

Freehold

R O Y A L T Y T R U S T

2004 ANNUAL INFORMATION FORM

March 15, 2005

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Forward-Looking Statements

Certain statements contained in this Annual Information Form, and in certain documents incorporated by reference into this Annual Information Form, constitute forward-looking statements. These statements relate to future events or our future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek", "anticipate", "budget", "plan", "continue", "estimate", "expect", "forecast", "may", "will", "project", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe" and similar expressions. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. We believe the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in, or incorporated by reference into, this Annual Information Form should not be unduly relied upon. These statements speak only as of the date of this Annual Information Form or as of the date specified in the documents incorporated by reference into this Annual Information Form, as the case may be.

In particular, this Annual Information Form and the documents incorporated by reference contain forward-looking statements pertaining to the following:

- the performance characteristics of our oil and natural gas properties;
- oil and natural gas production levels;
- the size of the oil and natural gas reserves;
- projections of market prices and costs and the related sensitivities of distributions;
- supply and demand for oil and natural gas;
- expectations regarding the ability to raise capital and to continually add to reserves through acquisitions and development;
- treatment under governmental regulatory regimes and tax laws; and
- capital expenditures programs.

The actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this Annual Information Form:

- volatility in market prices for oil and natural gas;
- liabilities inherent in oil and natural gas operations;
- uncertainties associated with estimating oil and natural gas reserves;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- incorrect assessments of the value of acquisitions;
- geological, technical, drilling and processing problems;
- changes in income tax laws or changes in tax laws and incentive programs relating to the oil and gas industry and income trusts; and
- the other factors discussed under "Risk Factors".

Statements relating to "reserves" or "resources" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the resources and reserves described can be profitably produced in the future. Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward-looking statements contained in this Annual Information Form and the documents incorporated by reference herein are expressly qualified by this cautionary statement. We do not undertake any obligation to publicly update or revise any forward-looking statements.

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 entities, which may be formed by the Trust as wholly owned entities to acquire corporate facilities and other types of oil and natural 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 natural gas rights acquired by us from time to time.

“Additional Royalties” means Royalty Interests in oil and natural gas rights acquired by us 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 net proved plus probable reserves shown in the most recent engineering report relating to such property, discounted at 10% and using forecast price and cost assumptions.

“CN Pension Trust Funds” means the pension trust funds for employees of Canadian National Railway Company.

“Canpar” means Canpar Holdings Ltd.

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

“COGE Handbook” means the “Canadian Oil and Gas Evaluation Handbook” prepared jointly by The Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society), as amended from time to time.

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

“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 “Description of Properties – Freehold Resources Royalty – Deferred Purchase Price Obligation”.

“Distributions to Unitholders” 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), expenses and withholding payable by the Trust and less other amounts reasonably determined by Freehold Resources to be retained for the purposes of the Trust.

“Freehold Resources” means Freehold Resources Ltd., a wholly owned subsidiary of the Trust, 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: (i) the interest paid on 2 year Government of Canada bonds minus 2%, or (ii) 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 natural gas rights, tangibles and miscellaneous interests, 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).

“Gross” or “gross” means:

- in relation to production and reserves, our working interest (operating and non-operating) share before deduction of royalties and without including any royalty interests of the Trust;
- in relation to wells, the total number of wells in which we have an interest; and
- in relation to properties, the total area of properties in which we have an interest.

“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 royalty assumption property acquired by us from Canpar pursuant to the Royalty Sale Agreement.

“Management Agreement” means the agreement dated November 25, 1996 as renewed between the Manager, Freehold Resources and the Trustee for and on behalf of the Trust pursuant to which the Manager provides management services to Freehold Resources and the Trust.

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

“Manager” means Rife Resources Management Ltd.

“Net” or **“net”** means:

- in relation to production and reserves, our working and non-working interest (operating and non-operating) share after deduction of royalty obligations, plus our Royalty Interests.
- in relation to wells, the number of wells obtained by aggregating our working interest in each of its gross wells; and
- in relation to our interest in a property, the total area in which we have an interest multiplied by the working interest owned by us.

“NI 51-101” means National Instrument 51-101 *Standard of Disclosure for Oil and Gas Activities*.

“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 February 7, 2005 prepared by the Manager, evaluating the potash reserves attributable to the HB Lands Royalties as at December 31, 2004.

“Proved” and **“probable”** reserves have the meanings given to those terms under “Disclosure of Reserves Data”.

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

“Replacement Properties” means properties, whether Additional Royalties or Additional Properties, which were acquired by us by means of an exchange of properties owned by us 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 rates. The index is calculated by dividing the reserves in the selected reserve category at a certain date by the estimated production for the following 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.

“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 qualified reserves evaluators.

“**Trimble Report**” means the report dated January 19, 2005 prepared by Trimble, evaluating the oil, natural gas, natural gas liquids and sulphur reserves attributable to the Royalty Interest properties and the Freehold Resources Properties as at December 31, 2004.

“**Trust**”, “**us**”, “**we**” or “**our**” means Freehold Royalty Trust and all of its controlled entities, from time to time, on a consolidated basis.

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

“**Unanimous Shareholders Agreement**” means the amended and restated unanimous shareholders agreement dated December 31, 2004 among Freehold Resources, the Manager and the Trustee for and on behalf of Unitholders.

“**Unitholders**” means holders of our Trust Units.

“**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.

ABBREVIATIONS

AECO:	reference pricing point for natural gas located at a natural gas storage facility near the Alberta-Saskatchewan border
API:	American Petroleum Institute
bbl and bbls:	barrel and barrels, respectively, each barrel representing 34.972 imperial gallons or 42 U.S. gallons
bbls/d and bopd:	barrels per day and barrels of oil per day, respectively
boe:	barrels of oil equivalent converting six Mcf of natural 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 natural 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.
boe/d:	barrels of oil equivalent per day
Mbbls:	one thousand barrels
Mboe:	one thousand barrels of oil equivalent
MMbbls:	one million barrels
MMboe:	one million barrels of oil equivalent
MMBtu:	one million British Thermal Units
Mcf:	one thousand cubic feet
Mcf/d:	one thousand cubic feet per day
MMcf:	one million cubic feet
MMcf/d:	one million cubic feet per day
Mtonne:	one thousand tones
NGL:	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).

To Convert From	To	Multiply By
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.

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 our 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 the Trust Indenture dated effective May 1, 2002. We were 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 3N4.

Freehold Resources Ltd.

Freehold Resources Ltd. (“Freehold Resources”) was incorporated under the Business Corporations Act (Alberta) on June 3, 1996 as 698108 Alberta Ltd., and 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 Trust. 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.

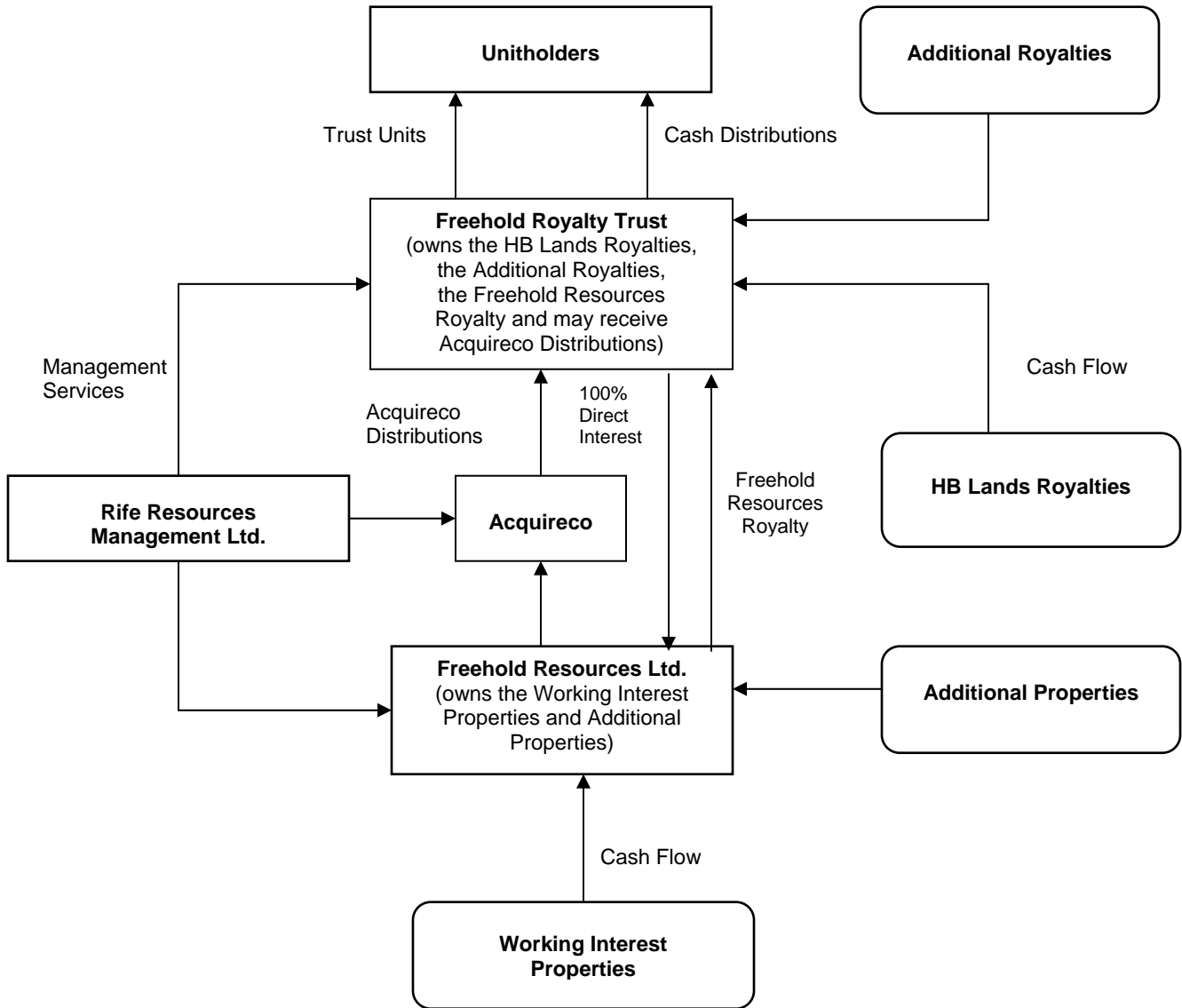
Rife Resources Management Ltd.

