlyle Properties Vendor to the Corporation pursuant to the Carlyle Properties Transaction.

Principal Properties

The following is a description of the principal oil and natural gas properties which constitute the Carlyle Properties acquired by the Carlyle Properties Vendor prior to the conveyance by it to the Corporation of the Carlyle Properties pursuant to the Carlyle Properties Transaction. The properties described below constitute the majority of the Carlyle Properties. Additional production of approximately 260 BOE/d is derived from various minor properties. The term "net", when used to describe the Carlyle Properties Vendor's share of production, means the total of the Carlyle Properties Vendor's Working Interest share before deducting royalties owned by others. Reserve volume amounts are stated, before deduction of royalties, at January 1, 2003, based on escalated cost and price assumptions as evaluated in the McDaniel Report – Carlyle Properties (see "Oil and Natural Gas Reserves" below). Information in respect of gross and net acres, well counts and production are as at September 30, 2003, except where indicated otherwise. Unless otherwise indicated, all information set forth below is net to the interests of the Carlyle Properties Vendor. OOIP numbers are published values from the Saskatchewan Government. All oil production is delivered into the Enbridge Saskatchewan pipeline system.

Hazelwood

This area is comprised of nine separate pools producing 1,840 BOE/d of 34° API oil from 142 oil wells in the Tilston formation. Prior to the Carlyle Properties Transaction, the Carlyle Properties Vendor held an average 98% Working Interest in 19,107 gross acres including 8,669 net undeveloped acres. The McDaniel Report – Carlyle

Properties has assigned 6,849 MBOE of Established Reserves to this area. The area contains 142 gross (139 net) producing oil wells. OOIP is estimated at 160 Mmbbls of oil for all Hazelwood pools. Operatorship (100% Working Interest in all but one facility) along with extensive proprietary 3D seismic coverage offer control of the opportunity to increase oil production and reserve life through workovers, step-out drilling and horizontal infill drilling. Natural gas volumes at Hazelwood are marketed through an area rural natural gas co-operative.

Moose Valley

This area is comprised of five pools producing 1,150 BOE/d of 28° API oil from 98 oil wells in the Tilston formation. Prior to the Carlyle Properties Transaction, the Carlyle Properties Vendor held an average 97% Working Interest in 8,417 gross acres including 3,794 net undeveloped acres. The McDaniel Report – Carlyle Properties has assigned 4,135 MBOE of Established Reserves to this area. The area contains 98 gross (97 net) producing oil wells. OOIP is estimated at 80 Mmbbls of oil for all Moose Valley pools. Operatorship (100% WI in all but one facility) along with extensive proprietary 3D seismic coverage offer control of the opportunity to increase production and reserve life through workovers, water handling upgrades and water control measures and additional infill and step-out drilling.

Whitebear

This area is comprised of three main pools producing 790 BOE/d of 34° API oil from 67 oil wells in the Tilston formation. Prior to the Carlyle Properties Transaction, the Carlyle Properties Vendor held a 100% Working Interest in 11,245 gross acres including 6,204 net undeveloped acres. The McDaniel Report – Carlyle Properties has assigned 2,517 MBOE of Established Reserves to this area. The area contains 67 gross (58 net) producing oil wells. OOIP is estimated at 120 Mmbbls of oil for all Whitebear pools. A significant portion of the property is located on the Whitebear First Nation Reserve. The Carlyle Properties Vendor holds an option to acquire an additional 23% average Working Interest in 960 gross acres plus royalty interests in 96 acres at Willmar, which is part of the Whitebear area (the "Whitebear Reserve Option Lands"). Operatorship of all facilities along with extensive proprietary 3D seismic coverage offer control of the opportunity to increase oil production and reserve life through workovers, water handling upgrades and water control measures, horizontal infill drilling and additional step-out drilling on the Whitebear Reserve Option Lands prior to December 31, 2003.

Corning/Flinton

This area is comprised of five pools producing 720 BOE/d of 28.5° API oil from 67 oil wells in the Tilston formation. Prior to the Carlyle Properties Transaction, the Carlyle Properties Vendor held an average 100% Working Interest in 13,748 gross acres, including 6,309 net undeveloped acres. The McDaniel Report – Carlyle Properties has assigned 2,524 MBOE of Established Reserves to this area. The area contains 67 gross (66 net) producing oil wells. OOIP is estimated at 53 Mmbbls of oil for all Corning/Flinton pools. Operatorship (100% WI) in all facilities along with extensive proprietary 3D seismic coverage offer control of the opportunity to increase production and reserve life through workovers and drilling of selected infill and step-out wells.

Parkman East

This area is comprised of the Parkman East pools, producing 300 BOE/d of 33.5° API oil from 37 oil wells in the Tilston formation. Prior to the Carlyle Properties Transaction, the Carlyle Properties Vendor held an average 88.1% Working Interest in 6,198 gross acres including 2,506 net undeveloped acres. The McDaniel Report – Carlyle Properties has assigned 673 MBOE of Established Reserves to this area. The area contains 37 gross (26 net) producing oil wells. OOIP is estimated at 230 Mmbbls of oil for all Parkman East pools. Opportunity exists to increase oil production and reserve life through workovers, water handling upgrades and water control measures, and selective infill drilling.

Wauchope/Lightning

This area is comprised of three pools producing 140 BOE/d of 33° API oil from 12 oil wells in the Tilston formation. Prior to the Carlyle Properties Transaction, the Carlyle Properties Vendor held an average 93% Working

Interest in 4,079 gross acres including 2,514 net undeveloped acres. The McDaniel Report – Carlyle Properties has assigned 149 MBOE of Established Reserves to this area. The area contains 12 gross (11 net) producing oil wells. OOIP is estimated at 26 Mmbbls of oil for all Wauchope/Lightning pools. Operatorship (100% WI) in all facilities along with extensive proprietary 3D seismic coverage offer control of the opportunity to increase production and reserve life through workovers, water handling upgrades and water control measures and additional step-out and new pool drilling.

Oil and Natural Gas Reserves

McDaniel has prepared the McDaniel Report – Carlyle Properties evaluating as at January 1, 2003 the crude oil, natural gas and natural gas liquids reserves attributable to the Carlyle Properties. **The McDaniel Report – Carlyle Properties evaluates the crude oil, natural gas and natural gas liquids reserves attributable to the Carlyle Properties prior to provision for income taxes, interest and debt service costs, general and administrative expenses, facility site restoration, well abandonment, well site restoration costs and salvage recovery, but after providing for estimated royalties, operating costs and future capital expenditures. The probable reserves and the present worth value of such reserves as set forth in the tables below have been reduced by 50% to reflect the degree of risk associated with recovery of such reserves. It should not be assumed that the discounted future net production revenues estimated by McDaniel represent the fair market value of the reserves.** Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized in the notes following the tables.

Petroleum and Natural Gas Reserves and Pre-Tax Net Cash Flows
Escalating Cost and Price Case (1)(9)

	Crude Oil and Natural Gas Liquids (Mbbls)		Natural Gas (6) (Mmcf)		Estimated Present Worth of Future Pre-Tax Net Cash Flows ($000's) (2)(7)(8)(11) Discounted at			
	Gross (4)	Net (3)	Gross (4)	Net (3)	0%	10%	15%	20%
Proved Reserves (4)								
Producing Reserves (4) (12)	15,113	13,427	506	486	151,643	104,737	92,182	82,904
Non-Producing Reserves (4)	9	9	–	–	63	47	41	36
Undeveloped Reserve (4)	462	415	–	–	3,588	1,554	987	583
Total Proved Reserves (4)	15,584	13,851	506	486	155,294	106,338	93,210	83,523
Risked Probable Reserves (5)	1,173	1,018	33	31	11,112	5,516	4,155	3,231
Established Reserves (4)	16,757	14,869	539	517	166,406	111,854	97,365	86,754

Petroleum and Natural Gas Reserves and Pre-Tax Net Cash Flows
Constant Cost and Price Case (1) (9)

	Crude Oil and Natural Gas Liquids (Mbbls)		Natural Gas (6) (Mmcf)		Estimated Present Worth of Future Pre-Tax Net Cash Flows ($000's) (2)(7)(8)(10) Discounted at			
	Gross (4)	Net (3)	Gross (4)	Net (3)	0%	10%	15%	20%
Proved Reserves (4)								
Producing Reserves (4) (12)	16,969	15,120	624	601	224,781	136,687	116,202	101,771
Non-Producing Reserves (4)	13	12	–	–	137	96	82	71
Undeveloped Reserves (4)	504	453	–	–	6,148	3,073	2,224	1,616
Total Proved Reserves (4)	17,486	15,585	624	601	231,066	139,856	118,508	103,458
Risked Probable Reserves (5)	1,441	1,265	30	28	18,266	8,055	6,025	4,695
Established Reserves (4)	18,927	16,850	654	629	249,332	147,911	124,533	108,153

Notes:
(1) Columns may not add due to rounding.
(2) Does not include the value of undeveloped lands.
(3) Represents the prior owners of the Carlyle Properties interest after deduction of royalty encumbrances payable to others.

(4) The following definitions have been used in the McDaniel Report – Carlyle Properties:

(a) "Gross Reserves" represents the Carlyle Properties Vendor's interest before deduction of royalty encumbrances payable to others (excluding the Trust).

(b) "Proved Reserves" means those reserves estimated as recoverable under current technology and existing economic conditions from that portion of a reservoir which can be reasonably evaluated as economically productive on the basis of analysis of drilling, geological, geophysical and engineering data, including the reserves to be obtained by enhanced recovery processes demonstrated to be economic and technically successful in the subject reservoir.

(c) "Probable Reserves" means those reserves which analysis of drilling, geological, geophysical and engineering data does not demonstrate to be Proved under current technology and existing or anticipated economic conditions but where such analysis suggests the likelihood of their existence and future recovery. Probable additional reserves to be obtained by the application of enhanced recovery processes will be the increased recovery over and above that estimated in the proved category which can be realistically estimated for the pool on the basis of enhanced recovery processes which can be reasonably expected to be instituted in the future.

(d) "Established Reserves" means the sum of 50% of Probable Reserves and 100% of Proved Reserves.

(e) "Producing Reserves" means those reserves that are actually on production, or if not producing, that could be recovered from existing wells or facilities and where the reasons for the current non-producing status is the choice of the owner.

(f) "Non-Producing Reserves" means those proved reserves that are not currently producing either due to lack of facilities and/or markets.

(g) "Undeveloped Reserves" means those proved reserves expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major capital expenditure will be required.

(h) "Total Proved Reserves" means the sum of Proved Producing, Proved Non-Producing and Proved Undeveloped Reserves.

(5) The present worth values and quantities of Probable Reserves have been risked by reducing those values by 50% to reflect the degree of risk associated with the recovery of such reserves.

(6) All natural gas reserves are reserves remaining after deducting surface losses due to processing shrinkage and raw natural gas used as lease fuel.

(7) The $U.S./$Cdn. exchange rate used in the McDaniel Report – Carlyle Properties was $0.69 in 2003; $0.69 in 2004; $0.68 in 2005 and $0.68 thereafter.

(8) The McDaniel Report – Carlyle Properties estimates total capital expenditures (net to the Carlyle Properties Vendor) to achieve the estimated future pre-tax net cash flows from the Established Reserves based on escalating cost and price assumptions to be $9,344,600 ($7,025,645 if discounted by 15% per annum) with $0, $4,129,300 and $5,215,300 of those capital expenditures estimated for the calendar years 2003, 2004 and 2005 respectively. The corresponding capital expenditures to achieve the estimated future pre-tax net cash flows from the Established Reserves, based on constant cost and price assumptions are $8,883,500 ($7,312,849 if discounted by 15% per annum) with $0, $3,969,000 and $4,914,500 of those capital expenditures estimated for the calendar years 2003, 2004 and 2005.

(9) The extent and character of the interests evaluated in the McDaniel Report – Carlyle Properties and all factual data was supplied by the Corporation to McDaniel and were accepted by McDaniel as represented. The crude oil and natural gas reserve calculations and any projections on which the McDaniel Report – Carlyle Properties is based were determined with generally accepted petroleum engineering evaluation practices.

(10) The constant cost and price evaluation was based on the average yearly general product prices for 2002 as forecast in the escalated cost and price valuation (see note 11) adjusted for transportation and quality differentials to wellhead prices as set forth below:

Crude oil (WTI)	U.S. $28.14/Bbl
Heavy oil	$24.15/Bbl
Propane	$25.90/Bbl
Butane	$28.30/Bbl
Pentanes Plus	$30.32/Bbl
Natural Gas	$6.35/MMBTU

Operating and capital costs were not escalated in the constant cost and price evaluation.

(11) In respect of the escalated cost and price valuation, the average yearly general product prices utilized in the McDaniel Report – Carlyle Properties for natural gas, crude oil and natural gas liquids, are outlined in the following table.

Year	Heavy Crude Oil $/Bbl	Light Crude Oil: WTI Cushing Oklahoma* $U.S./Bbl	Light Crude Oil: Edmonton Par 40° API $/Bbl	Natural Gas Liquids at Edmonton: Propane $/Bbl	Natural Gas Liquids at Edmonton: Butane $/Bbl	Natural Gas Liquids at Edmonton: Edmonton NGL Mix $/Bbl
2003	26.54	28.23	40.28	28.72	29.19	31.23
2004	23.47	25.00	35.20	24.70	23.20	26.30
2005	23.38	24.00	34.30	23.10	22.60	25.20
2006	21.66	23.00	32.80	22.00	21.60	24.00
2007	21.83	23.30	33.20	21.80	21.90	24.10
2008	22.31	23.80	33.90	22.20	22.40	24.60
2009	22.78	24.30	34.60	22.70	22.80	25.10
2010	23.24	24.80	35.30	23.10	23.30	25.60
2011	23.70	25.30	36.00	23.60	23.70	26.10
2012	24.15	25.80	36.70	24.10	24.20	26.70
2013	24.70	26.30	37.50	24.60	24.70	27.20
2014	25.14	26.80	38.20	25.00	25.20	27.70
2015	25.58	27.30	38.90	25.50	25.60	28.20
2016	26.02	27.80	39.60	25.90	26.10	28.70
2017	26.55	28.40	40.40	26.40	26.60	29.30
2018	27.17	29.00	41.30	27.00	27.20	29.90
2019	27.79	29.60	42.20	27.60	27.80	30.60
2020	28.30	30.20	43.00	28.10	28.40	31.20
2021	28.90	30.80	43.90	28.80	28.90	31.90
2022	29.40	31.40	44.70	29.30	29.50	32.50
Thereafter	29.40	31.40	44.70	29.30	29.50	32.50

* 40 degree API, 0.4% sulphur.

