

FREEHOLD ROYALTY TRUST

Renewal Annual Information Form

May 14, 2003

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ABBREVIATIONS

bbl and bbls	barrel and barrels, respectively, each barrel representing 34.972 Imperial gallons or 42 U.S. gallons	mcf	one thousand cubic feet
bbls/d and bopd	barrels per day and barrels of oil per day, respectively	mcf/d	one thousand cubic feet per day
mbbls	one thousand barrels	mmcf	one million cubic feet
mmbbls	one million barrels	mmbtu	one million British Thermal Units
boe	barrels of oil equivalent converting 6 mcf of gas to one barrel of oil equivalent and one barrel of natural gas liquids to one barrel of oil equivalent. The factor used to convert gas and natural gas liquids to oil equivalent is not based on either energy content or prices but on a commonly used industry benchmark. Sulphur volumes are not included.	mtonne	one thousand tonnes
boe/d	barrels of oil equivalent per day	mtonne/d	one thousand tonnes per day
mboe	one thousand barrels of oil equivalent	Lton	one long ton
mmbboe	one million barrels of oil equivalent	Lton/d	one long ton per day
		mLton	one thousand long tons
		AECO	reference pricing point for gas located at a gas storage facility near the Alberta-Saskatchewan border
		API	American Petroleum Institute
		NGLs	natural gas liquids
		WTI	West Texas Intermediate

CONVERSIONS

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

<u>To Convert From</u>	<u>To</u>	<u>Multiply By</u>
mcf	cubic metres	28.174
cubic metres	cubic feet	35.494
bbls	cubic metres	0.159
cubic metres	bbls	6.290
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.4047
hectares	acres	2.471

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

This Annual Information Form may contain forward-looking statements. Such statements involve known and unknown risks, uncertainties and other factors outside of management's control that could cause actual results to differ materially from those expressed in the forward-looking statements. A discussion of such risk factors is included under "Risk Factors". Neither the Trust nor Freehold Resources undertakes any obligations to publicly revise these forward-looking statements to reflect subsequent events or circumstances.

GLOSSARY OF TERMS

In this Annual Information Form, the following terms shall have the meanings set forth below, unless otherwise indicated:

“Acquireco” means the one or more corporations, which may be formed by the Trust as wholly owned subsidiaries to acquire corporate facilities and other types of oil and gas related acquisitions in addition to Canadian resource properties.

“Acquireco Distributions” means cash distributions made to the Trust from Acquireco, which distributions will be distributed to Unitholders, after deduction of all required deductions.

“Acquisition Fee” means the acquisition fees payable to the Manager pursuant to the Management Agreement.

“Additional Properties” means working interests in oil and gas rights acquired by Freehold Resources from time to time.

“Additional Royalties” means royalty interests in oil and gas rights acquired by the Trust from time to time.

“ARC” means credits and rebates in respect of Crown royalties which are paid or credited by the Crown, including those paid or credited under the *Alberta Corporate Tax Act* which are commonly known as “Alberta Royalty Credits”.

“Asset Value” means, for any property at any time, the present value of all of the estimated pre-tax net cash flow from the Proved Reserves and 50% of the estimated pre-tax net cash flow from the Probable Reserves shown in the most recent engineering report relating to such property, discounted at 12% and using escalating price and cost assumptions (a common benchmark in the oil and gas industry).

“CN Pension Trust Funds” means the Canadian National Railway System Pension Trust Fund.

“Canpar” means Canpar Holdings Ltd.

“Cash Distribution Date” means the date Distributable Income is paid to Unitholders, being the 15th day following any Record Date.

“Debt Service Charges” means all interest and principal repayments and other costs, expenses and disbursements relating to the borrowing of funds by the Trust and Freehold Resources.

“Deferred Purchase Price Obligation” means the ongoing obligation of the Trust to pay to Freehold Resources, to the extent of the Trust’s available funds, an amount equal up to 99% of the cost of, or any amount outstanding in respect of money borrowed by Freehold Resources to acquire, any additional “Canadian resource property” (as defined in the Tax Act) acquired by Freehold Resources and of the cost of, or any amount borrowed by Freehold Resources to fund, certain designated capital expenditures as partial consideration for the Freehold Resources Royalty. See “Other Information Respecting Freehold Resources – Deferred Purchase Price Obligation”.

“Distributable Income” means, for any particular period, the HB Lands Royalties, Additional Royalties, the Freehold Resources Royalty and Acquireco Distributions received by the Trust plus the interest income from Permitted Investments and ARC, if any, received by the Trust less the Trust’s share of Crown royalties (other than Crown royalties which are deducted in the computation of the Royalty) and direct expenses of the Trust.

“Established Reserves” means proved reserves plus 50% of probable reserves.

“Freehold Resources” means Freehold Resources Ltd., which acquired the Working Interest Properties and granted the Freehold Resources Royalty to the Trust.

“Freehold Resources Notes” means promissory notes issued by Freehold Resources in series pursuant to a note indenture in the principal amount of the Market Redemption Price or Appraised Redemption Price of the Trust Units to be redeemed in consideration for a portion of the royalty having a fair market value equal to such principal amount on the following terms and conditions: (a) unsecured and bearing interest at the lessor of: (a) the interest paid on 2 year Government of Canada bonds minus 2%, or (b) 6% per annum payable monthly in arrears on the 20th day of the next following month; (b) 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 Freehold Resources or any subsidiary of Freehold Resources or the Trust on any creditor proceedings such as bankruptcy, liquidation or insolvency; (c) subject to earlier prepayment, being due and payable on the 15th anniversary of the date of issuance and (d) in an aggregate principal amount not exceeding \$500 million.

“Freehold Resources Properties” means the working, royalty or other interest of Freehold Resources from time to time in any oil and gas right, tangibles and miscellaneous interest, including the Working Interest Properties and Additional Properties.

“Freehold Resources Royalty” means the royalty payable by Freehold Resources to the Trust pursuant to the Freehold Resources Royalty Agreement which equals 99% of Freehold Resources Royalty Income.

“Freehold Resources Royalty Agreement” means the agreement regarding the creation and sale of the Freehold Resources Royalty dated November 25, 1996 between Freehold Resources and the Trustee as trustee for and on behalf of the Trust, as amended from time to time.

“Freehold Resources Royalty Income” in respect of any period for which Freehold Resources Royalty Income is calculated means: (a) the amount received in such period in respect of the sale of Petroleum Substances collected from the Freehold Resources Properties (including the share reserved to the Crown) and any other revenue received in such period other than the proceeds from the sale of the Freehold Resources Properties; less (b) the aggregate of the following costs and expenses paid in such period: (i) all costs and expenses (including both operating costs and capital costs) in respect of the Freehold Resources Properties, except to the extent that such costs or expenses are funded by borrowing and in the case of capital costs, except to the extent designated as Deferred Purchase Price Obligations, including, without limitation, the costs of gathering, compressing, processing, transporting and marketing all Petroleum Substances produced from the Freehold Resources Properties and all other amounts paid to third parties which are calculated with reference to production from the Freehold Resources Properties including, without limitation, gross overriding royalties and lessor’s royalties, but excepting Crown royalties and other Crown charges; (ii) income, capital and other direct taxes in respect of the Freehold Resources Properties; (iii) Debt Service Charges; (iv) General and Administrative Costs to the extent not paid from the residual income of Freehold Resources; (v) net contributions to Freehold Resources’ reclamation fund; (vi) the amount paid to the Trust to purchase Trust Units to satisfy its obligations under the Management Agreement and (vii) all other costs and expenses relating to the Freehold Resources Properties. Any income derived from Freehold Resources Properties which are not working interests in “Canadian resource properties” (as defined in the Tax Act), will not be included as Freehold Resources Royalty Income and will be used to defray capital expenditures and other expenses of Freehold Resources.

“General and Administrative Costs” means the amount in aggregate representing all expenditures and costs incurred under the Management Agreement in respect of Freehold Resources, the Trust or the HB Lands Royalties, Additional Royalties or the Freehold Resources Royalty or in the management and administration of Freehold Resources, the Trust or the HB Lands Royalties, Additional Royalties or the Freehold Resources Royalty including, without limitation: (a) all reasonable costs and expenses relating to Freehold Resources, the Trust and the HB Lands Royalties, Additional Royalties or the Freehold Resources Royalty paid to third parties by or on behalf of Freehold Resources, the Trust or their affiliates, including, without limitation, Trustee’s fees; and (b) all reasonable costs and expenses incurred specifically for Freehold Resources or the Trust relating to Freehold Resources, the Trust or the HB Lands Royalties, Additional Royalties or the Freehold Resources Royalty including, without limitation, auditing, accounting, bookkeeping, rent and other leasehold expenses, legal, land administration, engineering, travel, telephone, data processing, reporting, executive and management

time, salaries and all of those costs and expenses incurred by the Manager in discharging its obligations under the Management Agreement in respect of Freehold Resources, the Trust or the HB Lands Royalties, Additional Royalties or the Freehold Resources Royalty (other than the Acquisition Fee).

“**HB Lands**” means the lands from which the HB Lands Royalties are derived.

“**HB Lands Royalties**” means the royalties representing the right to receive revenue from the HB Lands from all formations to the base of the deepest formation which was producing Petroleum Substances or potash at January 1, 1996 with respect to each mineral title or gross overriding royalty acquired by the Trust from Canpar pursuant to the Royalty Sale Agreement.

“**Management Agreement**” means the agreement dated November 25, 1996 between the Manager, Freehold Resources and the Trustee for and on behalf of the Trust pursuant to which the Manager agreed to provide management services to Freehold Resources and the Trust. See “The Manager – Management Agreement”.

“**Management Fees**” means the fees payable to the Manager pursuant to the Management Agreement.

“**Manager**” means Rife Resources Management Ltd.

“**Permitted Investments**” means: (i) loan advances to Freehold Resources; (ii) interest-bearing accounts of a Canadian chartered bank or the Trustee; (iii) guaranteed investment certificates issued by a Canadian chartered bank or the Trustee; (iv) investment grade money market instruments or funds; (v) Government of Canada Treasury Bills; and (vi) Additional Royalties which are direct royalty interests in petroleum and natural gas rights; provided that an investment will not be a Permitted Investment if it would result in the Trust holding more than 8% of its assets at any particular time in the securities of any person other than the Government of Canada, any province or any municipality.

“**Petroleum Substances**” means petroleum, natural gas and related hydrocarbons (except coal) including, without limitation, all liquid hydrocarbons, and all other substances, including sulphur, whether gaseous, liquid or solid and whether hydrocarbon or not, produced in association with such petroleum, natural gas or related hydrocarbons.

“**Potash Report**” means the report dated January 25, 2003 prepared by the Manager, evaluating the potash reserves attributable to the HB Lands Royalties as at January 1, 2003.

“**Proved Reserves**” and “**Probable Reserves**” have the meanings given to those terms under “Oil and Gas Reserves”.

“**Record Date**” means the last day of each calendar month.

“**Replacement Properties**” means properties, whether Additional Royalties or Additional Properties, which were acquired by the Trust and/or Freehold Resources by means of an exchange of properties owned by the Trust or Freehold Resources or using funds obtained through the prior sale of HB Lands Royalties and/or Freehold Resources Properties.

“**Reserve Life Index**” is an index reflecting the theoretical production life of a property if the remaining reserves were to be produced out at current production rates. The index is calculated by dividing the reserves in the selected reserve category at a certain date by the estimated production for the preceding 12 month period.

“**Rife**” means Rife Resources Ltd.

“**Royalty Income**” means income to the Trust from the HB Lands Royalties, Additional Royalties and the Freehold Resources Royalty.

“Royalty Interest” means the percentage of the gross proceeds from the sale of the produced substances, or that same percentage of the produced substances delivered in-kind to the royalty owner as may be provided for by the lease agreement between the royalty owner(s) and the lessee(s).

“Royalty Lands” means the lands from which the HB Lands Royalties and the Additional Royalties are derived.

“Royalty Lands Royalty Income” means the income derived from the HB Lands Royalties and the Additional Royalties.

“Royalty Sale Agreement” means the purchase and sale agreement between Canpar and the Trust which provided for the purchase by the Trust from Canpar of the HB Lands Royalties.

“Share Trust” means the trust established by agreement dated September 30, 1996 which holds the 100 issued and outstanding common shares in the capital of Freehold Resources, the beneficiaries of which trust are the Manager as to 20 shares, and the independent directors of Freehold Resources from time to time, as to 80 shares.

“Special Resolution” means a resolution passed by a majority of not less than 66 2/3% of the votes cast, either in person or by proxy, at a meeting of Unitholders, called for the purpose of approving such resolution, or approved in writing by the holders of not less than 66 2/3% of the Trust Units entitled to be voted on such resolution.

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

“Trimble” means Trimble Engineering Associates Ltd., independent petroleum consultants.

“Trimble Oil and Gas Report” means the report dated January 31, 2003 prepared by Trimble, evaluating the oil, gas, natural gas liquids and sulphur reserves attributable to the HB Lands Royalties, the Additional Royalties and the Freehold Resources Properties as at January 1, 2003.

“Trustee” means Computershare Trust Company of Canada.

“Trust Indenture” means the amended and restated trust indenture dated May 1, 2002 between the Trustee and Freehold Resources as amended from time to time.

“Trust Interest Gross Reserves” are defined as the remaining reserves of the Trust and/or Freehold Resources, before deduction of any royalties.

“Trust Interest Net Reserves” are defined as the gross remaining reserves of the properties in which the Trust and/or Freehold Resources have acquired an interest, less all royalties and interest owned by others.

“Trust Interest Reserves” means the reserves associated with the HB Lands Royalties, the Freehold Resources Royalty and the Additional Royalties.

“Trust Units” means the units of the Trust, each unit representing an equal undivided beneficial interest therein.

“Unanimous Shareholder Agreement” means the agreement dated November 25, 1996 among Freehold Resources, the trustee of the Share Trust and the Trustee for and on behalf of Unitholders.

“Unitholders” means holders of Trust Units of the Trust.

“Working Interest Properties” means the properties and assets acquired by Freehold Resources from each of Canpar and Rife pursuant to the Working Interest Sale Agreements, and additional working interests acquired.

“Working Interest Sale Agreements” means the purchase and sale agreement between Freehold Resources and Rife and the purchase and sale agreement between Freehold Resources and Canpar which provided for the purchase by Freehold Resources from Rife and Canpar of the Working Interest Properties.

FREEHOLD ROYALTY TRUST

General

Freehold Royalty Trust (the “Trust”) was a closed-end investment trust created under the laws of the Province of Alberta pursuant to the Trust Indenture dated September 30, 1996 as amended and restated November 25, 1996 until its conversion to an open-end trust pursuant to an amended and restated Trust Indenture dated effective May 4, 1999. Computershare Trust Company of Canada (the “Trustee”) has been appointed as trustee pursuant to an amended and restated Trust Indenture dated effective May 1, 2002. The Trust was created for the purposes of purchasing the HB Lands Royalties from Canpar Holdings Ltd. (“Canpar”) and the Freehold Resources Royalty from Freehold Resources Ltd. (“Freehold Resources”) and issuing Trust Units to the public. The beneficiaries of the Trust are holders of the Trust Units. The principal and head office of the Trust is located at Suite 400, 144 – 4th Avenue S.W., Calgary, Alberta, T2P 2N4.

Freehold Resources was incorporated under the *Business Corporations Act* (Alberta) on June 3, 1996 as 698108 Alberta Ltd., then changed its name to “Freehold Resources Ltd.” on July 24, 1996. All of the issued and outstanding shares of Freehold Resources are held by the Share Trust, the beneficiaries of which are the Manager, as to 20 shares, and the independent directors of Freehold Resources from time to time, as to 80 shares. The business of Freehold Resources is restricted to the acquisition, development, exploitation and disposition of oil and natural gas properties, including the Working Interest Properties, and the granting of the Freehold Resources Royalty to the Trust. The head, principal and registered office of Freehold Resources is located at Suite 400, 144 – 4th Avenue S.W., Calgary, Alberta, T2P 3N4.

Rife Resources Management Ltd. (the “Manager”) was incorporated under the *Corporations Act* (Ontario) on March 5, 1968 under the name “75-89 Gosford Limited” and continued under the *Canada Business Corporations Act* on April 20, 1979. The Manager changed its name to “Rife Resources Management Ltd.” on October 1, 1996. Pursuant to the Management Agreement the Trust has retained the Manager to administer the Trust on behalf of the Trustee and Freehold Resources has retained the Manager for the purposes of identifying, evaluating and assisting in the acquisition, disposition and ongoing management and administering of the HB Lands Royalties, Additional Royalties, the Freehold Resources Royalty and the Freehold Resources Properties. The head, principal and registered office of the Manager is located at Suite 400, 144 – 4th Avenue S.W., Calgary, Alberta, T2P 3N4.

General Development of the Business

Freehold Resources and the Trust were created by the Manager for purposes of purchasing and managing the HB Lands Royalties, the Freehold Resources Royalty and the Working Interest Properties which were acquired in November 1996. The following is a description of the general development of the business of the Trust over its last three completed financial years.

Acquisitions During 2000

Effective April 1, 2000, the Trust acquired producing royalties at Luseland, Saskatchewan, and a 20% working interest in 520 acres in the same area for \$5.1 million. The properties acquired added approximately 250 boe/d (115 bbls of royalty oil production and 135 bbls of working interest oil production) in 2000. Effective June 1, 2000 the Trust increased its royalty interest in The Lindale Cardium Unit by acquiring mineral title land and gross overriding royalty lands in the unit.

Acquisitions During 2001

On April 30, 2001, the Trust completed the acquisition of producing royalty properties and an interest in approximately 95,000 gross acres of undeveloped mineral title and gross overriding royalty lands in southeast Saskatchewan. The properties were acquired by Rife on behalf of the Trust. The adjustment date for revenue and cost adjustment purposes

for the acquisition was January 1, 2001. The purchase price, net of closing adjustments, was \$25.4 million and was initially financed through the Trust's credit facility.

The properties added approximately 2.0 million boe of Established Reserves and approximately 500 boe/d of primarily medium to light oil royalty production.

On November 1, 2001, the Trust acquired approximately 140 boe/d of royalty production in the Hayter property and 20 boe/d of miscellaneous royalty and working interest production in proximal properties for \$4.3 million. The properties were acquired by Rife on behalf of the Trust. The acquisition was funded through the Trust's existing credit facility.