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.

Structure of the Trust

The structure of the Trust is such that income taxation occurs only in the hands of the Unitholder. Distributions to Unitholders consist 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:



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.

History and Development

The following is a description of the general development of the business of the Trust, including acquisitions, over its last three completed financial years.

Year Ended December 31, 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 18-49-23 W3. 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 its working interest holdings for a 4.4% gross overriding royalty interest in 2,760 acres.

Year Ended December 31, 2003

In 2003, the Trust purchased an additional royalty interest in the Elswick Midale Beds Voluntary Unit No. 2 in Southeast Saskatchewan, a 12% royalty interest in 4 natural gas wells at Cecilia, Alberta and a 7.5% working interest in a natural gas well at Woodriver, Alberta. In the Loon area of Northern Alberta, the Trust swapped its working interest holdings for a royalty interest in 28 producing oil wells. The purchase price for these interests was \$3.4 million (net of adjustments) in aggregate. Combined, these properties added 75 boe/d to the Trust's production base in 2004.

Year Ended December 31, 2004

On June 25, 2004, the Trust closed the acquisition of a 6% overriding royalty in 18 oil wells on 2,720 acres of land in the Pembina Area of Alberta for the purchase price of \$0.3 million. Production is light oil and natural gas from the Belly River formation. For the six month period from July to December 2004, production averaged 6 boe/d.

Effective July 31, 2004, Freehold acquired all of the outstanding shares of Ventana Ventures Inc., a private corporation for approximately \$3.0 million (including \$0.2 million working capital). The primary assets are royalty interests in oil and natural gas properties covering 42,080 acres in the Peace River area of Alberta. The properties added approximately 80 boe/d of royalty production from the effective date of the acquisition.

Effective October 1, 2004, the Trust acquired royalty interests in 10,880 acres of land and working interests in 3,520 acres of land in the Willesden Green area of Alberta for \$9.8 million (net of adjustments). Presently, production is only from the Royalty Lands and is primarily from the Jurassic Rock Creek formation. Production is 70% natural gas and 30% light oil. Including the anticipated future development, 2005 production is estimated to be approximately 175 boe/d, mostly natural gas.

BUSINESS OF THE TRUST

Overview

The Trust is structured as a mutual fund trust under the Tax Act. This enables the Trust to return the majority of its income to Unitholders in a tax-effective manner. The Trust receives revenue from oil and natural gas properties as reserves are produced, which is paid to Unitholders on a regular basis over the economic life of the properties. The Trust has a diverse production base, with interests in more than 17,000 oil and natural gas wells throughout western Canada. This includes significant mineral title and gross overriding royalty interests that provide the majority of revenue. Royalties offer the benefit of sharing in production, without exposure to the capital, operating and environmental costs associated with oil and natural gas production. Oil and natural gas are finite resources. Over time, reserves are depleted and capital investment is required to sustain production and cash flow.

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 entities which would initially be wholly-owned subsidiaries of the Trust (each such entity 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 entity has been organized. Any such entity 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.

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 Distributions to Unitholders while 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 natural 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 that 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 natural 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.

RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The statement of reserves data and other oil and gas information set forth below (the "Statement") is dated March 15, 2005. The effective date of the Statement is December 31, 2004 and the preparation date of the Statement is March 15, 2005.

In accordance with the requirements of NI 51-101, the Report on Reserves Data by Independent Qualified Reserves Evaluator in Form 51-101 F2 and the Report of Management and Directors on Reserves Data and Other Information in Form 51-101 F3 are attached as Appendices A and B.

Disclosure of Reserves Data

The reserves data set forth below (the "Reserves Data") is based upon an evaluation by an independent qualified reserves evaluator, Trimble Engineering Associates Ltd. ("Trimble"), with an effective date of December 31, 2004 contained in the Trimble Report. The Reserves Data summarizes the oil, natural gas liquids and natural gas reserves of the Trust and the net present values of future net revenue for these reserves using constant prices and costs and forecast prices and costs. The Trimble Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101. Information not required by NI 51-101 has been presented to provide continuity and additional information which we believe is important to the readers of this information. The Trust engaged Trimble to provide an evaluation of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

All of the Trust's reserves are in Canada and, specifically, in the provinces of Alberta, Saskatchewan, British Columbia, and Manitoba.

In order to provide a single unit of production for analytical purposes, natural gas production and reserves volumes are mathematically converted to equivalent barrels of oil (boe). The Trust uses a conversion rate of six thousand cubic feet of natural gas to one barrel of oil (6 Mcf = 1 bbl). The 6:1 boe ratio approximates an equivalent energy value at the burner tip and does not represent a value equivalency at the wellhead. While it is useful for comparative measures, it may not accurately reflect individual product values and may be misleading if used in isolation.

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

Constant Prices and Costs

SUMMARY OF OIL AND GAS RESERVES as at December 31, 2004 CONSTANT PRICES AND COSTS

Reserves Category	Reserves ⁽¹⁾							
	Light and Medium Oil		Heavy Oil		Natural Gas		Natural Gas Liquids	
	Gross (Mbbls)	Net (Mbbls)	Gross (Mbbls)	Net (Mbbls)	Gross (MMcf)	Net (MMcf)	Gross (Mbbls)	Net (Mbbls)
Proved								
Developed producing	2,553	4,577	949	4,173	5,586	24,652	315	1,044
Developed non-producing	-	2	-	-	397	591	3	16
Undeveloped	-	10	130	184	6	9	-	(1)
Total proved	2,553	4,589	1,079	4,357	5,990	25,252	318	1,058
Probable	486	1,478	1,462	3,080	1,647	12,091	97	325
Total proved plus probable	3,040	6,066	2,541	7,437	7,636	37,342	415	1,383

Note:

- (1) The Trust is unique in that the majority of its assets are royalty interests. Under NI 51-101 the definition of Gross reserves excludes royalty interests. This results in the anomaly of the Trust's Gross reserves being lower than Net reserves.

NET PRESENT VALUES OF FUTURE NET REVENUE as at December 31, 2004 CONSTANT PRICES AND COSTS

Reserves Category	Before Income Taxes (\$000s)				
	Discounted at (%/year)				
	0%	5%	10%	15%	20%
Proved					
Developed producing	414,118	277,622	214,965	178,460	154,185
Developed non-producing	4,229	3,521	3,007	2,622	2,325
Undeveloped	1,485	1,106	853	671	534
Total proved	419,832	282,250	218,826	181,753	157,044
Probable	172,127	92,143	60,636	44,396	34,572
Total proved plus probable	591,959	374,393	279,461	226,149	191,615

TOTAL FUTURE NET REVENUE (UNDISCOUNTED) as at December 31, 2004 CONSTANT PRICES AND COSTS

(\$000s)	Reserves Category	
	Proved	Proved Plus Probable
Royalty Income	294,725	437,353
Revenue from Working Interest Properties	191,513	262,268
Royalty expense on Working Interest Properties	(15,039)	(22,599)
Operating costs	(48,039)	(73,632)
Development costs	(1,559)	(9,756)
Well abandonment costs	(3,628)	(4,096)
Alberta Royalty Credits	1,858	2,422
Future net revenue before income taxes	419,832	591,959

FUTURE NET REVENUE
BY PRODUCTION GROUP
as at December 31, 2004
CONSTANT PRICES AND COSTS

Reserves Category	Production Group	Future Net Revenue Before Income Taxes Discounted at 10%/year (\$000s)
Proved	Heavy Oil (including solution gas and other by-products)	98,372
	Light and Medium Oil (including solution gas and other by-products)	42,821
	Natural Gas (including by-products but excluding solution gas and by-products from oil wells)	77,632
Total proved		218,826
Proved plus probable	Light and Medium Oil (including solution gas and other by-products)	119,133
	Heavy Oil (including solution gas and other by-products)	59,439
	Natural Gas (including by-products but excluding solution gas and by-products from oil wells)	100,889
Total proved plus probable		279,461

Forecast Prices and Costs

SUMMARY OF OIL AND GAS RESERVES
as at December 31, 2004
FORECAST PRICES AND COSTS

Reserves Category	Reserves ⁽¹⁾							
	Light and Medium Oil		Heavy Oil		Natural Gas		Natural Gas Liquids	
	Gross (Mbbls)	Net (Mbbls)	Gross (Mbbls)	Net (Mbbls)	Gross (MMcf)	Net (MMcf)	Gross (Mbbls)	Net (Mbbls)
Proved								
Developed producing	2,548	4,587	1,330	4,544	5,573	24,649	315	1,045
Developed non-producing	-	2	-	-	397	591	3	16
Undeveloped	-	10	213	267	10	13	1	(1)
Total proved	2,548	4,599	1,543	4,811	5,980	25,253	318	1,059
Probable	485	1,479	1,056	2,672	1,612	12,061	95	324
Total proved plus probable	3,033	6,078	2,599	7,483	7,592	37,313	413	1,384

Note:

- (1) The Trust is unique in that the majority of its assets are royalty interests. Under NI 51-101 the definition of Gross reserves excludes royalty interests. This results in the anomaly of the Trust's Gross reserves being lower than Net reserves.