Year	Henry Hub $U.S./MMBTU	AECO Spot $/GJ	Alberta Spot $/MMBTU
2003	5.79	7.04	7.13
2004	4.56	5.51	5.65
2005	4.00	4.95	5.05
2006	3.75	4.71	4.80
2007	3.66	4.57	5.65
2008	3.69	4.61	4.70
2009	3.77	4.71	5.80
2010	3.85	4.81	4.90
2011	3.93	4.90	5.00
2012	4.00	5.00	5.10
2013	4.08	5.10	5.20
2014	4.16	5.19	5.30
2015	4.24	5.29	5.40
2016	4.31	5.38	5.50
2017	4.41	5.50	5.60
2018	4.50	5.62	5.70
2019	4.59	5.73	5.85
2020	4.69	5.85	5.95
2021	4.78	5.97	6.10
2022	4.87	6.08	6.20
Thereafter	4.87	6.08	6.20

Operating and capital costs have been escalated at 2% annually.

(12) All of the Proved Producing Reserves are currently on production.
(13) Does not include Saskatchewan capital taxes.

Summary of Selected Reserve Information

The following table sets forth the Working Interest of the prior owners of the Carlyle Properties, Gross Reserves and Reserve Value information respecting the Carlyle Properties as at January 1, 2003, the effective date of the McDaniel Report – Carlyle Properties.

Property	Carlyle Properties Vendor's Working Interest (1)(2) (%)	Gross Reserves (MBOE) (2)(3)	Reserve Value (2)(3)(4)(5) ($000's)	%
Hazelwood	97.7	6,849	46,457	41.6
Moose Valley	96.5	4,135	26,648	23.9
Corning/Flinton	100.0	2,524	16,935	15.2
Whitebear	100.0	2,517	15,432	13.8
Parkman East	88.1	673	4,782	4.3
Wauchope/Lightning	93.2	149	1,448	1.3
TOTAL (6)		16,847	111,700	100.0

Notes:
(1) The weighted average Working Interest share of Established Reserves of the prior owners of the Carlyle Properties before the deduction of royalties payable to others.
(2) Based on Established Reserves as derived from the McDaniel Report – Carlyle Properties.
(3) Utilizing escalating cost and price assumptions.
(4) Discounted at 10%, before general and administrative expenses, interest costs, taxes, site restoration and abandonment costs.
(5) Net of capital expenditures. Does not include the value of undeveloped lands.
(6) Columns may not add due to rounding.

Undeveloped Lands

The following table sets out the Undeveloped Land holdings associated with the Carlyle Properties as at July 1, 2003:

	Gross(1) (acres)	Net(2) (acres)
Saskatchewan	32,509	30,710
Total	32,509	30,710

Notes:
(1) "Gross" refers to the total acres in which the prior owners of the Carlyle Properties held an interest.
(2) "Net" refers to the total acres in which the prior owners of the Carlyle Properties held an interest, multiplied by the percentage working interest therein.

The Seaton Jordan Report – Carlyle Properties has estimated the market value of the Undeveloped Land holdings associated with the Carlyle Properties as at July 1, 2003 at $1,665,293. For purposes of the Seaton Jordan Report – Carlyle Properties, "market value" is defined as the price which Seaton Jordan feels could reasonably be expected to be received for the properties. In order to determine market value, Seaton Jordan analyzed the most current prices paid at land sales for properties in the immediate vicinity of each of the properties evaluated. In areas where current prices were not available in the immediate vicinity, Seaton Jordan used its best judgement.

Incremental Exploitation and Development Potential

Management of the Corporation has identified several opportunities to take advantage of possible development potential in order to increase existing production supplemental to the future development projects included in the determination of the Reserve Values contained in the McDaniel Report – Carlyle Properties. Neither the capital costs nor the potential incremental production associated with these opportunities are reflected in the McDaniel Report – Carlyle Properties. Opportunities being considered include:

- Increasing water handling and water disposal capacity at key fields to add incremental oil volumes. This includes the use of inclined free water knock-outs and additional disposal wells;
- Debottlenecking existing fluid handling facilities and surface infrastructure;
- Infill horizontal drilling and step-out drilling opportunities at Hazelwood beyond those included in the McDaniel Report – Carlyle Properties. Locations are fully defined by 3D seismic;
- 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;
- Reperforating existing shut-in wells to access undrained reserves;
- Numerous exploratory opportunities defined by seismic from which value might be extracted by sale or farmout; and
- Selected development drilling opportunities for prolific Alida and Souris Valley subcrop oil accumulations.

Oil Wells

The following table sets forth the number and status of wells located on the Carlyle Properties as at April 1, 2003 which are producing or which are considered by the Corporation to be capable of producing. The Carlyle Properties do not include any producing natural gas wells.

	Producing (4) (5)		Shut-in(1)	
	Oil		Oil	
	Gross Wells (2)	Net Wells (3)	Gross Wells (2)	Net Wells (3)
Hazelwood	142	139.16	62	60.76
Moose Valley	98	97.02	25	24.75
Whitebear	67	58.29	29	25.23
Parkman East	37	26.27	25	17.75
Corning / Flinton	67	66.33	25	25.00
Wauchope/Lightning	12	11.28	11	10.34
TOTAL	423	398.35	177	163.83

Notes:
(1) "Shut-in" wells are wells which are not producing but which are considered by the Corporation to be capable of producing. Shut-in wells associated with the Carlyle Properties are located within a reasonable distance from or are already tied into gathering systems, pipelines or other means of transportation.
(2) "Gross" wells are the total number of wells in which the prior owners of the Carlyle Properties held a Working Interest.
(3) "Net" wells means the aggregate of the numbers obtained by multiplying each gross well by the percentage Working Interest therein of the prior owners of the Carlyle Properties.
(4) Royalty interest wells have been assigned a net number of zero.
(5) Not all wells associated with the Carlyle Properties have been assigned reserves in the McDaniel Report – Carlyle Properties or are included in this table. See "Description of the Trust – The NPI and Direct Royalties – Reclamation Fund".

Production History

The sales volumes of crude oil, natural gas and natural gas liquids attributable to the Carlyle Properties, before deduction of royalties, for the periods indicated is summarized below.

	2003(1)			Year Ended December 31(1)		
	Third Quarter	Second Quarter	First Quarter	2002	2001	2000
Crude Oil (Bbl/d)	5,137	5,479	5,976	6,287	6,964	6,299
Natural Gas (Mcf/d)	223	230	372	513	707	394
Natural Gas Liquids (Bbl/d)	27	28	20	–	–	–
Total (BOE/d 6:1)	5,201	5,546	6,058	6,373	7,082	6,365

Note:
(1) Based on information provided to the Corporation by the prior owners of the Carlyle Properties.

Approximately 99.5% of gross revenue from the Carlyle Properties is derived from crude oil and natural gas liquids with the remainder from natural gas production. On a BOE (6:1) basis, production is split between crude oil and natural gas liquids as to approximately 99% and natural gas as to approximately 1%.

The mix of the crude oil production and natural gas liquids from the Carlyle Properties for the January 1, 2003 period was approximately 98.5% light quality crude oil (27° API or greater), 1.0% condensate and 0.5% natural gas liquids. None of the crude oil production was comprised of heavier gravity (less than 20° API) crude oil.

Drilling History

The following table sets forth the gross and net development wells in respect of the Carlyle Properties in which the prior owners of the Carlyle Properties participated during the periods indicated.

	Year Ended December 31,			
	2002		2001	
	Gross (1)	Net (2)	Gross (1)	Net (2)
Crude Oil	14	13.8	47	47
Natural Gas	0	0.0	0	0
Dry	3	3.0	0	0
Service	0	0.0	9	9
Total	17	16.8	56	56

Notes:
(1) "Gross Wells" means the total number of wells in which the prior owners of the Carlyle Properties held a Working Interest.
(2) "Net Wells" means the aggregate of the numbers obtained by multiplying each gross well by the percentage Working Interest therein of the prior owners of the Carlyle Properties.
(3) Royalty interest wells have been assigned a net number of zero.

Capital Expenditures

The following table summarizes capital expenditures made by the prior owners of the Carlyle Properties on acquisitions, exploration and development drilling and production facilities and other equipment in respect of the Carlyle Properties for the periods indicated.

($000's)	2003(1) Third Quarter	2003(1) Second Quarter	2003(1) First Quarter	2002(1) Fourth Quarter	2002(1) Third Quarter	2002(1) Second Quarter	2002(1) First Quarter	2001(1) Fourth Quarter	2001(1) Third Quarter	2001(1) Second Quarter	2001(1) First Quarter
Property acquisitions(2)	–	–	–	–	78	10	–	95	47	10	105
Drilling(3)	717	1,015	212	2,760	349	1,026	1,797	4,834	6,507	2,371	5,945
Abandonments	–	–	–	234	135	–	11	276	74	–	–
Production equipment(4)	195	394	399	1,095	875	–	1,359	1,481	4,002	1,413	4,395
Workovers	–	–	–	–	–	4	–	–	2,166	1,179	2,317
Total	912	1,409	611	4,089	1,437	1,040	3,167	6,686	12,796	4,973	12,762

Notes:
(1) Based on information provided to the Corporation by the prior owners of the Carlyle Properties.
(2) Property acquisitions include production lease and production royalty purchases and property exchanges of lease and royalty interests.
(3) Drilling includes development drilling and miscellaneous intangible expenditures.
(4) Production equipment includes production and facility equipment, pipelines and miscellaneous tangible assets.

Netback History

The following table sets forth information respecting average net product prices received, royalties paid, operating expenses and netbacks received by the prior owners of the Carlyle Properties in respect of production of crude oil, natural gas liquids and natural gas from the Carlyle Properties for the periods indicated.

	Nine months ended September 30, 2003	Year ended December 31, 2002	2001	2000
Average Net Production Prices Received				
Crude Oil ($/Bbl)	38.66	36.19	34.37	48.12
Oil Equivalent ($/BOE 6:1)	38.75	36.66	34.50	51.43
Royalties Paid	8.09	7.81	7.39	11.97
Crude Oil ($/Bbl)	8.09	7.81	7.39	11.97
Oil Equivalent ($/BOE 6:1)				
Operating Expenses	12.77	10.61	8.75	10.85
Crude Oil ($/Bbl)	12.77	10.61	8.75	10.85
Oil Equivalent ($/BOE 6:1)				
Netback Received				
Crude Oil ($/Bbl)	17.80	17.77	18.23	25.30
Oil Equivalent ($/BOE 6:1)	17.89	18.24	18.36	28.61

Note:
(1) Based on information provided to the Corporation.

Future Commitments

Pursuant to the Carlyle Properties Transaction, the Corporation assumed an oil price hedge for 2,500 Bbls/d of WTI sales within a range defined by:

	Q4 2003	Calendar 2004
Floor	U.S. $24.00	U.S. $22.00
Ceiling	U.S. $30.45	U.S. $28.10

Marketing Arrangements

Crude oil from the Carlyle Properties is gathered into the Enbridge Saskatchewan pipeline system and sold to creditworthy customers at competitive market prices. Slightly more than half the current net sales volume is sold under the hedge contract described above under "Future Commitments" which expires in 2004. The balance of the crude oil production is sold on short term contracts.

SELECTED PRO FORMA INFORMATION

The following pro forma information reflects combined information related to the Provost Properties and the Carlyle Properties. All references in this section to the "Corporation" refers to all of the Operating Subsidiaries unless otherwise indicated or the context otherwise requires. See also "Description of the Provost Properties", "Acquisition of Carlyle Properties", "Schedule of Revenue and Expenses for the Initial Properties Acquired from Devon Canada Corporation – Years Ended December 31, 2001, 2000 and 1999 and Six Months Ended June 30, 2002 and 2001", "Schedule of Revenue and Expenses for the Additional Properties Acquired from Anadarko Canada Corporation – Years Ended December 31, 2001, 2000 and 1999 and Six Months Ended June 30, 2002 and 2001", "Schedule of Revenue and Expenses for the Carlyle Properties – Years Ended December 31, 2002, 2001 and 2000 and Nine Months Ended September 30, 2003 and 2002" and "Pro Forma Consolidated Financial Statements of Harvest Energy Trust as at September 30, 2003 and for the Nine Months Ended September 30, 2003 and the Year Ended December 31, 2002" included in this Annual Information Form and the Consolidated Financial Statements of Harvest Energy Trust for the nine months ended September 30, 2003 and Consolidated Financial Statements of Harvest Energy Trust for the period from July 10, 2002 to December 31, 2002 for a description of each group of properties and their related reserve information, production information and direct revenue and operating expenses.

Pro Forma Description of Properties

The Provost Properties are located in East Central Alberta near Provost and include interests in the following major oilfields: Hayter, Thompson Lake, David North, Killarney, Amisk, Czar, West Provost, Bellshill Lake and Metiskow. The Carlyle Properties are located in South East Saskatchewan near Carlyle and include the following major oilfields: Hazelwood, Whitebear, Parkman East, Wauchope/Lightning, Corning/Flinton and Moose Valley. See "Description of the Provost Properties – Existing Principal Properties" and "Acquisition of Carlyle Properties – Principal Properties".

The Corporation has approximately an average 99% Working Interest in the Provost Properties and will acquire approximately an average 98% Working Interest in the Carlyle Properties. The Provost Properties are primarily operated by the Corporation and the Corporation expects to operate almost all of the Carlyle Properties following completion of the Carlyle Properties Transaction.

Established Reserves (according to the McDaniel Report – Provost Properties and the McDaniel Report – Carlyle Properties using escalating price and cost assumptions), before deduction of royalties, for the Provost Properties and the Carlyle Properties are comprised of 16,568 Mbbls of light crude oil, 7,616 Mbbls of medium gravity crude oil, 8,870 Mbbls of heavy gravity crude oil, 273 Mbbls of natural gas liquids and 2,531 Mmcf of natural gas.

Associated with the Provost Properties are 17,745 net acres of Undeveloped Land, 757 net producing oil wells, 3.3 net producing natural gas wells, 290 net shut-in oil wells and 1.4 net shut-in natural gas wells and with the Carlyle Properties are 30,710 net acres of Undeveloped Land, 398 net producing oil wells, no net producing natural gas wells, 164 net shut-in oil wells, no net shut-in natural gas wells. In addition, the Corporation will acquire a 5% non-convertible gross overriding royalty, which is not subject to deductions, on over 200,000 net acres of undeveloped land adjacent to the area where the Carlyle Properties are situated.

This portfolio of Provost Properties and Carlyle Properties has the following characteristics:

(a) **Significant Reserve Accumulations:** The majority of the Provost Properties and Carlyle Properties share the similar attribute of containing large accumulations of oil reserves. In total, management estimates the OOIP of these properties is approximately 1,000 MMBOE. Management believes that exposure to large OOIP enables it to pursue expanded reserve recovery programs which could have a meaningful impact on extending the reserve life of the Properties and the profitability of the Operating Subsidiaries.

(b) **Reservoir Energy Through Active Water Drive:** The majority of the Provost Properties and Carlyle Properties share a reservoir attribute of having a natural bottom water drive derived from an underlying acquifier. It is management's view that this natural water flood provides ongoing reservoir sweep, and if managed properly, can increase ultimate reserve recovery.