Additional Equity Offering During 2001

On May 17, 2001, the Trust issued 3.3 million Trust Units at a price of \$9.65 per Trust Unit for gross proceeds of \$31.8 million (\$30.5 million net of issuance costs). The net proceeds were used to reduce debt.

Acquisitions During 2002

The Trust acquired two royalty properties and completed one property swap for \$2.3 million (net of adjustments) in the last half of 2002.

At Lashburn, Saskatchewan, the Trust purchased a 6% gross overriding royalty interest in the north half of Section 18-49-23W3. The working interest owners are considering a horizontal well program for 2003.

In the Southeast Saskatchewan area, the Trust acquired a variety of minor title interests in 960 acres of land producing medium to light gravity oil.

In the Enchant area of Southern Alberta, the Trust swapped their working interest holdings for a 4.4% gross overriding royalty interest in 2,760 acres. The operator has plans to increase production through facility expansion.

These properties will contribute approximately 100 boe per day to the Trust's royalty production base in 2003.

RECENT DEVELOPMENTS

Exercise of Unit Options

On February 25, 2003, the Manager exercised previously granted options to acquire 1,000,000 Trust Units. The proceeds of this exercise of \$9.2 million were used to pay down bank debt. The Manager is a wholly-owned subsidiary of the CN Pension Trust Funds, which now holds 9,824,536 Trust Units representing 31.43 percent of the outstanding Trust Units.

TRENDS

Commodity Prices

Crude oil and natural gas prices are volatile and subject to a number of external factors. Prices are cyclical and fluctuate as a result of shifts in the balance between supply and demand for crude oil and natural gas, world and North American market forces, inventory and storage levels, OPEC policy, political uncertainty, weather patterns and other factors. Recent world events have caused commodity prices to spike.

In 2002, the price of WTI crude oil ranged from a low of US\$19.73 per barrel for the month of January to a high of US\$29.38 per barrel for December, averaging \$26.08 per barrel for the year. Overall, the average WTI price was relatively unchanged in 2002 compared with 2001. High prices in the latter part of 2002 continued through the first quarter of 2003, largely owing to a war premium for oil due to the U.S.-led military action against Iraq. It is the Manager's expectation that stability will return to the political climate with respect to energy supply and oil prices will weaken as the year progresses. The Manager believes WTI crude oil will move down over the next two years to a longer-term price in the range of US\$22.00 to US\$25.00 per barrel.

In 2002, improving fundamentals for heavy oil resulted in a narrowing of the price differential between light and heavy oil. This resulted in 25% higher prices for Bow River heavy oil in 2002. The differential narrowed to \$8.27 per barrel compared with \$14.11 per barrel in 2001. The price outlook for heavy oil is stable as a result of a return to supply/demand balance in mid-2002. The Manager anticipates the Trust's light/heavy oil differential will average \$9.50 per barrel in 2003.

Natural gas prices are greatly influenced by market forces in North America. Prices have exhibited considerable volatility in the last several years. In 2002, AECO prices ranged from a low of \$2.77 per mcf for the month of August to a high of \$5.66 per mcf for November, averaging \$4.07 per mcf for the year. Overall, the average AECO natural gas price was 35% lower in 2002 compared with 2001. The Manager believes that natural gas has potential upside in terms of short-term pricing as there is a shortage of natural gas production to meet peak demand periods of high heating load or high electrical demand and natural gas storage levels are low. It is the Manager's expectation that the price of natural gas will average in the order of \$5.00 per mcf for the next few years. This expectation is based on the Manager's view of supply and demand fundamentals in the North American energy markets.

Industry Activity

The Canadian Association of Oilwell Drilling Contractors forecasts an 11% increase in industry drilling in 2003, approaching the number of wells drilled in 2001, which was a record year. This industry activity will increase competition for oilfield goods and services and may cause drilling and operating costs to increase. The Trust is expected to benefit from increased industry drilling activity as drilling on its royalty lands generally mirrors industry levels. The Trust will be somewhat sheltered from the effects of increased costs as the majority of its production comes from royalty lands, which do not require capital investments or incur operating expense or abandonment liabilities.

Industry Consolidation and Acquisition Activity

As a result of strong investor interest, a number of new income trusts have entered the market in the last year. There are now over 20 oil and gas royalty trusts and a total of over 200 trusts, REITS, and income funds listed on the Toronto Stock Exchange. This trend, which has increased competition for investment dollars and property acquisitions, is expected to continue in the short-term, and may ultimately lead to consolidation within the Trust sector.

All oil and gas trusts look to acquire additional assets to replace declining reserves and production. The Manager anticipates that incremental drilling on the Trust's existing royalty lands will continue to provide new sources of royalty income in future years – at no cost to the Trust – as new wells reduce the rate at which production and royalty income would otherwise decline. In addition, the Trust actively seeks to augment production and reserves growth through the purchase of producing properties, with a bias towards acquisition of royalty interests. However, subject to threshold requirements in terms of cash flow, return on investment, reserve life and future development potential, the Trust may also pursue working interest properties and/or corporate acquisitions. The strong demand for natural gas production and reserves is expected to result in a high level of corporate and asset transactions as buyers strive to increase their natural gas assets and sellers take advantage of high transaction prices. The Manager believes that continued industry consolidation will create acquisition opportunities that are attractive to the Trust.

Kyoto Protocol

In December 2002, Canada became a signatory to the Kyoto Protocol. It is currently uncertain as to what implications Canada's ratification will have on the oil and gas industry. This uncertainty will remain until the Federal government provides its detailed implementation plan and it becomes clearer what the effect will be on business economics, primarily on the cost side. However, the Manager does not currently expect ratification of the Kyoto Protocol to have a material effect on the Trust's performance in 2003.

Elimination of Outside Management Contracts

The elimination of contracts for outside managers of oil and gas trusts was a major trend that began in 2002. Freehold Resources' Board has discussed internalizing management with respect to the Trust and has decided to make no move in that direction, for three reasons. First, the management fees paid to the Manager continue to be among the lowest in the royalty trust group. Second, the Trust pays its management fees in Trust Units, which clearly aligns the interests of the Manager with the interests of the Unitholders. Third, the management company that is responsible for the Trust's operations also manages the business of two other private corporations and the synergy available by having a larger, more diversified staff to manage the assets of the Trust is considered by the Board to be advantageous to Unitholders. (See also "Trust Units" and "Corporate Governance".)

Reference is also made to the information under the heading "Management's Discussion and Analysis" on pages 12-29, inclusive, of the Trust's 2002 Annual Report, which pages are incorporated herein by reference.

BUSINESS OF THE TRUST

Overview

The Trust was created for the purposes of purchasing the HB Lands Royalties from Canpar, purchasing the Freehold Resources Royalty from Freehold Resources and issuing Trust Units to the public. The Trust permits investors to participate in the HB Lands Royalties, the Additional Royalties and the Freehold Resources Royalty derived from the Working Interest Properties. Pursuant to the Deferred Purchase Price Obligation, Unitholders also participate in a royalty of 99% of royalty income derived from any Additional Properties and Replacement Properties which Freehold Resources acquires. As a result of the conversion to an open-end trust, Unitholders may also participate in distributions received by the Trust from Acquireco, if any.

The Trust's current assets consist of Permitted Investments, the HB Lands Royalties, Additional Royalties and the Freehold Resources Royalty. The Freehold Resources Royalty consists of 99% of the Freehold Resources Royalty Income. To date no additional assets have been acquired by the Trust through Acquireco.

New Acquisitions Through Acquireco

As a result of the conversion to an open-ended trust on May 4, 1999, the business of the Trust was expanded to include the ability to acquire and hold all forms of petroleum and natural gas related assets that can be reasonably expected to provide long-term returns and Unitholder distributions. As a result, the Trust is now able to form one or more corporations, which would initially be wholly-owned subsidiaries of the Trust (each such company referred to as "Acquireco"), through which future acquisitions of all forms of petroleum and natural gas related assets (for example, the shares of an oil and gas company or petroleum and natural gas related facilities without associated properties) could be effected. To date no such corporation has been organized. Any such corporation would be organized substantially along the lines of Freehold Resources in terms of its relationship with management, the Trust and the Unitholders with the same directors as the board of directors of Freehold Resources.

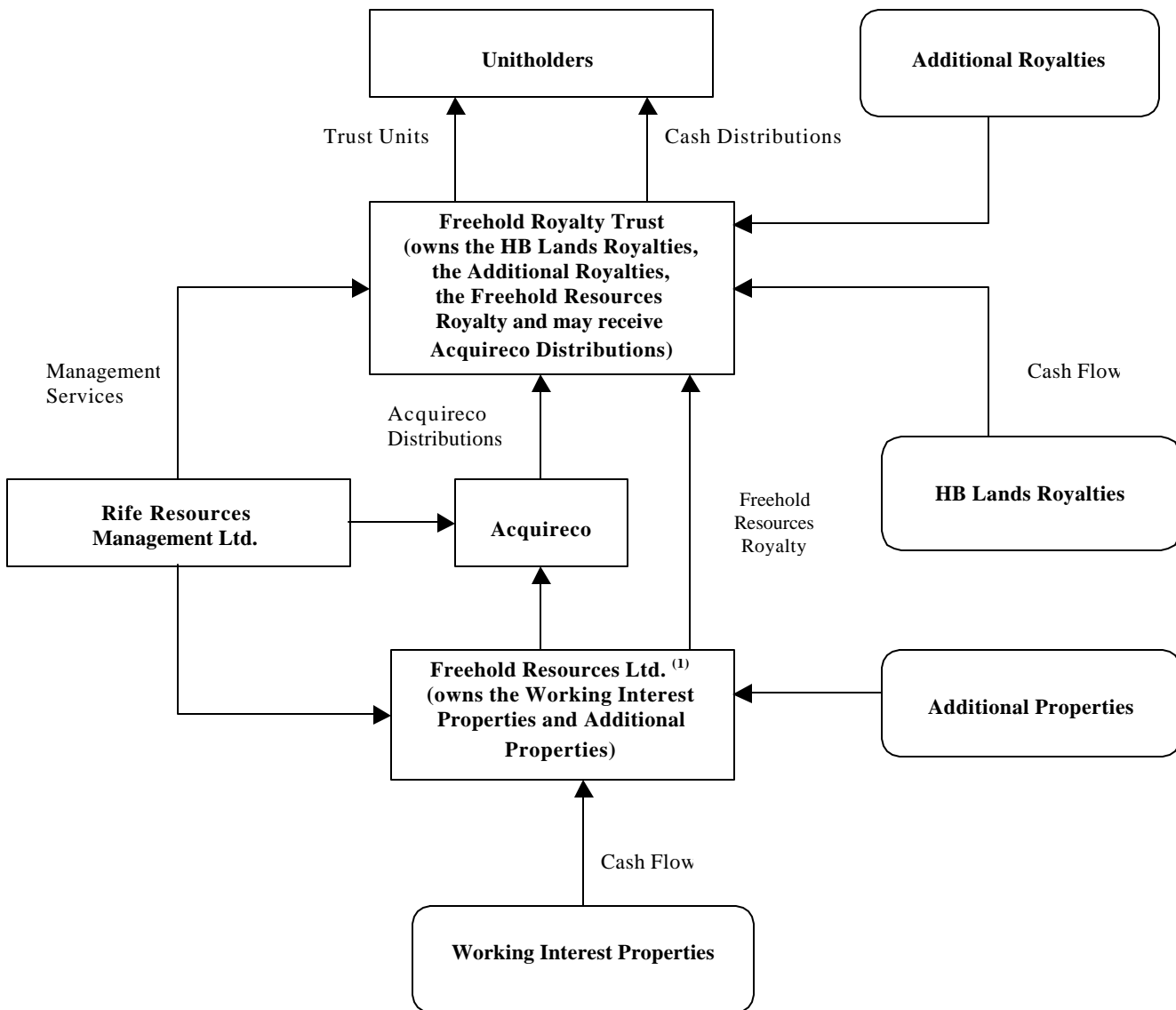
Upon Acquireco closing any acquisition, Acquireco (or, if merged with Freehold Resources, the merged corporation) will receive cash flow from the operation and ownership of its assets. With the approval of its board of directors and subject to applicable law, Acquireco will distribute to the Trust all of its available cash flow, less certain deductions, including, without limitation, ongoing capital expenditures to the extent not funded by debt and subject to retaining such reasonable reserves or funds for the acquisition of replacement assets as may be considered appropriate by its board of directors (“Acquireco Distributions”).

The Trust will make cash distributions of such funds, subject only to required deductions and other deductions similar in nature to those made in respect of the Trust’s cash distributions of funds paid to it by Freehold Resources. Such cash distributions may be wholly or in part taxable. In approving any future acquisitions, the board of directors will be required to consider the impact that such acquisition would have on anticipated after-tax distributions to Unitholders.

Structure of the Trust

The structure of the Trust is such that income taxation occurs only in the hands of the Unitholder. Distributable Income received by Unitholders consists essentially of the HB Lands Royalties, the Additional Royalties and the Freehold Resources Royalty received by the Trust together with any interest or other income earned by the Trust from Permitted Investments and any ARC received by the Trust less the direct expenses of the Trust. Freehold Resources determines the Freehold Resources Royalty for each calendar month and arranges for payment of all direct expenses of the Trust from the HB Lands Royalties, the Additional Royalties and the Freehold Resources Royalty. To the extent that the Trust receives Acquireco Distributions, the Trust will make cash distributions of such funds, subject to required deductions, to Unitholders.

The structure of the Trust and the flows of cash from the HB Lands Royalties, the Additional Royalties, the Working Interest Properties, the Freehold Resources Royalty and Acquireco Distributions to Unitholders is set forth below:



Note:

(1) Owned by the Share Trust.

Management Policies and Acquisition Strategy

The Manager manages the Trust and Freehold Resources in accordance with the Management Agreement. All activities undertaken by the Manager are directed towards maximizing Distributable Income to the Unitholders while at the same time striving to acquire appropriate assets to provide for long-term growth in the value of the Trust. These two objectives are fundamental to the operation of the Trust and are pursued to maximize value to the Unitholders. The Manager utilizes its contract staff's extensive experience and employs prudent oil and gas business practices to increase the assets of the Trust through the acquisition of both royalty and working interest producing oil and gas properties.

The Trust may acquire Additional Royalties and may acquire all forms of petroleum and natural gas related assets through Acquireco. Freehold Resources may acquire Additional Properties or participate in development activities on Working Interest Properties that are of a low risk nature and that have long-term value enhancement potential. Properties to be acquired may be operated by competent third parties or may require the Manager to assume operatorship on behalf of Freehold Resources.

The Manager's acquisition strategy will target individual properties, or groups of properties, that generally comply with the following criteria and procedures:

- (i) quality producing properties with an established production history and low reserve risk;
- (ii) on the basis of a technical and economic engineering evaluation, a property, or group of properties, acquired in a single transaction which is forecast to provide an internal rate of return that is greater than 400 basis points above long-term (10 year) Government of Canada bonds after deducting General and Administrative Costs and incorporating the impact of debt financing, but before income taxes;
- (iii) commodity price and exchange rate assumptions used in acquisition evaluations will be from an independent engineering firm acceptable to the Board of Directors of Freehold Resources as recommended by the Manager;
- (iv) each acquisition of a property, or group of properties, for a purchase price of \$5 million or more, will be based on a technical and economic valuation in a report prepared by an independent engineering firm, which, with the acceptance of the Board of Directors of Freehold Resources, may be modified to incorporate the technical views of the Manager;
- (v) properties which have high netbacks;
- (vi) properties having strong third party operators or properties where the Manager can assume operatorship;
- (vii) the expected economic life of a property, or group of properties, acquired in a single transaction will not be less than 10 years.
- (viii) no acquired property which is comprised of an interest in a single oil or gas pool shall represent more than 30% of the Asset Value of the Trust and Freehold Resources; and
- (ix) the Trust may acquire Additional Royalties, of the nature of the HB Lands Royalties, from Canpar or others. The criteria for acquisition of such royalties may be varied from the criteria set out herein, with the approval of a majority of the independent members of the Board of Directors of Freehold Resources, in recognition of the unique economic characteristics of such royalties.

These criteria will serve as guidelines for the Manager on presenting acquisitions for approval by the board of directors of Freehold Resources. The board of directors of Freehold Resources may vary these criteria for any particular acquisition

based on the Manager's recommendations and consideration of the qualitative aspects of the subject properties including risk profile, technical upside, reserve life index and asset quality.

Cash Distributions of Distributable Income

Cash distributions are made on the 15th day of the month following each Record Date to Unitholders of record on the Record Date. Royalty Income and consequently Distributable Income are determined on a cash received basis.

Alberta Royalty Credits

The entitlement to ARC is based on the payment of Alberta crown royalties in respect of properties located in Alberta. The HB Land Royalties held by the Trust are not eligible for ARC because no Alberta crown royalties are paid by the Trust in respect to revenue received from HB Lands. The original Working Interest Properties acquired by Freehold Resources from each of Canpar and Rife are also not eligible for ARC. Canpar and Rife are associated corporations and were "restricted corporations" (at the maximum credit limit) at the time of disposing of the Working Interest Properties. Consequently, these interests became "restricted resource properties" to Freehold Resources. Royalties on production attributed to these interests are excluded from Alberta crown royalties for ARC purposes. However, wells drilled and completed in Alberta on lands acquired from Canpar and Rife, subsequent to their acquisition by Freehold Resources, are entitled to ARC with respect to Alberta crown royalties paid on production from these wells.

Certain properties acquired in 1997 by Freehold Resources are eligible for ARC. These credits are applied for on a monthly basis by Freehold Resources and form part of the monthly distributable income. Throughout 2002, the ARC quarterly rate was 25%. The total Alberta crown royalties eligible for ARC in 2002 was approximately \$1.1 million and the total royalty tax credits for the year was approximately \$327,000, after giving effect to prior period adjustments.

DESCRIPTION OF PROPERTIES

HB Lands Royalties

The HB Lands Royalties are derived from the leased mineral title lands and gross overriding royalty lands acquired by the Trust from Canpar which generated production revenue in 1995. Canpar retained all non-producing deeper rights associated with the HB Lands. The Trust's interest in leased mineral titles lands and gross overriding royalty lands, in addition to oil and gas, also includes most other minerals excluding coal. The Trust also derives income from the mining of potash. See "Potash Interests and Reserves".

Additional Royalties

Since inception, the Trust has acquired Additional Royalties from properties located near Swift Current, Luseland, Lashburn and Southeast Saskatchewan, and Hayter, Wildmere, Giltedge and Enchant, Alberta. This category provided approximately 28% of the Royalty Lands Royalty Income received by the Trust in 2002.