NET PRESENT VALUES OF FUTURE NET REVENUE
as at December 31, 2004
FORECAST PRICES AND COSTS

Reserves Category	Before Income Taxes (\$000s) Discounted at (%/year)				
	0%	5%	10%	15%	20%
	Proved				
Developed producing	416,020	284,842	224,751	189,767	166,387
Developed non-producing	4,037	3,405	2,943	2,594	2,323
Undeveloped	3,657	2,987	2,487	2,108	1,813
Total proved	423,714	291,234	230,181	194,469	170,523
Probable	189,881	96,150	62,066	45,324	35,457
Total proved plus probable	613,595	387,384	292,247	239,793	205,980

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
as at December 31, 2004
FORECAST PRICES AND COSTS

(\$000s)	Reserves Category	
	Proved	Proved Plus Probable
Royalty Income	311,642	476,482
Revenue from Working Interest Properties	211,620	278,118
Royalty expense on Working Interest Properties	(13,730)	(20,786)
Operating costs	(79,263)	(104,899)
Development costs	(1,905)	(9,893)
Well abandonment costs	(6,261)	(7,530)
Alberta Royalty Credits	1,612	2,103
Future net revenue before income taxes	423,714	613,595

FUTURE NET REVENUE
BY PRODUCTION GROUP
as at December 31, 2004
FORECAST PRICES AND COSTS

Reserves Category	Production Group	Future Net Revenue Before Income Taxes Discounted at 10%/year (\$000s)
Proved	Light and Medium Oil (including solution gas and other by-products)	86,297
	Heavy Oil (including solution gas and other by-products)	70,198
	Natural Gas (including by-products but excluding solution gas and by-products from oil wells)	73,686
Total proved		230,181
Proved plus probable	Light and Medium Oil (including solution gas and other by-products)	103,025
	Heavy Oil (including solution gas and other by-products)	93,502
	Natural Gas (including by-products but excluding solution gas and by-products from oil wells)	95,719
Total proved plus probable		292,247

Definitions and Other Notes:

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

Reserve Categories

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

- analysis of drilling, geological, geophysical and engineering data;
- the use of established technology; and
- specified economic conditions.

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

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

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

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

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

Levels of Certainty for Reported Reserves

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

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

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

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

3. Constant Prices and Costs

Constant prices and costs are:

- (a) The prices and costs as at December 31, 2004, held constant throughout the estimated lives of the properties to which the estimate applies; and
- (b) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which the Trust is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

For the purposes of paragraph (a), the Trust's prices are the actual December 31, 2004 prices for oil, natural gas and natural gas liquids after historical adjustments for transportation, gravity and other factors.

The constant oil and natural gas benchmark reference pricing and the exchange rate utilized in the Trimble Report were as follows:

CONSTANT PRICES USED IN ESTIMATES
as at December 31, 2004

Oil				Natural Gas	Natural Gas Liquids FOB Field Gate (Cdn\$/bbl)			Exchange Rate
WTI Cushing Oklahoma US\$/bbl	Edmonton Par Price 40° API Cdn\$/bbl	Hardisty Heavy 12° API Cdn\$/bbl	Hardisty Bow River 24.9° API Cdn\$/bbl	AECO 30 Day Spot (Cdn\$/MMBtu)	Propane	Butane	Pentane	US\$/Cdn\$
43.45	48.31	16.66	24.15	6.24	35.71	42.08	48.94	0.83

4. Forecast Prices and Costs

Forecast prices and costs are those:

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

The forecast cost and price assumptions assume increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. Oil and natural gas benchmark reference pricing, inflation and exchange rates as at December 31, 2004 utilized in the Trimble Report were as follows:

FORECAST PRICES USED IN ESTIMATES
as at December 31, 2004

Year	Oil				Natural Gas	Natural Gas Liquids FOB Field Gate (Cdn\$/bbl)			Inflation Rate	Exchange Rate
	WTI Cushing Oklahoma US\$/bbl	Edmonton Par Price 40° API Cdn\$/bbl	Hardisty Heavy 12° API Cdn\$/bbl	Hardisty Bow River 24.9° API Cdn\$/bbl	AECO 30 Day Spot (Cdn\$/MMBtu)	Propane	Butane	Pentane	%/year	US\$/Cdn\$
Forecast										
2005	44.29	51.25	28.91	36.26	6.97	32.09	38.20	52.49	2.50	0.84
2006	41.60	48.03	28.12	34.89	6.66	30.07	34.01	49.19	2.50	0.84
2007	37.09	42.64	26.19	32.11	6.21	26.70	30.20	43.67	2.50	0.84
2008	33.46	38.31	25.06	30.68	5.73	23.98	27.13	39.23	2.50	0.84
2009	31.84	36.36	23.60	29.08	5.37	22.76	25.75	37.24	1.50	0.84
Escalation rate thereafter	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	0.84

FREEHOLD WEIGHTED AVERAGE PRICES
Year ended December 31, 2004

	Light and Medium Oil (\$/bbl)	Heavy Oil (\$/bbl)	Natural Gas (\$/Mcf)	Natural Gas Liquids (\$/bbl)
Freehold weighted average price	46.41	31.56	6.28	37.29

5. "Development well" means a well drilled inside the established limits of an oil and natural gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.

6. "Development costs" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and natural gas from reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:
 - (a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, natural gas lines and power lines, to the extent necessary in developing the reserves;
 - (b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and wellhead assembly;
 - (c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and
 - (d) provide improved recovery systems.
7. "Service well" means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt water disposal, water supply for injection, observation or injection for combustion.
8. Future Development Costs

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

Year	Forecast Prices and Costs		Constant Prices and Costs
	Proved Reserves (\$000s)	Proved Plus Probable Reserves (\$000s)	Proved Reserves (\$000s)
2005	1,204	3,737	1,204
2006	117	3,317	117
2007	119	2,280	117
2008	60	60	58
2009	62	62	58
Remainder	338	433	0
Total undiscounted	1,900	9,889	1,554
Total discounted at 10%	1,585	8,500	1,421

The source of funding for future development costs will be internally generated cash flow, debt or a combination of both. Disclosed reserves and future net revenue will not be materially affected by the costs of funding the future development expenditures.

9. ARC is included in the cumulative cash flow amounts.
10. Estimated future well abandonment costs for working interest properties have been taken into account by Trimble in determining reserves and the aggregate future net revenue. No allowance was made, however, for reclamation of wellsites or the abandonment and reclamation of any facilities.
11. Both the constant and forecast price and cost assumptions assume the continuance of current laws and regulations.
12. The extent and character of all factual data supplied to Trimble were accepted by Trimble as represented. No field inspection was conducted.

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

Reconciliation of Changes in Reserves and Future Net Revenue

RECONCILIATION OF NET RESERVES BY PRINCIPAL PRODUCT TYPE FORECAST PRICES AND COSTS

Factors	Light and Medium Oil			Heavy Oil			Associated and Non-Associated Gas		
	Net Proved	Net Probable	Net Proved Plus Probable	Net Proved	Net Probable	Net Proved Plus Probable	Net Proved	Net Probable	Net Proved Plus Probable
	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(MMcf)	(MMcf)	(MMcf)
December 31, 2003	4,729	1,505	6,233	5,114	2,993	8,106	27,499	10,950	38,449
Extensions	115	104	219	205	106	312	705	754	1,459
Improved recovery	1	3	3	-	-	-	1	2	2
Technical revisions	138	(165)	(27)	253	(422)	(169)	(744)	2	(742)
Discoveries	-	-	-	-	-	-	77	66	142
Acquisitions	97	37	134	-	-	-	1,013	345	1,358
Dispositions	-	-	-	-	-	-	-	-	-
Economic factors	(6)	-	(6)	10	(2)	8	(28)	(16)	(45)
Production	(475)	(4)	(479)	(771)	(4)	(774)	(3,269)	(42)	(3311)
December 31, 2004	4,599	1,479	6,078	4,811	2,672	7,483	25,253	12,061	37,313

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

For the year ended December 31, 2004	(\$000s)
Estimated future net revenue at beginning of year	226,581
Sales and transfers of oil and natural gas produced, net of production costs and royalties	(67,521)
Net change in prices, production costs and royalties related to future production	14,998
Changes in previously estimated development costs incurred during the year	(1,250)
Changes in estimated future development costs	-
Extensions and improved recovery	7,632
Discoveries	241
Acquisitions of reserves	10,118
Dispositions of reserves	-
Net change resulting from revisions in quantity estimates	5,369
Accretion of discount	22,658
Estimated future net revenue at end of year	218,826

Undeveloped Reserves

Proved and probable undeveloped reserves have been estimated in accordance with procedures and standards in the COGE Handbook. In general, undeveloped reserves are scheduled to be developed within the next two years. Capital expenditures to develop proved undeveloped reserves are estimated at \$1.2 million in 2005 and \$0.1 million in 2006.

Almost all of the proved undeveloped reserves assigned in the Trimble Report are in the Hayter, Alberta property. Ten (2.4 net) infill wells are scheduled to be drilled in 2005.

The majority of the probable undeveloped reserves in the Trimble Report are also in the Hayter, Alberta property. Ten (2.4 net) wells are forecast to be drilled in each of 2006 and 2007.

Significant Factors or Uncertainties

The reserve and recovery information contained in the Trimble Report are only estimates and the actual production and ultimate reserves may be greater or less than the estimates prepared by Trimble.

The value of the Trust Units will depend upon, among other things, the reserves attributable to the Trust's properties. Estimating reserves is inherently uncertain. Ultimately, actual production, revenues and expenditures for the Trust's properties will vary

from estimates and those variations could be material. The reserve and cash flow information contained in this Statement represents estimates only. Reserves and estimated future net cash flow from the Trust's properties have been evaluated by Trimble, an independent qualified reserves evaluator. Trimble considers a number of factors and makes assumptions when estimating reserves. These factors and assumptions include, among others:

- historical production in the area compared with production rates from similar producing areas;
- the assumed effect of governmental regulation;
- assumptions about future commodity prices; production and development costs, severance and excise taxes, and capital expenditures;
- initial production rates;
- production decline rates;
- ultimate recovery of reserves;
- timing and amount of capital expenditures;
- marketability of production;
- future prices of oil and natural gas;
- operating costs and royalties; and
- other government levies that may be imposed over the producing life of reserves.

These factors and assumptions were based on prices at the date the evaluation was prepared. If these factors and assumptions prove to be inaccurate, the actual results may vary materially from the reserve estimates. Many of these factors are subject to change and are beyond the Trust's control. For example, the evaluation is based in part on the assumed success of exploitation activities intended to be undertaken in future years. Actual reserves and estimated cash flows will be less than those contained in the evaluation to the extent that such exploitation activities do not achieve the level of success assumed in the evaluation. Furthermore, cash flows may differ from those contained in the evaluation depending upon whether capital expenditures and operating costs differ from those estimated in the evaluation.