(c) **Predictable Production Performance:** The production from the Provost Properties and the Carlyle Properties is derived from approximately 1,137 wells, which in aggregate have demonstrated a stable production history leading management to believe the production forecast is more predictable and reliable.

(d) **Operated:** The Corporation, as operator of the Provost Properties and the Carlyle Properties, will be able to exercise management and operating control to enhance the value of the Provost Properties and the Carlyle Properties for the benefit of the Trust.

(e) **Concentrated:** The Provost Properties and the Carlyle Properties are concentrated in relatively small areas in East Central Alberta and South East Saskatchewan. Management believes this will enable the Corporation to gain benefits from economies of scale in managing the Provost Properties and the Carlyle Properties and will also enable the Corporation to effectively enhance the value of the Provost Properties and the Carlyle Properties by applying experience gained from one property to the balance of the Provost Properties and the Carlyle Properties.

(f) **Development Potential:** Although the Provost Properties and the Carlyle Properties have been subject to extensive drilling and development programs, management believes that there are opportunities to improve the production and to further develop the reserves associated with the Provost Properties and the Carlyle Properties.

Pro Forma Reserve Information

McDaniel has prepared the McDaniel Report – Provost Properties and the McDaniel Report – Carlyle Properties, evaluating as at January 1, 2003 the crude oil, natural gas and natural gas liquids reserves attributable to the Provost Properties, the Direct Royalties and the Carlyle Properties. The reserves shown in this section are the combined reserves as shown in the McDaniel Report – Provost Properties and the McDaniel Report – Carlyle Properties. **The McDaniel Report – Provost Properties and the McDaniel Report – Carlyle Properties evaluate the crude oil, natural gas and natural gas liquids reserves attributable to the Provost Properties, the Direct Royalties and the Carlyle Properties prior to provision for income taxes, interest and debt service costs, general and administrative expenses, facility site restoration, well abandonment, well site restoration costs and salvage recovery, but after providing for estimated royalties, operating costs and future capital expenditures. The probable reserves and the present worth value of such reserves as set forth in the tables below have been reduced by 50% to reflect the degree of risk associated with recovery of such reserves. It should not be assumed that the discounted future net cash flows estimated by McDaniel represent the fair market value of these reserves.** Additional assumptions and qualifications relating to costs, prices for future production and other matters are summarized in the notes following the tables.

Pro Forma Petroleum and Natural Gas
Reserves and Pre-Tax Net Cash Flows
Escalating Cost and Price Case (1)

	Crude Oil and Natural Gas Liquids (Mbbls)		Natural Gas (Mmcf)		Estimated Present Worth of Future Pre-Tax Net Cash Flows ($000's) (2) Discounted at			
	Gross (2)	Net (2)	Gross (2)	Net (2)	0%	10%	15%	20%
Proved Reserves(2)								
Producing Reserves(2)	28,436	25,338	1,913	1,612	297,076	228,796	208,046	191,762
Non-Producing Reserves(2)	355	332	336	259	5,580	4,285	3,815	3,426
Proved Undeveloped(2)	2,286	1,919	95	78	22,383	15,274	12,844	10,894
Total Proved Reserves(2)	31,077	27,589	2,344	1,949	325,038	248,355	224,704	206,082
Risked Probable Reserves(2)	2,249	1,963	187	155	23,596	14,001	11,335	9,397
Established Reserves(2)	33,326	29,552	2,531	2,104	348,635	262,356	236,039	215,479

Notes:

(1) Columns may not add due to rounding.

(2) See Notes (1) through (12) to the table included in "Oil and natural gas Reserves of the Provost Properties and the Direct Royalties" and Notes (1) through (13) to the table included in "Acquisition of Carlyle Properties – Oil and natural gas Reserves".

Pro Forma Petroleum and Natural Gas
Reserves and Pre-Tax Net Cash Flows
Constant Cost and Price Case (1)

	Crude Oil and Natural Gas Liquids (Mbbls)		Natural Gas (Mmcf)		Estimated Present Worth of Future Pre-Tax Net Cash Flows ($000's) (1)(2) Discounted at			
	Gross (2)	Net (2)	Gross (2)	Net (2)	0%	10%	15%	20%
Proved Reserves(2)								
Producing Reserves(2)	30,322	27,030	2,032	1,729	391,921	274,927	243,714	220,279
Non-Producing Reserves(2)	359	334	336	259	6,766	5,152	4,570	4,091
Proved Undeveloped(2)	2,327	1,956	95	78	27,374	18,617	15,688	13,356
Total Proved Reserves(2)	33,008	29,320	2,463	2,066	426,061	298,696	263,971	237,726
Risked Probable Reserves(2)	2,514	2,205	184	152	33,515	18,150	14,466	11,864
Established Reserves(2)	35,522	31,525	2,647	2,218	459,576	316,846	278,437	249,590

Notes:

(1) Columns may not add due to rounding.

(2) See Notes (1) through (12) to the table included in "Oil and natural gas Reserves of the Provost Properties and the Direct Royalties" and Notes (1) through (13) to the table included in "Acquisition of Carlyle Properties – Oil and natural gas Reserves".

Estimated Pre-Tax Net Cash Flows – Established Reserves of Pro Forma Properties
Escalating Cost and Price Case (1)
(Dollar amounts in thousands)

Year	Annual Production (MBOE)	Company Interest Revenue	Royalty Burdens (2)	Operating Expenses	Other Income	Net Operating Income	Net Capital Investment	Net Cash Flow (3) (4)
2003	5,986	184,557	30,111	52,529	60	101,977	8,155	93,822
2004	5,328	146,401	22,537	51,854	54	72,065	6,710	65,354
2005	4,536	125,055	18,645	49,301	48	57,157	5,221	51,937
2006	3,732	97,184	13,632	47,574	43	36,022	–	36,022
2007	3,055	80,929	10,717	44,736	39	25,515	–	25,515
2008	2,421	66,370	8,402	39,611	35	18,392	–	18,392
2009	1,716	49,020	5,893	30,978	32	12,182	–	12,182
2010	1,085	32,610	3,921	20,189	–	8,500	–	8,499
2011	839	26,188	2,970	16,871	–	6,347	–	6,347
2012	689	22,016	2,455	14,403	–	5,158	–	5,158
2013	588	19,321	2,128	12,804	–	4,390	–	4,390
2014	510	17,026	1,673	11,911	–	3,442	–	3,442
2015	456	15,485	1,467	11,220	–	2,799	–	2,799
2016	399	13,739	1,252	10,129	–	2,358	–	2,358
2017	365	12,856	1,122	9,757	–	1,977	–	1,977
Remainder	2,043	79,490	7,539	61,509	–	10,442	–	10,442
Total	33,747	988,245	134,462	485,374	311	368,723	20,085	348,636

Notes:
(1) Numbers may not agree with the McDaniel Report – Provost Properties and the McDaniel Report – Carlyle Properties and columns may not add, in both cases due to rounding.
(2) Includes mineral taxes.
(3) Undiscounted.
(4) Net cash flow before income taxes, interest, general and administrative expenses and estimated site restoration and abandonment costs.

Selected Pro Forma Production Information

The sales volumes of crude oil, natural gas and natural gas liquids attributable to the Provost Properties and the Carlyle Properties, before deduction of royalties, for the periods indicated are summarized below.

	2003 (1) (4)			Year Ended December 31, (1)(2)(3) (4)		
	Third Quarter	Second Quarter	First Quarter (2)(3)	2002	2001	2000
Crude Oil (Bbls/d)	16,191	14,850	14,010	15,623	14,836	12,826
Natural Gas (Mcf/d)	1,676	1,391	1,247	1,694	1,303	640
Natural Gas Liquids (Bbls/d)	104	95	63	5	–	–
Total (BOE/d 6:1)	16,574	15,177	14,281	15,910	15,053	12,933

Notes:
(1) In respect of the Provost Properties, based on information provided to the Corporation by the Provost Properties Vendors for the periods where the applicable Provost Properties were not held by the Operating Subsidiaries and the Corporation's records for all other purposes.
(2) In respect of the Carlyle Properties, based on information provided to the Corporation by the prior owners of the Carlyle Properties.
(3) Does not include production from the Killarney, Amisk and Czar properties.
(4) See also "Other Information About the Provost Properties – Production History" and "Acquisition of Carlyle Properties – Production History".

Pro Forma Direct Revenue and Operating Expenses

The following table sets forth revenue and operating expenses directly attributable to the Provost Properties and the Carlyle Properties for the periods indicated.

	2003(1)			Year Ended December 31, (1)(3)		
	Third Quarter	Second Quarter	First Quarter(3)	2002	2001	2000
	($000's) (unaudited)	($000's) (unaudited)	($000's) (unaudited)	($000's)	($000's)	($000's)
Revenue:						
Petroleum and natural gas sales (1)(2)	36,444	33,588	30,701	153,285	144,231	191,219
Operating expenses	15,022	12,944	13,152	51,325	47,031	43,335
Operating Income	21,422	20,644	17,549	101,960	97,200	147,884

Notes:

(1) See "Schedule of Revenue and Expenses for the Initial Properties Acquired from Devon Canada Corporation – Years ended December 31, 2001, 2000 and 1999 and Six Months ended June 30, 2002 and 2001", "Schedule of Revenue and Expenses for the Additional Properties Acquired from Anadarko Canada Corporation – Years Ended December 31, 2001, 2000 and 1999 and Six Months Ended June 30, 2002 and 2001", "Schedule of Revenue and Expenses for the Carlyle Properties – Years Ended December 31, 2002, 2001 and 2000 and Nine Months Ended September 30, 2003 and 2002" and "Pro Forma Consolidated Financial Statements of Harvest Energy Trust as at September 30, 2003 and for the Nine Months Ended September 30, 2003 and the Year Ended December 31, 2002" included in this Annual Information Form. See also "Other Information about the Provost Properties – Direct Revenue and Operating Expenses" and "Acquisition of Carlyle Properties – Netback History". See also the Consolidated Financial Statements of the Trust for the nine months ended September 30, 2003, and the Consolidated Financial Statements of the Trust for the period from July 10, 2002 to December 31, 2002.

(2) Including royalties and royalty income.

(3) Does not include revenue and expenses from the Killarney, Amisk and Czar properties.

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 which does not form part of the NPI is retained by the Operating Subsidiaries, together with any income of the Operating Subsidiaries 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), 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 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:

(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 which 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. The Corporation currently estimates that the future environmental and reclamation obligations, after salvage recovery, in respect of the Provost Properties will aggregate approximately $20 million over the life of the Provost Properties, and in respect of the Carlyle Properties will aggregate approximately $9.9 million over the remaining life of the Carlyle Properties.

In addition to the identified producing wells and wells capable of production, the Provost Properties include interests in 222 gross (191 net) active injection, disposal or service wells and 146 gross (126 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. **The estimates of reserves associated with the Provost Properties and the present worth of future net cash flows from such reserves contained in the McDaniel Report – Provost Properties are stated before**

providing for estimated facility site restoration, well abandonment, well site restoration costs and salvage recovery.

The Carlyle Properties include interests in 91 gross (87 net) active injection, disposal or service wells and 165 gross (158 net) suspended or shut-in wells, all of which have been included in the estimate of the Corporation's future environmental and reclamation obligations. **The estimates of reserves associated with the Carlyle Properties and the present worth of future net cash flows from such reserves contained in the McDaniel Report – Carlyle Properties are stated before providing for estimated facility site restoration, well abandonment, well site restoration costs and salvage recovery.**

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 in its Capital Fund 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. Allocations to the Capital Fund as at September 30, 2003 were approximately $2.5 million.

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 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.

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 and capitalized issue expenses in accordance with the provisions of the Tax Act. The 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 has a board of directors consisting of 5 individuals. 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 and the transition from the Provost Properties Vendors and the Carlyle Properties Vendor to the Corporation of ownership, management and operatorship of the Provost Properties and the Carlyle Properties. To the extent that such costs have been incurred to date, they have been paid by the Corporation through drawdowns under a prior credit facility and an interim loan which had been provided to the Trust by Caribou.

Borrowing by the Trust

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 the Carlyle 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 provide 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 Carlyle Properties and to pay out the Prior Bank Facility. No commitment or arrangement fee has or will be 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. Notwithstanding the above, the outstanding principal portion and all accrued and unpaid interest on the Bridge Agreements is due and payable in full on January 1, 2005. The amount due on January 1, 2005 may be settled by the payment of cash and in the case of the Equity Bridge Notes, subject to receipt of applicable regulatory approvals, the issue of Trust Units, with notice provided and the calculation of the number of Trust Units to be issued as indicated above. Security has been provided to the Bridge Lenders in the form of a fixed and floating debenture on the Trust's NPI. The Bridge Lenders may demand payment of the full amount if specified events of default under the Bridge Agreements occur. The Trust does not have the option to issue Trust Units to satisfy its repayment obligations under such a demand.

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

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.". The head and principal office of the Corporation is located at Suite 1900, 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 WEI 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 18 years. The Corporation has a staff made up of 23 head office employees and consultants and 62 field employees and consultants/contractors dedicated to the Provost Properties and Carlyle 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 reserves. 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 Provost 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.

On October 3, 2003, the Corporation entered into the Interim Bank Facility with the Interim Lender to provide a $15 million revolving operating demand loan which was used to pay out WEI's credit facility with a Canadian chartered bank and for general working capital purposes. On October 3, 2003, the Corporation paid out $2.9 million in respect of the borrowings and accrued interest on WEI's credit facility. Upon closing of the Carlyle Properties Transaction on October 16, 2003, the Interim Bank Facility was paid out and replaced with the Current Bank Facility described below.

On October 16, 2003, Harvest Operations Corp. entered into an $89 million bank facility with the Current Lender. The facility bears interest at rates ranging from 0.25% to 1.5% above prime rate, and is dependent upon the Trust's debt to cash flow ratio. The borrowing base is reduced monthly by $4.5 million commencing January 31, 2004. A portion of this facility was used to pay out the $15 million Interim Bank Facility, $31.35 million was used to finance in part the acquisition of the Carlyle Properties, $8.5 million was used to repay a portion of the Equity Bridge Notes and $25 million was used to repay the Bridge Notes.