Royalty Lands Royalty Income

The Royalty Lands are comprised of a large and widely diversified portfolio of properties extending from northeast British Columbia to southwest Manitoba, which have been divided into seven areas. The single largest royalty from an individual lease acquired by the Trust on the Royalty Lands accounted for less than 7% of the total revenue attributable to the Royalty Lands Royalty Income in 2002. The majority of Royalty Lands Royalty Income is derived from the central area of southern Alberta and southern Saskatchewan.

Royalty Lands

The following is a summary of information pertaining to the Royalty Lands, including the HB Lands Royalties and Additional Royalties on a combined basis.

Leased Mineral Title Lands

This category of land provided approximately 77% of the Royalty Lands Royalty Income received by the Trust in 2002. This royalty income is derived from the royalties payable to the Trust through the lease documents issued to the companies which have producing wells located thereon. The Trust has ownership interests in mineral titles ranging from 10% to 100% and recovers a similar percentage of the applicable royalty, ranging from 10% to 20% of all oil and gas products and potash produced and sold from the leased lands. For example if the Trust's interest in a mineral title property is 50% and the royalty rate applicable to the lease is 20% then the Trust would be entitled to receive the proceeds from the sale of 10% (50% x 20%) of the oil or gas produced for the period. The area of leased mineral title lands totals approximately 478,500 gross acres. Certain of the leased mineral title lands have over time been included within 178 oil and gas units which ensure royalty payments to the Trust over the entire producing life of the unit. The leased mineral title lands also include approximately 132,900 gross undeveloped acres, representing potential for further development of the leased mineral title lands. See "Description of Properties – Royalty Lands – Undeveloped Lands".

Gross Overriding Royalty Lands

These lands consist of properties owned by a number of third party oil and gas companies in respect of which varying gross overriding royalties have been reserved to the Trust. This category of land provided approximately 23% of the Royalty Lands Royalty Income received by the Trust in 2002. Certain of the gross overriding royalty interests have been included within 80 oil and gas units. The Trust holds a royalty interest in 326,608 acres, of which approximately 64,400 acres are undeveloped. See "Description of Properties – Royalty Lands – Undeveloped Lands".

Royalty Lands Summary

In the following discussion all references to reserves are Trust Interest Gross Reserves based on Established Reserves as outlined in the Trimble Oil and Gas Report utilizing escalated price and cost assumptions. All references to the Trust's interest in lands, wells and units are with respect to the HB Lands Royalties and the Additional Royalties attributable thereto.

The following table summarizes by area the Trust's average interest, 2002 wells drilled, 2002 oil and gas production, gross revenues, reserve life index, 2002 net pre-tax cash flow and asset value of the HB Lands Royalties and the Additional Royalties:

Royalty Lands	Average Royalty Interest (%)	2002 Wells Drilled	2002 Production (boe/d)	Trust Interest Gross Reserves (mboe) ⁽¹⁾	Reserve Life Index (years) ⁽¹⁾⁽²⁾	2002 Net Pre-Tax Cash Flow (\$000's)	Asset Value ⁽³⁾	
							(\$000's)	(%)
Western Alberta	0.5	31	744	5,372.9	19.8	7,387	45,956	24.0
Bashaw/Leduc	0.4	56	392	1,123.6	7.9	3,931	15,832	8.3
Northeast Alberta	2.1	38	649	3,147.2	13.3	6,424	32,029	16.7
Saskatchewan Heavy Oil	6.0	14	1,060	2,612.3	6.7	10,390	33,506	17.5
Southeast Alberta	1.0	317	334	1,553.3	12.7	2,988	17,068	8.9
Hatton/Gull Lake	0.9	72	227	1,166.2	14.1	2,326	13,592	7.1
Southeast Saskatchewan	0.9	69	591	1,695.8	7.9	7,598	25,140	13.1
Other	0.5	12	155	635.3	11.2	2,143	8,333	4.4
TOTAL⁽⁴⁾	0.8	609	4,153	17,306.5	11.4	43,187	191,456	100.0

Notes:

- (1) Based on Established Reserves as outlined in the Trimble Oil and Gas Report utilizing escalating price and cost assumptions before income tax and undiscounted.
- (2) Reserve Life Index is calculated by dividing the gross reserves by the 2002 annual production.
- (3) Discounted at 12% before income taxes and other indirect costs and based on the escalated price and cost forecast contained in the Trimble Oil and Gas Report.
- (4) Columns may not add due to rounding.
- (5) Does not include \$54,000 of interest income.

The following table summarizes the acreage, wells and unit interests owned by the Trust in the core areas of the Royalty Lands:

Area	Total Acres	Undeveloped Acres ⁽¹⁾	Non-Unitized		Unitized		
			Gas Wells	Oil Wells	Production Units	Gas Wells	Oil Wells
Western Alberta	88,525	15,540	78	132	64	392	1,892
Bashaw/Leduc	66,954	8,058	105	108	38	491	637
Northeast Alberta	122,343	17,300	199	520	32	492	824
Saskatchewan Heavy Oil	62,829	14,836	60	505	6	33	423
Southeast Alberta	127,451	11,173	694	163	35	3,431	270
Hatton/Gull Lake	125,581	24,426	327	207	36	9	871
Southeast Saskatchewan	130,442	97,981	3	384	34	0	2,147
Other	81,013	7,938	73	62	13	248	109
TOTAL	805,138	197,252	1,539	2,081	258	5,096	7,173

Note:

- (1) Undeveloped lands are non-producing spacing units on the Royalty Lands.

Western Alberta

In the Western Alberta area, the Trust has interests in the revenue from 88,525 gross acres which currently includes an interest in 78 non-unitized gas wells and 132 non-unitized oil wells and approximately 15,500 gross acres of undeveloped lands. The Trust also owns interests in 64 units currently containing 392 gas wells and 1,892 oil wells. The Trimble Oil and Gas Report has assigned Established Reserves of 2,769.9 mbbbls of oil and NGLs and 15,617.8 mmcf of gas to this royalty interest.

Geologically, the Western Alberta area represents a wide distribution of producing fields from the foothills structurally distributed belt at Turner Valley, Jumping Pound West and Wildcat Hills to the northern plains at Whitecourt. Stratigraphically, the properties range from the Devonian Beaver Hill Lake formation in the Caroline Swan Hills Gas Unit at a depth of 13,000 feet to the shallower Upper Cretaceous Belly River zone in the Pembina and Keystone areas at a depth of 3,400 feet. The single largest revenue property is the Caroline Swan Hills Gas Unit #1, which produces most of the Trust's NGLs. The Cardium formation is the most common producing formation in which the Trust has interests, including 24 unitized pools in the Ricinus, Ferrier, Willesden Green and Pembina fields.

The oil production from this area is typically of higher degree API quality and the natural gas production may often contain NGLs.

Oil and NGLs production decreased 20% during 2002 to 333 bbls/d, and natural gas production was 17% lower at 2,465 mcf/d. During 2002, lessees drilled 31 (0.3 net) wells in the area compared to 39 (0.3 net) wells in 2001.

Bashaw/Leduc

In the Bashaw/Leduc area, the Trust owns an interest in the revenue from 66,954 gross acres which includes interests in 105 non-unitized gas wells and 108 non-unitized oil wells and approximately 8,100 acres of undeveloped land. The Trust also has interests in 38 production units containing 491 gas wells and 637 oil wells. The Trimble Oil and Gas Report has assigned Established Reserves of 530.4 mbbbls of oil and NGLs and 3,558.9 mmcf of gas to this royalty interest.

This area encompasses a wide diversity of productive zones from the Devonian Leduc Reef at a depth of 7,500 feet to the Upper Cretaceous Belly River at less than 2,500 feet. The highest revenue properties in 2002 in this area were the Red Willow Ellerslie gas pool, the Leduc-Woodbend Glauconitic D Unit No. 1 and the Halkirk Ellerslie oil pool.

Oil and NGLs production increased 16% in 2002 to 155 bbls/d while natural gas production increased 30% to 1,421 mcf/d. Lessees drilled 56 (0.5 net) wells in this area during 2002 compared to 39 (0.7 net) wells drilled in 2001.

Northeast Alberta

The Northeast Alberta royalty area was created in 2000 by combining the Provost and Lloydminster/Bonnyville areas. Within the Northeast Alberta area, the Trust owns an interest in the revenue from 122,343 gross acres which includes an interest in 199 non-unitized gas wells, 520 non-unitized oil wells and approximately 17,300 acres of undeveloped land. The Trust also has interests in 32 production units currently containing 492 gas wells and 824 oil wells. The Trimble Oil and Gas Report has assigned Established Reserves of 2,709.3 mbbbls of oil and NGLs and 2,627.5 mmcf of gas to this royalty interest.

The main producing horizons in the Northeast Alberta area are the Viking and Mannville formations. The northern part of the area is characterized by the production of heavier oil and/or gas from the shallow (less than 3,300 feet) Mannville sands. In the southern part of the area, the Trust is represented in seven Viking gas units and three Viking oil units while the Mannville formation produces low to medium gravity oil from multiple sands at depths of less than 3,500 feet. The largest single revenue property is the Hayter Section 26-40-1W4 Dina Oil pool. The Wildmere Lloydminster "A" Unit No. 1 is the largest revenue unit.

The Trust's 2002 oil and NGLs production was up 9% to 500 bbls/d, and natural gas production was down 4% to 893 mcf/d. In this area 38 (1.7 net) wells were drilled during 2002 compared to 48 (0.6 net) wells drilled in 2001.

Saskatchewan Heavy Oil

In the Saskatchewan Heavy Oil area, the Trust has an interest in the revenue from 62,829 gross acres which includes interests in 60 non-unitized gas wells and 505 non-unitized oil wells and approximately 14,800 acres of undeveloped land. The Trust also has interests in six production units currently containing 33 gas wells and 423 oil wells. The Trimble Oil and Gas Report has assigned Established Reserves of 2,467.5 mbbls of oil and NGLs and 868.6 mmcf of gas to this royalty interest.

The major productive zones are the Mississippian Bakken, the Cretaceous Mannville and the Cretaceous Viking formations. Production of light gravity oil and gas from the Viking formation is concentrated in the southern part of the area near Dodsland. Depths of the productive zones range from 2,800 feet in the south to less than 1,000 feet in the north. The Mannville formation is comprised of multiple sands which have the potential to produce heavy oil or gas. Significant revenue properties are the Luseland and Hoosier Bakken pools, the Baldwinton and Tangleflags Sparky pools, and the Low Lake Waseca pool. The Trust's lands in this area may have reduced spacing drilling opportunities.

Oil and NGLs production increased 7% during 2002 to 971 bbls/d, while natural gas production was 65% higher at 535 mcf/d. During 2002, lessees drilled 14 (1.4 net) wells compared to 43 (1.5 net) in 2001.

Southeast Alberta

The Southeast Alberta area represents the largest number of gas wells in which the Trust owns an interest. The Trust has an interest in the revenue from 127,451 gross acres which includes an interest in 694 non-unitized gas wells and 163 non-unitized oil wells and approximately 11,200 acres of undeveloped lands in this area. The Trust also owns interests in 35 production units containing 3,431 gas wells and 270 oil wells. These units are predominantly productive from the shallow Upper Cretaceous Milk River, Medicine Hat and Second White Specks zones at depths of less than 2,000 feet. The Trimble Oil and Gas Report has assigned Established Reserves of 344.2 mbbls of oil and NGLs and 7,254.6 mmcf of gas to this royalty interest.

Although shallow gas is the dominant play, oil production from the underlying Mannville Sands also contributes significantly to revenue.

Oil and NGLs production averaged 140 bbls/d in 2002, down 18% from the previous year. Gas production was steady averaging 1,168 mcf/d for the year. Approximately 52% of the wells drilled on the Trust's royalty properties during 2002 were drilled in this region. Lessees drilled 317 (2.2 net) wells during 2002 compared to 232 (2.5 net) wells in 2001.

Hatton/Gull Lake

The Hatton/Gull Lake area of southwestern Saskatchewan has historically provided revenue to the Trust from shallow gas production. Following the 1997 acquisition of royalty interests near Swift Current, the Trust now has revenue from oil production.

The Trust has an interest in 125,581 gross acres which includes an interest in 327 non-unitized gas wells and 207 non-unitized oil wells and approximately 24,400 acres of undeveloped land. The Trust also has interests in 36 production units containing 9 gas wells and 871 oil wells. The Trimble Oil and Gas Report has assigned Established Reserves of 3,234.6 mmcf of gas and 627.1 mbbls of oil and NGLs to this royalty interest.

Oil and NGLs production declined 6% to 130 bbls/d in 2002, and natural gas production declined 21% to 585 mcf/d. Lessees drilled a total of 72 (3.3 net) wells on these lands in 2002 compared to 33 (1.1 net) wells drilled in 2001

Southeast Saskatchewan

The Southeast Saskatchewan royalty area was created in 2001 following the Trust's acquisition of producing and undeveloped mineral title and gross overriding royalty properties in southeast Saskatchewan. See "Freehold Royalty Trust – General Development of the Business – Acquisitions During 2001".

The Trust owns an interest in 130,442 gross acres which includes an interest in 3 non-unitized gas wells, 384 non-unitized oil wells and approximately 98,000 acres of undeveloped land. The Trust also owns an interest in 34 production units containing 2,147 oil wells. The Trimble Oil & Gas Report has assigned Established Reserves of 1,656.4 mmbbls of oil and NGLs and 236.5 mmcf of gas to this royalty interest.

Geologically, the Southeast Saskatchewan area is situated on the northern edge of the Williston Basin. Most of the oil is produced from unconformity related traps in the carbonate rocks of the Mississippian aged Madison Group. Light and medium gravity oil is produced from an average depth of approximately 4,000 feet. In the past decade, horizontal wells have become the favored method of exploitation and account for the majority of production.

The properties acquired contributed approximately 591 boe/d of primarily medium to light oil royalty production (average 30° API) to the Trust's production base in 2002. During 2002, 69 (3.3 net) wells were drilled by lessees on the acquired lands compared to 72 (3.7 net) wells drilled in 2001.

Undeveloped Lands

The undeveloped lands which are included in the Royalty Lands are non-producing spacing units totaling 197,252 acres approximately one half are in the Southeast Saskatchewan area. Potential exists on these lands for drilling non-unitized uphole zones within producing units, drilling or completing additional uphole zones, infill drilling by downsizing the spacing (e.g. 160 acre to 80 acre spacing in the case of an oil well), optimizing drilling locations within spacing units and horizontal drilling. If a well is drilled on lands adjacent to Royalty Lands and that well is producing from a formation in which the Trust has an interest but which is not producing on the Royalty Lands, the Trust has the right to require the lessee of the mineral title to either: (a) drill a well on an undrilled spacing unit on the Royalty Lands; (b) pay a compensatory royalty; or (c) surrender the lease.

Drilling Activity

The Trust is not responsible for any drilling or development activity or expenditures with respect to the Royalty Lands, but receives appropriate royalty income from successful wells. Drilling activity on the Royalty Lands is anticipated to provide continued new sources of oil and gas royalty income in future years, with new wells and production thereon reducing the rate at which production and royalty income would otherwise decline. The extent of drilling and development activity in future years by lessees cannot be predicted.

The following table summarizes the drilling activity conducted by lessees on the Royalty Lands for the two most recently completed fiscal years. During this period 1,134 unitized and non-unitized wells have been drilled on the Royalty Lands.

	Years Ended December 31			
	2002		2001	
	Unit	Non-unit	Unit	Non-unit
Oil wells	98	95	132	68
Gas wells	279	84	203	84
Service/other wells	1	41	1	20
Dry and abandoned	0	11	0	17
TOTAL	378	231	336	189
Success rate	100%	95%	100%	91%

The drilling activity on the Royalty Lands in the last two fiscal years may not be indicative of future activity.

Reconciliation of Royalty Lands Reserves

The following table provides a summary of the changes in the Trust's interest in the oil, gas and natural gas liquids Established Reserves on its Royalty Lands which occurred in the period commencing January 1, 2002 and ending January 1, 2003:

	Crude Oil (mdbl)		Natural Gas (mmcf)		NGLs (mdbl)		Total (mboe)		Total (mboe) @6:1
	Proved	Probable ⁽¹⁾	Proved	Probable ⁽¹⁾	Proved	Probable ⁽¹⁾	Proved	Probable ⁽¹⁾	Established Reserves ⁽¹⁾
Balance Jan. 1/02	8,318	1,504	32,884	7,982	1,568	175	15,367	3,010	18,376
Reserves Additions	264	140	1,168	28	2	0	460	145	605
Acquisitions	211	15	40	9	0	0	218	17	234
Revisions	133	(116)	(910)	(2,344)	153	(21)	135	(528)	(394)
Dispositions	0	0	0	0	0	0	0	0	0
Production	(970)		(2,813)		(77)		(1,516)		(1,516)
Balance Jan. 1/03	7,956	1,543	30,369	5,675	1,646	154	14,664	2,643	17,306
Change over prior year	(362)	39	(2,515)	(2,307)	78	(21)	(703)	(367)	(1,070)

Notes:

- (1) Probable reserves are risked at 50%.
- (2) Columns may not add due to rounding.

Freehold Resources Royalty

The Freehold Resources Royalty granted to the Trust pursuant to the Freehold Resources Royalty Agreement consists of a 99% share of the Freehold Resources Royalty Income.

Freehold Resources is required to pay the Trust, on each Cash Distribution Date, 99% of the Freehold Resources Royalty Income received by Freehold Resources from the Freehold Resources Properties for the period ending on the last day of the second month immediately preceding that Cash Distribution Date.

The Trust reimburses Freehold Resources for 99% of the Crown royalties and other Crown charges payable by Freehold Resources in respect of production from or ownership of the Freehold Resources Properties. Freehold Resources will at all times be entitled to set off its right to be so reimbursed against its obligations to pay the Freehold Resources Royalty.