DESCRIPTION OF PROPERTIES

In the following discussion, all references to reserves are Net, utilizing escalated price and cost assumptions, before tax. Unless stated otherwise, reserve values are proved plus probable.

Royalty Lands

HB Lands Royalties

The HB Lands Royalties are derived from the leased mineral title lands and royalty assumption 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 royalty assumption lands, in addition to oil and natural 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, and Lashburn, Saskatchewan and the Southeast Saskatchewan core area; and near Cecilia, Loon, Hayter, Wildmere, Giltedge, Enchant, Peace River, Pembina and Willesden Green, Alberta. This category provided approximately 32% of the Royalty Lands Royalty Income received by the Trust in 2004.

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 3.6% of the total revenue attributable to the Royalty Lands Royalty Income in 2004. The majority of Royalty Lands Royalty Income is derived from the central area of southern Alberta and southern Saskatchewan.

Royalty Lands Summary

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

The Trust's royalty reserves are derived from (i) mineral title lands which are owned by the Trust and upon which the Trust is paid lessor royalties (approximately 72% of royalty revenue); (ii) royalty assumption lands owned by third parties and which by their terms, are expressed to be interests in land (approximately 11% of royalty revenue); and (iii) reserves owned by third parties upon which such third parties pay royalties or net profits interests to the Trust, which may or may not be interests in land (approximately 17% of royalty revenue).

Mineral Title Lands

This category of land provided approximately 72% of the Royalty Income received by the Trust in 2004. This Royalty Income is derived from the royalties payable to the Trust through the lease documents issued to the companies that 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 natural gas products 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 natural gas produced for the period. The area of leased mineral title lands totals approximately 480,200 gross acres. Certain of the leased mineral title lands have over time been included within 176 oil and natural gas production units which ensure royalty payments to the Trust over the entire producing life of the unit. The leased mineral title lands also include approximately 151,100 gross undeveloped acres, representing potential for further development of the leased mineral title lands.

Royalty Assumption Lands

These lands consist of mineral title properties owned by a number of third party oil and gas companies in respect of which gross overriding royalties varying from 4.7% to 6.5% have been reserved to the Trust. Certain of the gross overriding royalty interests have been included in 29 oil and natural gas production units. This category of land provided approximately 11% of the Royalty Income received by the Trust in 2004. The Trust holds a royalty interest in 96,402 acres, of which approximately 17,700 acres are undeveloped.

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 or net profits interests have been reserved to the Trust. This category of land provided approximately 17% of the Royalty Income received by the Trust in 2004. Certain of the gross overriding royalty interests or net profits interests have been included within 64 oil and natural gas production units. The Trust holds a royalty interest in 280,775 acres, of which approximately 77,300 acres are undeveloped.

The following table summarizes by area the Trust's average interest, 2004 wells drilled, 2004 oil and natural gas production, net reserves, 2004 Royalty Income and reserve value for the Trust's Royalty Lands:

Royalty Lands	Average Royalty Interest (%)	2004 Wells Drilled (gross)	2004 Production (boe/d)	Net Proved Plus Probable Reserves (Mboe)	2004 Royalty Income (\$000s)	Reserve Value Discounted at 10%/year (\$000s) (%)	
Western Alberta	0.6	39	743	3,823	11,042	56,570	25.1
Saskatchewan Heavy Oil	5.3	14	604	1,895	7,073	26,490	11.7
Northeast Alberta	1.9	55	603	2,529	7,648	34,613	15.3
Southeast Saskatchewan	0.6	51	593	1,650	10,050	32,941	14.6
Southeast Alberta	1.0	406	365	1,521	4,904	23,296	10.3
Bashaw/Leduc	0.8	24	326	862	4,892	16,378	7.3
Hatton/Gull Lake	0.9	65	268	1,142	3,322	15,559	6.9
Other	0.5	17	209	910	3,716	19,980	8.8
Total	0.8	671	3,711	14,332	52,647	225,826	100.0

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

Area	Total Acres	Undeveloped Acres ⁽¹⁾	Non-Unitized		Unitized		
			Natural Gas Wells	Oil Wells	Production Units	Natural Gas Wells	Oil Wells
Western Alberta	104,608	16,941	106	151	65	396	1,818
Saskatchewan Heavy Oil	62,398	15,633	51	507	6	25	432
Northeast Alberta	123,332	23,453	176	509	32	536	797
Southeast Saskatchewan	129,287	99,391	2	426	34	-	1,981
Southeast Alberta	126,918	11,136	793	144	46	3,235	465
Bashaw/Leduc	65,827	6,955	115	108	38	465	623
Hatton/Gull Lake	124,858	30,614	387	176	33	7	809
Other	129,927	42,054	91	119	15	257	149
Total	867,155	246,177	1,721	2,140	269	4,921	7,074

Note:

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

Western Alberta

In the Western Alberta royalty area, we have interests in revenue from 104,608 gross acres, which currently includes an interest in 106 non-unitized natural gas wells and 151 non-unitized oil wells and approximately 16,900 gross acres of undeveloped lands. We also own interests in 65 production units currently containing 396 natural gas wells and 1,818 oil wells. The Trimble Report has assigned reserves of 1,749 Mbbbls of oil and NGL and 12,445 MMcf of natural gas to this royalty area. 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 No. 1 at a depth of 13,000 feet to the shallower Upper Cretaceous Edmonton Group zone in the Pembina and Keystone areas at depths of less than 2,500 feet. The single largest revenue property is the Caroline Swan Hills Gas Unit No. 1, which produces most of the Trust's NGL. The Cardium formation is the most common producing formation in which the Trust has interests, including 25 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 NGL. Oil and NGL production was 4% lower in 2004 at 324 bbls/d and natural gas production was 12% lower than 2003 at 2,518 Mcf/d. In 2004, we acquired additional royalty interests at Pembina and Willesden Green, which will contribute approximately 175 boe/d in 2005. During 2004, lessees drilled 39 wells in the area compared with 22 wells in 2003.

Saskatchewan Heavy Oil

In the Saskatchewan Heavy Oil royalty area, we have an interest in revenue from 62,398 gross acres, which includes interests in 51 non-unitized natural gas wells and 507 non-unitized oil wells and approximately 15,600 acres of undeveloped land. We also own interests in 6 production units currently containing 25 natural gas wells and 432 oil wells. The Trimble Report has assigned reserves of 1,795 Mbbbls of oil and NGL and 601 MMcf of natural gas to this royalty area. The major productive zones are the Mississippian Bakken, the Cretaceous Mannville and the Cretaceous Viking formations. Production of light gravity oil and natural 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 natural gas. Significant revenue properties are the Luseland Bakken pool, the Baldwinton Sparky pool, and the Carruthers Cummings pool. Oil and NGL production declined 23% during 2004 to 546 bbls/d, while natural gas production was 16% lower at 346 Mcf/d. During 2004, lessees drilled 14 wells compared with 49 in 2003.

Northeast Alberta

The Northeast Alberta royalty area was created in 2000 by combining the Provost and Lloydminster/Bonnyville areas. Within the Northeast Alberta area, we own an interest in the revenue from 123,332 gross acres, which includes an interest in 176 non-unitized natural gas wells, 509 non-unitized oil wells and approximately 23,500 acres of undeveloped land. We also have interests in 32 production units currently containing 536 natural gas wells and 797 oil wells. The Trimble Report has assigned reserves of 2,089 Mbbbls of oil and NGL and 2,638 MMcf of natural gas to this royalty area. 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 natural gas from the shallow (less than 3,300 feet) Mannville sands. In the southern part of the area, we are represented in seven Viking natural gas production units and three Viking oil production 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 which contributed 150 bbls/d in 2004. Freehold Resources also has a 23.52%

working interest at Hayter. The Wildmere Lloydminster "A" Pool Unit No. 1 is the largest revenue unit. In 2004, oil and NGL production was down 1% to 469 bbls/d and natural gas production was up 6% to 805 Mcf/d. In this area, 55 wells were drilled during 2004 compared with 58 wells drilled in 2003.

Southeast Saskatchewan

The Southeast Saskatchewan royalty area was created in 2001 following our acquisition of producing and undeveloped mineral title and gross overriding royalty properties. We own an interest in 129,287 gross acres, which includes an interest in 2 non-unitized natural gas wells, 426 non-unitized oil wells and approximately 99,400 acres of undeveloped land. We also own an interest in 34 production units containing 1,981 oil wells. The Trimble Report has assigned reserves of 1,583 MMbbls of oil and NGL and 402 MMcf of natural gas to this royalty area. 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. Oil and NGL production declined 11% to 568 bbls/d in 2004 and natural gas production decreased 11% to 151 Mcf/d. During 2004, 51 wells were drilled by lessees compared with 74 wells drilled in 2003.

Southeast Alberta

The Southeast Alberta royalty area contains the largest number of natural gas wells in which we own an interest. We have an interest in the revenue from 126,918 gross acres, which includes an interest in 793 non-unitized natural gas wells and 144 non-unitized oil wells and approximately 11,100 acres of undeveloped lands in this area. We also own interests in 46 production units containing 3,235 natural gas wells and 465 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 Report has assigned reserves of 456 Mbbls of oil and NGL and 6,390 MMcf of natural 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 NGL production averaged 132 bbls/d in 2004, down 12% from the previous year. Natural gas production was 21% lower averaging 1,401 Mcf/d for the year compared with 1,776 Mcf/d in 2003. Approximately 61% of the wells drilled on the Trust's Royalty Lands during 2004 were drilled in this region. Lessees drilled 406 wells during 2004 compared with 253 wells in 2003. However, approximately 50% of the wells drilled in 2004 were not yet on production at year end.