		Debt to Annualized Cash Flow Ratio				
Borrowing	**Base Rate**	**<1.0x**	**1.0x – 1.5x**	**1.5x – 2.0x**	**2.0x – 3.0x**	**>3.0x**
Canadian $	Cdn. Bank Prime	+0.25%	+0.375%	+0.50%	+0.75%	+1.50%
Banker's Acceptances	Market rates	+1.25%	+1.50%	+1.75%	+2.00%	N/A
U.S. $	U.S. Bank Prime	+0.25%	+0.375%	+0.50%	+0.75%	+1.50%
LIBOR	Market rates	+1.25%	+1.50%	+1.75%	+2.00%	N/A

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

Security for the Current Bank Facility consists of: a general assignment of book debts; a $150,000,000 debenture with a floating charge over all of the assets of the Corporation; representation as to title of oil and natural gas leases and reserves; subordination agreements on NPI payments, Bridge Agreements payments, and distribution payment restrictions to Unitholders upon demand for repayment or an event of default, or under certain circumstances, upon a borrowing base shortfall or default. Covenants for the Current Bank Facility include: maintenance of a working capital ratio (current assets plus unused portion of the Current Bank Facility divided by current liabilities excluding bank debt) of at least 1:1; maintenance of minimum hedging of 50% and 25% of oil volumes for the first four forward and next four calendar quarters, respectively; and industry standard requirements in respect of reporting, operations, compliance with laws, payment of taxes, environmental, lender access to books and records, maintenance of records, change in control, merger, amalgamation, payment of dividends or distribution of capital, incur additional secured indebtedness or guarantee of obligations of others, dispose of assets with annual proceeds greater than $100,000 and hedge more than 75% of working interest production volumes.

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 the date hereof, approximately $64 million is outstanding under the Current Bank Facility.

Commodity Hedging

The Corporation has entered into the following oil price hedging contracts with various counterparties, including the Corporation's prior lender:

Swaps:	Term	Price per Barrel
1,000 Bbls/d	October through December 2003	Cdn $36.63
1,510 Bbls/d	January through March 2004	U.S. $23.23
1,300 Bbls/d	January through March 2004	U.S. $24.33
500 Bbls/d	January through December 2004	U.S. $24.12
500 Bbls/d	January through December 2004	U.S. $24.25
1,430 Bbls/d	April through June 2004	U.S. $22.93
1,200 Bbls/d	April through June 2004	U.S. $25.50
1,380 Bbls/d	July through September 2004	U.S. $22.70
500 Bbls/d	July through September 2004	U.S. $24.56
1,325 Bbls/d	October through December 2004	U.S. $22.54
500 Bbls/d	October through December 2004	U.S. $24.03
500 Bbls/d	January through December 2005	U.S. $24.00
1,100 Bbls/d	January through March 2005	U.S. $22.38
1,030 Bbls/d	April through June 2005	U.S. $22.18
Swaps based on Lloydminster Blend Crude differential		
2,000 Bbls/d	January through December 2004	U.S. ($7.75)
1,100 Bbls/d	January through December 2004	U.S. ($8.20)

Collars:	Term	Price per Barrel
500 Bbls/d	October through December 2003	Cdn $35.50 – 37.35
1,000 Bbls/d	January through December 2004	U.S. $23.00 – 27.95
1,000 Bbls/d	January through December 2004	U.S. $25.00 – 28.25

Options:	Term	Price per Barrel
500 Bbls/d	January through December 2004	Short put U.S. $15.50
1,000 Bbls/d	January through December 2004	Short put U.S. $18.00
1,000 Bbls/d	January through December 2004	Short put U.S. $18.00

Effective November 15, 2002, the Corporation entered into a physical contract to deliver at Hardisty, Alberta until December 31, 2003, 6,000 Bbls/d of Lloydminster blend crude oil to a vendor from whom properties had been acquired. This requires the Corporation to purchase approximately 1,000 Bbls/d of diluent to blend with its production to meet the oil quality requirements at the delivery point. Under the contract, the Corporation is paid a price equal to the NYMEX calendar WTI price less a fixed differential of U.S. $8.233 per Bbl, such price not to be less than U.S. $14.40 per Bbl or greater than U.S. $17.244 per Bbl. In effect, this contract applies a fixed differential to a WTI price collar between U.S. $22.633 and U.S. $25.477 per Bbl. This contract is effective until December 31, 2003. In addition, pursuant to the Current Bank Facility, the Corporation is required to maintain a minimum hedging of 50% and 25% of oil volumes (net of royalties) for the first four forward and next four calendar quarters, respectively, and a maximum hedging of 75% of oil equivalent volumes (net of royalties).

The Corporation has also entered into the following electrical power swap contracts with various counterparties:

	Term	Price per MegaWatt
5MW	January through December 2003	Cdn $46.30
5MW	January through December 2004	Cdn $46.00
5MW	January through December 2004	Cdn. $46.00
5MW	January through December 2005	Cdn $43.00
10MW	April 2003 through March 2006	Cdn $44.50
5MW	January through December 2005	8.40 GJ/MWh heat rate
5MW	January through December 2004	Cdn $45.50

On October 27, 2003, the Corporation purchased an average rate U.S. dollar put option with a strike price of 1.3333, for a premium of $2 million. The notional amount of the option is U.S. $3 million per month, and has a term from November 1, 2003 to December 31, 2004. The contract is settled monthly on the last business day of each month.

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 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
John A. Brussa (2)(4) Calgary, Alberta	Director	249,600	Barrister and Solicitor; Partner of Burnet, Duckworth & Palmer LLP (a law firm).
M. Bruce Chernoff (3)(4) Calgary, Alberta	Director, Chairman	4,934,406 (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.

Name and Municipality of Residence	Position with the Corporation	No. of Trust Units Held [(1)]	Principal Occupation
Hank B. Swartout [(3)] Calgary, Alberta	Director	500,000	Chairman, President and Chief Executive Officer of Precision Drilling Corporation since July, 1987.
Verne G. Johnson [(2)(3)] Calgary, Alberta	Director	20,000	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)(4)] Calgary, Alberta	Director	20,000	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).
Jacob Roorda Calgary, Alberta	President	160,339 [(8)]	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).
J.A. Ralston Calgary, Alberta	Vice President, Operations	107,262	Vice President, Operations of the Corporation; from 1996 to 2002, Manager, Production of Penn West Petroleum ("PennWest") (a public oil and natural gas company).
David M. Fisher Calgary, Alberta	Vice President, Finance	48,451 [(9)]	Vice President, Finance of the Corporation since October 2002; from September 1998 to October 2002, Director, Vice President, Finance and Chief Financial Officer of Integra Resources Ltd. ("Integra") (a private oil and natural gas corporation); from April 1995 to July 1998, Vice President, Finance and Chief Financial Officer of Canrise Resources Ltd. (a public oil and natural gas corporation); from June 1994 to April 1995 independent consultant; from April 1985 to May 1994, Manager, Corporate Reporting of Canadian Hunter Exploration Ltd.

Name and Municipality of Residence	Position with the Corporation	No. of Trust Units Held [(1)]	Principal Occupation
David J. Rain Calgary, Alberta	Corporate Secretary	80,700 [(10)]	Chartered Accountant; Corporate Secretary of the Corporation; Vice President, Finance and Chief Financial Officer of Petrobank since October 2001; Vice President and Director of Caribou since April 2001; from April 2000 to September 2001, Director, Corporate Finance of Petrobank; from May 1997 to June 1999, Corporate Controller and Treasurer of Pacalta.

Notes:

(1) Represents all Trust Units held directly or indirectly or over which such person exercises control or direction as at September 30, 2003. Based upon information provided by the director or officer to the Trust.
(2) Member of the Audit and Corporate Governance Committee.
(3) Member of the Reserves, Safety and Environment Committee.
(4) Member of the Compensation Committee.
(5) The Corporation does not have an executive committee.
(6) The terms of office of all of the directors will expire at the next annual shareholders' meeting of the Corporation.
(7) Includes Trust Units held by Caribou, a company controlled by Mr. Chernoff, and Trust Units held in RESP accounts for the benefit of Mr. Chernoff's children.
(8) Includes 43,919 Trust Units held in Mr. Roorda's spouse's account which is controlled by Mr. Roorda.
(9) Excludes 7,250 Trust Units held in the name of Mr. Fisher's children but otherwise controlled by Mr. Fisher.
(10) Includes 30,700 Trust Units held by Mr. Rain's spouse.

As at September 30, 2003, the 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 6,494,480 Trust Units or 38.6% of the outstanding Trust Units.

The following is a brief description of the background of each of the senior officers 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.

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.

David M. Fisher, Vice President, Finance

Mr. Fisher is a Chartered Accountant and graduated in 1980 with a Bachelor of Commerce degree from the University of Alberta. Mr. Fisher has in excess of 20 years experience in financial reporting, management and administration of entities active in the oil and natural gas industry.

From September 1998 to October 2002, Mr. Fisher was a founder, Director and Vice President, Finance and Chief Financial Officer of Integra, a private upstream oil and natural gas corporation with assets located in the province of Alberta. Mr. Fisher was responsible for all financial aspects of Integra including reporting systems, financial reporting, securing equity and bank financing, managing financial assets, taxation, and working with legal counsel and transfer agents in the management of shareholder and regulatory items.

From April 1995 to July 1998, Mr. Fisher was the Vice President, Finance and Chief Financial Officer of Canrise. Canrise was a public upstream oil and natural gas corporation with assets located in west-central Alberta.

During the period June 1980 to April 1995 Mr. Fisher's was an external auditor for KPMG Chartered Accountants (formerly Peat Marwick Mitchell & Co.), incentives auditor for Energy Mines and Resources Canada, Manager of Corporate Reporting for Canadian Hunter Exploration Ltd. and an independent consultant providing financial administration for domestic and international entities.

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. 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 for $1 billion.

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 and real estate. Mr. Chernoff became a Director, and the Executive Vice President and Chief Financial Officer of Petrobank in March 2000. Mr. Chernoff resigned as Chief Financial Officer of Petrobank in October 2001 to focus on his other business interests, but remains a director of the company. Mr. Chernoff initiated the formation of the Corporation in June 2002 to pursue oil and natural gas development and acquisition opportunities. Mr. Chernoff is also a director of several other public companies.

Hank B. Swartout, Director

Mr. Swartout is 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 majority 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.

David J. Rain, Corporate Secretary

Mr. Rain is a Chartered Accountant and holds a Bachelor of Commerce degree from the University of Saskatchewan (1986).

Mr. Rain articled at KPMG LLP Chartered Accountants and was a Manager in their audit group until 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.

Corporate Cease Trade Orders or Bankruptcies

No director, officer or promoter of the Corporation or shareholder holding sufficient securities of the Corporation to affect materially the control 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 reporting issuer 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 or shareholder holding sufficient securities of the Corporation to affect materially the control of the Corporation, 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 been subject to or instituted any proceeding, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold the assets of the individual.

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".

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 November 28, 2003, there were 17,013,543 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 2003 Unitholders' Meeting, the Unitholders approved an amendment to the Trust Indenture to provides 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. 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, after the Closing, 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.

The initial term of the Trustee's appointment is until the first annual meeting of Unitholders. The Unitholders shall, at the first annual meeting of the Unitholders, re-appoint, or appoint a successor to the Trustee for an additional one year term, and thereafter, the Unitholders shall reappoint or appoint a successor to the Trustee at the annual meeting of Unitholders following the reappointment or appointment of the successor to the Trust. 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 12, 2003 the total number of Trust Units issuable under the Unit Incentive Plan was increased from 875,000 Trust Units to a cumulative maximum number of 1,121,000 Trust Units. The total number of Trust Units issuable under the Unit Incentive Plan as at September 30, 2003 was 885,500 Trust Units.

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. The exercise price ("Exercise Price") per Right shall be calculated by deducting from the Grant Price the aggregate of all distributions, on a per Unit basis, made by the

Trust after the Grant Date, provided the aggregate amount of such distribution represents a return of more than 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 and any future income tax liability associated with such capital assets at the end of each month.

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 Trust 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 September 30, 2003.

Group	Date Incentive Rights Granted	Trust Units Under Option	Grant Price	Closing Price on Day Prior to Grant	Exercise Price as at September 30, 2003	Expiry Date	Market Value of Incentive Right (1)
Executive Officers (4)	November 25, 2002	475,000	$8.00	$8.00	$6.20	November 25, 2007	$2,755,000
Directors (4)	November 25, 2002	75,000	$8.00	$8.00	$6.20	November 25, 2005	$435,000
	February 14, 2003	34,500	$10.75	$10.75	$9.35	February 14, 2008	$91,425
Employees and Consultants (16)	November 25, 2002	237,500	$8.00	$8.00	$6.20	November 25, 2005	$1,377,500
	January 24, 2003	32,500	$10.21	$10.21	$8.61	January 24, 2008	$110,175
	July 15, 2003	12,500	$10.18	$10.18	$9.78	July 15, 2008	$27,750
	July 17, 2003	7,500	$10.20	$10.20	$10.00	July 17, 2008	$15,000
	July 18, 2003	11,000	$10.30	$10.30	$10.10	July 18, 2008	$20,900

Note:

(1) Based on the difference between the closing price of $12.00 per Trust Unit on the TSX on September 30, 2003 and the grant price of the Incentive Right less distributions per Trust Unit paid after the date the Incentive Right was granted 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 September 30, 2003, 735,389 Trust Units have been issued from treasury since February 15, 2003 for proceeds of $7,385,435 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.

SELECTED FINANCIAL INFORMATION

Annual and Financial Information

The following is a summary of selected consolidated financial information of the Trust for the period from July 10 to December 31, 2002 and the three month period ended on each of March 31, 2003, June 30, 2003 and September 30, 2003. The following should be read in conjunction with the information contained under the heading "Management's Discussion and Analysis" below and the unaudited interim consolidated financial statements of the Trust for the nine months ended September 30, 2003 and the audited consolidated financial statements of the Trust for the period from July 10, 2002 to December 31, 2002. The selected consolidated financial information is not necessarily reflective of the Trust's future results from operations or financial condition.

($000's, except unit amounts)	For the period from July 10 to December 31, 2002	2003 Three month period ended March 31	Three month period ended June 30	Three month period ended September 30
Net Revenue	18,955	14,738	17,623	21,181
Net Income	5,136	3,736	1,180	5,751
Net Income per unit - basic	3.46	0.36	0.10	0.46
Net Income per unit - diluted	3.69	0.34	0.10	0.45
Total Assets	93,729	92,041	120,122	144,369
Total Liabilities	53,723	38,891	61,645	51,473
Distributions declared, per unit	0.20	0.60	0.60	0.60

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(2)	$0.20

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 November 18, 2003 that the next monthly cash distribution of $0.20 per Trust Unit will be paid on December 15, 2003 to Unitholders of record on November 30, 2003.

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

In connection with the completion of the Initial Public Offering, certain members of the Management Group holding an aggregate $4,777,500 principal amount of debentures of 990148 Alberta Ltd. (which were settled with 4,777,500 Trust Units which, as at September 30, 2003 represented approximately 38.4% of the then outstanding Trust Unit and as at the date hereof approximately 28.1%) executed an undertaking in favour of the underwriters of the Initial Public Offering not to offer or sell, agree to offer or sell, or enter into an arrangement to offer or sell any Trust Units or other securities of the Trust or the Corporation, or securities convertible into, exchangeable for, or otherwise exercisable to acquire any securities of the Trust or the Corporation then held by such holder or such holder's spouse, directly or indirectly, at any time until November 28, 2004.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Management's discussion and analysis of the Trust's financial condition and results of operations should be read in conjunction with the unaudited interim consolidated financial statements for the three and nine month periods ended September 30, 2003 and the audited consolidated financial statements contained in this Annual Information Form.