Deferred Purchase Price Obligation

Under the terms of the Freehold Resources Royalty Agreement, the purchase price of the Freehold Resources Royalty acquired by the Trust was an amount equal to 99% of the portion of Freehold Resource's acquisition cost of the Working Interest Properties attributable to "Canadian resource properties" (as defined in the Tax Act) (estimated to be 87% of

Resource's total acquisition cost) plus a Deferred Purchase Price Obligation which recognizes that cash flows from Additional Properties and certain capital expenditures will be subject to the Freehold Resources Royalty for the benefit of Unitholders. The Deferred Purchase Price Obligation consists of 99% of the cost of, or any amount borrowed to acquire, a "Canadian resource property", as defined under the Tax Act, subsequently acquired by Freehold Resources and up to 99% of the amount of, or any amount borrowed to incur, certain capital expenditures on the Freehold Resource Properties to the extent so designated by Freehold Resources. Freehold Resources will only designate an amount under the Deferred Purchase Price Obligation in excess of a nominal amount to the extent that the Trust has funds on hand from the issuance of Trust Units or the disposition of HB Lands Royalties or the Freehold Resources Royalty in respect of Freehold Resources Properties which are disposed of. The Trust intends to finance the Deferred Purchase Price Obligations through additional issues of Trust Units or the application of the proceeds of disposition of HB Lands Royalties or Freehold Resources Properties.

Working Interest Properties

Freehold Resources owns interests in 72 Working Interest Properties. Production from these properties is comprised of approximately 73% oil and 27% gas. The majority (56%) of the Trust's working interest production comes from four properties – Hayter, Pembina Cardium Unit No. 9, Pouce Coupe and Luseland.

Working interest production accounted for 1,850 boe/d in 2002, down 6% from 2001. The decrease in production was mainly the result of normal production declines.

In 2002, 54 (4.9 net) wells were drilled on the working interest properties, up 8% from 50 (3.4 net) wells during 2001. Freehold Resources will spend approximately \$5.9 million on development projects during 2003. Of this amount, \$1.9 million is forecast to be spent at Hayter on drilling and related facilities, and \$1.8 million will be incurred to continue the drilling program at Pembina Cardium Unit No. 9. The remaining capital will be spent on miscellaneous properties.

Approximately 68% of the present value of the estimated future net cash flow from the Working Interest Properties on which the Freehold Resources Royalty was granted is represented by the Hayter, Pembina Cardium Unit No. 9, Luseland and Pouce Coupe properties as outlined in the table below:

Property	%	2002 Production (boe/d)	Trust Interest Gross Reserves (mboe) ⁽²⁾	Reserve Life Index (years) ⁽²⁾⁽³⁾	2002 Net Pre-Tax Cash Flow (\$000)	Asset Value ⁽⁴⁾	
						Interest ⁽¹⁾	(\$000)
Hayter	23.5	470	2,115.8	12.3	3,164	9,213	16.4
Pembina Cardium Unit No. 9	9.9	282	4,253.8	41.4	2,545	23,149	41.3
Luseland	20.0	183	380.1	5.7	1,211	1,767	3.1
Pouce Coupe	25.56	95	539.3	15.6	793	4,000	7.1
Other	2.0	820	2,218.1	7.4	4,474	17,986	32.1
TOTAL⁽⁵⁾	5.7	1,850	9,507.0	14.1	12,187	56,115	100.0

Notes:

- (1) The percentage working and royalty interest share of reserves and production owned by Freehold Resources, before the deduction of royalties payable to others.
- (2) Based on Established Reserves as outlined in the Trimble Oil and Gas Report utilizing escalated price and cost assumptions before income taxes and undiscounted.
- (3) Reserve Life Index is calculated by dividing the gross reserves by annual production for 2002.
- (4) Discounted at 12% before income taxes and other indirect costs and based on the escalated price and cost forecast contained in the Trimble Oil and Gas Report.
- (5) Columns may not add due to rounding.
- (6) Does not include \$327,000 of ARC.

Hayter, Alberta

Freehold Resources owns a 23.52% working interest in the 640 acre Hayter property located in east central Alberta. The Hayter Dina B pool is situated in the northeast portion of Township 40 Range 1 W4M covering portions of six sections. Freehold Resources has a working interest in only Section 26. The pool produces 15° API oil from an average net pay interval of approximately 11 metres. The pool was discovered and delineated with vertical wells but due to the presence of an active bottom water drive has been more effectively developed with the advent of horizontal drilling. Development opportunities were delayed in 2001 while the operator was selling the property. In 2002, 10 (2.3 net) wells were drilled. An additional 10 (2.3 net) wells are planned to be drilled in 2003. There are also plans to expand the water injection facilities to return shut-in wells to production.

Pembina Cardium Unit No. 9, Alberta

Freehold Resources has a 9.96584% working interest and a 0.6% royalty interest in the Pembina Cardium Unit No. 9 located 85 miles southwest of Edmonton. Light oil production is from part of the Pembina oilfield, the largest conventional oilfield discovered in Canada. This unit encompasses approximately 25,280 acres, and has been on an 80-acre, five-spot waterflood pattern for more than 40 years.

In 2002, 18 (1.8 net) wells were drilled in the unit. The operator has plans to drill an additional 27 (2.7 net) infill wells in 2003.

Luseland, Saskatchewan

In 2001, Freehold Resources acquired a 20% working interest in 520 acres in the Luseland area of Saskatchewan located 75 miles southwest of North Battleford. Freehold Resources' Luseland property produces from the Middle Bakken Sandstone, which is of Lower Mississippian age. Averaging about 10 metres of high quality pay, this fine grained unconsolidated sand reservoir contains 13° API heavy oil.

Production decreased 16% to 183 boe/d in 2002, due to normal declines. The operator currently has no drilling plans for 2003.

Pouce Coupe, Alberta

Freehold Resources owns a 25.56% interest in the Pouce Coupe South Boundary "B" Unit #2 in west central Alberta. This property is under waterflood and produces light oil from the Boundary Lake formation.

Production from this unit decreased 6% to approximately 95 boe/d in 2002.

Other Working Interest Properties

Sixty eight other properties accounted for 44% of the working interest production volumes during 2002. Development activities included 4 (0.7 net) oil wells at Ribstone, and 1 (0.2 net) well at Athabasca. The remainder of the wells were drilled at Ring Border.

Working Interest Wells

The following table sets forth the number and status of wells as at January 1, 2003 in which Freehold Resources has a working interest which are producing or which are considered capable of production:

Property	Producing ⁽¹⁾⁽⁵⁾				Shut-in ⁽¹⁾⁽²⁾⁽⁵⁾			
	Oil		Gas		Oil		Gas	
	Gross ⁽³⁾	Net ⁽⁴⁾	Gross ⁽³⁾	Net ⁽⁴⁾	Gross ⁽³⁾	Net ⁽⁴⁾	Gross ⁽³⁾	Net ⁽⁴⁾
Hayter	97	22.8	0	0.0	4	0.9	0	0.0
Pembina Cardium Unit No. 9	153	15.2	0	0.0	11	1.1	0	0.0
Luseland	10	2.0	0	0.0	1	0.2	0	0.0
Pouce Coupe	11	2.8	0	0.0	1	0.3	0	0.0
Other	533	36.2	393	9.3	151	8.6	59	4.3
TOTAL	804	79.1	393	9.3	168	11.1	59	4.3

Notes:

- (1) Based on public records.
- (2) "Shut-in" wells means wells which are not producing but which are considered capable of production. Shut-in wells in which Freehold Resources has an interest are located no further than ten kilometers from gathering systems, pipeline or other means of transportation.
- (3) "Gross" wells are defined as the total number of wells in which Freehold Resources has a working interest.
- (4) "Net" wells are defined as the aggregate of the numbers obtained by multiplying each gross well by the percentage working interest owned by Freehold Resources therein.
- (5) Not all wells owned by Freehold Resources have been assigned reserves in the Trimble Oil and Gas Report.

Drilling History

The following table sets forth the gross and net development wells in respect of the Working Interest Properties in which Freehold Resources participated during the two most recently completed fiscal years:

	Years ending December 31			
	2002		2001	
	Gross ⁽¹⁾	Net ⁽²⁾	Gross ⁽¹⁾	Net ⁽²⁾
Development				
Oil	32	4.8	23	2.5
Gas	22	0.1	27	0.9
Dry	0	0.0	0	0
TOTAL	54	4.9	50	3.4

Notes:

- (1) "Gross Wells" means the number of wells in which Freehold Resources has a working interest.
- (2) "Net Wells" means the aggregate of the numbers obtained by multiplying each gross well by the percentage working interest.
- (3) Freehold Resources has not drilled any exploration wells in respect of the Working Interest Properties.

Disposition of Freehold Resources Properties

To the extent that the Freehold Resources Properties are disposed of, the Trust is entitled to 99% of the net proceeds of disposition of the "Canadian resource property", as defined in the Tax Act, less the amount of any debt which is retired from the sale and relates to such Canadian resource property component in consideration for the resale of the Freehold Resources Royalty from such Freehold Resources Properties and such proceeds may be distributed to the Trust or Freehold Resources may reinvest such proceeds on behalf of the Trust pursuant to the Deferred Purchase Price Obligation. The balance of the proceeds shall be used either to retire other debt of Freehold Resources, defer cost and expenses of Freehold Resources or to finance that portion of the acquisition cost of any Additional Properties which are not financed through the Deferred Purchase Price Obligation.

Reconciliation of Working Interest Property Reserves

The following table provides a summary of the changes in working interest share of crude oil, gas and natural gas liquids Established Reserves before royalties which occurred in the period commencing January 1, 2002 and ending January 1, 2003:

	Crude Oil (mdbl)		Natural Gas (mmcf)		NGLs (mdbl)		Total (mboe)		Total (mboe)
	Proved	Probable ⁽¹⁾	Proved	Probable ⁽¹⁾	Proved	Probable ⁽¹⁾	Proved	Probable ⁽¹⁾	Established Reserves ⁽¹⁾
Balance Jan. 1/02	5,425	1,484	11,451	1,829	568	110	7,902	1,899	9,801
Reserves Additions	0	296	340	19	3	1	60	300	360
Acquisitions	0	0	0	0	0	0	0	0	0
Revisions	495	(300)	46	398	(60)	(40)	443	(274)	169
Dispositions	(49)	(14)	(490)	(6)	(1)	(0)	(131)	(15)	(147)
Production	(463)		(1,109)		(28)		(675)		(675)
Balance Jan. 1/03	5,409	1,465	10,239	2,241	483	70	7,598	1,909	9,507
Change over prior year	(17)	(19)	(1,213)	412	(85)	(40)	(304)	10	(294)

Notes:

- (1) Probable reserves are risked at 50%.
- (2) Columns may not add due to rounding.

OIL AND GAS RESERVES

Trimble has prepared the Trimble Oil and Gas Report, evaluating as at January 1, 2003, the oil, gas and natural gas liquids reserves attributable to the Royalty Lands, Additional Properties and the Working Interest Properties acquired by the Trust and Freehold Resources, respectively. The Trimble Oil and Gas Report evaluates the oil, gas and natural gas liquids reserves attributable to the Royalty Lands, Additional Properties and the Working Interest Properties prior to provision for income taxes, Debt Service Charges and General and Administrative Costs. **The probable additional reserves and the present 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 Trimble 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.

Conversion of Natural Gas to Oil Equivalent – In order to provide a single unit of production for analytical purposes, natural gas is converted to equivalent barrels of oil (boe). Freehold Resources uses the international conversion of six thousand cubic feet of natural gas to one barrel of oil (6 mcf = 1 bbl).

Petroleum and Natural Gas Reserves and Net Pre-Tax Cash Flows Escalating Cost and Price Case

	Trust Interest Reserves								Present Value of Future Net Pre-Tax Cash Flow (\$000)				
	Crude Oil (mdbl)		Natural Gas (mmcf)		NGL's (mdbl)		Sulphur (mLton)		Discounted at				
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Undiscounted	10%	12%	15%	
Proved													
Producing	12,815	12,588	39,076	36,000	2,107	1,781	54	38	584,529	239,558	218,799	194,827	
Non-Producing	550	540	1,531	1,104	22	16	0	0	13,249	7,496	6,860	6,066	
Total Proved	13,365	13,128	40,607	37,104	2,129	1,797	54	38	597,778	247,054	225,659	200,893	
Risked Probable Additional	3,008	2,891	7,915	7,340	224	185	5	4	127,161	25,893	21,912	17,639	
Established Reserves	16,373	16,019	48,522	44,445	2,354	1,982	59	41	724,939	272,947	247,571	218,532	

**Petroleum and Natural Gas Reserves and Net Pre-Tax Cash Flows
Constant Cost and Price Case**

	Trust Interest Reserves								Present Value of Future Net Pre-Tax Cash Flow (\$000)			
	Crude Oil (mdbl)		Natural Gas (mmcf)		NGL's (mdbl)		Sulphur (mLton)		Discounted at			
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Undiscounted	10%	12%	15%
Proved												
Producing	12,834	12,599	39,090	36,081	2,107	1,810	54	40	565,865	265,715	243,653	217,603
Non-Producing	550	540	1,544	1,113	23	16	0	0	15,526	9,041	8,301	7,373
Total Proved	13,384	13,139	40,633	37,194	2,129	1,826	54	40	581,391	274,756	251,954	224,976
Risked Probable Additional	3,007	2,887	7,914	7,351	224	188	5	4	105,585	29,197	25,121	20,607
Established Reserves	16,391	16,026	48,547	44,545	2,354	2,013	59	44	686,976	303,953	277,075	245,583

Notes:

- (1) Columns may not add due to rounding.
- (2) The following definitions have been used in the Trimble Oil and Gas Report:
 - (a) "Proved" reserves are those reserves estimated as recoverable under current technology and existing economic conditions, from that portion of the 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.
 - (b) "Proved producing" reserves are those proved 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 are the choice of the owner rather than the lack of markets or some other reasons. An illustration of such a situation is where a well or zone is capable but is shut-in because its deliverability is not required to meet contract commitments.
 - (c) "Proved non-producing" reserves are those proved reserves that are not currently producing either due to lack of facilities and/or markets.
 - (d) "Probable" reserves are those reserves which analysis of drilling, geological, geophysical and engineering data does not demonstrate to be proved under current technology and existing 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.
- (3) The natural gas reserves stated in the tables are sales volumes.
- (4) **The Trimble Oil and Gas Report forecasts of unrisked probable reserves and values have been reduced by 50% to reflect the degree of risk associated with the recovery of such reserves.**
- (5) The Trimble Oil and Gas Report used the average yearly product price forecast, as provided by Sproule Associates Limited, Petroleum Consultants as at January 1, 2003 for natural gas, oil and condensate, as outlined in the following table:

Year	WTI Cushing Oklahoma* \$U.S./bbl.	Edmonton Par Price 40 API \$/bbl	Alberta Royalty Par Price \$/bbl	Propane \$/bbl	Butane \$/bbl	Pentane Plus \$/bbl	Ethane \$/bbl	Sulphur \$/Lton
2003	25.99	38.43	36.43	21.53	24.35	39.36	16.32	5.00
2004	23.60	34.82	32.79	19.50	22.06	35.66	14.92	7.61
2005	21.63	32.22	30.16	18.05	20.42	33.00	13.22	10.30
2006	21.96	32.78	30.69	18.36	20.77	33.57	12.34	15.69
2007	22.29	33.90	31.77	18.99	21.48	34.72	12.77	15.92
2008	22.62	34.42	32.27	19.28	21.81	35.25	12.95	16.16
2009	22.96	35.58	33.39	19.93	22.54	36.44	13.45	16.40
2010	23.31	36.13	33.91	20.24	22.89	37.00	13.70	16.65
2011	23.66	36.69	34.44	20.55	23.24	37.57	13.95	16.90
2012	24.01	37.26	34.97	20.87	23.60	38.16	14.20	17.15
2013	24.37	37.83	35.51	21.19	23.97	38.75	14.46	17.41
2014	24.74	38.42	36.06	21.52	24.34	39.35	14.72	17.67
2015	25.11	39.00	36.60	21.84	24.71	39.94	14.94	17.94

*40 API, 0.4% sulphur

Oil prices escalate at 1.5% after the year 2015.

Year	Alberta Gas Reference Price Cdn\$/MMBtu	Alberta Plantgate Cdn\$/MMBtu	Henry Hub US\$/MMBtu	BC Plantgate Cdn\$/MMBtu	BC Wellhead Cdn\$/MMBtu
2003	5.66	5.72	4.39	5.94	5.54
2004	5.18	5.21	4.05	5.43	5.03
2005	4.56	4.60	3.61	4.82	4.42
2006	4.25	4.27	3.40	4.48	4.08
2007	4.42	4.42	3.45	4.66	4.26
2008	4.50	4.48	3.50	4.74	4.34
2009	4.69	4.67	3.56	4.93	4.53
2010	4.76	4.75	3.61	5.01	4.61
2011	4.85	4.84	3.66	5.10	4.70
2012	4.94	4.94	3.72	5.20	4.80
2013	5.03	5.03	3.77	5.29	4.89
2014	5.13	5.12	3.83	5.38	4.98
2015	5.21	5.20	3.89	5.46	5.05

Gas prices escalate at 1.5% after the year 2015.

(6) The constant cost and price evaluation was based upon general product prices as set forth below:

Crude Oil, Edmonton Par Price 40° API	\$ 38.43 per bbl
Ethane	\$ 16.32 per bbl
Propane	\$ 21.53 per bbl
Butane	\$ 24.35 per bbl
Pentanes Plus	\$ 39.36 per bbl
Natural Gas, Alberta Plant Gate	\$ 5.72 per mmbtu
Sulphur	\$ 5.00 per Lton

- (7) The Sproule Associates Limited forecast is based on a \$US/\$Cdn exchange rate of \$0.633 for 2003, \$0.63 for 2004, \$0.62 for 2005 and 2006, \$0.610 for 2007 and 2008, \$0.60 thereafter.
- (8) The Trimble Oil and Gas Report estimates total capital expenditures (net to the Trust and Freehold Resources) to achieve the estimated future net revenues from the Proved reserves based upon escalating cost and price assumptions to be \$7.935 million with \$2.039 million, \$0.245 million and \$0.173 million of such costs estimated for the calendar years 2003, 2004 and 2005, respectively. The corresponding costs to achieve the estimated future net revenues from the Proved reserves plus 50% risked Probable reserves are \$14.862 million with \$2.830 million, \$1.843 million and \$1.734 million, respectively.
- (9) The Trimble Oil and Gas Report estimates total capital expenditures (net to the Trust and Freehold Resources) to achieve the estimated future net revenues from the Proved reserves based upon constant cost and price assumptions to be \$6.000 million with \$2.026 million, \$0.219 million and \$0.170 million of such costs estimated for the calendar years 2003, 2004 and 2005, respectively. The corresponding costs to achieve the estimated future net revenues from the Proved reserves plus 50% risked Probable reserves are \$12.499 million with \$2.823 million, \$1.811 million and \$1.702 million, respectively.
- (10) The extent and character of the Trust and Freehold Resources interests evaluated in the Trimble Oil and Gas Report and all factual data supplied by the Trust and Freehold Resources to Trimble were accepted by Trimble as represented. The oil and gas reserve calculations and any predictions upon which the Trimble Oil and Gas Report is based were determined in accordance with generally accepted petroleum engineering evaluation practices.
- (11) For the Escalating Cost and Price Case, operating and capital costs have been escalated at 1.5% annually. For the Constant Cost and Price Case, operating and capital costs have not been escalated.