Bashaw/Leduc

In the Bashaw/Leduc royalty area, we own an interest in revenue from 65,827 gross acres, which includes interests in 115 non-unitized natural gas wells and 108 non-unitized oil wells and approximately 7,000 acres of undeveloped land. We also own interests in 38 production units containing 465 natural gas wells and 623 oil wells. The Trimble Report has assigned reserves of 450 Mbbls of oil and NGL and 2,472 MMcf of natural gas to this royalty area. 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 Edmonton at depths of less than 1,000 feet. In 2004, the highest revenue properties in this area were the Red Willow Ellerslie natural gas pool, the Leduc-Woodbend Glauconitic "D" Unit No. 1 and the Nevis gas pool. Oil and NGL production declined 13% in 2004 to 130 bbls/d while natural gas production increased 9.1% to 1,177 Mcf/d. Lessees drilled 24 wells in this area during 2004 compared with 39 wells drilled in 2003.

Hatton/Gull Lake

The Hatton/Gull Lake royalty area of southwestern Saskatchewan provides revenue from shallow natural gas and oil production. We have an interest in 124,858 gross acres, which includes an interest in 387 non-unitized natural gas wells and 176 non-unitized oil wells and approximately 30,600 acres of undeveloped land. We also have interests in 33 production units containing 7 natural gas wells and 809 oil wells. The Trimble Report has assigned reserves of 2,974 MMcf of natural gas and 646 Mbbls of oil and NGL to this royalty area. Oil and NGL production increased 51% to 156 bbls/d in 2004, and natural gas production increased 36% to 672 Mcf/d. Production increased as a result of successful drilling and a prior period accounting adjustment. Lessees drilled a total of 65 wells on these lands in 2004 compared with 73 wells drilled in 2003.

Undeveloped Royalty Lands

The undeveloped lands are non-producing spacing units totaling 246,177 gross acres, approximately 40% of which 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

We are not responsible for any drilling or development activity or expenditures with respect to the Royalty Lands, but receive appropriate Royalty Income from successful wells. Drilling activity on the Royalty Lands is anticipated to provide continued new sources of oil and natural 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 1,247 unitized and non-unitized wells were drilled.

Years Ended December 31 (gross wells)	2004		2003	
	Unitized	Non-unitized	Unitized	Non-unitized
Oil wells	61	85	105	99
Natural gas wells	351	108	215	100
Service/other wells	1	60	2	44
Dry and abandoned	-	5	-	11
Total	413	258	322	254
Success rate	100%	99%	100%	98%

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 oil and natural gas reserves on our Royalty Lands during 2004, based on forecast prices and costs:

Factors	Light and Medium Oil			Heavy Oil			Associated and Non-Associated Gas		
	Net Proved (Mbbls)	Net Probable (Mbbls)	Net Proved Plus Probable (Mbbls)	Net Proved (Mbbls)	Net Probable (Mbbls)	Net Proved Plus Probable (Mbbls)	Net Proved (MMcf)	Net Probable (MMcf)	Net Proved Plus Probable (MMcf)
December 31, 2003	2,192	917	3,109	3,592	1,757	5,349	22,342	9,409	31,751
Extensions	110	95	205	205	106	312	616	565	1,180
Improved recovery	-	-	-	-	-	-	-	-	-
Technical revisions	5	(41)	(36)	-	(204)	(204)	(698)	503	(195)
Discoveries	-	-	-	-	-	-	-	-	-
Acquisitions	97	37	134	-	-	-	1,013	345	1,358
Dispositions	-	-	-	-	-	-	-	-	-
Economic factors	-	-	-	-	-	-	-	-	-
Production	(351)	(2)	(353)	(491)	(3)	(494)	(2,646)	(32)	(2,678)
December 31, 2004	2,053	1,007	3,059	3,306	1,657	4,962	20,626	10,790	31,416

Note:

(1) 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 Freehold 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

We own interests in 90 Working Interest Properties. Production from these properties is comprised of approximately 77% oil and 23% natural gas. The majority (60%) of our working interest production comes from four properties in Alberta - Hayter, Pembina Cardium Unit No. 9, Ribstone/Chauvin and Pouce Coupe South Boundary "B" Unit #2. Working interest production accounted for 1,877 boe/d in 2004, up from 1,845 boe/d in 2003. In 2004, 90 (5.4 net) wells were drilled on the working interest properties, compared with 74 (6.9 net) wells during 2003. We plan to spend approximately \$6.6 million on development projects during 2005. The majority of this amount is forecast to be spent at Hayter on drilling and related facilities, and to continue the drilling program at Pembina Cardium Unit No. 9. The remaining capital will be spent on miscellaneous properties. Approximately 70% 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, Ribstone/Chauvin and Pouce Coupe properties as outlined in the table below:

Property	Working Interest ⁽¹⁾	2004 Production	Net Proved Plus Probable Reserves	2004 Net Pre-Tax Cash Flow ⁽²⁾	Reserve Value ⁽⁵⁾ Discounted at 10%/year	
	(%)	(boe/d)	(Mboe)	(\$000)	(\$000)	(%)
Hayter ⁽³⁾	23.52	606	1,944	4,923	14,549	22.3
Pembina Cardium Unit No. 9 ⁽⁴⁾	9.97	274	2,857	3,407	23,496	36.0
Ribstone/Chauvin	16.67	150	152	1,118	2,500	3.8
Pouce Coupe South Boundary "B" Unit #2	25.56	105	480	1,158	4,862	7.4
Other (86 properties)	2.13	742	1,398	6,005	19,870	30.4
Total		1,877	6,831	16,611	65,277	100.0

Notes:

- (1) The percentage working interest share of reserves and production owned by Freehold Resources in the properties before the deduction of royalties payable to others.
- (2) Excludes \$366,000 of ARC for 2004.
- (3) Excludes a 6.25% royalty interest (included in the Northeast Alberta royalty area).
- (4) Includes a 0.6% royalty interest.
- (5) Excludes \$1.1 million of ARC over the life of the reserves.

Hayter, Alberta

We own a 23.52% working interest and a 6.25% royalty interest (included in the Northeast Alberta royalty area) in Hayter, located in east-central Alberta. Historically, Freehold Resources owned 23.52% working interest in only Section 26-40-1W4. In 2003, Freehold Resources acquired a 23.52% working interest in 160 acres in the northern portion of Section 23, which lies directly south of Section 26. The Hayter Dina B pool is situated in the northeast portion of Township 40 Range 1 W4M covering portions of six sections. The pool produces 15° API oil from an average net pay interval of approximately 50 feet. 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 horizontal drilling. In 2004, 11 (2.6 net) wells were drilled. An additional 10 (2.4 net) wells are planned to be

drilled in 2005. Oil and NGL production was 9% higher at 602 bbls/d during 2004 and natural gas production was 29% higher than 2003 at 26 Mcf/d. There are also plans to expand the water injection facilities to return shut-in wells to production.

Pembina Cardium Unit No. 9, Alberta

We have a 9.97% 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 production unit encompasses approximately 25,280 acres. This unit has an extremely long reserve life and has been on an 80-acre, five-spot waterflood pattern for more than 40 years. In 2004, the operator of the unit focused on improving water injection into the pool to increase reservoir pressure. One (0.1 net) well was drilled in 2004. Oil and NGL production was 8% lower at 205 bbls/d during 2004 and natural gas production was 19% lower than 2003 at 413 Mcf/d. The operator has plans to drill an additional 20 (0.2 net) infill wells in 2005, including 7 (0.7 net) injection wells.

Ribstone/Chauvin

Production from Ribstone/Chauvin has grown to 150 boe/d compared with 46 boe/d when we acquired the properties in 1997. Oil and natural gas production is primarily from the Mannville sands. Our largest property in this area is a 16.67% working interest in the Ribstone Sparky A Pool located in Section 34-42-04 W4M, which produced 100 boe/d in 2004. Oil and NGL production was 14% higher at 100 bbls/d during 2004 and natural gas production was 11% lower than 2003 at 299 Mcf/d.

Pouce Coupe, Alberta

We own a 25.56% working 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. Oil and NGL production was 5% higher at 90 bbls/d during 2004 and natural gas production was 9% higher than 2003 at 88 Mcf/d. In 2005, plans include the drilling of 2 (0.5 net) wells.

Other Working Interest Properties

We own various working interests in 86 other properties, which accounted for 40% of the working interest production volumes during 2004. Development activities included the drilling of 74 (2.0 net) wells.

Working Interest Wells

The following table sets forth the number and status of wells as at December 31, 2004 in which we have a working interest which are producing or considered capable of production:

Property	Producing ⁽¹⁾				Non-Producing ⁽¹⁾⁽²⁾⁽³⁾			
	Oil		Natural Gas		Oil		Natural Gas	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Hayter	98	23.1	-	-	21	4.9	-	-
Pembina Cardium Unit No. 9	165	16.4	-	-	9	0.9	-	-
Ribstone/Chauvin	26	4.3	6	1.0	2	0.5	3	0.5
Pouce Coupe South Boundary “B” Unit #2	12	3.1	-	-	1	0.3	-	-
Other (86 properties)	508	35.1	414	10.1	134	9.3	52	3.0
Total	809	82.0	420	11.1	167	15.9	55	3.5

Notes:

- (1) Based on public records.
- (2) “Non-producing” wells means wells which are not producing but which are considered capable of production. Non-producing 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) Not all wells owned by Freehold Resources have been assigned reserves in the Trimble Report.

Development Activities

The following table sets forth the development wells in which we participated during the years ended December 31, 2004 and December 31, 2003:

Wells Drilled Years ending December 31	2004		2003	
	Gross	Net	Gross	Net
Development				
Oil	32	3.6	39	6.6
Natural Gas	57	1.8	35	0.3
Dry	1	0.0	-	-
Total	90	5.4	74	6.9

Reconciliation of Working Interest Property Reserves

The following table provides a summary of the changes in the oil and natural gas reserves on our Working Interest Properties during 2004, based on forecast prices and costs:

Factors	Light and Medium Oil			Heavy Oil			Associated and Non-Associated Gas		
	Net Proved	Net Probable	Net Proved Plus Probable	Net Proved	Net Probable	Net Proved Plus Probable	Net Proved	Net Probable	Net Proved Plus Probable
	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(MMcf)	(MMcf)	(MMcf)
December 31, 2003	2,537	588	3,125	1,522	1,236	2,758	5,157	1,541	6,699
Extensions	5	9	14	-	-	-	89	189	278
Improved recovery	1	3	3	-	-	-	1	2	2
Technical revisions	134	(125)	9	253	(218)	35	(46)	(501)	(547)
Discoveries	-	-	-	-	-	-	77	66	142
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-
Economic factors	(6)	-	(6)	10	(2)	8	(28)	(16)	(45)
Production	(125)	(2)	(126)	(279)	(1)	(280)	(623)	(10)	(633)
December 31, 2004	2,546	473	3,019	1,505	1,015	2,520	4,626	1,271	5,897

Note:

(1) Columns may not add due to rounding.