Forward-Looking Information

The following discussion contains forward-looking information with respect to the Trust. 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. The information and opinions concerning the Trust's future outlook are based on information available at November 25, 2003. See "Special Note Regarding Forward-Looking Statements".

Nine Months Ended September 30, 2003

Sales Volumes

Harvest's production consists of medium and heavy oil, natural gas liquids, and natural gas from properties located in East Central Alberta. Sales of oil and natural gas averaged 11,373 BOE/d and 9,754 BOE/d in the three and nine month periods ended, respectively.

Average Sales Volumes

	Three Month Period Ended September 30, 2003		Nine Month Period Ended September 30, 2003	
Medium oil (Bbls/d)	5,044	44%	4,300	44%
Heavy Oil (Bbls/d)	6,010	53%	5,192	53%
Total Oil (Bbls/d)	11,054	97%	9,492	97%
Natural Gas liquids (Bbls/d)	77	1%	68	98%
Total oil and natural gas liquids (Bbls/d)	11,131	98%	9,560	98%
Natural Gas (mcf/d)	1,453	2%	1,165	2%
Total oil equivalent (6:1 BOE/d)	11,373	100%	9,754	100%

Harvest exited September 30, 2003 with a higher daily production rate of approximately 11,600 BOE/d, which reflects the impact of the ongoing development and optimization activities during the quarter. Harvest anticipates further production growth in the balance of 2003 due to the oil and natural gas property acquisition in Southeastern Saskatchewan and the continuing development and optimization program.

Revenue

Revenues, before royalties, totaled $28.5 million and $79.4 million, which was the result of average realized prices of $27.22 and $29.66 per barrel for oil and natural gas liquids and $4.94 and $6.28 per mcf for natural gas during the three and nine month periods ended September 30, 2003 respectively. The overall impact of Harvest's hedging program is an approximate decrease of $3.37 and $5.94 per BOE of production, for the three and nine month periods ended respectively. Harvest plans to continue with its current hedging strategy, and has approximately 10,000 Bbls/d of production hedged for the balance of 2003 at an approximate average price of $30.00 Cdn per barrel.

Operating Netbacks

The following is a summary of Harvest's operating netbacks for the periods ended September 30, 2003:

	($/BOE)	
	Three Month Period Ended September 30, 2003	Nine Month Period Ended September 30, 2003
Market Price	27.27	29.82
Hedging Loss	3.37	5.94
Realized Price	23.90	23.88
Royalties Net	3.66	3.77
Operating Costs	9.23	8.66
Netback	11.01	11.45

Royalty Expense

Harvest paid net royalties of $3.8 million and $10 million in the three and nine month periods ended or approximately $3.66/BOE and $3.77/BOE, respectively. The net royalty amount for the three month period ended is comprised of $2.6 million in freehold royalties and freehold mineral tax, $1.1 million in crown royalties, $0.2 million in gross overriding royalties and $0.1 million in royalty income received. The net royalty amount for the nine month period ended is comprised of $6.7 million in freehold royalties and freehold mineral tax, $3.2 million in crown royalties, $0.4 million in gross overriding royalties and $0.3 million in royalty income received.

Operating Expenses

Harvest's operating expenses were $9.7 million and $23 million for the three and nine month periods ended or approximately $9.23 and $8.66 per BOE, respectively. Substantially all of the entity's properties are operated by Harvest. The significant portions of Harvest's operating costs are electricity (60%) and maintenance (15%). For the remainder of 2003, Harvest has approximately 48% of its current electricity usage hedged at an average price of $45.10 per MWh.

General and Administration Expenses

General and administrative expenses totaled $0.6 million or $0.54 per BOE for the three month period ended, and $2.1 million or $0.78 per BOE for the nine month period ended. During the three and nine month periods ended, $0.2 million and $0.7 million, respectively, of general and administrative costs were capitalized with respect to field enhancement and acquisition activities. Third quarter general and administrative expenditures have been reduced by recoveries related to the capital expenditure program during the third quarter.

Interest Expense and Amortization of Deferred Financing Charges

Interest expense and deferred financing charges amounted to $1.2 million and $3.4 million in the three and nine month periods ended, respectively. The amortization of deferred financing charges associated with fees to secure bank lending facilities amounted to $0.8 million and $1.6 million for the three and nine month periods ended, respectively.

Depletion, Depreciation and Amortization and Future Site Reclamation Expenses

Harvest's depletion, depreciation, and amortization and site restoration provision totaled $9.3 million and $22.8 million and for the three and nine month periods ended, respectively. This balance is comprised of oil and natural gas properties depletion and depreciation of $8 million and $20.1 million, approximately $28,000 and $78,000 for depreciation of office furniture and equipment, and $1.3 million and $2.7 million for future abandonment and site restoration costs, respectively. The depletion rate for oil and natural gas properties was approximately $7.68 and $7.58 per BOE for the three and nine month periods ended respectively, and is based on the costs of the oil and natural gas properties purchased, capital expenditures incurred and capitalization of general and administrative expenses. The $1.21 and $1.00 per BOE rate for the three and nine month periods ended, respectively, used to provide for future site reclamation costs is founded on an ultimate net future expenditure of approximately $18.8 million. The depreciation of office furniture and equipment and leasehold improvement costs has been calculated on a straight-line basis of 20% to 50%.

Income Taxes

Income taxes for the three and nine month periods ended are comprised of approximately $86,000 and $138,000 in large corporation tax and a $3.6 million and $3.3 million future income tax recovery, respectively. Other than large corporations tax, neither the Trust nor its operating subsidiary are expected to pay cash taxes in 2003.

Cash Flow and Income

For the three and nine month periods ended September 30, 2003, consolidated cash flow from operations was $16.8 million and $32.8 million, and net income was $5.8 million and $10.7 million, respectively.

Cash flow from operations per trust unit is calculated and disclosed by the Trust, as it is a widely accepted measure of financial performance used by analysts and investors to compare oil and natural gas royalty trusts and producing companies. Analysts and investors use cash flow from operations per trust unit as a basis for measuring unit valuation and as a measure of liquidity. In order to determine whether a trust's units are trading at an appropriate price, analysts and investors often multiply cash flow from operations per trust unit by an appropriate benchmarking multiple. In addition, analysts and investors consider higher distributions per unit as a positive measure of liquidity. Analysts and investors are able to use a trust's cash flow from operations per trust unit and the trust's payout policy to evaluate whether the trust will have the ability to maintain a certain level of distributions per unit for future periods and assess a trust's ability to fund growth opportunities utilizing internally derived cash flow.

Cash flow from operations per trust unit is not defined under Canadian generally accepted accounting principles ("GAAP") and should not be considered in isolation or as an alternative to conventional GAAP measurements. Harvest's measure of cash flow from operations is not necessarily comparable to a similarly titled measure of another company or trust.

The corresponding per Trust Unit and per BOE figures are as follows.

	Three Month Period Ended September 30, 2003			Nine Month Period Ended September 30, 2003		
	Per Trust Unit			Per Trust Unit		
	Basic	Diluted	Per BOE	Basic	Diluted	Per BOE
Cash flow from operations	$1.35	$1.31	$16.02	$2.88	$2.79	$12.32
Net Income	$0.46	$0.45	$5.50	$0.94	$0.91	$4.01

The cash flow from operations amounts are higher than anticipated due to the extinguishment of U.S. denominated debt and the realization of the foreign exchange gain on this instrument.

Capital Expenditures

Capital expenditures totaled $10.1 million and $48.5 million in the three and nine month periods ended, respectively, including non-cash charges. The expenditures during these periods primarily consist of the acquisition of oil and natural gas producing properties in Eastern Alberta, that complement Harvest's current operations and production.

Subsequent to the end of the quarter, on October 16, 2003 Harvest closed the purchase of oil and natural gas producing properties in Southeastern Saskatchewan through its wholly owned subsidiary, Harvest Operations Corp. This asset purchase is anticipated to add approximately 5,200 BOE/d in production, for an approximate consideration of $80.0 million.

Capitalization and Financial Resources

Royalty trusts all employ basically the same fundamental approach to funding. As with other trusts, the primary sources of funding employed by the Trust to finance its growth are cash flow, the Trust's DRIP Plan, issuances of Trust Units and Equity Bridge Notes, and debt, primarily bank debt and short-term bridge debt. To date, cash flow alone has enabled the Trust to pay out stable monthly distributions of $0.20 per Trust Unit to Unitholders since the time the Trust became a public entity in December 2002, as well as helping to support an active capital expenditures program, provide funds for working capital and meet debt-servicing requirements.

Currently, the Trust has utilized less than 75% of the $89 million Current Bank Facility. Monthly distributions paid to Unitholders represent less than 70% of monthly cash flow generated from operations before inclusion of cash from or for non-cash operating working capital items. Of the distributions paid to Unitholders, approximately 1/3 is re-invested back into the Trust through the DRIP Plan. This combination of available debt financing, cash flow and reinvested distributions means that the Trust has the financial ability to meet its obligations and carry out its business plan in the short-term without the need for an increase in debt facilities.

As at September 30, 2003, the demand loan payable was approximately $2.8 million, compared to a balance of $45.3 million of demand loan payable as at December 31, 2002. The demand loan denominated in U.S. dollars was extinguished on September 30, 2003, with the funds received from the debt and equity bridge note facilities. The debt and equity bridge note facilities outstanding as at September 30, 2003 were $25 million and $33.5 million, respectively.

The working capital balance as at September 30, 2003 was $18.1 million, excluding the demand loan and bridge note payable. This is in comparison to working capital of $10.7 million as at December 31, 2002. The difference of $7.4 million is primarily due to an increase in cash and short-term investments, resulting from the timing of the receipt of the debt and equity bridge note facilities in the latter part of the third quarter. These funds were subsequently used as a portion of the financing of the acquisition of the Southeastern Saskatchewan properties.

On October 1, 2003 the Trust met its quarterly obligations to pay interest under the Equity Bridge Notes and Bridge Note payable. In addition, the Trust also repaid $11 million of the Bridge Note principal. The quarterly interest principal repayments were financed with funds realized from working capital.

On October 3, 2003 the Trust used a $15 million Interim Bank Facility of which $2.9 million was used to repay accrued interest and principal on a demand loan. The Interim Bank Facility was used to satisfy payable obligations until October 16, 2003 when it was paid out and replaced with the $89 million revolving Current Bank Facility.

On October 16, 2003 the Trust closed the $80 million purchase of the Carlyle Properties located in Southeast Saskatchewan. The Trust also repaid the remaining $4.5 million plus $57,534 in accrued interest owing under the Bridge Note payable and repaid $8.5 million of Equity Bridge Notes principal. These payments were financed with funds from the issue of Trust Units providing $51.8 million in gross proceeds and the $89 million Current Bank Facility.

Capitalization and Liquidity Outlook

In excess of $20 million of borrowing capacity currently remains available under the Current Bank Facility. The facility will be used to meet working capital requirements and to finance additional capital expenditures or oil and natural gas property acquisitions. Starting on January 31, 2004 the total borrowings available under the Current Bank Facility are scheduled to decrease by $4.5 million per month (i.e. on January 31, 2004 the maximum borrowing permitted under the facility will decrease to $84.5 million and $80 million on February 29, 2004, etc.). Given the current utilization and anticipated borrowings, the $4.5 million dollar reducing amount is unlikely to limit the Trust's ability to carry out its business plan. The Current Bank Facility is subject to an annual review on or before May 1, 2004 at which time the Trust's borrowing base will be reviewed with updated oil and natural gas property reserve data. In the interim period prior to May 1, 2004, should the Trust require additional bank debt to assist in the financing of a significant acquisition, the Trust has the right to request a review under the agreement governing the Current Bank Facility.

If necessary, the Trust will consider issuing additional equity to finance oil and natural gas property acquisitions. In addition, the Trust has the right to satisfy the payment of interest and repayment of principal in respect of the Equity Bridge Notes with cash or the issue of Trust Units (calculated with reference to the volume adjusted weighted average trading price for the 10 day period preceding the payment). Current expectations are that the quarterly interest amounts will be satisfied with cash payments. The principal is due on January 3, 2005. At this time no decision has been made on whether cash or trust units will be used to satisfy this obligation.

The Trust anticipates that the monthly cash flow generated by operations will continue to exceed the amount required to fund the forecast monthly $0.20 per Trust Unit distributions to Unitholders. As such, the excess funds will be applied to reduce borrowings under the Current Bank Facility. Similarly, any reinvestment of distributions paid to unitholders through DRIP activity will also be applied against borrowings under the Current Bank Facility.

Distributions

During the first half of 2003, Harvest paid distributions of $0.20 per month. Of the distributions declared and paid in the first nine months of 2003, approximately 39% were reinvested by unitholders through Harvest's distribution reinvestment plan. This resulted in a net cash distributions paid during the first nine months of $12.4 million. The Trust anticipates the 2003 distributions will likely be 40% taxable, and a 60% return of capital to unitholders. Additional oil and natural gas property acquisitions may change the taxability of the distributions.

For the period from July 10 (date of formation) to December 31, 2002

Production and Sales Volumes

The Trust's production consists of medium oil, heavy oil, natural gas liquids, and natural gas from properties located in Eastern Alberta. Sales of oil and natural gas averaged 4,307 BOE/d in 2002. The table below lists the components of sales volumes averaged over the 175 day period that the Trust operated in 2002.

2002 Sales Volumes		**(%)**
Medium oil	2,718 Bbls/d	63
Heavy oil	1,463 Bbls/d	34
Total oil	4,181 Bbls/d	97
Natural gas liquids	22 Bbls/d	1
Total oil and liquids	4,203 Bbls/d	98
Natural gas	624 Mcf/d	2
Total oil equivalent	4,307 BOE/d	100

Approximately 2,785 BOE/d was contributed by the properties acquired on July 10, 2002 (Thompson Lake area), and 1,522 BOE/d contributed by the properties purchased on November 15, 2002 (Hayter/Provost area). Over the final 46 days of 2002 the Hayter/Provost oil and natural gas properties averaged production of 5,791 BOE/d. The Trust's 2002 exit production totalled 8,610 BOE/d consisting of 5,795 Bbls/d of heavy oil, 2,600 Bbls/d of medium oil, 19 Bbls/d of natural gas liquids and 1,177 Mcf/d of natural gas.

Commodity Prices

The Trust recorded an average selling price of $30.13/BOE in the 2002 fiscal period. The corresponding price after reflecting the impact of $1.0 million in oil hedging losses is $28.79/BOE. The following table indicates the average field price received by the Trust for each of its products in 2002.