Estimated Future Net Pre-Tax Cash Flows Based on Established Reserves⁽¹⁾
Escalating Cost and Price Case
From the Trimble Oil and Gas Report
(\$000's, except production)

<u>Year</u>	<u>Estimated Production (boe/d)</u>	<u>Company Interest Revenue⁽²⁾</u>	<u>Royalty Burdens⁽³⁾</u>	<u>Net Revenue After Royalty Burdens</u>	<u>Operating Expenses</u>	<u>ARC</u>	<u>Net Production Revenue⁽⁴⁾</u>	<u>Net Capital Investment⁽⁷⁾</u>	<u>Net Cash Flow Before Income Taxes⁽⁵⁾⁽⁶⁾</u>
2003	6,208	67,675	3,786	63,889	4,916	391	59,364	2,836	56,528
2004	5,722	56,614	3,217	53,397	4,966	370	48,801	1,843	46,959
2005	5,078	45,068	2,465	42,603	4,753	423	38,273	1,734	36,540
2006	4,511	39,817	1,972	37,845	4,625	355	33,575	1,579	31,996
2007	4,019	36,953	1,665	35,288	4,482	272	31,078	571	30,507
2008	3,591	33,596	1,352	32,244	4,331	209	28,122	253	27,869
2009	3,197	31,211	1,150	30,061	4,012	159	26,208	622	25,587
2010	2,867	28,547	992	27,555	3,788	141	23,908	45	23,863
2011	2,609	26,505	859	25,646	3,680	127	22,093	105	21,988
2012	2,379	24,677	739	23,938	3,441	115	20,612	43	20,570
2013	2,174	23,009	650	22,359	3,256	99	19,202	70	19,133
2014	1,993	21,476	573	20,903	3,021	87	17,969	84	17,885
2015	1,845	20,214	525	19,689	2,891	81	16,879	88	16,791
2016	1,711	19,056	461	18,595	2,650	73	16,018	66	15,951
2017	1,502	17,106	416	16,690	2,238	67	14,519	676	13,843
Remainder		389,341	9,100	380,241	54,093	861	327,009	4,247	322,762
TOTAL		880,865	29,923	850,942	111,141	3,831	743,630	14,862	728,770

Total Future Cash Flow Before Income Taxes Including ARC Discounted to January 1, 2003 at:

10%	\$	275,004
12%	\$	249,474
15%	\$	220,248
20%	\$	186,167

Notes:

- (1) Proved reserves plus 50% Probable reserves.
- (2) Includes working interest revenue and royalty interest revenue.
- (3) Includes Alberta and Saskatchewan freehold mineral taxes.
- (4) Trust interest revenue less royalty burdens and operating expenses.
- (5) Undiscounted.
- (6) Cash flow before income taxes is stated prior to interest, general and administrative expenses and management fees.
- (7) Net Capital Investment includes abandonment liabilities as forecast by Trimble.
- (8) Columns may not add due to rounding.

Estimated Future Net Pre-Tax Cash Flows Based on Established Reserves⁽¹⁾
Constant Cost and Price Case
From the Trimble Oil and Gas Report
(\$'000's, except production)

<u>Year</u>	<u>Estimated Production (boe/d)</u>	<u>Company Interest Revenue⁽²⁾</u>	<u>Royalty Burdens⁽³⁾</u>	<u>Net Revenue After Royalty Burdens</u>	<u>Operating Expenses</u>	<u>ARC</u>	<u>Net Production Revenue⁽⁴⁾</u>	<u>Net Capital Investment⁽⁷⁾</u>	<u>Net Cash Flow Before Income Taxes⁽⁵⁾⁽⁶⁾</u>
2003	6,208	67,675	3,786	63,889	4,916	391	59,364	2,823	56,540
2004	5,724	62,354	3,581	58,773	4,943	375	54,205	1,811	52,395
2005	5,086	55,566	3,162	52,404	4,710	343	48,037	1,702	46,336
2006	4,521	49,418	2,607	46,811	4,524	313	42,600	1,524	41,076
2007	4,027	44,017	2,101	41,916	4,319	263	37,860	543	37,317
2008	3,599	39,327	1,678	37,649	4,112	214	33,751	275	33,475
2009	3,199	35,007	1,351	33,656	3,714	186	30,128	573	29,555
2010	2,867	31,440	1,142	30,298	3,444	162	27,016	44	26,971
2011	2,610	28,656	974	27,682	3,297	143	24,528	94	24,434
2012	2,379	26,164	818	25,346	3,035	127	22,438	38	22,401
2013	2,176	23,967	710	23,257	2,839	107	20,525	51	20,475
2014	1,997	22,019	630	21,389	2,630	92	18,851	69	18,782
2015	1,850	20,394	565	19,829	2,473	84	17,440	74	17,365
2016	1,717	18,919	487	18,432	2,234	74	16,272	58	16,214
2017	1,504	16,755	428	16,327	1,848	68	14,547	566	13,981
Remainder		273,600	6,380	267,220	32,364	714	235,570	2,254	233,316
TOTAL		815,278	30,402	784,877	85,401	3,657	703,132	12,499	690,633

Total Future Cash Flow Before Income Taxes Including ARC Discounted to January 1, 2003 at:

10%	\$	305,955
12%	\$	278,924
15%	\$	247,246
20%	\$	209,376

Notes:

- (1) Proved reserves plus 50% Probable reserves.
- (2) Includes working interest revenue and royalty interest revenue.
- (3) Includes Alberta and Saskatchewan freehold mineral taxes.
- (4) Trust interest revenue less royalty burdens and operating expenses.
- (5) Undiscounted.
- (6) Cash flow before income taxes is stated prior to interest, general and administrative expenses and management fees.
- (7) Net Capital Investment includes abandonment liabilities as forecast by Trimble.
- (8) Columns may not add due to rounding.

POTASH INTERESTS AND RESERVES

Description of Potash Interests

In addition to royalties received on Petroleum Substances, the Trust also receives royalty income from leased potash rights. Potash is used to manufacture agricultural fertilizers.

The Trust has acquired the right to the revenue derived from Canpar's lessor royalty interest in over 9,750 gross acres of leases issued to various operators of seven potash mines, all located within the Province of Saskatchewan. These leases are included within larger potash units, which cover the total mine areas. Canpar originally acquired a 23.52% freehold mineral title interest in those potash properties leased to third parties as of January 1, 1979. The royalties derived from the potash leases are calculated in the same manner as royalties payable to the Province of Saskatchewan from provincially owned potash rights. Canpar subsequently entered into an agreement with its partners in 1993 with respect to the six mines producing at that time. It was agreed that Canpar would receive 100% of its partners' share of all potash royalties from leased and producing properties from an effective date of December 1, 1993, until the sum of \$3 million had been received. As payout occurred in the first half of 2000, ownership interest in the properties has reverted to 50% to the Trust and 50% to its partner.

The Trust also acquired a royalty interest in a seventh mine within a unit formed by Central Canada Potash in the Colonsay area of Saskatchewan. The Trust's unitized royalty interest is 7.52% and the mine, currently in production, is expected to be operational until at least the year 2011.

Potash Reserves

Due to the immaterial value of the potash reserves to the Trust, the Trust has not obtained a recent independent evaluation of the potash reserves attributable to the HB Lands Royalties. However, the Manager has internally generated a report evaluating, as at January 1, 2003, the potash reserves attributable to the HB Lands Royalties acquired by the Trust. The Potash Report evaluates the potash reserves attributable to the HB Lands Royalties prior to provision for income taxes, Debt Service Charges and General and Administrative Costs. It should not be assumed that the estimated discounted future net production revenues 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 table.

Potash Reserves and Net Pre-Tax Cash Flows Constant and Escalated Price and Cost Case

	Trust Interest Reserves		Present Net Value Of Future Net Pre-Tax Cash Flows			
	Potash		(\$000)			
	(mtonnes)		Undiscounted	Discounted at		
Gross ⁽¹⁾	Net ⁽¹⁾	10%		12%	15%	
Proved						
Constant Price and Cost ⁽²⁾	63,162	63,162	20,512	5,633	4,890	4,101
Escalated Price and Cost ⁽³⁾	63,162	63,162	15,408	5,005	4,411	3,762

Notes:

- (1) The following definitions have been used in the Potash Report:
 - (a) "Proved Reserves" are those reserves estimated as recoverable under current technology and existing economic conditions from that portion of the ore body which can be reasonably evaluated as economically recoverable using mining processes demonstrated to be economic and technically successful.
 - (b) "Net Production Revenue" is income derived from the sale of potash, less any capital and operating costs.
- (2) The constant price and cost evaluation was based upon a potash price of Cdn. \$132.88 per tonne.
- (3) Average yearly potash prices, which were deemed appropriate as at January 1, 2003 for potash are outlined in the following table:

<u>Year</u>	<u>2003</u>	<u>2004</u>	<u>2005</u>	<u>2006</u>	<u>2007</u>	<u>2008</u>	<u>2009</u>	<u>2010</u>	<u>2011</u>	<u>2012</u>	<u>2013</u>	<u>Thereafter</u>
Price/tonne (\$Cdn.)	132.88	134.87	136.90	138.95	141.03	143.15	145.30	147.48	149.69	151.93	154.22	1.5%/year

There are no operating and capital costs associated with these reserves.

- (4) The net production of potash in 2002 was 7.8 tonnes per day in both the constant and escalated price cases. The estimated undiscounted net pre-tax cash flow in 2003 is \$511,052 in both the constant and escalated price cases.

HISTORY

The following tables set out daily average production volumes, netback calculations, average net product prices received and capital spending for each quarter of 2002 and 2001.

Average Daily Production Volumes

	2002				2001			
	Fourth Quarter	Third Quarter	Second Quarter	First Quarter	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
Oil (bbls/d)	4,006	3,883	3,783	4,031	4,072	4,098	3,804	3,509
NGLs (bbls/d)	297	289	282	280	309	443	345	318
Gas (mmcf/d)	10.4	10.5	11.7	10.4	11.0	10.9	11.4	11.3
Total (boe/d)	6,033	5,922	6,015	6,046	6,219	6,359	6,050	5,709

Netback History

	2002				2001			
	Fourth Quarter	Third Quarter	Second Quarter	First Quarter	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
Average Net Production Prices Received								
Crude Oil (\$/bbl)	31.89	34.64	32.98	25.61	18.35	31.57	24.36	23.17
Natural Gas (\$/mcf)	5.02	3.29	3.80	3.11	3.17	3.09	6.15	10.12
Natural Gas Liquids (\$/bbl)	29.79	25.77	24.48	19.91	21.20	23.03	34.05	43.80
Oil Equivalent (\$/boe 6:1)	31.27	29.81	29.27	23.35	18.69	27.26	28.84	36.70
Royalties Paid								
Crude Oil (\$/bbl)	1.12	1.22	1.11	0.87	0.65	1.25	1.09	1.36
Natural Gas (\$/mcf)	0.36	0.24	0.22	0.20	0.09	0.31	0.50	0.75
Natural Gas Liquids (\$/bbl)	3.32	1.11	1.21	0.43	1.22	1.06	2.68	3.85
Oil Equivalent (\$/boe 6:1)	1.53	1.28	1.18	0.94	0.64	1.42	1.78	2.53
Operating Expenses								
Crude Oil (\$/bbl) ⁽¹⁾	2.60	2.83	3.24	2.40	2.55	2.37	2.43	2.77
Natural Gas (\$/mcf)	0.15	0.18	0.15	0.16	0.18	0.25	0.11	0.19
Natural Gas Liquids (\$/bbl)	1.00	1.06	0.82	0.68	0.85	0.97	0.58	0.83
Oil Equivalent (\$/boe 6:1)	2.03	2.23	2.37	1.91	2.04	2.02	1.77	2.12
Netback Received								
Crude Oil (\$/bbl)	28.17	30.59	28.63	22.35	15.15	27.95	20.84	19.04
Natural Gas (\$/mcf)	4.50	2.87	3.43	2.75	2.90	2.53	5.53	9.18
Natural Gas Liquids (\$/bbl)	25.47	23.61	22.45	18.79	19.13	20.99	30.78	39.13
Oil Equivalent (\$/boe 6:1)	27.70	26.30	25.72	20.50	16.01	23.81	25.29	32.05

Note:

- (1) Operating expenses are composed of direct costs incurred and costs allocated among oil, natural gas and natural gas liquids production. Operating recoveries associated with operated properties were excluded from operating costs and accounted for as a reduction to general and administrative costs.

Average Net Product Price Received (\$/bbl)

	2002				2001			
	Fourth Quarter	Third Quarter	Second Quarter	First Quarter	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
Light and medium oil	38.04	38.58	37.54	29.24	24.73	36.94	33.13	34.55
Heavy oil	27.35	31.74	29.40	22.72	12.32	26.72	17.08	16.45

Capital Expenditures (\$000's)

	2002				2001			
	Fourth Quarter	Third Quarter	Second Quarter	First Quarter	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
Acquisitions	1,181	1,145	-	-	4,307	(490)	25,890	-
Exploration	-	-	-	-	-	-	-	-
Development	394	1,476	516	560	452	1,063	393	1,084

The Trust does not have any commitments to buy, sell, exchange or transport oil or natural gas.

SELECTED FINANCIAL INFORMATION
Financial Summary
(\$000's, except Trust Unit and per Trust Unit numbers)

Summary of Annual Financial Information

	2002	2001	2000
<u>Earnings Information</u>			
Total Revenue	63,143	61,885	64,500
Royalty expense	2,709	3,482	3,306
Other expenses	32,877	31,104	29,502
Net Income	27,557	27,299	31,692
Per Unit, Basic and Diluted	0.91	0.95	1.19
<u>Distributable Income Information</u>			
Distributable Income	39,530	45,264	35,226
Distributable Income per Unit	1.31	1.56	1.32
<u>Balance Sheet Information</u>			
Total Assets	224,322	235,585	227,356
Long Term Liabilities	30,000	33,000	38,000
Trust Units Outstanding	30,225,236	30,129,236	26,728,000

Summary of Quarterly Financial Information

	2002				2001			
	Fourth Quarter	Third Quarter	Second Quarter	First Quarter	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
<u>Earnings Information</u>								
Total Revenue	17,561	16,503	16,235	12,844	10,780	16,086	16,018	19,001
Royalty expense	850	697	649	513	369	832	980	1,301
Other expenses	9,393	7,790	7,883	7,811	7,981	8,157	7,620	7,346
Net Income	7,318	8,016	7,703	4,520	2,430	7,097	7,418	10,354
Per Unit, Basic and Diluted	0.24	0.27	0.26	0.15	0.08	0.24	0.26	0.39
<u>Distributable Income Information</u>								
Distributable Income	11,477	11,169	9,653	7,231	9,034	12,337	13,199	10,693
Distributable Income per Unit	0.38	0.37	0.32	0.24	0.30	0.41	0.45	0.40
<u>Balance Sheet Information</u>								
Total Assets	224,322	227,329	229,271	232,875	235,585	240,727	246,161	227,461
Long Term Liabilities	30,000	30,500	30,500	33,000	33,000	31,000	31,000	38,000
Trust Units Outstanding	30,225,236	30,202,736	30,180,236	30,135,000	30,129,236	30,106,736	30,084,236	26,748,000

MANAGEMENT'S DISCUSSION AND ANALYSIS

Reference is made to the information under the heading "Management's Discussion and Analysis" on pages 12 to 29 inclusive, of the Trust's 2002 Annual Report, which pages are incorporated herein by reference.

OTHER INFORMATION RESPECTING FREEHOLD RESOURCES

Additional and Replacement Properties

Freehold Resources may acquire Additional Properties and related tangible equipment and fund such acquisitions from Freehold Resources Royalty Income, additional issuances of Trust Units, borrowings, farmouts or with working capital of Freehold Resources. See "Other Information Respecting Freehold Resources – Capital Expenditures".

Freehold Resources may sell any of its interests in Freehold Resources Properties and release the Freehold Resources Royalty therefrom if it determines that such sale would be in the best interest of Unitholders. The Freehold Resources Royalty Agreement permits Freehold Resources to effect such sale provided that the sale is approved by a Special Resolution of the Unitholders in the event the interests in the Freehold Resources Properties being sold constitute greater than 50% of the Asset Value of all Freehold Resources Properties and provided such sale is approved by the board of directors of Freehold Resources for sales of Freehold Resources Properties for proceeds in excess of \$5.0 million. The proceeds of a disposition of an interest in the Freehold Resources Properties to the extent related to Canadian resource properties, as defined in the Tax Act, will be allocated 99% to the Trust, after retiring any borrowing which relates to the Canadian resource property component of such interest, in consideration for the release of the Freehold Resources Royalty from such Freehold Resources Properties.

In connection with the sale of any interests in the Freehold Resources Properties, Freehold Resources will determine whether the net proceeds of the sale should be distributed to Unitholders or reinvested and Freehold Resources may consider Replacement Properties for purchase.

Capital Expenditures

Freehold Resources may approve future capital expenditures or farmouts on Freehold Resources Properties under the terms of the Freehold Resources Royalty Agreement. Future capital expenditures are anticipated to be of the type which are intended to maintain or improve production from the Freehold Resources Properties. Freehold Resources may finance capital expenditures from Freehold Resources Royalty Income, additional issuances of Trust Units, borrowings, farmouts or with working capital of Freehold Resources. Freehold Resources will not initiate any exploratory drilling but may participate in exploratory drilling initiated by the operator of a property where, in the opinion of Freehold Resources, to do so would be in the best interests of the Trust. Under the terms of the Freehold Resources Royalty Agreement, annual capital expenditures (including acquisitions of Additional Properties) will not exceed 15% of the annual net cash flow from the HB Lands Royalties, Additional Royalties and the Freehold Resources Properties unless financed with borrowings, additional issuances of Trust Units or Freehold Resources Royalty disposition proceeds.