Oil and Natural Gas Wells

The following tables set forth, by province, the number and status of wells in which the Trust has an interest as at December 31, 2004.

Working Interest Properties	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	647	65.6	132	14.3	265	10.7	43	2.9
British Columbia	14	0.4	5	0.2	155	0.4	11	0.1
Saskatchewan	134	14.9	27	1.2	-	-	1	0.5
Manitoba	14	1.1	3	0.2	-	-	-	-
Total	809	82.0	167	15.9	420	11.1	55	3.5

Royalty Lands ⁽¹⁾	Non-Unitized		Unitized	
	Natural Gas Wells	Oil Wells	Natural Gas Wells	Oil Wells
Alberta	1,281	990	4,889	3,852
British Columbia	-	-	-	-
Saskatchewan	440	1,137	32	3,196
Manitoba	-	13	-	26
Total	1,721	2,140	4,921	7,074

Note:

(1) Gross wells in which the Trust has a royalty interest.

Properties with No Attributable Reserves

The following table sets out our undeveloped land holdings as at December 31, 2004.

	Undeveloped Acres		
	Royalty Lands	Working Interest Lands	
	Gross	Gross	Net
Alberta	93,988	38,180	7,018
British Columbia	-	4,948	9
Saskatchewan	150,642	2,384	731
Manitoba	1,547	40	-
Total	246,177	45,552	7,758

There are no material work commitments on the undeveloped land holdings.

Tax Horizon

The Trust is a mutual fund trust under the Tax Act and distributes substantially all of its taxable income to Unitholders. By doing so, exposure to current tax at the Trust level is eliminated. In addition, the Trust is exempt from future income taxes because it is contractually committed to distribute all of its income to Unitholders.

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. 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.

The following table summarizes capital expenditures (net of incentives and net of certain proceeds and including capitalized general and administrative expenses) related to the Trust's activities for the year ended December 31, 2004:

	(\$000s)
Property acquisition costs	
Proved properties	12,881
Undeveloped/unproved properties	-
Development costs	5,823
Total	18,704

Production Estimates

The following table sets out the volume of net production estimated for the year ended December 31, 2005 in the Trimble Report which is reflected in the estimate of future net revenue disclosed in the tables contained under "Disclosure of Reserves Data".

2005 Forecast Net Production	
Light and Medium Oil (bbls/d)	1,220
Heavy Oil (bbls/d)	2,252
Natural Gas (MMcf/d)	10
Natural Gas Liquids (bbls/d)	322
Oil Equivalent (boe/d)	5,454

Production History

The following table summarizes our production, product prices received, royalties paid, operating expenses and resulting netback for the periods indicated below:

	Quarter Ended				Quarter Ended			
	2004				2003			
(6:1)	Dec. 31	Sept. 30	June 30	Mar. 31	Dec. 31	Sept. 30	June 30	Dec. 31
Average Daily Production ⁽¹⁾								
Light and Medium Oil (bbls/d)	1,550	1,556	1,618	1,593	1,565	1,628	1,600	1,618
Heavy Oil (bbls/d)	2,129	1,918	1,908	2,104	2,174	2,153	1,923	2,089
Natural Gas (Mcf/d)	9,582	10,191	11,520	9,797	10.4	10.7	11.4	11.0
NGL (bbls/d)	298	274	3,11	248	293	338	330	309
Combined (boe/d)	5,575	5,447	5,757	5,577	5,768	5,909	5,746	5,847
Average Price Received								
Light and Medium Oil (\$/bbl)	49.40	50.57	44.38	41.40	35.48	37.07	36.70	46.69
Heavy Oil (\$/bbl)	29.85	37.21	31.17	28.46	23.64	27.07	26.74	34.78
Natural Gas (\$/Mcf)	6.44	6.09	6.34	6.24	5.25	5.73	6.39	7.29
NGL (\$/bbl)	40.62	40.08	34.78	33.28	29.45	28.91	29.40	36.36
Combined (\$/boe)	38.37	40.96	37.37	35.00	29.51	32.15	33.49	40.97
Royalties Paid								
Light and Medium Oil (\$/bbl)	1.27	1.30	1.52	1.12	0.82	1.27	1.29	1.20
Heavy Oil (\$/bbl)	0.86	1.40	1.10	0.77	0.59	0.77	0.86	1.21
Natural Gas (\$/Mcf)	0.35	0.23	0.32	0.37	0.37	0.43	0.36	0.46
NGL (\$/bbl)	2.73	3.11	2.02	2.63	1.80	1.70	2.59	3.19
Combined (\$/boe)	1.43	1.46	1.55	1.38	1.20	1.52	1.50	1.81
Operating Expenses (\$/boe) ⁽²⁾								
Light and Medium Oil (\$/bbl)	3.66	3.63	4.33	4.09	3.84	2.17	2.86	3.03
Heavy Oil (\$/bbl)	3.52	4.53	3.55	3.14	3.87	3.78	3.76	3.10
Natural Gas (\$/Mcf)	0.21	0.20	0.18	0.23	0.15	0.20	0.05	0.18
NGL (\$/bbl)	1.10	1.07	1.31	1.03	1.06	1.19	0.32	1.38
Combined (\$/boe)	2.77	3.05	2.83	2.81	2.83	2.41	2.18	2.35
Netback Received (\$/boe) ⁽³⁾								
Light and Medium Oil (\$/bbl)	44.48	45.63	38.52	36.19	30.82	33.63	32.56	42.47
Heavy Oil (\$/bbl)	25.47	31.28	26.53	24.55	19.18	22.52	22.12	30.47
Natural Gas (\$/Mcf)	5.88	5.66	5.84	5.63	4.72	5.10	5.98	6.65
NGL (\$/bbl)	36.79	35.90	31.45	29.63	26.59	26.02	26.49	31.79
Combined (\$/boe)	34.17	36.45	33.00	30.80	25.88	28.61	30.47	37.18

Notes:

- (1) Before deduction of royalty expenses.
- (2) Operating expenses are comprised 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.
- (3) Netbacks are calculated by subtracting royalty expenses and operating costs from revenues.

The following table summarizes our average daily production from important fields for the year ended December 31, 2004:

	Light and Medium Oil	Heavy Oil	Natural Gas	Natural Gas Liquids	Oil Equivalent
	(bbls/d)	(bbls/d)	(Mcf/d)	(bbls/d)	(boe/d)
Royalty Lands					
Western Alberta	137	-	2,518	187	743
Saskatchewan Heavy Oil	-	545	345	1	604
Northeast Alberta	8	460	805	1	603
Southeast Saskatchewan	567	-	151	-	593
Southeast Alberta	48	83	1,401	1	365
Bashaw/Leduc	112	-	1,177	18	326
Hatton/Gull Lake	130	26	672	-	268
Other	90	-	657	9	209
Working Interest Properties					
Hayter	-	602	26	-	606
Pembina Cardium Unit No. 9	168	-	413	37	274
Ribstone/Chauvin	-	100	299	-	150
Pouce Coupe Southern Boundary "B" Unit #2	87	-	88	3	105
Other (86 properties)	233	198	1,718	26	742
Total	1,580	2,014	10,270	283	5,588

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 \$9.9 million. A reclamation fund, consisting of cash invested in an interest-bearing account, has been established and is funded by quarterly cash payments. In 2004, contributions to the reclamation fund totalled \$414,000, including interest, bringing the balance of the reclamation fund at December 31, 2004 to \$1.6 million. The funding level is reviewed and approved by the board of directors of Freehold Resources annually based on estimated future liabilities and spending profile. For 2005, quarterly contributions will remain at \$100,000, plus interest, to ensure that future obligations can be met.

Future abandonment and reclamation costs have been estimated based on actual costs incurred to date for abandonment and reclamation activities. We expect to abandon and reclaim approximately 137 net wells at the estimated costs identified in the table below.

As at December 31, 2004	Abandonment and Reclamation Costs (Net of Salvage Value) (\$000s)	
	Undiscounted	Discounted at 10%
Total costs as at December 31, 2004	9,872	2,534
Total costs not deducted from future net revenue	7,534	1,201
Expected to be paid in 2005	8	8
Expected to be paid in 2006	109	97
Expected to be paid in 2007	33	27

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.

OTHER INFORMATION ABOUT 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.

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.

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.

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 Freehold Resources in their capacity as directors or officers of Freehold Resources.

POTASH INTERESTS AND RESERVES

Description of Potash Interests

The HB Lands Royalties are derived from the leased mineral title lands and royalty assumption lands acquired by the Trust from Canpar. The Trust's interest in these leased mineral titles lands and royalty assumption lands includes not only Petroleum Substances but other minerals such as potash. Potash is a naturally occurring substance that is mined, processed and then used as an agricultural fertilizer.

In 1996, the Trust acquired the right to the revenue 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. 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. As of January 1, 1979, Canpar owned a 23.52% freehold mineral title interest to these potash properties and its partner owned the remaining 76.48%. Canpar subsequently entered into an agreement with its partner in 1993 with respect to the six mines producing at that time. It was agreed that Canpar would receive 100% of the partner's share of all potash royalties from an effective date of December 1, 1993 until the sum of \$3 million had been recovered. The agreement reached payout in 2000 and since that time ownership 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.

The potash mines from which the Trust receives royalties are operated by Potash Corporation of Saskatchewan, Central Canada Potash and IMC Esterhazy Canada Limited Partnership.