2002 Average Field Selling Prices	
Heavy oil	$22.63/Bbl
Medium oil	$34.21/Bbl
Total oil	$30.16/Bbl
Natural gas liquids	$37.64/Bbl
Total oil and liquids	$30.20/Bbl
Natural gas	$4.54/Mcf
Oil equivalent	$30.14/BOE

The majority of the Trust's heavy oil production was purchased on November 15, 2002 in the Hayter/Provost acquisition. Along with the acquisition, the Trust entered into a contract to sell the heavy oil from the date of the property purchase until December 31, 2003. The contract volume of 6,000 Bbls/d is comprised of approximately 5,000 Bbls/d of heavy oil production blended with 1,000 Bbls/d of condensate. The price received is based on a WTI collar less a fixed differential of U.S.$8.233/Bbl. The upper limit on the collar is U.S.$25.477/Bbl and the lower value is U.S.$22.633/Bbl. Essentially, this contract limits the impact of changes in oil prices and heavy oil differential on the Trust's business plan.

The Trust has entered into physical hedges with respect to a portion of its medium oil production. During the period of September 2002 to December 31, 2002, the Trust received a price of $39.31/Bbl on 1,200 Bbls/d and also sold 500 Bbls/d under a collar of $36.50/Bbl and $41.67/Bbl. The Trust has also entered into a number of financial hedges for 2003, 2004 and 2005. The hedges are disclosed in detail in the Financial Instrument Note in the audited consolidated financial statements of the Trust for the period from July 10, 2002 to December 31, 2002.

The Board of Directors of the Corporation reviews and approves a risk management policy that provides management with guidance in terms of hedging arrangements. The Board of Directors also reviews and approves the hedges negotiated by management. Consistent with its risk management policy, the Trust entered into the hedges with a diverse portfolio of financially sound parties to reduce the risk associated with the counterparties' abilities to fulfill contractual obligations.

The Trust enters into hedging arrangements to help assure that the prices received for production from proved producing reserves will offer a sufficient level of cash flow for its monthly distributions and to fund capital development and acquisitions programs to Unitholders as part of the "Going Concern" business plan. Overall, during 2003, the Trust ensured that the prices received for 7,600 Bbls/d of production would render sufficient cash flow to pay distributions of $0.20 per month in 2003 and to assist in funding the capital program.

Revenue

Revenues, before royalties, totalled $21.8 million in 2002 through the composition of sales indicated below.

Product	**($000)**	**(%)**
Heavy oil	5,791	27
Medium oil	16,277	75
Natural gas liquids	144	1
Natural gas	496	2
Production revenue	22,708	105
Hedging	(1,009)	(5)
Total	21,699	100

Royalty Expense

The Trust paid royalties of $2.9 million in 2002 or approximately $3.80/BOE. The table below provides details of the royalty expense.

Product	Royalty Expense ($000) Crown	Non-crown	Total	% of Production Revenue
Heavy oil	358	841	1,199	21
Medium oil	746	807	1,553	10
Natural gas liquids	19	1	20	14
Natural gas	77	15	92	19
Overall Total	1,200	1,664	2,864	13

The royalties associated with the 2002 production were not eligible for the ARTC as the production was purchased from corporations that had received the maximum ARTC. However, any crown royalties resulting from production of the wells drilled by the Trust will be eligible for ARTC.

Operating Expenses

The Trust's operating expenses were $6.4 million in 2002 or $8.49/BOE. The Trust operates all of its major properties. Operatorship is considered important to the Trust in order to ensure that its best practices are applied to operating activities to minimize costs and maximize production and the recovery of reserves.

Electrical power (49%), maintenance (17%) and labour costs (8%) represent the majority of the Trust's operating costs. Historical net field electrical power usage for the properties has been approximately 18 MW. Including the impact of the Killarney property acquisition in April 2003, the 2003 electrical power usage will increase to approximately 24 MW. During 2002, the Trust entered into contracts to purchase 5 MW of electrical power at a price of $46.30 per MWh for 2003. Early in 2003, the Trust also entered into a contract to fix an additional 5 MW of power at a price of $46.00 per MWh for 2004. The Trust also agreed to purchase 9.75 MW of power at a price of $44.50 per MWh for the period from April 1, 2003 to March 31, 2006.

Given the maturity of the Trust's oil and natural gas properties and management's plan to optimize the rate of production decline and increase recovery of the hydrocarbons in place, maintenance expense will continue to represent a significant portion of operating costs. However, the Trust believes that with the appropriate level of day-to-day attention and planning, the costs can be controlled.

The Trust's 26 field employees operate the wells. Field employees receive remuneration comparable to industry standards and are further motivated with bonuses based upon corporate and personal performance. Management believes that employing dedicated field personnel, rather than engaging third party contractors, is a key factor in successfully carrying out the Trust's business plan.

Netback

The Trust's operating margin in 2002 was $12.6 million or $16.66/BOE. The table below provides a summary of the Trust's netback.

	$000	$/BOE	% of Revenue
Production revenue	22,708	30.13	104
Hedging losses	(1,009)	(1.34)	(5)
Royalty income	120	0.16	1
Royalties	(2,864)	(3.80)	(13)
Operating expenses	(6,396)	(8.49)	(29)
Netback	12,559	16.66	58

General and Administration Expenses

General and administrative expenses totalled $0.8 million or $1.00/BOE in 2002. Of this amount, $0.6 million or $0.77/BOE was charged against income. Consistent with The Trust's "Going Concern" strategy, and unlike other conventional energy trusts, a portion of the Trust's general and administrative expenditures is in respect to oil and natural gas development activity. As such $0.2 million or $0.23/BOE of general and administrative costs were capitalized.

Interest Expense and Amortization of Deferred Financing Charges

Interest charges were $2.0 million, while amortized deferred financing charges associated with fees to secure bank lending facilities amounted to $0.6 million. During 2002, the Trust incurred $0.8 million of interest charges for bank debt used to partially finance oil and natural gas property acquisitions and to provide working capital. The Trust also paid $1.2 million of interest for bridge financing and a debenture to assist with the start-up of the Trust. The bridge financing and debenture were both repaid on December 5, 2002 upon completion of the Trust's initial public offering.

On December 31, 2002, bank debt was $45.7 million and unamortized deferred financing costs were $2.2 million. The deferred financing charges will be amortized on a straight-line basis over the life of the bank credit facility.

Depletion, Depreciation, and Future Site Reclamation Expenses

The Trust's 2002 depletion, depreciation, and amortization ("DD&A") and site restoration provision totalled $5.7 million. This number includes DD&A for oil and natural gas properties of $5.1 million, $32,000 for depreciation of office furniture and equipment, and $0.5 million for future abandonment and site restoration costs. The DD&A rate for oil and natural gas properties was $6.77/BOE and is based on the purchase costs of the oil and natural gas properties. The $0.72/BOE rate used to provide for future site reclamation costs is founded on an ultimate future expenditure of $9.2 million estimated by management and an independent third party. The depreciation of office furniture and equipment has been calculated on a straight-line basis of 20% to 33%.

Income Taxes

Income taxes for 2002 were comprised of $47,000 for large corporation tax and $1.3 million of future income tax recovery, as a result of the consolidation of the Trust and the Corporation.

At the end of 2002, the Corporation had tax pools of $32 million available to reduce future income. The tax pools are made up of $6.3 million in COGPE, $0.2 million in Canadian Development Expenses, $0.3 million of Canadian Exploration Expenses, $21.7 million in unclaimed tangible costs, $2.2 million in deferred financing costs and $1.3 million in non-capital loss carry forward. Similarly, the Trust has tax pools totalling $63 million, consisting of $48.3 million in COGPE, $2.7 million in Trust Unit issue costs, and $12.0 million in tax losses.

Cash Flow and Earnings

The 2002 fiscal year cash flow from operations and net income were $9.5 million ($12.61/BOE) and $5.1 million ($6.81/BOE), respectively. The corresponding per Trust Unit figures are $6.83 (diluted – $6.43) and $3.69 (diluted $3.46). The per unit figures are significantly higher than will be recorded in 2003 as nearly all of the Trust's 2002 Trust Units were outstanding for only 26 days.

Capital Expenditures

Capital expenditures totalled $76.9 million in the 2002 fiscal year. The oil and natural gas property acquisitions of $76.2 million represent the majority of the costs incurred. The details in respect of the property acquisitions are outlined in the following table.

Acquisitions

				Cost per BOE	
Area	**Closing Date**	**Purchased Production (BOE/d)**	**Closing Price ($000)**	**Established Reserves ($/BOE)**	**Production at Closing ($/BOE/d)**
Thompson Lake	July, October, 2002	2,754	27,185	5.85	9,871
Hayter	November 15, 2002	5,752	48,968	6.57	8,513
Total Property Acquisitions		8,506	76,153	6.30	8,953

MARKET FOR SECURITIES

The Trust Units are listed and traded on the TSX. The trading symbol for the Trust Units is HTE.

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.

Public and Insider Ownership

As at September 30, 2003, the directors and officers of the Corporation and their associates and affiliates, as a group, held, directly or indirectly, or exercised control or direction over, approximately 6,494,480 Trust Units or approximately 38.6% of the outstanding Trust Units.

As part of the Initial Public Offering, certain members of the Management Group holding an aggregate $4,777,500 principal amount of the Management Group Debentures executed an undertaking in favour of the Underwriters not to offer or sell, agree to offer or sell, or enter into an arrangement to offer or sell any Trust Units or other securities of the Trust or the Corporation, or securities convertible into, exchangeable for, or otherwise exercisable to acquire any securities of the Trust or the Corporation then held by such holder or such holder's spouse, directly or indirectly, at any time until November 28, 2004.

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".

Purchase of the NPI, the Properties and the Direct Royalties

The price paid for the purchase of the NPI, the Provost Properties and the Direct Royalties or to be paid for the purchase of the Carlyle Properties was based 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 Provost Properties and the Carlyle Properties.

Dispute Relating to Acquisition of Properties

The Corporation and Anadarko Canada Corporation (the "Vendor") are engaged in a dispute as to whether an adjustment to the purchase price paid for oil and natural gas properties acquired by the Corporation from the Vendor on November 15, 2002 should be made in favour of the Vendor. This dispute relates to whether or not the value of a hedging contract held by the Vendor impacts the net proceeds from the properties acquired from the effective date of the acquisition of June 1, 2002 to the closing date of November 15, 2002. Following various post closing adjustments, the Vendor is claiming that a net $3.3 million ($5.8 million disputed amount, less $2.5 million of holdbacks from the Vendor) is still owing by the Corporation. Management of the Corporation believes that such amount is not owing to the Vendor. This dispute will be resolved through an arbitration process. Should the Corporation be unsuccessful in defending on this amount, it will increase the amount of debt outstanding under its bank facility. This would increase the Corporation's debt service obligations which would have a negative impact on Cash Available for Distribution. Should the Corporation be successful in defending on this amount, it will reduce the amount of debt outstanding under its bank facility.

Changes in Legislation

There can be no assurance that income and capital tax laws and government incentive programs relating to the oil and natural gas industry, such as the status of mutual fund trusts and the resource allowance, 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. See "Eligibility for Investment" and "Canadian Federal Income Tax Considerations".

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 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 Provost Properties and believes it will become the operator of the Carlyle Properties, there is no guarantee that it will remain operator of the Provost Properties or that the Corporation will operate the Carlyle Properties or any other Properties it may acquire.

A significant portion of the operating expenses of the Provost Properties, and to a lesser degree, the Carlyle 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 Carlyle 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.

Reserve Estimates

The reserve and recovery information contained in the McDaniel Report – Provost Properties and the McDaniel Report – Carlyle Properties is only an estimate and the actual production and ultimate reserves from the Provost Properties and the Carlyle Properties may differ from the estimates prepared by McDaniel.

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". Although the Operating Subsidiaries have established reclamation funds for the purpose of funding estimated future environmental and reclamation obligations, there can be no assurance that the Operating Subsidiaries will be able to satisfy its actual environmental and reclamation obligations. See "Description of the Trust – The NPI and Direct Royalties – Reclamation Fund".

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 will only become legally binding when it is ratified by at least 55 countries, covering at least 55 percent of the emissions addressed by the Protocol. If the Protocol is ratified and becomes legally binding, it 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 Service

As at the date hereof, the Trust had indebtedness of approximately $64 million under the Current Bank Facility. In addition, the New Lender has issued letters of credit to third parties of approximately $3.3 million on behalf of the Corporation to secure services on the Properties. See "Information Respecting the Corporation – Borrowing by the Corporation". In addition, as of the date hereof, approximately $25 million is outstanding under the Equity Bridge Notes. See "Description of the Trust – Borrowing by the Trust.

The Current Lender was provided with security over all of the assets of the Operating Subsidiaries. See "Information Respecting the Corporation – Borrowing by the Corporation". If the Corporation, WEI and the Trust experience an unremedied borrowing base shortfall or default, commit an event of default or the Current Lender demands repayment, the Current Lender 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 to the Trust, and amounts payable to the Trustee under the Trust Indenture are subordinate to the Current Bank Facility pursuant to a subordination agreement between the Current Lender, the

Trustee, and the Corporation dated October 16, 2002. This Subordination Agreement may restrict the ability of the Corporation to pay the NPI to the Trust or pay interest or principal on any indebtedness to the Trust, and therefore may limit or eliminate the Cash Available For Distribution.

The Corporation must meet certain ongoing hedging and financial 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.

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. To the extent that borrowings under the New Interim Bank Facility are made in U.S. dollars, the interest payable thereunder is also payable in U.S. dollars. Variations in the Canadian/U.S. dollar exchange could result in a significant increase in the amount of the interest paid under the New Interim Bank Facility, 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. 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 pursuant to the NPI and subsequently distributed to the Unitholders. Future cash flows generated by such additional Properties may not be similar to those of the Provost Properties and may not generate sufficient cash flows to allow the Operating Subsidiaries to generate sufficient income from the NPI 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.

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. 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 exploited.

Trust Units will have no value when reserves from the Properties can no longer be economically marketed and, as a result, subscribers for Trust Units will need to obtain a return of capital invested out of cash flow derived from their investment in Trust Units 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.

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.

Limited Operational History

The Corporation and the Trust were only recently organized and have a limited history of operations and the Trust has made only limited distributions.

Impact of Future Capital Expenditures

The Reserve Value of the Properties as estimated by McDaniel 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 McDaniel will be reduced to the extent that such capital expenditures on the Properties do not achieve the level of success assumed by McDaniel.

Volatility of Commodity Prices

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. The Corporation must also meet certain ongoing hedging covenants under the New Interim Bank Facility and the New Bank Facility. To the extent that commodity prices increase significantly, Cash Available for Distribution could be negatively affected. See "Information Respecting the Corporation – Commodity Hedging."

Crude Oil Differentials

The Corporation's crude oil production from the Provost Properties and the Carlyle Properties will be approximately 62.5% light and medium oil, 36.5% heavy oil and 1.2% natural gas and 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.

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. 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 Provost 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 that 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.

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 n 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 which minimizes taxes and other expenses payable with respect to the operation of the Trust and the Operating Subsidiaries and which 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.

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 April 30, 2003 which relates to the Annual and Special Meeting of Unitholders held on June 12, 2003, and additional financial information is provided in the consolidated financial statements of the Trust for the year ended December 31, 2002.