Deferred Purchase Price Obligation

Under the terms of the Freehold Resources Royalty Agreement, the purchase price of the Freehold Resources Royalty included the Deferred Purchase Price Obligation which recognizes that cash flows from any after-acquired property and certain capital expenditures will be subject to the Freehold Resources Royalty for the benefit of Unitholders. The Deferred Purchase Price Obligation consists of 99% of the cost of, or any amount borrowed to acquire, a "Canadian resource property", as defined under the Tax Act, subsequently acquired by Freehold Resources and up to 99% of the cost of, or any amount borrowed to fund, certain capital expenditures incurred on the Freehold Resources Properties to the extent so designated by Freehold Resources. The Trust intends to finance the Deferred Purchase Price Obligations

through additional issues of Trust Units or the application of the proceeds of disposition of HB Lands Royalties or Freehold Resources Properties.

Borrowing by Freehold Resources

Pursuant to the Freehold Resources Royalty Agreement, Freehold Resources is permitted to borrow funds to finance the purchase of Additional Properties, for capital expenditures or for other financial obligations or expenditures in respect of the Freehold Resources Properties or for working capital purposes. Freehold Resources has established guidelines which provide that: (a) the amounts borrowed to finance the purchase of Additional Properties when combined with existing debt of Freehold Resources and existing debt of the Trust will not exceed 40% of the Asset Value of all of the HB Lands Royalties, the Additional Royalties and the Freehold Resources Properties at the time of borrowing; and (b) the Debt Service Charges on amounts borrowed to finance the purchase of Additional Properties or capital expenditures to maintain or improve production from the Freehold Resources Properties or other borrowings as permitted above will not exceed 10% of the estimated annual Royalty Income. Freehold Resources will be entitled to grant security or guarantee the obligations of the Trust with respect to any borrowing by the Trust. See “Trust Units – Borrowing by the Trust”.

Debt Service Charges will be deducted in computing Freehold Resources Royalty Income. The debt repayment will be scheduled to minimize, to the extent possible, any income tax payable by Freehold Resources.

Freehold Resources has entered into an agreement establishing a credit facility from a Canadian chartered bank to provide a revolving term loan facility of up to \$65.0 million for general corporate purposes including acquisitions. The outstanding principal amount of such facility bears interest at either the bank’s Canadian dollar prime rate or bankers’ acceptance rate, plus 90 to 165 basis points (based on certain debt to cash flow ratio) at the option of Freehold Resources.

In addition, Freehold Resources may borrow from the Trust without reference to the foregoing test at a commercial rate of interest, provided that the Trust funds such lending out by the sale of Trust Units or by borrowing.

Environmental Obligations – Reclamation Fund

Freehold Resources will be liable for its share of ongoing environmental obligations and for the ultimate reclamation of the Freehold Resources Properties upon abandonment. Ongoing environmental obligations are expected to be funded out of cash flow.

Freehold Resources currently estimates that the future environmental and reclamation obligations in respect of the Working Interest Properties will aggregate approximately \$5.6 million. A reclamation fund, consisting of cash invested in an interest-bearing account, has been established and is funded by quarterly cash payments. This will result in the estimated future environmental and reclamation obligations being fully funded. This payment may be adjusted by Freehold Resources from time to time based on its assessment of its share of expected environmental and final site reclamation costs.

With respect to the HB Lands, the responsibilities for adherence to environmental regulations reside with the operators and working interest owners of the HB Lands and not with the Trust. Therefore, no reclamation fund has been established for the HB Lands.

The estimates of reserves and the present value of future net cash flows from reserves contained in the Trimble Oil and Gas Report are stated after providing for estimated well abandonment and site restoration costs.

Insurance

Freehold Resources carries insurance policies to provide protection for its working interest in the Freehold Resources Properties at or above industry standards. Insurance policies cover property damage, general liability and, for certain

properties, business interruption. The ongoing level, type and maintenance of insurance are determined by Freehold Resources based upon the availability and cost of such insurance and Freehold Resources' perception of the risk of loss. Freehold Resources carries insurance which provides standard industry levels of coverage to individuals for all good faith acts carried out by them on behalf of the Corporation in their capacity as directors or officers of the Corporation.

TRUST UNITS

The Trust Indenture

An unlimited number of Trust Units have been created and may be issued pursuant to the Trust Indenture. The Trust Units represent equal undivided beneficial interests in the Trust. All Trust Units share equally in all distributions from the Trust and all Trust Units carry equal voting rights at meetings of Unitholders. No Unitholder will be liable to pay any further calls or assessments in respect of the Trust Units.

The Trust Indenture, among other things, provides for the calling of meetings of Unitholders, the conduct of business thereof, notice provisions, the appointment and removal of the Trustee and the form of Trust Unit certificates. The Trust Indenture may be amended from time to time. Substantive amendments to the Trust Indenture, including early termination of the Trust and the sale or transfer of the property of the Trust as an entirety or substantially as an entirety requires approval by Special Resolution of the Unitholders. See "Trust Units - Meetings and Voting".

The following is a summary of certain provisions of the Trust Indenture. For a complete description of such indenture, reference should be made to the Trust Indenture, copies of which may be viewed at the offices of, or obtained from, the Trustee.

Trustee

Computershare Trust Company of Canada (the "Trustee") is the trustee of the Trust and also acts as the transfer agent for the Trust Units. The Trustee is responsible for, among other things: (a) accepting subscriptions for Trust Units and issuing Trust Units pursuant thereto; (b) maintaining books and records of the Trust and providing timely reports to holders of Trust Units; and (c) paying cash distributions to Unitholders. The Trust Indenture provides that the Trustee shall 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 Trustee may resign upon 60 days notice to Freehold Resources and the Manager. The Trustee may also be removed by Special Resolution of the Unitholders. Such resignation or removal becomes effective upon the acceptance or appointment of a successor trustee.

The Trust has retained the Manager to administer the Trust on behalf of the Trustee. The Manager, on behalf of the Trustee, keeps such books and records as are necessary for the proper recording of the business transactions of the Trust.

The Trust Indenture provides that the Trustee shall be under no liability for any action or failure to act unless such liabilities arise out of the Trustee's gross negligence, willful default or fraud. The Trustee, where it has met its standard of care, shall be indemnified out of the assets of the Trust in consequence of its performance of its duties but shall have no additional recourse against Unitholders. In addition, the Trust Indenture contains other customary provisions limiting the liability of the Trustee.

Cash Distributions of Royalty Income

The amount of cash distributed annually per Trust Unit is equal to a pro rata share of the Distributable Income for the year. Cash distributions are made on a monthly basis on the 15th day of the month following each Record Date to Unitholders of record on the Record Date.

The actual amount of Distributable Income will depend on, among other things, the quantity of oil, gas, natural gas liquids and potash produced, prices received, General and Administrative Costs, direct expenses of the Trust, Capital Expenditures, Debt Service Charges, Crown royalties and other Crown charges, net contributions to Freehold Resources' reclamation fund, and interest income.

By utilizing available tax deductions, cash distributions in the Trust's initial years were sheltered from income tax. The Trust paid \$1.31 per Trust Unit in cash distributions during 2002. For Canadian tax purposes, 58% of these distributions (\$0.7598 per Trust Unit) were taxable to Unitholders as other income and 42% (\$0.5502 per Trust Unit) was tax deferred (return of capital). Over time, an increasing percentage of the annual distributions will become taxable. Based on production and commodity price forecasts, it is estimated that approximately 60% to 65% of distributable income will be taxable in 2003.

Income Tax Considerations

Future acquisitions of Canadian resource properties would result in royalty payments to the Trust and, in turn, distributions to Unitholders that would, under most circumstances, be on the same tax deferred basis as are current distributions. Future acquisitions of corporations, facilities or other forms of oil and gas assets may result in dividend, interest or other forms of payments to the Trust (as opposed to royalty payments) and, in turn, distributions to Unitholders that may be wholly or in part taxable. In approving any future acquisition, the board of directors of Freehold Resources would be required to consider the impact that such acquisition would have on anticipated after-tax distributions to Unitholders.

Right of Redemption

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 requesting redemption. Upon receipt of the redemption request by the Trust, all rights to and under the Trust Units tendered for redemption shall be surrendered and the holder thereof shall be entitled to receive a price per Trust Unit ("Market Redemption Price") equal to the lesser of: (i) 90% of the market price of the Trust Units on The Toronto Stock Exchange or if not trading on The Toronto Stock Exchange at such time the principal market on which the Trust Units are quoted for trading at such time (the "Principal Market") during the 10 trading day period commencing immediately after the date on which the Trust Units are surrendered for redemption; and (ii) 90% of 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 surrendered for redemption.

The aggregate cash 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 cash payment on the last day of the following month; provided that the entitlement of Unitholders to receive cash upon the redemption of their Trust Units is subject to the limitations that: (i) the total amount payable by the Trust in respect of such Trust Units and all other Trust Units tendered for retraction in the same calendar month shall not exceed \$100,000 provided that such limitation may be waived at the discretion of the board of directors of Freehold Resources in respect of any calendar month; (ii) at the time such Trust Units are tendered for retraction the outstanding Trust Units of the Trust shall be listed for trading on a stock exchange or traded or quoted on any other market which the board of directors of Freehold Resources consider, in its sole discretion, provided representative fair market value prices for the Trust Units and on which market price can be calculated; or (iii) the normal trading of Trust Units is not suspended or halted on any stock exchange on which the Trust Units are listed (or, if not listed on a stock exchange, on any market on which the Trust Units are quoted for trading) on the date that the Trust

Units are tendered for retraction or for more than five trading days during the ten day trading period commencing immediately after the date on which the Trust Units are tendered for retraction.

If a Unitholder is not entitled to receive cash upon the redemption of Trust Units as a result of the foregoing limitations, then the Market Redemption Price for such Trust Units shall be paid on the last day of the following month by the Trust distributing Freehold Resources Notes having an aggregate principal amount equal to the aggregate Market Redemption Price of the Trust Units tendered for redemption but not redeemed as provided above.

If at the time Trust Units are tendered for redemption by a Unitholder the outstanding Trust Units are not listed for trading on The Toronto Stock Exchange and are not traded or quoted on any other stock exchange or market which Freehold Resources considers in its sole discretion, provides representative fair market values for the Trust Units or trading of the outstanding Trust Units is suspended or halted on the date such Trust Units tendered for redemption or for more than five trading days during the 10 trading days 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 Freehold Resources as at the date upon 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 Freehold Resources: (i) a cash payment, or (ii) a distribution of Freehold Resources Notes.

The Freehold Resources Notes, if and when needed, are proposed to be created and issued by Freehold Resources to the Trust pursuant to a note indenture and are to be unsecured and bear interest from the date of issue at the lessor of: (a) the interest paid on two year Government of Canada bonds minus 2%; or (b) 6% per annum. A new series of Freehold Resources Notes will be created and issued for each monthly redemption of Trust Units, if any. The Freehold Resources Notes are due and payable on maturity on the 15th anniversary of the date of issuance.

The holder of the Freehold Resources Notes of a particular series (equal in principal amount to the Market Redemption Price or Appraised Redemption price, as the case may be, of one Trust Unit for a particular series) will be paid interest and principal, if any, monthly, in arrears on the 20th day of the next following month (and interest will only be deemed to accrue and principal to be payable only to the extent of the amount calculated hereunder) in an amount calculated in accordance with the following formula:

$$\frac{\text{RUU}}{\text{All RUU} + \text{All OS}} \times \text{Distributable Income}$$

Where:

RUU	means the number of the redeeming Unitholder's Units tendered for redemption.
All RUU	means the aggregate of the number of the redeeming Unitholders' Units tendered for redemption.
All OS	means all of the issued and outstanding Units.
Distributable Income	means the amounts held by the Trust which are to be actually distributed to Unitholders for the applicable month.

All amounts paid will be applied firstly to interest and then to principal. Any interest not paid when due will not bear interest but will be carried forward to the next interest payment date.

The Freehold Resources Notes may be prepaid at any time without notice, bonus or penalty at the discretion of the board of directors of Freehold Resources and will be prepaid to the extent the sale of resource properties increases Distributable

Income. The Freehold Resources Notes will be paid in full in cash or *in specie* prior to any distributions to Unitholders in the event of the dissolution or winding-up of the Trust.

The Freehold Resources Notes will be in default and become immediately due and payable on the occurrence of the following events of default: (i) default in payments of principal or interest when due for a period of three months, (ii) default by Freehold Resources on indebtedness exceeding \$10.0 million, (iii) certain events of insolvency, bankruptcy, winding-up or receivership, (iv) taking of possession of all or substantially all of the property of Freehold Resources by an encumbrancer, or (v) breach of any material term of the note indenture for a period of 30 days after notice of breach.

The Freehold Resources Notes will be unsecured debt obligations of the Trust and will be subordinate to any “senior indebtedness” which includes all indebtedness for borrowed money (or for the purchase of property) on any default in payment of any such senior indebtedness and to all trade debt of the Trust or Freehold Resources or any subsidiary of either of them or any creditor proceedings such as bankruptcy, liquidation or insolvency.

It is anticipated that this retraction right will not be the primary mechanism for holders of Trust Units to dispose of their Trust Units. Freehold Resources 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 the Freehold Resources Notes. Freehold Resources Notes may be subject to resale restrictions under applicable securities laws. Freehold Resources Notes so distributed may be qualified investments for trusts governed by registered retirement savings plans, registered retirement income trusts and deferred profit sharing plans.

Future Offerings

Under the Trust Indenture, the Trust may offer additional Trust Units or rights to acquire additional Trust Units at such times and on such terms as the board of directors of Freehold Resources may determine. Pursuant to the Deferred Purchase Price Obligation, the Freehold Resources Royalty will attach to the interests of Freehold Resources in any Additional Properties it may acquire from time to time. Accordingly, the proceeds from any offerings of Trust Units will be used to finance the acquisition of Additional Royalties by the Trust or Additional Properties should such interests be available on terms and conditions acceptable to Freehold Resources on behalf of Unitholders.

Borrowing by the Trust

Pursuant to the Trust Indenture, the Trust will be permitted to borrow funds to finance the purchase of Additional Royalties, for capital expenditures or for other financial obligations or expenditures in respect of the HB Lands Royalties and Additional Royalties or for working capital purposes and to grant security on the HB Lands Royalties and Additional Royalties to secure the loan of such funds. The Trust has established guidelines which provide that: (a) the amounts borrowed to finance the purchase of Additional Royalties when combined with existing debt of the Trust and existing debt of Freehold Resources will not exceed 40% of the Asset Value of all of the HB Lands Royalties, the Additional Royalties and the Freehold Resource Properties at the time of borrowing; and (b) the Debt Service Charges on amounts borrowed to finance the purchase of Additional Royalties or capital expenditures to maintain or improve production from the HB Lands Royalties or other borrowing as permitted above will not exceed 10% of the estimated annual Royalty Income.

Debt Service Charges incurred by the Trust will be deducted in computing the Distributable Income. The debt repayment will be scheduled to minimize, to the extent possible, any income tax payable by the Trust.

Meetings and Voting

Annual meetings of the Unitholders are held annually. Special meetings of Unitholders may be called at any time by the Trustee and shall be called by the Trustee upon the written request of Unitholders holding in aggregate not less than 20% of the Trust Units. Notice of all meetings of Unitholders shall be given to Unitholders at least 21 days prior to the meeting.

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

Unitholders are entitled to one vote per Trust Unit at all meetings of Unitholders called pursuant to the Trust Indenture. A Special Resolution of Unitholders is required to, among other things, make certain amendments to the Trust Indenture, remove the Trustee or terminate the Trust.

Management of the Trust

Pursuant to the provisions of the Management Agreement, the Manager provides certain administrative and support services to the Trust, including those necessary: (i) to ensure compliance by the Trust with continuous disclosure obligations under applicable securities legislation; (ii) to provide investor relations services; (iii) to provide or cause to be provided to Unitholders all information to which Unitholders are entitled under the Trust Indenture; (iv) to call, hold and distribute materials including notices of meetings and information circulars in respect of all necessary meetings of Unitholders; (v) to determine the amounts payable from time to time to Unitholders and to arrange for distributions to Unitholders of Distributable Income; (vi) to determine the timing and terms of future offerings of Trust Units, if any; (vii) to determine the terms and conditions upon which the Trust may acquire Additional Royalties; and (viii) to determine the terms and conditions upon which the Trust may from time to time borrow money. The board of directors of Freehold Resources is required to approve all matters referred to in items (iv), (v), (vi), (vii) and (viii) above and, in addition will be required to approve any amendment to the Management Agreement, the HB Lands Royalty Agreement or the Freehold Resources Royalty Agreement.

Limitation on Non-Resident Ownership

In order for the Trust to maintain its status as a mutual fund trust under the Tax Act, the Trust must not be established or maintained primarily for the benefit of non-residents of Canada (“non-residents”) within the meaning of the Tax Act. Accordingly, the Trust Indenture provides that at no time may non-residents be the beneficial owners of a majority of the Trust Units. If the Trustee becomes aware that the beneficial owners of 49% of the Trust Units then outstanding are or may be non-residents or that such a situation is imminent, the Trustee may make a public announcement thereof and shall not accept a subscription for Trusts Units from or issue or register a transfer of Trust Units to a person unless the person provides a declaration that the person is not a non-resident. Notwithstanding the foregoing, if the Trustee determines that a majority of the Trust units are held by non-residents, the Trustee may send a notice to non-resident holders of Trust Units, chosen in inverse order to the order of acquisition or registration or in such other manner as the Trustee may consider equitable and practicable, requiring them to sell their Trust Units or a portion thereof within a specified period of not less than 60 days. If the Unitholders receiving such notice have not sold the specified number of Trust Units or provided the Trustee with satisfactory evidence that they are not non-residents within such period, the Trustee may on behalf of such Unitholders sell such Trust Units and, in the interim, shall suspend the voting and payment of Distributable Income and other rights attached to such Trust Units and shall make any distribution in respect of such Trust Units by depositing such amounts in a separate bank account. Upon such sale, the affected holders shall cease to be holders of Trust Units and their rights shall be limited to receiving the net proceeds of sale upon surrender of the certificates representing such Trust Units.

Termination of the Trust

The Unit holders may vote to terminate the Trust at any meeting of the Unitholders, 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 Trust Units or the Trust Units have become ineligible for investment by RRSPs, RESPs, RRIFs or DPSPs; (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 the Unitholders.

Unless the Trust is terminated or extended by vote of the Unitholders earlier, the Trustee shall commence to wind-up the affairs of the Trust on December 31, 2096. In the event that the Trust is wound-up, the Trustee will liquidate all the assets of the Trust, pay, retire, discharge or make provision for some or all obligations of the Trust and then distribute the remaining proceeds of sale to the Unitholders.