In 2004, the Trust received revenue of \$464,000 from the production of 7.6 tonnes per day of potash.

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 December 31, 2004, 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 Potash Reserves ⁽¹⁾		Present Net Value Of Future Net Pre-Tax Cash Flows (\$000)			
	(Mtonnes)		Undiscounted	Discounted at		
	Gross	Net		5%	10%	15%
Proved Reserves						
Constant Price and Cost ⁽²⁾	57,553	57,553	15,152	7,180	4,519	3,331
Escalated Price and Cost ⁽³⁾	57,553	57,553	20,385	8,719	5,137	3,650

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\$165.96 per tonne.

- (3) Average yearly potash prices, which were deemed appropriate as at December 31, 2004 for potash are outlined in the following table:

<u>Year</u>	<u>Price/tonne (Cdn\$)</u>
2005	165.96
2006	168.45
2007	170.98
2008	173.54
2009	176.14
2010	178.79
2011	181.47
2012	184.19
2013	186.95
Thereafter	1.5%/year

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

- (4) The net production of potash in 2004 was 7.6 tonnes per day in both the constant and escalated price cases. The estimated undiscounted net pre-tax cash flow in 2005 is \$464,468 in both the constant and escalated price cases.

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.

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and NGL, reserves and cash flows to be derived therefrom, including many factors beyond the Trust's control. The reserve and associated cash flow information set forth in the AIF represents estimates only. In general, estimates of economically recoverable oil and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary from actual results. All such estimates are to some degree speculative, and classifications of reserves are only attempts to define the degree of speculation involved. For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom prepared by different engineers, or by the same engineers at different times, may vary. The Trust's actual production, revenues and development and operating expenditures with respect to its reserves from the Royalty Lands, the Additional Properties and Working Interest Properties will vary from estimates thereof and such variations could be material.

Estimates of proved reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history and production practices will result in variations in the estimated reserves and such variations could be material.

In accordance with applicable securities laws, Trimble used both constant and forecast price and cost estimates in calculating reserve quantities for the Trust. Actual future net cash flows will be affected by other factors such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

Actual production and cash flows derived therefrom will vary from the estimates contained in the Trust's engineering reports. The reserve reports are based in part on the assumed success of activities the Trust intends to undertake in future years. The reserves and estimated cash flows to be derived therefrom contained in the engineering reports will be reduced to the extent that such activities do not achieve the level of success assumed in the engineering reports.

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 fluctuate 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 Distributions to Unitholders. The Trust may manage the risk associated with changes in commodity prices by entering into oil or natural gas price hedges, but has not done so to date. If the Trust hedges its commodity price exposure, the Trust will forego the benefits it would otherwise experience if commodity prices were to increase. In addition, commodity hedging activities could expose the Trust to losses. To the extent that the Trust engages in risk management activities related to commodity prices, it will be subject to credit risks associated with counterparties with which it contracts.

Variations in Interest Rates and Foreign Exchange Rates

An increase in interest rates could result in a significant increase in the amount the Trust pays to service debt, resulting in a decrease in distributions to Unitholders, as well as impact the market price of the Trust Units on the TSX.

Our operating costs are generally paid in Canadian dollars. World oil prices are quoted in U.S. dollars. The price that Canadian producers receive is therefore affected by the Canadian/U.S. dollar exchange rate. As experienced, that exchange rate may fluctuate over time. A material increase in the value of the Canadian dollar may negatively impact our production revenue.

The exchange rate for the Canadian dollar versus the U.S. dollar has increased significantly over the last 12 months, resulting in the Trust receiving fewer Canadian dollars for its share of production which may affect future distributions. The Trust may initiate certain hedges to attempt to mitigate these risks, but has not done so to date. To the extent that the Trust engages in risk management activities related to foreign exchange rates, it will be subject to credit risk associated with counterparties with which it contracts. The increase in the exchange rate for the Canadian dollar and future Canadian/United States exchange rates will impact future distributions and the future value of the Trust's reserves as determined by independent evaluators.

Depletion of Reserves

The Trust has certain unique attributes which differentiate it from other oil and gas industry participants. Distributions to Unitholders 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.

Changes in Legislation

Income tax laws, or other laws or government incentive programs relating to the oil and gas industry, such as the treatment of mutual fund trusts and resource taxation, may in the future be changed or interpreted in a manner that adversely affects the Trust and its Unitholders. Tax authorities having jurisdiction over the Trust or the Unitholders may disagree with how the Trust calculates its income for tax purposes or could change administrative practises to the detriment of the Trust or the detriment of its Unitholders.

Investment Eligibility; Mutual Fund Status

It is intended that the Trust qualify at all times as a mutual fund trust for the purposes of the Tax Act. The Trust may not, however, always be able to satisfy any future requirement for the maintenance of mutual fund trust status. Should the status of the Trust as a mutual fund trust be lost or successfully challenged by a relevant tax authority, certain adverse consequences may arise for the Trust and Unitholders. Some of the significant consequences of losing mutual fund trust status are as follows:

- the Trust Units would cease to be a qualified investment for trusts governed by RRSPs, RESPs, RRIFs and DPSPs ("Exempt Plans"). Where, at the end of a month, an Exempt Plan holds Trust Units that ceased to be a qualified investment, 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, trusts governed by a registered retirement savings plan ("RRSP") or a registered retirement income fund ("RRIF") which hold Trust Units that are not qualified investments will be subject to tax on the income attributable to the Trust Units while they are non qualified investments, including the full capital gains, if any, realized on the disposition of such Trust Units. Where a trust governed by a RRSP or a RRIF acquires Trust Units that are not qualified investments, the value of the investment will be included in the income of the annuitant for the year of the acquisition. Trusts governed by RESPs which hold Trust Units that are not qualified investments can have their registration revoked by the CRA;
- Trust Units would become foreign property for Exempt Plans, registered pension plans and other persons subject to tax under Part XI of the Tax Act upon the Trust ceasing to be a mutual fund trust;
- the Trust would be required to pay a tax under Part XII.2 of the Tax Act. The payment of Part XII.2 tax by the Trust may have adverse income tax consequences for certain Unitholders, including non resident persons and residents of Canada who are exempt from Part I tax;
- the Trust would cease to be eligible for the capital gains refund mechanism available under Canadian tax laws; and
- Trust Units would become taxable Canadian property. As a result, non resident Unitholders would be subject to Canadian income tax on any gains realized on a disposition of Trust Units held by them.

In addition, the Trust may take certain measures in the future to the extent the Trust believes such measures are necessary to ensure the Trust maintains its status as a mutual fund trust. These measures could be adverse to certain holders of Trust Units, particularly "non-residents" of Canada as defined in the Tax Act.

Non-Resident Ownership of Trust Units

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. The Trust Indenture provides that if at any time the Trust or the Trustee becomes aware that the beneficial owners of 49% or more of the Trust Units then outstanding are or may be non residents or that such a situation is imminent, the Trust, by or through the Trustee on the Trust's behalf, shall take such action as may be necessary to carry out the foregoing intention. See "Trust Units – Trust Indenture – Limitation on Non-Resident Ownership". These measures could be adverse to certain holders of Trust Units, and may not be effective to avoid the Trust losing its status as a mutual fund trust for the purposes of the Tax Act if certain proposed amendments are enacted as proposed.

Proposed amendments to the Tax Act originally published by the Minister of Finance on March 22, 2004 were to provide that after December 31, 2004, the Trust must continuously ensure that not more than 50% of its issued Trust Units are held by non-residents of Canada or partnerships (other than "Canadian partnerships" as defined in the Tax Act). These proposals were not included in the Notice of Ways and Means Motion tabled by the Minister of Finance on December 6, 2004 and the Minister of Finance has indicated that further discussions are to be held with the private sector on the appropriate tax treatment for non-residents investing in resource property through mutual funds.

Operational Matters

The operation of oil and natural gas wells involves a number of operating and natural hazards which may result in blowouts, environmental damage and other unexpected or dangerous conditions resulting in damage to 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.

Regulatory

Oil and natural gas operations (exploration, production, pricing, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government that may be amended from time to time. Freehold Resources' operations may require licenses from various governmental authorities. There can be no assurance that Freehold Resources will be able to obtain all necessary licenses and permits that may be required to carry out exploration and development at its projects.

Kyoto Protocol

Canada is a signatory to the United Nations Framework Convention on Climate Change and has ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nationwide emissions of carbon dioxide, methane, nitrous oxide and other so-called "greenhouse natural gases". Freehold Resources' exploration and production facilities and other operations and activities emit a small amount of greenhouse natural gases which may subject Freehold Resources to legislation regulating emissions of greenhouse natural gases. The Government of Canada has put forward a Climate Change Plan for Canada which suggests further legislation will set greenhouse natural gases emission reduction requirements for various industrial activities, including oil and natural gas exploration and production. Future federal legislation, together with provincial emission reduction requirements such as those proposed in Alberta's Bill 37: Climate Change and Emissions Management, may require the reduction of emissions or emissions intensity produced by Freehold Resources' operations and facilities. The direct or indirect costs of these regulations may adversely affect the business of Freehold Resources.

Environmental Concerns

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

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 Distributions to Unitholders. 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.

Additional Financing

In the normal course of making capital investments to maintain and expand the oil and natural gas reserves of the Trust additional Trust Units may be issued from treasury which may result in a decline in production per Trust Unit and reserves per Trust Unit. Additionally, from time to time the Trust may issue Trust Units from treasury in order to reduce debt and maintain a more optimal capital structure. 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 natural 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 Distributions to Unitholders will be reduced.

Competition

There is strong competition relating to all aspects of the oil and gas industry. There are numerous trusts in the oil and gas industry who are competing for the acquisition of properties. As a result of such increasing competition, it will be more difficult to acquire reserves on beneficial terms. 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.

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 natural 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".

Title

Although satisfactory title reviews of the properties are conducted in accordance with industry standards, those title reviews do not guarantee or certify that a defect in the chain of title may not arise to defeat the claim of the Trust to a property. A reduction of Royalty Income could result in those circumstances.