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

when the securities of the Trust are in the course of a distribution pursuant to a short form prospectus or a preliminary short form prospectus has been filed in respect of a distribution of its securities,

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;

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;

one copy of the Information Circular - Proxy Statement of the Trust dated April 30, 2003; and

one copy of any other documents that are incorporated by reference into the preliminary short form prospectus or the short form prospectus and are not required to be provided under (i) to (iii) above; or

at any other time, one copy of any other documents referred to in (a)(i), (ii) and (iii) 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.
1900, 330 – 5th Avenue S.W.
Calgary, Alberta T2P 0L4
Toll free in Canada: 1-866-666-1178
Fax: (403) 265-3940

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Schedule of Revenue and Expenses for the

INITIAL PROPERTIES

Acquired from Devon Canada Corporation

Years ended December 31, 2001, 2000 and 1999

AUDITORS' REPORT

To the board of directors of Harvest Operations Corp.

At the request of Harvest Operations Corp., we have audited the schedule of revenue and expenses for the properties (the "Initial Properties") referred to in the purchase and sale agreement dated May 28, 2002 between Harvest Operations Corp. and Devon Canada Corporation and Devon ARL Corporation for each of the years in the three year period ended December 31, 2001. This financial information is the responsibility of Harvest Operations Corp. 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 presentation of the financial information.

In our opinion, this financial information presents fairly, in all material respects, the revenue and expenses for the Initial Properties referred to in the purchase and sale agreement dated May 28, 2002 for each of the years in the three-year period ended December 31, 2001.

(signed) KPMG LLP

Chartered Accountants

Calgary, Canada
September 18, 2002

INITIAL PROPERTIES

Schedule of Revenue and Expenses for the Initial Properties

	Six months ended June 30,		Years ended December 31,		
	2002	2001	2001	2000	1999
	(unaudited)		(audited)		
Revenue	$ 13,935,019	$ 16,772,213	$ 30,675,360	$ 46,395,299	$ 30,506,217
Royalties	(1,210,816)	(1,630,888)	(2,791,810)	(4,406,652)	(2,984,815)
	12,724,203	15,141,325	27,883,550	41,988,647	27,521,402
Operating costs	5,050,362	6,901,821	11,587,364	9,333,045	7,266,639
Operating income	$ 7,673,841	$ 8,239,504	$ 16,296,186	$ 32,655,602	$ 20,254,763

See accompanying notes to schedule of revenue and expenses for the Initial Properties.

1. Basis of presentation:

On May 28, 2002 Harvest Operations Corp. entered into a purchase and sale agreement to acquire the Thompson Lake properties (the "Initial Properties") from Devon Canada Corporation and Devon ARL Corporation (collectively "Devon Canada"). This acquisition closed on July 10, 2002.

The schedule of revenue and expenses for the Initial Properties includes the operations of the Initial Properties by Devon Canada.

The schedule of revenue and expenses for the Initial Properties includes only amounts applicable to the working interest of Devon Canada for the Initial Properties.

The schedule of revenue and expenses for the Initial Properties does not include any provision for the depletion and depreciation, site restoration, future capital costs, impairment of unevaluated properties, general and administrative costs and income taxes for the Initial Properties as these amounts are based on the consolidated operations of Devon Canada of which the Initial Properties formed only a part.

2. Significant accounting policies:

(a) Revenue:

Revenue from the sale of oil and natural gas is recorded at the time that the product is produced and sold.

(b) Royalties:

Royalties are recorded at the time the product is produced and sold. Royalties are calculated in accordance with Alberta Energy regulations or the terms of individual royalty agreements.

(c) Operating expenses:

Operating expenses include amounts incurred to bring the oil and natural gas to the surface, gather, transport, field process, treat and store same. Operating expenses are reflected net of gathering, processing and transportation revenue associated with the Initial Properties.

Schedule of Revenue and Expenses for the

ADDITIONAL PROPERTIES

Acquired from Anadarko Canada Corporation

Years ended December 31, 2001, 2000 and 1999

AUDITORS' REPORT

To the board of directors of Harvest Operations Corp.

At the request of Harvest Operations Corp., we have audited the schedule of revenue and expenses for the Additional Properties referred to in the purchase and sale agreement dated August 1, 2002 between Harvest Operations Corp. and Anadarko Canada Corporation for each of the years in the three-year period ended December 31, 2001. This financial information is the responsibility of Harvest Operations Corp. 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 presentation of the financial information.

In our opinion, this financial information presents fairly, in all material respects, the revenue and expenses for the Additional Properties referred to in the purchase and sale agreement dated August 1, 2002 for each of the years in the three-year period ended December 31, 2001.

(signed) KPMG LLP

Chartered Accountants

Calgary, Canada
September 18, 2002

ADDITIONAL PROPERTIES

Schedule of Revenue and Expenses for the Additional Properties

	Nine months ended September 30,		Years ended December 31,		
	2002	2001	2001	2000	1999
	(unaudited)		(audited)		
Revenue	$ 55,459,785	$ 48,198,918	$ 57,615,104	$ 72,026,276	$ 42,693,456
Royalties	(7,323,940)	(7,860,337)	(11,340,031)	(14,465,051)	(7,268,179)
	48,135,845	40,338,581	46,275,073	57,561,225	35,425,277
Operating costs	12,665,536	10,404,008	12,832,174	8,799,976	7,452,752
Operating income	$ 35,470,309	$ 29,934,573	$ 33,442,899	$ 48,761,249	$ 27,972,525

See accompanying notes to schedule of revenue and expenses for the Additional Properties.

ADDITIONAL PROPERTIES

Notes to Schedule of Revenue and Expenses for the Additional Properties

Years ended December 31, 2001, 2000 and 1999
(Information for the nine months ended September 30, 2002 and 2001 is unaudited)

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1. Basis of presentation:

On August 1, 2002, Harvest Operations Corp. entered into a purchase and sale agreement to acquire the Hayter and Provost properties (the "Additional Properties") from Anadarko Canada Corporation ("Anadarko"). This acquisition closed on November 15, 2002.

The schedule of revenue and expenses for the Additional Properties includes the operations of the Additional Properties by Anadarko.

The schedule of revenue and expenses for the Additional Properties includes only amounts applicable to the working interest of Anadarko for the Additional Properties.

The schedule of revenue and expenses for the Additional Properties does not include any provision for the depletion and depreciation, site restoration, future capital costs, impairment of unevaluated properties, general and administrative costs and income taxes for the Additional Properties as these amounts are based on the consolidated operations of Anadarko of which the Additional Properties form only a part.

2. Significant accounting policies:

(a) Revenue:

Revenue from the sale of oil and natural gas is recorded at the time that the product is produced and sold.

(b) Royalties:

Royalties are recorded at the time the product is produced and sold. Royalties are calculated in accordance with Alberta Energy regulations or the terms of individual royalty agreements.

(c) Operating expenses:

Operating expenses include amounts incurred to bring the oil and natural gas to the surface, gather, transport, field process, treat and store same and variable operating overhead as established by Anadarko.

KPMG

Schedule of Revenue and Expenses for the

CARLYLE PROPERTIES

Years ended December 31, 2002, 2001 and 2000

KPMG LLP
Chartered Accountants
1200-205 5 Avenue SW
Calgary AB T2P 4B9

Telephone (403) 691-8000
Telefax (403) 691-8008
www.kpmg.ca

AUDITORS' REPORT

To the board of directors of Harvest Operations Corp.

At the request of Harvest Operations Corp., we have audited the schedule of revenue and expenses for the properties (the "Carlyle Properties") referred to in the purchase and sale agreement dated October 1, 2003 between Harvest Operations Corp. and the vender for each of the years in the three year period ended December 31, 2002. This financial information is the responsibility of Harvest Operations Corp. 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 presentation of the financial information.

In our opinion, this financial information presents fairly, in all material respects, the revenue and expenses for the Carlyle Properties referred to in the purchase and sale agreement dated July 29, 2003 for each of the years in the three-year period ended December 31, 2002.

KPMG LLP

Chartered Accountants

Calgary, Canada
October 3, 2003

CARLYLE PROPERTIES

Schedule of Revenue and Expenses for the Carlyle Properties

	Nine months ended September 30,		Years ended December 31,		
	2003	2002	2002	2001	2000
	(unaudited)		(audited)		
Revenue	$ 59,838,735	$ 60,740,813	$ 85,270,787	$ 89,172,498	$ 119,482,399
Royalties	(12,646,317)	(13,595,661)	(18,163,421)	(19,099,841)	(27,813,069)
	47,192,418	47,145,152	67,107,366	70,072,657	91,669,330
Operating costs	18,057,001	19,334,790	24,688,372	22,610,861	25,202,098
Operating income	$ 29,135,417	$ 27,810,362	$ 42,418,994	$ 47,461,796	$ 66,467,232

See accompanying notes to schedule of revenue and expenses for the Carlyle Properties.

1. Basis of presentation:

On October 1, 2003 Harvest Operations Corp. entered into a purchase and sale agreement to acquire the properties (the “Carlyle Properties”) from an arm's length vender.

The schedule of revenue and expenses for the Carlyle Properties includes the operations of the Carlyle Properties by the previous owners. The schedule of revenue and expenses for the Carlyle Properties includes only amounts applicable to the working interest of the previous owners for the Carlyle Properties.

The schedule of revenue and expenses for the Carlyle Properties does not include any provision for the depletion and depreciation, site restoration, future capital costs, impairment of unevaluated properties, general and administrative costs and income taxes for the Carlyle Properties as these amounts are based on the consolidated operations of the previous owners of which the Carlyle Properties formed only a part.

2. Significant accounting policies:

(a) Revenue:

Revenue from the sale of oil and natural gas is recorded at the time that the product is produced and sold.

(b) Royalties:

Royalties are recorded at the time the product is produced and sold. Royalties are calculated in accordance with Alberta Energy regulations or the terms of individual royalty agreements.

(c) Operating expenses:

Operating expenses include amounts incurred to bring the oil and natural gas to the surface, gather, transport, field process, treat and store same. Operating expenses are reflected net of gathering, processing and transportation revenue associated with the Carlyle Properties.

KPMG LLP
Chartered Accountants
1200-205 5 Avenue SW
Calgary AB T2P 4B9

Telephone (403) 691-8000
Telefax (403) 691-8008
www.kpmg.ca

COMPILATION REPORT

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

We have read the accompanying unaudited pro forma consolidated balance sheet of Harvest Energy Trust (the "Trust") as at September 30, 2003 and the unaudited pro forma consolidated statements of income for the nine-month period ended September 30, 2003 and for the year ended December 31, 2002, and have performed the following procedures:

1. Compared the figures in the columns captioned "Harvest Energy Trust" to the unaudited consolidated financial statements of the Trust as at September 30, 2003 and the nine-month period ended September 30, 2003, and to the audited consolidated financial statements of the Trust for the period ended December 31, 2002, respectively and found them to be in agreement.
2. Compared the figures in the columns captioned "Initial and Additional Properties" to the unaudited schedules of revenues and expenses for periods from January 1, 2002 to the respective dates of the completion of the acquisitions and found them to be in agreement.
3. Compared the figures in the columns captioned "Carlyle Properties" to the unaudited schedule of revenue and expenses for the nine-month period ended September 30, 2003, and to the audited consolidated schedule of revenue and expenses for the year ended December 31, 2002, respectively and found them to be in agreement.
4. Made enquiries of certain officials of the Trust who have responsibility for financial and accounting matters about:

   (a) The basis for the determination of the pro forma adjustments; and

   (b) Whether the pro forma consolidated financial statements comply in all material respects with the applicable regulatory requirements.

   The officers:

   (a) Described to us the basis for determination of the pro forma adjustments, and

   (b) Stated that the pro forma consolidated financial statements comply as to form in all material respects with the applicable regulatory requirements.

5. Read the notes to the pro forma consolidated financial statements, and found them to be consistent with the basis described to us for determination of the pro forma adjustments.

6. Recalculated the application of the pro forma adjustments to the aggregate of the amounts in the other columns as at September 30, 2003 and for the nine-month period ended September 30, 2003 and the year ended December 31, 2002 and found the amounts in the column captioned to "Pro forma Consolidated" to be arithmetically correct.

A pro forma financial statement is based on management assumptions and adjustments which are inherently subjective. The foregoing procedures are substantially less than either an audit or a review, the objective of which is the expression of assurance with the adjustments to the historical financial information. Accordingly, we express no such assurance. The foregoing procedures would not necessarily reveal matters of significance to the pro forma financial statements, and we therefore make no representation about the sufficiency of the procedures for the purposes of a reader of such statements.

KPMG LLP

Chartered Accountants

Calgary, Canada
November 21, 2003

HARVEST ENERGY TRUST

Pro Forma Consolidated Balance Sheet

As at September 30, 2003
(Unaudited)

	Harvest Energy Trust	Adjustments	Notes	Pro Forma Consolidated
Assets				
Current assets:				
Cash and short-term investments	$ 17,403,711	$ –		$ 17,403,711
Accounts receivable	14,496,072	–		14,496,072
Prepaid expenses	6,759,342	–		6,759,342
	38,659,125	–		38,659,125
Capital assets	99,943,318	81,100,000	2(a)	181,043,318
Deferred financing charges	1,173,593	–		1,173,593
Future income tax asset	4,593,313	–		4,593,313
	$ 144,369,349	$ 81,100,000		$ 225,469,349
Liabilities and Unitholders' Equity				
Current liabilities:				
Accounts payable and accrued liabilities	$ 17,850,114	$ –		$ 17,850,114
Cash distribution payable	2,504,578	–		2,504,578
Accrued interest payable	218,904	–		218,904
Demand loan	2,825,000	65,950,000	2(d)	68,775,000
Bridge note payable	25,000,000	(25,000,000)	2(d)	–
	48,398,596	40,950,000		89,348,596
Site restoration and reclamation provision	3,074,185	–		3,074,185
	51,472,781	40,950,000		92,422,781
Unitholders' equity:				
Unitholders' capital	66,094,529	48,650,000	2(b)	114,744,529
Equity Bridge Facility	33,500,000	(8,500,000)	2(c)	25,000,000
Accumulated income	15,598,172	–		15,598,172
Contributed surplus	41,728	–		41,728
Accumulated cash distributions	(22,337,861)	–		(22,337,861)
	92,896,568	40,150,000		133,046,568
	$ 144,369,349	$ 81,100,000		$ 225,469,349

See accompanying notes to pro forma consolidated financial statements.