Reporting to Unitholders

The financial statements of the Trust are audited annually by an independent recognized firm of chartered accountants. The auditors of the Trust are KPMG LLP, Chartered Accountants. The audited financial statements of the Trust, together with the report of such chartered accountants, are mailed by the Trustee to Unitholders and the unaudited interim financial statements of the Trust are 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.

Unitholders are entitled to inspect, during normal business hours, at the offices of the Trustee, and, upon payment of reasonable reproduction costs, to receive photocopies of the HB Lands Royalty Agreement (other than schedules), the Freehold Resources Royalty Agreement (other than schedules), the Trust Indenture, the Management Agreement and a listing of the registered holders of Trust Units.

Direct Deposit Plan

A Direct Deposit Plan (the “Deposit Plan”) has been established for the Trust to provide holders who have Canadian bank accounts with a method of receiving cash distributions as a direct deposit into their bank account. The main features of the Deposit Plan are as follows:

- a. distributions will be deposited directly into the Unitholder’s Canadian bank account;
- b. optional confirmation of deposit feature will be offered; and
- c. all administrative costs of the Deposit Plan are borne by the Trust.

Cash Distribution Reinvestment Plan

A Trust Unit Cash Distribution reinvestment plan (the “DRIP”) has been established for the Trust to provide Unitholders who are residents of Canada (within the meaning of the Tax Act) with a method of reinvesting cash distributions into new Trust Units.

The main features of the DRIP Plan are as follows:

- (i) Any Canadian resident holder of record holding a minimum of 1,000 Trusts Units may join or opt out of the DRIP Plan at any time.
- (ii) Trust Units are purchased monthly with reinvested cash distributions on the open market or from the Trust at prevailing market prices, at the option of the Trust;
- (iii) DRIP Plan participants receive quarterly statements detailing the number of additional Trust Units acquired through reinvestment to assist their record-keeping; and
- (iv) All administrative costs of the DRIP Plan are borne by the Trust.

Once a Unitholder has enrolled in the DRIP Plan, his participation in the DRIP Plan continues automatically until terminated by the Unitholder or until the DRIP Plan is terminated by the Trust in the Trust's sole discretion.

If the Trust Units are issued directly by the Trust, participating Unitholders will pay no service or brokerage charges in respect of additional Trust Units acquired under the DRIP Plan and proceeds from the issuance of those additional Trust Units will be added to working capital of the Trust.

US Currency Payment Plan

The US Currency Payment plan (the "US Currency Plan") allows holders of Trust Units of the Trust who maintain US currency accounts to obtain convenient payments in US currency.

The main features of the US Currency Plan are as follows:

- (i) Unitholders may elect to obtain their cash distributions from Trust Units in US currency.
- (ii) US currency distributions will be made by the Trustee of the Trust, Computershare Trust Company of Canada.
- (iii) Participants do not pay any costs associated with the US Currency Plan.
- (iv) Due to the structure of the US Currency Plan, participants shall not be permitted to coincidentally participate in the DRIP Plan.

CORPORATE GOVERNANCE

General

In general, Freehold Resources has been delegated the significant management decisions of the Trust. The Unitholders are entitled to elect a majority of the board of directors of Freehold Resources pursuant to the terms of the Unanimous Shareholder Agreement. Subject to the ultimate authority of the board of directors of Freehold Resources, Freehold Resources and the Trust are managed by the Manager.

Unanimous Shareholders Agreement

Pursuant to the Unanimous Shareholder Agreement dated November 25, 1996 among the Manager, Freehold Resources, the trustee of the Share Trust and the Trustee as trustee for and on behalf of the Trust, the Unitholders will be entitled to attend all meetings of shareholders of Freehold Resources and except as set forth below, to direct the manner in which the Share Trust will vote its shares in Freehold Resources at all such meetings. Prior to the Share Trust voting its shares in Freehold Resources each Unitholder shall be entitled to vote in respect of the matter on the basis of one vote per Trust Unit held, and the Share Trust shall be required to vote its shares in Freehold Resources in accordance with the result of the vote of the Unitholders. Unitholders shall be entitled to direct the Share Trust as to how to vote in respect of all matters placed before the shareholders of Freehold Resources including, in respect of matters relating to the election of the directors of Freehold Resources (other than the directors of Freehold Resources to be elected by the Manager pursuant to the terms of the Unanimous Shareholder Agreement, which is currently two), approving its financial statements and appointing auditors of Freehold Resources. In addition, Unitholders will be entitled to direct the Share Trust as to how to vote its shares in Freehold Resources on any proposed amendment to the Unanimous Shareholder Agreement, where such amendment is required to be approved by Special Resolution. The Share Trust will not be entitled, without the direction of Unitholders, to exercise its rights as shareholder of Freehold Resources except as set forth above.

The Unanimous Shareholder Agreement provides that the board of directors of Freehold Resources shall consist of a minimum of five and a maximum of nine directors, and that the Unitholders will be entitled to elect a majority of the board of directors of Freehold Resources and the Manager will be entitled to elect the balance of the directors. The number of directors is currently set at seven.

The Unanimous Shareholder Agreement also provides that Freehold Resources will be prohibited from making payment of dividends on its shares.

Decision Making

Although the Manager provides certain advisory and management services to the Trust and Freehold Resources pursuant to the Management Agreement, the board of directors of Freehold Resources supervises the management of the business and affairs of the Trust and Freehold Resources. In particular, significant operational decisions and all decisions relating to: (a) issuances of additional Trust Units; (b) the acquisition and disposition of properties of the Trust or Freehold Resources for a purchase price or proceeds in excess of \$5.0 million; (c) capital expenditures outside of approved budgets; (d) establishment of credit facilities; and (e) the payment of Distributable Income, will be made by the board of directors of Freehold Resources. Any amendment to the Management Agreement or the Freehold Resources Royalty Agreement requires the approval of the board of directors of Freehold Resources on behalf of the Trust. The board of directors of Freehold Resources has held regularly scheduled meetings to review the business and affairs of Freehold Resources and make any necessary decisions relating thereto.

Board of Directors of Freehold Resources

Freehold Resources has a board of directors consisting of seven individuals, two of whom have been elected by the Manager and five of whom are independent directors. Four of the five independent directors have been elected by the Unitholders. The Chairman of the board of directors is one of the independent directors.

The name, municipality of resident, position held and principal occupation of each director and officer of Freehold Resources are set out below:

Name and Municipality of Residence	Position with Freehold Resources	Principal Occupation	Director/Officer Since	Number of Trust Units Held
William W. Siebens ⁽²⁾⁽⁴⁾ Calgary, Alberta	Chairman and Director	President and Chief Executive Officer, Candor Investments Ltd. (private energy and investment corporation)	July 29, 1996	50,000
D. Nolan Blades ⁽¹⁾⁽²⁾⁽⁴⁾ Calgary, Alberta	Director	President, Sunny Gables Holdings Ltd. (private holding company)	July 29, 1996	15,000
Harry S. Campbell, Q.C. ⁽²⁾ Calgary, Alberta	Director	Managing Partner, Burnet, Duckworth & Palmer LLP (barristers and solicitors)	July 29, 1996	2,800
Peter T. Harrison ⁽¹⁾⁽²⁾ Brossard, Quebec	Director	Senior Vice-President, Monrusco Bolton Inc. (investment counsel)	July 29, 1996	28,000
Dr. P. Michael Maher ⁽¹⁾⁽²⁾⁽⁴⁾ Calgary, Alberta	Director	Professor, Haskayne School of Business, University of Calgary	July 29, 1996	1,000
Tullio Cedraschi ⁽³⁾ Montreal, Quebec	Director	President and Chief Executive Officer, CN Investment Division (manages the pension funds for employees of the Canadian National Railway Company)	January 21, 1998	nil ⁽⁵⁾
David J. Sandmeyer ⁽³⁾ Calgary, Alberta	Director, President and Chief Executive Officer	President of Rife Resources Ltd. (private oil and gas exploration and production company)	July 29, 1996	17,000 ⁽⁵⁾⁽⁶⁾
J. Frank George Calgary, Alberta	Vice-President, Exploitation	Vice President, Exploration of Rife Resources Ltd. (private oil and gas exploration and production company)	July 29, 1996	nil ⁽⁵⁾⁽⁶⁾
Joseph N. Holowisky Calgary, Alberta	Vice-President, Finance & Administration, Chief Financial Officer and Secretary	Vice-President, Finance & Administration and Secretary of Rife Resources Ltd. (private oil and gas exploration and production company)	July 29, 1996	nil ⁽⁵⁾⁽⁶⁾
William O. Ingram Calgary, Alberta	Vice-President, Production	Vice-President, Production of Rife Resources Ltd. (private oil and gas exploration and production company)	July 29, 1996	nil ⁽⁵⁾⁽⁶⁾
Michael J. Okrusko Calgary, Alberta	Vice-President, Land	Vice-President, Land of Rife Resources Ltd. (private oil and gas exploration and production company)	July 29, 1996	1,000 ⁽⁵⁾⁽⁶⁾

Notes:

- (1) Member of Audit Committee.
- (2) Independent directors of Freehold Resources who were elected by the Unitholders at the last Annual meeting of the Trust on May 7, 2003.
- (3) Nominees of the Manager.
- (4) Member of Corporate Governance & Nominating Committee.
- (5) CN Pension Trust Funds, including the Trust Units owned by the Manager, owns 9,824,536 Trust Units (31.43%) of Freehold Royalty Trust. Rife Resources Ltd. is 100% owned by the CN Pension Trust Funds.
- (6) The Manager, which is a wholly owned subsidiary of Rife Resources Ltd., owns 1,526,736 Trust Units.

Each of the proposed nominees has been engaged in his principal occupation or in other capacities with the same firm or organization for the past five years except for: D. Nolan Blades who, until April 13, 2000 was President and C.E.O. of Pursuit Resources Corporation.

As at May 14, 2003, the directors and senior officers of Freehold Resources, as a group, beneficially owned, directly or indirectly, or exercised control or direction over, 114,800 Trust Units or less than 1% of the issued and outstanding Trust Units.

THE MANAGER

The Manager is a wholly-owned subsidiary of Rife Resources Ltd., which is 100% owned by the CN Pension Trust Funds (the pension funds for the employees of the Canadian National Railway Company).

Management Agreement

Freehold Resources and the Trustee, as trustee for and on behalf of the Trust, entered into the Management Agreement with the Manager, pursuant to which Freehold Resources and the Trust engaged the Manager for an initial term of five years, which initial term has automatically renewed for an additional three year term expiring in November, 2004, to:

- a. manage the Trust, subject to the supervision of Freehold Resources;
- b. administer all matters relating to the HB Lands Royalties, Additional Royalties, Freehold Resources Royalty and Trust Units, including: (i) determining the total amount owing to the Trust and Freehold Resources from third parties and conducting joint venture audits as required; (ii) determining the total amounts owing to Unitholders and arranging for cash distributions of Distributable Income, subject to the supervision of Freehold Resources; (iii) providing Unitholders with periodic reports on the HB Lands Royalties, Additional Royalties, Freehold Resources Royalty and the Freehold Resources Properties; and (iv) providing Unitholders with financial reports and tax information relating to the HB Lands Royalties, Additional Royalties, Freehold Resources Properties and the Freehold Resources Royalty;
- c. provide management services for the economic and efficient exploitation of oil and natural gas properties;
- d. operate oil and natural gas properties which Freehold Resources is entitled to operate and monitor the activities of third party operators;
- e. recommend, carry out and monitor property acquisitions and dispositions and exploitation and development programs for the Trust and Freehold Resources;
- f. negotiate on behalf of Freehold Resources all exploitation and development agreements, operating agreements, working agreements, farmin and farmout agreements, leases and other documents relating to the exploitation of the oil and natural gas properties as may be advisable;
- g. recommend and, subject to the supervision of Freehold Resources, negotiate banking arrangements for the Trust and Freehold Resources; and
- h. provide office space, office furnishings and equipment and personnel necessary for the proper administration of the assets of the Trust and Freehold Resources.

The Management Agreement will be renewed for successive three year terms following the end of its current three year term unless the termination of the Management Agreement at the end of a term has been approved by a Special Resolution of Unitholders and the Manager is given 12 months written notice of termination or unless the Trustee is given 12 months written notice of termination by the Manager prior to the end of a term.

Proceeds relating to subscription offerings, Royalty Income and any cash flow and other revenues generated from or associated with any interest of the Trust in the HB Lands Royalties, the Additional Royalties or the Freehold Resources Royalty, or of Freehold Resources in the Freehold Resources Properties may not be commingled with the funds of any other entity which is managed by the Manager.

The Manager is paid Management Fees for providing all of the management services. The Manager will be indemnified by Freehold Resources in respect of certain damages which it may suffer in discharging its obligations under the Management Agreement provided that such damages do not arise from the fraud, willful default, gross negligence or bad faith of the Manager.

The board of directors of Freehold Resources and the Trustee will review on an ongoing basis both the nature and extent of the services required of the Manager and the costs of providing the same. All amendments to the Management Agreement must be approved by a majority of the independent members of the board of directors of Freehold Resources and the Trustee, upon the recommendation of Freehold Resources and the Manager.

Compensation

The Manager will be compensated as follows for providing services to the Trust and Freehold Resources.

Management Fees

Pursuant to the Management Agreement, the Manager receives a Management Fee, paid in Trust Units, based on the number of issued and outstanding Trust Units at the end of each quarter. The quarterly Management Fee was initially 20,000 Trust Units. The Management Fee is adjusted, based on the total issued and outstanding Trust Units, so that the quarterly Management Fee is in the same proportion as 20,000 was to the outstanding Trust Units on November 25, 1996, excluding Trust Units issued as a Management Fee. The issuance of 3.3 million Trust Units in May 2001 resulted in a pro-rata increase in the management fee to 22,500 Trust Units per quarter in accordance with the Management Agreement.

During 2002, the Manager received 90,000 Trust Units as the Management Fee to the Manager, bringing the total number of units received by the Manager since inception of the Trust in late 1996 to 504,236.

General and Administrative Costs

The Manager is reimbursed for General and Administrative Costs incurred on behalf of the Trust. General and Administrative Costs are deducted in computing Freehold Resources Royalty Income to the extent not paid from the residual income of Freehold Resources. General and Administrative Costs are generally charged to Freehold Resources and the Trust by the Manager based on time spent and direct costs incurred in fulfilling the obligations of the Manager to Freehold Resources and the Trust pursuant to the Management Agreement. The Manager charged the Trust \$2.0 million for General and Administrative Costs for the year ended December 31, 2002.

Acquisition and Disposition Fees

The Manager is paid an acquisition fee equal to 1.5% of the purchase price of any Additional Royalties purchased by the Trust or any Additional Properties acquired by Freehold Resources. In the case of property exchanges or swaps, the Manager will receive the 1.5% acquisition fee up to the purchase price of the properties acquired. No fees will be payable with respect to the proceeds of disposition of any HB Lands Royalties, Additional Royalties or Freehold Resources

Properties. The Manager did not receive any acquisition fees for the acquisition of the HB Lands Royalties or the Working Interest Properties. During 2002, \$38,000 (2001 - \$483,000) was paid related to acquisitions. This fee is charged to capital assets as part of the properties acquired.

Directors and Officers of the Manager

The name, municipality of residence, position held and principal occupation of each director and officer of the Manager are set out below:

Name and Municipality of Residence	Position with the Manager	Principal Occupation	Director/Officer Since	Number of Trust Units Held
David J. Sandmeyer Calgary, Alberta	President and Director	President of Rife Resources Ltd.	October 1, 1996	17,000
J. Frank George Calgary, Alberta	Vice-President Exploitation	Vice-President, Exploration of Rife Resources Ltd.	October 1, 1996	nil
Joseph N. Holowisky Calgary, Alberta	Vice-President, Finance and Administration, Secretary and Director	Vice-President, Finance and Administration and Secretary of Rife Resources Ltd.	October 1, 1996	nil
William O. Ingram Calgary, Alberta	Vice-President, Production	Vice-President, Production of Rife Resources Ltd.	October 1, 1996	nil
Michael J. Okrusko Calgary, Alberta	Vice-President, Land	Vice-President, Land of Rife Resources Ltd.	October 1, 1996	1,000

As at May 14, 2003 the directors and senior officers of the Manager, as a group, beneficially owned, directly or indirectly, or exercised control or direction over, 18,000 Trust Units. The Manager owns 1,526,736 Trust Units directly or approximately 4.9% of the issued and outstanding Trust Units, and the indirect owner of the Manager, CN Pension Trust Funds, owns, directly or indirectly, excluding the Trust Units owned by the Manager, 8,297,800 Trust Units or approximately 26.5% of the issued and outstanding Trust Units.

Business of the Manager

The Manager was established to provide comprehensive oil and gas company management and operational services to the Trust and Freehold Resources. The Manager is a wholly-owned subsidiary of Rife. Pursuant to an agreement between Rife and the Manager dated November 25, 1996, Rife provides the Manager, on a contract basis, with all necessary personnel, equipment and facilities required to provide management and operational services to the Trust and Freehold Resources on a cost recovery basis.

CONFLICTS OF INTEREST

There may be situations in which the interests of the Manager will conflict with those of Unitholders. As part of the ordinary course of business of the Manager, the Manager may continue to acquire oil and natural gas properties on its own behalf and on behalf of persons other than the Unitholders. The Manager may manage and administer such additional properties, as well as enter into other types of energy-related management, advisory and investment activities. Thus neither the Manager, nor its management, will carry on their full-time activities on behalf of Unitholders and, when acting on its own behalf or on behalf of others, may at times act in contradiction to or competition with the interests of Unitholders.

In resolving such conflicts, decisions will be made by the Manager on a basis consistent with the objectives and financial resources of each group of interested parties, the time limitations on investment of such financial resources, and on the basis of operating efficiencies having regard to the then current holdings of properties of each group of interested parties all consistent with the duties of the Manager to each such group of persons. The Management Agreement contains provisions which require the Manager to make disclosure to the board of directors of Freehold Resources of the fact and substance of any particular conflict of interest and to use all reasonable efforts to resolve such conflicts of interest in a manner which will treat the Trust or Freehold Resources, as the case may be, and the other interested party fairly taking into account all of the circumstances of the Trust or Freehold Resources, as the case may be, and such interested party and to act honestly and in good faith in resolving such matters.