HARVEST ENERGY TRUST

Pro Forma Consolidated Statement of Income

Nine month period ended September 30, 2003
(Unaudited)

	Harvest Energy Trust	Carlyle Properties	Adjustments	Notes	Pro Forma Consolidated
Revenue:					
Petroleum and natural gas sale	$ 79,407,339	$ 59,838,736	$ –	3(b)	$ 139,246,075
Hedging loss	(15,821,359)	–	–		(15,821,359)
Royalty income	342,999	–	–		342,999
Royalties	(10,387,959)	(12,646,317)	–	3(b)	(23,034,276)
	53,541,020	47,192,419	–		100,733,439
Expenses:					
Operating	23,061,371	18,057,001	–	3(b)	41,118,372
General and administrative	2,086,594	–	–		2,086,594
Interest and amortization of deferred financing charges	3,386,465	–	1,367,902	3(f)	4,754,367
Site restoration and reclamation	2,654,682	–	1,290,112	3(d)	3,944,834
Depletion, depreciation and amortization	20,181,186	–	4,216,399	3(c)	24,397,585
Foreign exchange gain	(5,313,053)	–	–		(5,313,053)
	46,057,245	18,057,001	6,874,413		70,988,699
Income (loss) before taxes	7,483,775	29,135,418	(6,874,413)		29,744,740
Taxes:					
Large corporation taxes	137,805	–	100,000	3(g)	237,805
Future tax expense	(3,321,313)	–	3,338,245	3(g)	16,932
	(3,183,508)	–	3,438,245		254,737
Net income (loss)	$ 10,667,283	$ 29,135,418	$ (10,312,658)		$ 29,490,003
Net income per trust unit:					
Basic	$ 0.94			3(h)	$ 1.75
Diluted	$ 0.91			3(h)	$ 1.56

See accompanying notes to pro forma consolidated financial statements.

HARVEST ENERGY TRUST

Pro Forma Consolidated Statement of Income

Year ended December 31, 2002
(Unaudited)

	Harvest Energy Trust	Initial and Additional Properties	Carlyle Properties	Adjustments	Notes	Pro Forma Consolidated
Revenue:						
Petroleum and natural gas sale	$ 21,699,861	$ 76,362,314	$ 85,270,787	$ –	3(a)(b)	$ 183,332,962
Royalties	(2,864,411)	(9,140,164)	(18,163,421)	–	3(a)(b)	(30,167,996)
Royalty income	119,982	–	–	–		119,982
	18,955,432	67,222,150	67,107,366	–		153,284,948
Expenses:						
Operating	6,396,294	20,241,079	24,688,372	–	3(b)(c)	51,325,745
General and administrative	576,780	–	–	4,796,947	3(e)	5,373,727
Interest and amortization of deferred financing charges	2,645,543	–	–	2,509,597	3(f)	5,155,140
Site restoration	544,178	–	–	3,413,465	3(d)	3,957,643
Depletion, depreciation and amortization	5,136,829	–	–	21,248,481	3(c)	26,385,310
Foreign exchange gain	(255,056)	–	–	–		(255,056)
	15,044,568	20,241,079	24,688,372	31,968,490		91,942,509
Income (loss) before taxes	3,910,864	46,981,071	42,418,994	(31,968,490)		61,342,439
Taxes:						
Large corporation taxes	46,771	–	–	200,000	3(g)	246,771
Future tax recovery	(1,272,000)	–	–	6,619,872	3(g)	5,347,872
	(1,225,229)	–	–	6,819,872		5,594,643
Net income (loss)	$ 5,136,093	$ 46,981,071	$ 42,418,994	$ (38,788,362)		$ 55,747,796
Net income per trust unit:						
Basic	$ 3.69				3(h)	$ 4.08
Diluted	$ 3.46				3(h)	$ 3.47

See accompanying notes to pro forma consolidated financial statements.

HARVEST ENERGY TRUST

Notes to Pro Forma Consolidated Financial Statements

As at September 30, 2003 and for the nine month period ended September 30, 2003 and for the year ended December 31, 2002
(Unaudited)

---

1. Basis of presentation:

Harvest Energy Trust (the "Trust") is an open-ended, unincorporated investment trust formed under the laws of Alberta. Pursuant to a trust indenture and an administration agreement, the Trust is managed by its wholly owned subsidiary, Harvest Operations Corp (the "Corporation"). The Trust acquires and holds net profits interests in oil and gas properties acquired and held by the Corporation.

The accompanying unaudited pro forma consolidated financial statements have been prepared by the management of the Corporation in accordance with accounting principles generally accepted in Canada. In the opinion of management, the pro forma consolidated financial statements include all material adjustments necessary for fair presentation in accordance with generally accepted accounting principles in Canada.

The pro forma financial statements are not necessarily indicative either of the results that actually would have occurred if the events reflected herein had taken place on the dates indicated or of the results that may be obtained in the future.

The Trust was formed on July 10, 2002 and the Corporation acquired certain direct royalties and properties from a major oil and gas producer for an aggregate purchase price of $26.1 million (the "Initial Properties"). On November 15, 2002, the Corporation completed the acquisition of certain direct royalties and properties from a senior oil and gas producer for an aggregate purchase price of $78.1 million (the "Additional Properties"). On October 1, 2003 the Trust and the Corporation entered into an agreement to acquire properties from a third party (the "Carlyle Properties"). The cost to the Corporation is estimated to be approximately $81.1 million including the closing adjustments and estimated transaction costs of approximately $2 million.

The unaudited pro-forma consolidated balance sheet as at September 30, 2003 has been based on the unaudited balance sheet of the Trust as at September 30, 2003. The unaudited pro forma consolidated statement of income for the nine-month period ended September 30, 2003 has been based on:

- The unaudited statement of income and accumulated income of the Trust for the nine-month period ended September 30, 2003; and
- the unaudited schedule of revenue and expenses for the Carlyle Properties for the six-month period ended June 30, 2003 plus the figures from the applicable accounting information for the three months ended September 30, 2003.

The unaudited pro forma consolidated statement of income for the year ended December 31, 2002 has been based on:

- The audited statement of income and accumulated income of the Trust for the period from formation on July 10, 2002 to December 31, 2002;

1. Basis of presentation (continued):

- the unaudited schedule of revenue and expenses for the Initial Properties and the Additional Properties for the periods from January 1, 2002 to the date of completion of the respective acquisitions; and
- the audited schedule of revenue and expenses for the Carlyle Properties for the year ended December 31, 2002.

The pro forma financial statements should be read in conjunction with the financial statements and notes thereto included in this prospectus.

2. Pro forma consolidated balance sheet assumptions and adjustments:

The unaudited pro forma consolidated balance sheet gives effect to the following transactions and assumptions as if they had occurred on September 30, 2003:

(a) Acquisition of Carlyle Properties:

On October 1, 2003 the Trust and the Corporation entered into an agreement to acquire its interest in the Carlyle Properties for a purchase price of $81.1 million including closing adjustments and estimated transaction costs of approximately $2 million

(b) Issue of Trust Units:

On October 7, 2003, the Trust entered into an underwriting agreement for the issue of 4,312,500 trust units at an issue price of $12 per unit for gross proceeds of $51,750,000. The net proceeds were $48.65 million after deduction of the underwriters' commission at 6% and costs of $0.35 million.

(c) Equity Bridge Facility:

On July 28, 2003, the Trust entered into an equity bridge agreement with Caribou Capital Corp. (a private corporation controlled by a Director of Harvest Operations Corp.) and a Director of Harvest Operations Corp. (the "Equity Bridge Agreement") that provides up to $40 million to the Trust to assist with the acquisition of the Carlyle Properties. Under the terms of the Equity Bridge Agreement, interest is payable quarterly and calculated daily at a fixed rate of 10% per annum. The Trust has the option to settle the quarterly interest payments, and the principal amounts at any time, with cash or the issue of trust units. The number of trust units to be issued to settle the interest payments or principal amount is equivalent to the amount being settled divided by 90% of an ten-day weighted average trading price of the trust units.

2. Pro forma consolidated balance sheet assumptions and adjustments (continued):

(c) Equity Bridge Facility (continued):

At the time of the acquisition of the Carlyle Properties, $25 million was drawn on this facility.

As the Trust has the ability to settle the interest and principal amounts outstanding under the Equity Bridge Agreement through the issue of trust units, the amounts drawn have been presented in Unitholders' Equity in these pro forma financial statements. The corresponding interest amounts will be presented as a direct charge to accumulated income rather than as a deduction in determining income for the applicable periods. The Corporation also executed bridge notes from the same parties as with the Equity Bridge Agreement. Amounts drawn on these bridge notes will be repaid with proceeds from the offering of units or drawings on the new bank facility.

(d) Additional bank borrowings:

For purposes of this pro forma consolidated balance sheet, it has been assumed that the cost of the Carlyle Properties, less the proceeds from the issue of additional trust units and drawings under the Equity Bridge Agreement, will initially be financed through additional drawings on the bank facility as follows:

Net cost of Carlyle Properties (excluding acquisition costs which have been included in accounts payable)	$	81,100,000
Net proceeds from issue of trust units		(48,650,000)
Repayment on Equity Bridge Agreement		8,500,000
Repayment of bridge note payable		25,000,000
Net additional bank borrowing	$	65,950,000

Subsequent to September 30, 2003 the Corporation entered into a new bank facility with a syndicate of Canadian chartered banks (the "New Bank Facility") which was available on the completion of the acquisition of the Carlyle Properties. The New Bank Facility is a revolving reducing demand loan of $105 million with availability reducing by $4.5 million on the last day of each calendar month starting July 31, 2003. Interest will be payable at variable rates based on the lenders' prime rates or market rates for bankers' acceptances plus a spread adjusted for changes in certain financial ratios.

3. Pro forma consolidated statement of income and assumptions and adjustments:

The pro forma consolidated statements of income for the nine month period ended September 30, 2003 and the year ended December 31, 2002 have been prepared assuming that the transactions described in notes 1 and 2 were completed on January 1, 2002 as follows:

(a) Acquisition of Initial and Additional Properties:

As described in note 1, the Corporation completed two major acquisitions during 2002. The following revenues and expenses for the periods from January 1, 2002 to the dates of the completion of the respective acquisitions have been included in the pro forma consolidated statement of income for the year ended December 31, 2002 as follows:

	Initial Properties Six months ended June 30, 2002	Additional Properties Nine months ended September 30, 2002	Additional Properties Period from October 1, to November 15, 2002	Total Pro forma Adjustment
Revenue	$13,935,019	$55,459,785	$ 6,967,510	$76,362,314
Royalties	(1,210,816)	(7,323,940)	(605,408)	(9,140,164)
	12,724,203	48,135,845	6,362,102	67,222,150
Operating costs	5,050,362	12,665,536	2,525,181	20,241,079
Operating income	$ 7,673,841	$35,470,309	$ 3,836,921	$46,981,071

As the acquisitions of the Initial and Additional Properties were completed prior to January 1, 2003, no pro forma adjustments are required for these properties for the nine month period ended September 30, 2003

(b) Acquisition of Carlyle Properties:

The amounts included in the pro forma consolidated statement of income for the revenue, royalties and operating costs for the Carlyle Properties for the year ended December 31, 2002 have been derived from the schedule of revenue and expenses for the respective periods.

(c) Depletion, depreciation and amortizations:

The pro forma adjustments for depletion, depreciation and amortization have been determined using the full cost method of accounting based on combined proved reserves, future development costs and production volumes and incorporation of the costs of acquiring the Carlyle Properties (including estimated future development costs of $10 million).

3. Pro forma consolidated statement of income and assumptions and adjustments (continued):

(d) Provision for future site restoration and reclamation costs:

The pro forma consolidated statements of income include adjustments to the provision for future site restoration and reclamation costs determined on the basis of the rate per unit of production recorded by the Trust and the pro forma production volumes.

(e) General and administrative costs:

The Trust was created during 2002 and did not complete the second of its major acquisitions until late in 2002. The amounts recorded for general and administrative costs for the year ended December 31, 2002 have been adjusted to an amount determined on the basis of the actual costs incurred per unit of production and the pro forma production volumes. As the Trust was fully operational during the entire nine month period ended September 30, 2003, no adjustments have been recorded for general and administrative costs for that period.

(f) Interest and amortization of deferred financing charges:

As discussed above, the Trust completed two major property acquisitions during the year ended December 31, 2002. The revenue and expenses for the Initial and Additional properties for the period from January 1, 2002 to the date of the completion of the respective acquisitions have been included as a pro forma adjustment as described above. The interest expense for the year ended December 31, 2002 has been adjusted to an amount determined on the basis of the debt outstanding at the end of the year and the applicable interest rates for the period, and the interest that would be applicable to the additional bank borrowings that would result from the acquisition of the Carlyle Properties as if that transaction was completed on January 1, 2002. The amount recorded for the amortization of the deferred financing charge has been adjusted to reflect the amount for a full year.

As the acquisition of the Initial and Additional Properties was completed prior to January 1, 2003, no adjustment is required for interest expense for that period or for the amortization of the deferred financing charge. The interest expense has been adjusted for the interest that would be applicable to the additional bank borrowings that would result from the acquisition of the Carlyle Properties as if that transaction was completed prior to the beginning of the period.

As the Trust has the ability to settle the interest and principal amounts outstanding under the Equity Bridge Agreement through the issue of trust units, the amounts drawn have been presented in Unitholders' Equity in these pro forma financial statements. The corresponding interest amounts of $2.5 million for the year ended December 31, 2002 and $1.88 million for the nine month period ended September 30, 2003 will be presented as a direct charge to accumulated income rather than as a deduction in determining income for the applicable periods.

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3. Pro forma consolidated statement of income and assumptions and adjustments (continued):

(g) Taxes:

Large Corporation Tax has been adjusted for each period for the tax that would be applicable to the additional capital resulting from the acquisition of the Carlyle Properties.

For income tax purposes, the Trust is able to, and intends to, claim a deduction for all amounts paid or payable to unitholders, and then to allocate the remaining income, if any, to the unitholders. However, the pro forma adjustment for future income taxes has been based on the assumption that 50% of the incremental cash flow would have been paid by the Corporation to the Trust as a royalty payment.

(h) Income per trust unit:

For the year ended December 31, 2002 the number of trust units issued under the terms of the underwriting agreement dated October 7, 2003 were treated as issued at the beginning of the year. This includes the trust units issued on the settlement of loans entered into on the acquisition of the Initial Properties. The pro forma income available to unitholders was reduced by the interest applicable to amounts drawn under the Equity Bridge Agreement.

The diluted weighted average number of trust units for the year ended December 31, 2002 included 300,000 trust units with respect to the trust unit incentive plan and 2,694,256 trust units with respect to the settlement of the amounts assumed to drawn under the Equity Bridge Agreement.

For the nine month period ended September 30, 2003, the number of trust units included in the basic weighted average number outstanding for the period was based on the weighted average number of trust units actually outstanding for the period and the 4,312,500 trust units issued under the terms of the underwriting agreement dated October 7, 2003. The pro forma income available to unitholders was reduced by the interest applicable to amounts drawn under the Equity Bridge Agreement.

The diluted weighted average number of trust units for the nine month period ended September 30, 2003 included 300,000 trust units with respect to the trust unit incentive plan and 2,509,284 trust units with respect to the settlement of the amounts drawn under the Equity Bridge Agreement.