Although the Manager provides advisory and management services to Freehold Resources, the board of directors of Freehold Resources supervises the management of the business and affairs of Freehold Resources. The board makes significant operational decisions and all decisions relating to: (i) the issuance of additional Trust Units; (ii) the acquisition and disposition of properties for a purchase price or proceeds in excess of \$5.0 million; (iii) the approval of capital expenditure budgets; (iv) the establishment of credit facilities; and (v) the determination of the amount of Distributable Income.

Properties will not be acquired from officers or directors of the Manager 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 Manager 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 board of directors of Freehold Resources. 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 and Commission des valeurs mobilières du Québec Policy Q-27.

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

DISTRIBUTIONS TO UNITHOLDERS

The following per Trust Unit distributions have been made to date:

Historical Distributions	Record Date	Payment Date	Per Trust Unit
Quarterly			
December 31, 1996 (37 day period)	Jan. 31, 1997	Feb. 28, 1997	\$0.1300
March 31, 1997	Apr. 30, 1997	May 15, 1997	\$0.3200
June 30, 1997	July 31, 1997	Aug. 15, 1997	\$0.2800
September 30, 1997	Oct. 31, 1997	Nov. 15, 1997	\$0.2500
December 31, 1997	Jan. 31, 1998	Feb. 15, 1998	\$0.2500
March 31, 1998	Apr. 30, 1998	May 15, 1998	\$0.1700
Monthly			
April, 1998	Apr. 30, 1998	May 15, 1998	\$0.0575
May, 1998	May 31, 1998	June 15, 1998	\$0.0575
June, 1998	June 30, 1998	July 15, 1998	\$0.0575
July, 1998	July 31, 1998	Aug. 15, 1998	\$0.0575
August, 1998	Aug. 31, 1998	Sept. 15, 1998	\$0.0500
September, 1998	Sept. 30, 1998	Oct. 15, 1998	\$0.0500
October, 1998	Oct. 31, 1998	Nov. 15, 1998	\$0.0500
November, 1998	Nov. 30, 1998	Dec. 15, 1998	\$0.0500
December, 1998	Dec. 31, 1998	Jan. 15, 1999	\$0.0500
January, 1999	Jan. 31, 1999	Feb. 15, 1999	\$0.0500
February, 1999	Feb. 28, 1999	Mar. 15, 1999	\$0.0400
March, 1999	Mar. 31, 1999	Apr. 15, 1999	\$0.0400

Historical Distributions	Record Date	Payment Date	Per Trust Unit
April, 1999	Apr. 30, 1999	May 15, 1999	\$0.0400
May, 1999	May 31, 1999	June 15, 1999	\$0.0500
June, 1999	June 30, 1999	July 15, 1999	\$0.0500
July, 1999	July 31, 1999	Aug. 15, 1999	\$0.0600
August, 1999	Aug. 31, 1999	Sept. 15, 1999	\$0.0700
September, 1999	Sept. 30, 1999	Oct. 15, 1999	\$0.0700
October, 1999	Oct. 31, 1999	Nov. 15, 1999	\$0.0700
November, 1999	Nov. 30, 1999	Dec. 15, 1999	\$0.1700
December, 1999	Dec. 31, 1999	Jan. 15, 2000	\$0.0700
January, 2000	Jan. 31, 2000	Feb. 15, 2000	\$0.0700
February, 2000	Feb. 29, 2000	Mar. 15, 2000	\$0.1300
March, 2000	Mar. 31, 2000	Apr. 15, 2000	\$0.0700
April, 2000	Apr. 30, 2000	May 15, 2000	\$0.0700
May, 2000	May 31, 2000	June 15, 2000	\$0.1700
June, 2000	June 30, 2000	July 15, 2000	\$0.0800
July, 2000	July 31, 2000	Aug. 15, 2000	\$0.0800
August, 2000	Aug. 31, 2000	Sept. 15, 2000	\$0.1500
September, 2000	Sept. 30, 2000	Oct. 15, 2000	\$0.1000
October, 2000	Oct. 31, 2000	Nov. 15, 2000	\$0.1000
November, 2000	Nov. 30, 2000	Dec. 15, 2000	\$0.2000
December, 2000	Dec. 31, 2000	Jan. 15, 2001	\$0.1000
January, 2001	Jan. 31, 2001	Feb. 15, 2001	\$0.1000
February, 2001	Feb. 28, 2001	Mar. 15, 2001	\$0.2000
March, 2001	Mar. 31, 2001	Apr. 15, 2001	\$0.1000
April, 2001	Apr. 30, 2001	May 15, 2001	\$0.1000
May, 2001	May 31, 2001	June 15, 2001	\$0.2300
June, 2001	June 30, 2001	July 15, 2001	\$0.1200
July, 2001	July 31, 2001	Aug. 15, 2001	\$0.1200
August, 2001	Aug. 31, 2001	Sept. 15, 2001	\$0.1700
September, 2001	Sept. 30, 2001	Oct. 15, 2001	\$0.1200
October, 2001	Oct. 31, 2001	Nov. 15, 2001	\$0.1000
November, 2001	Nov. 30, 2001	Dec. 15, 2001	\$0.1000
December, 2001	Dec. 31, 2001	Jan. 15, 2002	\$0.1000
January, 2002	Jan. 31, 2002	Feb. 15, 2002	\$0.0800
February, 2002	Feb. 28, 2002	Mar. 15, 2002	\$0.0800
March, 2002	Mar. 31, 2002	Apr. 15, 2002	\$0.0800
April, 2002	Apr. 30, 2002	May 15, 2002	\$0.0800
May, 2002	May 31, 2002	June 15, 2002	\$0.1400
June, 2002	June 30, 2002	July 15, 2002	\$0.1000
July, 2002	July 31, 2002	Aug. 15, 2002	\$0.1000
August, 2002	Aug. 31, 2002	Sept. 15, 2002	\$0.1700
September, 2002	Sept. 30, 2002	Oct. 15, 2002	\$0.1000
October, 2002	Oct. 31, 2002	Nov. 15, 2002	\$0.1000
November, 2002	Nov. 30, 2002	Dec. 15, 2002	\$0.1800
December, 2002	Dec. 31, 2002	Jan. 15, 2003	\$0.1000
January, 2003	Jan. 31, 2003	Feb. 15, 2003	\$0.1000
February, 2003	Feb. 28, 2003	Mar. 15, 2003	\$0.2000
March, 2003	Mar. 31, 2003	Apr. 15, 2003	\$0.1000
April, 2003	Apr. 30, 2003	May 15, 2003	\$0.1000
May, 2003	May 31, 2003	June 15, 2003	\$0.3000
Total distributions to date			\$7.6500

2002 Income Tax Information

All cash distributions paid to Unitholders from inception of the Trust to the end of the taxation year 2000 were 100% tax deferred and have been treated as a return of capital. Beginning in the taxation year 2001, the Trust's distributions became taxable. Distributions received in the year 2002 were 58% taxable (other income) and 42% were tax deferred (return of capital). Unitholders are required to report any taxable income resulting from distributions on their 2002 personal income tax returns.

Record Date	Payment Date	Taxable Amount	Return of Capital Amount	Total Distribution Paid
December 31, 2001	January 15, 2002	\$ 0.0580	\$ 0.0420	\$ 0.10
January 31, 2002	February 15, 2002	0.0464	0.0336	0.08
February 28, 2002	March 15, 2002	0.0464	0.0336	0.08
March 31, 2002	April 15, 2002	0.0464	0.0336	0.08
April 30, 2002	May 15, 2002	0.0464	0.0336	0.08
May 31, 2002	June 15, 2002	0.0812	0.0588	0.14
June 30, 2002	July 15, 2002	0.0580	0.0420	0.10
July 31, 2002	August 15, 2002	0.0580	0.0420	0.10
August 31, 2002	September 15, 2002	0.0986	0.0714	0.17
September 30, 2002	October 15, 2002	0.0580	0.0420	0.10
October 31, 2002	November 15, 2002	0.0580	0.0420	0.10
November 30, 2002	December 15, 2002	0.1044	0.0756	0.18
Total paid during the 2002 Taxation Year		0.7598	0.5502	1.31

2003 Taxability

Freehold estimates that approximately 60% to 65% of distributions received in 2003 will be taxable. The actual level of taxability is dependent upon commodity prices received and company activities undertaken to year-end.

Environmental Regulation

The oil and natural gas industry is subject to environmental regulation pursuant to local, provincial and federal legislation. Environmental legislation provides for restrictions and prohibitions on releases or emissions of various substances produced in association with certain oil and gas industry operations and can affect the location of wells and facilities and the extent to which exploration and development is permitted. In addition, legislation requires that well and facilities sites be abandoned and reclaimed to the satisfaction of provincial authorities. A breach of such legislation may result in the imposition of fines or issuance of clean-up orders. Environmental legislation in Alberta has undergone a major revision and has been consolidated into the *Environmental Protection and Enhancement Act*. Under the new Act, environmental standards and compliance for releases, clean-up and reporting are stricter. Also, the range of enforcement actions available and the severity of penalties have been significantly increased. These changes will have an incremental effect on the cost of conducting operations in Alberta. British Columbia's *Environmental Assessment Act* became effective June 30, 1995. This legislation rolled the previous processes for the review of major energy projects into a single environmental assessment process with public participation in the environmental review process. Freehold Resources is committed to meeting its responsibilities to protect the environment wherever it operates and anticipates making increased expenditures of both a capital and expense nature as a result of the increasingly stringent laws relating to the protection of the environment. Freehold Resources' internal procedures are designed to ensure that the environmental aspects of new developments are taken into account prior to proceeding. The Manager believes that Freehold Resources is in material compliance with applicable environmental laws and regulations with respect to the Freehold Resources Properties.

With respect to the HB Lands, the responsibilities for adherence to environmental regulations reside with the operators and working interest owners of the HB Lands and not with the Trust.

MARKET FOR SECURITIES

The Trust Units are listed and traded on The Toronto Stock Exchange. The trading symbol for the Trust Units is FRU.UN.

RISK FACTORS

The following is a summary of certain risk factors relating to the business of the Trust which prospective investors should carefully consider before deciding whether to purchase Trust Units.

Purchase of Royalties

The price paid for the purchase of the HB Lands Royalties, the Additional Royalties and the Freehold Resources Royalty was based on engineering and economic assessments of the reserves made by independent engineers. These assessments include a number of material assumptions regarding such factors as recoverability and marketability of 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 operators of the Properties, Freehold Resources, the Manager and the Trust. In particular, changes in the prices of and markets for oil, 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 attributed to the properties.

Reserve Estimates

The reserve and recovery information contained in the Trimble Oil and Gas Report and the Potash Report are only estimates and the actual production and ultimate reserves from the Royalty Lands, the Additional Properties and the Working Interest Properties may be greater or less than the estimates prepared by Trimble and the Manager.

Volatility of Oil and Natural Gas Prices

The Trust's operational results and financial condition, and therefore the amounts paid to the Trust pursuant to the HB Lands Royalties, the Additional Royalties and the Freehold Resources Royalty, will be dependent on the prices received for oil and natural gas production. Oil and natural gas prices have fluctuated widely during recent years and are determined by supply and demand factors, including weather and general economic conditions as well as conditions in other oil and natural gas regions, all of which are beyond the control of the Trust and the Manager. Any decline in oil and natural gas prices could have an adverse effect on the Trust's financial condition and therefore on the Distributable Income to be distributed to holders of Trust Units.

Changes in Legislation

There can be no assurance that income tax laws and government incentive programs relating to the oil and gas industry, such as ARC 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 RRSPs, RESPs, RRIFs and DPSPs ("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 while they are not qualified investments.

Operational Matters

The operation of oil and 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 Freehold Resources and possible liability to third parties. Freehold Resources will 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. Freehold Resources 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 Freehold Resources Royalty Income.

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 satisfactory title reviews are generally conducted in accordance with industry standards, such reviews do not guarantee or certify that a defect in the chain of title may not arise to defeat the claim of Freehold Resources to certain Working Interest Properties. A reduction of the Freehold Resources Royalty Income could result in such circumstances.

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 issuance of clean up orders in respect of Freehold Resources or the Freehold Resources Properties. Such legislation may be changed to impose higher standards and potentially more costly obligations on Freehold Resources. Although Freehold Resources has established a reclamation fund for the purpose of funding its currently estimated future environmental and reclamation obligations based on its current knowledge, there can be no assurance that the Trust will be able to satisfy actual future environmental and reclamation obligations. See "Other Information Respecting Freehold Resources – Environmental Obligations Reclamation Fund".

Debt Service

Amounts paid in respect of interest and principal on debt incurred in respect of the HB Lands Royalties, the Additional Royalties, the Additional Properties and the Working Interest Properties will reduce Royalty Lands Royalty Income and Freehold Resources Royalty Income. Variations in interest rates and scheduled principal repayments could result in significant changes in the amount required to be applied to debt service before payment of the Royalty Lands Royalty Income and Freehold Resources Royalty Income and Distributable Income. Certain covenants of the agreements with the lender may also limit distributions to the Trust. Although the Manager and Freehold Resources believe the credit facility is sufficient for the Trust's and Freehold Resources' immediate requirements, there can be no assurance that the amount will be adequate for the future financial obligations of the Trust or Freehold Resources or that additional funds will be able to be obtained.

The lender has been provided with security over substantially all of the assets of the Trust and Freehold Resources. If the Trust or Freehold Resources becomes unable to pay its Debt Service Charges or otherwise commits an event of default such as bankruptcy, the lender may foreclose on or sell all or some of the HB Lands Royalties, the Additional Royalties, Additional Properties and the Working Interest Properties free from or together with the Freehold Resources Royalty.

Delay in Cash Distributions

In addition to the usual delays in payment by purchasers of oil and natural gas to the payors of the HB Lands Royalties, the Additional Royalties and/or operators of the Freehold Resources Properties, and by those payors and operators to the Manager or Freehold Resources, 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 operators of expenses incurred in the operation of the Freehold Resources Properties or the establishment by the operators of reserves for such expenses.

Reliance on the Manager

Unitholders are dependent on the management of the Manager in respect of the administration and management of all matters relating to the HB Lands Royalties, the Additional Royalties and the Freehold Resources Royalty, the Trust and Trust Units. Investors who are not willing to rely on the management of the Manager should not invest in the Trust Units.

Depletion of Reserves

The Trust has certain unique attributes which differentiate it from other oil and gas industry participants. Distributions of Distributable Income 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 Freehold Resources will not be reinvesting cash flow in the same manner as other industry participants. Accordingly, absent capital injections, successful development or acquisition of additional reserves, the Trust and Freehold Resources will have difficulty maintaining current production levels and reserves.

The Trust's and Freehold Resources' future oil and natural gas reserves and production, and therefore its cash flows, will be highly dependent on activities of the working interest owners of the Royalty Lands and Freehold Resources' success in exploiting its reserve base and acquiring additional reserves on the Freehold Resources Properties. Without reserve additions through acquisition or development activities, the Trust's and Freehold Resources' reserves and production will decline over time as reserves are exploited.

There can be no assurance that the Manager, on behalf of Freehold Resources, will be successful in developing or acquiring additional reserves on terms that meet the Trust's investment objectives.

Additional Financing

To the extent that external sources of capital, including the issuance of additional Trust Units become limited or unavailable, the Trust's and Freehold Resources' ability to make the necessary capital investments to maintain or expand its oil and gas reserves will be impaired. To the extent that the Trust or Freehold Resources is required to use cash flow to finance capital expenditures or property acquisitions, the level of Distributable Income will be reduced.

Competition

There is strong competition relating to all aspects of the oil and gas industry. The Trust and Freehold Resources will actively compete for reserve acquisitions and skilled industry personnel with a substantial number of other oil and gas companies, many of which have significantly greater financial and other resources than the Trust or Freehold Resources.

Return of Capital

Trust Units will have no value when reserves from the HB Lands Royalties, the Additional Royalties and/or the Freehold Resources Properties can no longer be economically marketed and, as a result, investors will have to obtain the return of capital invested out of cash distributions during the period when reserves can be economically recovered.

Potential Conflicts of Interest

There may be circumstances in which the interests of the Manager will conflict with those of Unitholders. The Manager may acquire oil and gas properties on its own behalf or on behalf of persons other than the Unitholders. The Manager may manage and administer such additional properties, as well as enter into other types of energy-related management, advisory and investment activities. Neither the Manager, nor its management, will carry on their full-time activity on behalf of Unitholders and, when acting on their own behalf or on behalf of others, may at times act in competition with the interests of Unitholders.

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

Nature of Trust Units

Securities such as Trust Units are hybrids in that they share certain attributes common to both equity securities and debt instruments. 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 Freehold Resources. 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 HB Lands Royalties, Additional Royalties and the Freehold Resources Royalty. The price per Trust Unit is a function of anticipated Distributable Income, the HB Lands Royalties, the Additional Royalties and the Freehold Resources Royalty and Manager's ability to effect long-term growth in the value of the Trust. The market price of the Trust Units is 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 will be subject to any liability in connection with the Trust or its obligations and affairs and, in the event that a court determines Unitholders are subject to any such liabilities, the liabilities will be enforceable only against, and will be satisfied only out of the Trust's assets. Pursuant to the Trust Indenture, the Trust will indemnify and hold harmless each Unitholder from any costs, damages, liabilities, expenses, charges and losses suffered by a Unitholder resulting from or arising out of such Unitholder not having such limited liability.

The Trust Indenture provides that all written instruments signed by or on behalf of the Trust must contain a provision to the effect that such obligation will not be binding upon Unitholders personally. Personal liability may also arise in respect of claims against 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 of this nature arising is considered unlikely.

The operations of the Trust are 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 on the Unitholders for claims against the Trust.

ADDITIONAL INFORMATION

Additional information including remuneration and indebtedness of directors and officers of Freehold Resources and the Manager, principal holders of the Trust Units and options to purchase Trust Units, is contained in the Information Circular – Proxy Statement of the Trust dated March 18, 2003 which relates to the Annual Meeting of Unitholders held on May 7, 2003 and additional financial information is provided in the combined financial statements of the Trust and Freehold Resources for the period ended December 31, 2002.

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

- a. 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,
 - (i) 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,
 - (ii) one copy of the combined financial statements of the Trust and Freehold Resources for the period ended December 31, 2002 together with the accompanying report of the auditor and one copy of any subsequent interim financial statements,
 - (iii) one copy of the Information Circular – Proxy Statement of the Trust dated March 18, 2003, and
 - (iv) 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
- b. 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:

Corporate Secretary
Freehold Royalty Trust
400, 144 – 4th Avenue S.W.
Calgary, Alberta T2P 3N4
Telephone: (403) 221-0802
Fax: (403) 221-0888