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 Distributions to Unitholders, 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.

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.

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

Cash on Cash Yield

Cash on cash yield is a useful and widely used supplemental measure that provides investors with information on cash actually distributed relative to trading price. Unitholders are cautioned that cash on cash yield does not have any standardized meaning prescribed by generally accepted accounting principles ("GAAP") and should not be construed as an alternate to net income as determined by GAAP. Unitholders are also cautioned that cash on cash yield represents a blend of return of capital (i.e. a repayment of a portion of their initial investment) and a return on capital (i.e. income) and is not comparable to traditional yield on debt instruments where investors are entitled to a full return of the principal amount of debt on maturity in addition to a return on investment through interest payments.

Redemption Right

Unitholders have a limited right to require the Trust to repurchase their Trust Units, which is referred to as a redemption right. It is anticipated that the redemption right will not be the primary mechanism for Unitholders to liquidate their investment. The right to receive cash in connection with a redemption is subject to limitations. Any securities which may be distributed in specie to Unitholders in connection with a redemption may not be listed on any stock exchange and a market may not develop for such securities. In addition, there may be resale restrictions imposed by law upon the recipients of the securities pursuant to the redemption right.

Accounting Write-Downs as a Result of GAAP

Canadian GAAP require that management apply certain accounting policies and make certain estimates and assumptions which affect reported amounts in the consolidated financial statements of the Trust. The accounting policies may result in non-cash charges to net income and write-downs of net assets in the financial statements. Such non-cash charges and write-downs may be viewed unfavourably by the market and result in an inability to borrow funds and/or may result in a decline in the Trust Unit price.

Under GAAP, the net amounts at which petroleum and natural gas costs on a property or project basis are carried are subject to a cost-recovery test, which is based in part upon estimated future net cash flows from reserves. If net capitalized costs exceed the estimated recoverable amounts, Freehold Resources will have to charge the amounts of the excess to earnings. A decline in the net value of oil and natural gas properties could cause capitalized costs to exceed the cost ceiling, resulting in a charge against earnings. The net value of oil and natural gas properties are highly dependent upon the prices of oil and natural gas. See "Risk Factors – Volatility of Oil and Natural Gas Prices".

GAAP requires that goodwill balances be assessed at least annually for impairment and that any permanent impairment be charged to net income. A permanent reduction in reserves, decline in commodity prices, and/or reduction in the Trust Unit price may indicate a goodwill impairment. As at December 31, 2004 the Trust had no goodwill recorded on its balance sheet. An impairment would result in a write-down of the goodwill value and a non-cash charge against net income. The calculation of impairment value is subject to management estimates and assumptions.

Emerging GAAP surrounding hedge accounting may result in non-cash charges against net income as a result of changes in the fair market value of hedging instruments. A decrease in the fair market value of the hedging instruments as the result of fluctuations in commodity prices and foreign exchange rates may result in a write-down of net assets and a non-cash charge

against net income. Such write-downs and non-cash charges may be temporary in nature if the fair market value subsequently increases.

Under Canadian accounting rules, a “ceiling limit” test is applied to the carrying value of oil and natural gas assets, net of the provision for site restoration, plus future development costs, to ensure that such costs do not exceed future estimated net revenues from production of proved reserves at year-end prices and costs. A severe decline in oil and natural gas prices could cause our capitalized costs to exceed the cost ceiling. If our net capitalized costs exceed this “ceiling limit” we must charge the amount of the excess against earnings. Although this charge to earnings, or write-down, would not affect cash flow, such a charge could be viewed unfavorably in the market and it may also affect our ability to borrow funds or to comply with covenants in our credit arrangements, current or future.

DESCRIPTION OF CAPITAL STRUCTURE

The Trust has authorized an unlimited number of Trust Units of which 31,544,236 were issued at December 31, 2004. The Trust has reserved 820,000 Trust Units pursuant to a Trust Unit Option Plan. Options to purchase Trust Units may be issued to the independent directors of Resources or the Manager. As at December 31, 2004, no options to purchase Trust Units were outstanding. Effective May 1, 2002 the Trust reserved 500,000 Trust Units for issuance to the Manager pursuant to the Management Agreement, of which 264,236 have been issued as at December 31, 2004. During 2004, the Manager received 90,000 Trust Units as the Management Fees, bringing the total number of Trust Units received by the Manager to 684,236 from inception of the Trust in late 1996 to December 31, 2004.

For a detailed description of the rights, privileges and restrictions that characterize the Trust Units, see “Trust Units”.

TRUST UNITS

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, which is available on SEDAR at www.sedar.com or 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. The Trustee also acts as the transfer agent and registrar for the Trust Units, from their offices located in Calgary, Alberta and Toronto, Ontario. 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

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 Distributions to Unitholders will depend on, among other things, the quantity of oil, natural 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. Over time, an increasing percentage of the annual distributions will become taxable.

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 natural 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 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:

$$\frac{\text{RUU}}{\text{All RUU} + \text{All OS}} \quad \times \quad \text{Distributions to Unitholders}$$

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.

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 Distributions to Unitholders. 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 acquired 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 Distributions to Unitholders. 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; (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.

Unitholder Limited Liability

The Income Trusts Liability Act (Alberta) came into force on July 1, 2004. The legislation provides that a Unitholder will not be, as a beneficiary, liable for any act, default, obligation or liability of the Trustee that arises after the legislation came into force.

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.

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 Trust 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 Distributions to Unitholders 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.

MARKET FOR SECURITIES

The Trust Units are listed on The Toronto Stock Exchange and commenced trading on November 25, 1996. The trading symbol for the Trust Units is FRU.UN. The following table sets forth the price range and trading volume of the Trust Units for the periods indicated.

	Toronto Stock Exchange Trust Unit Trading Range			Volume Traded
	High	Low	Close	
	(Cdn\$ per Trust Unit)			
2004				
January	16.30	14.52	15.19	850,297
February	15.60	14.02	14.81	760,334
March	15.49	14.37	14.75	788,283
April	15.80	14.65	15.39	419,684
May	15.75	14.75	15.19	1,794,041
June	15.50	14.85	15.00	935,305
July	15.24	14.57	15.00	313,003
August	16.97	14.75	15.45	989,324
September	16.60	15.00	16.25	465,484
October	17.13	15.75	16.55	1,706,506
November	18.42	16.25	18.16	2,043,336
December	18.40	16.75	17.45	501,872
2005				
January	17.75	16.77	17.21	381,984
February	18.49	17.10	18.19	665,487
March 1-15, 2005	18.30	16.65	17.14	328,466

DISTRIBUTIONS TO UNITHOLDERS

Distributions to Unitholders consist of Royalty Income, ARC and other income received by the Trust less royalties, expenses and withholdings payable by the Trust and less other amounts reasonably determined by Freehold Resources to be retained for the purposes of the Trust.

The Trust retains cash to, among other things, fund capital expenditures or acquisitions, and reduce bank indebtedness. The distribution policy allows the use of up to 15% of net cash flow for capital expenditures, including minor acquisitions, as determined under the Trust Indenture. The Trust's distribution policy includes withholding a portion of cash available for distribution to contribute to the Trust's reclamation fund to provide a cash reserve for the eventual abandonment of oil and gas properties.

Regular distributions are made to Unitholders on a monthly basis. On a quarterly basis, the board of directors of Freehold Resources reviews the application of any cash available for distribution in excess of these amounts. The board of directors' policy has been to apply some portion, up to 50%, of funds in excess of regular monthly distributions to the repayment of debt and/or working capital improvement, with the remainder distributed to Unitholders as an extra distribution. The actual percentage retained by the Trust is subject to the discretion of the board of directors of Freehold Resources.

Distribution History

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 Distributions to Unitholders are determined on a cash received basis.

The table below sets forth the amount of cash distributions the Trust has paid on the Trust Units during the three most recently completed financial years:

Record Date	Payment Date	Per Trust Unit (\$)
2002		
Dec. 31, 2001	Jan. 15, 2002	0.1000
Jan. 31, 2002	Feb. 15, 2002	0.0800
Feb. 28, 2002	Mar. 15, 2002	0.0800
Mar. 31, 2002	Apr. 15, 2002	0.0800
Apr. 30, 2002	May 15, 2002	0.0800
May 31, 2002	Jun. 15, 2002	0.1400 ⁽¹⁾
Jun. 30, 2002	Jul. 15, 2002	0.1000
Jul. 31, 2002	Aug. 15, 2002	0.1000
Aug. 31, 2002	Sep. 15, 2002	0.1700 ⁽¹⁾
Sep. 30, 2002	Oct. 15, 2002	0.1000
Oct. 31, 2002	Nov. 15, 2002	0.1000
Nov. 30, 2002	Dec. 15, 2002	0.1800 ⁽¹⁾
		1.3100
2003		
Dec. 31, 2002	Jan. 15, 2003	0.1000
Jan. 31, 2003	Feb. 15, 2003	0.1000
Feb. 28, 2003	Mar. 15, 2003	0.2000 ⁽¹⁾
Mar. 31, 2003	Apr. 15, 2003	0.1000
Apr.30, 2003	May 15, 2003	0.1000
May 31, 2003	Jun. 15, 2003	0.3000 ⁽¹⁾
Jun. 30, 2003	Jul. 15, 2003	0.1000
Jul. 31, 2003	Aug. 15, 2003	0.1000
Aug. 31, 2003	Sep. 15, 2003	0.2000 ⁽¹⁾
Sep. 30, 2003	Oct. 15, 2003	0.1000
Oct. 31, 2003	Nov 15, 2003	0.1000
Nov. 30, 2003	Dec. 15, 2003	0.2000 ⁽¹⁾
		1.7000
2004		
Dec. 31, 2003	Jan. 15, 2004	0.1000
Jan. 31, 2004	Feb. 15, 2004	0.1000
Feb. 28, 2004	Mar. 15, 2004	0.1700 ⁽¹⁾
Mar. 31, 2004	Apr. 15, 2004	0.1000
Apr.30, 2004	May 15, 2004	0.1000
May 31, 2004	Jun. 15, 2004	0.2000 ⁽¹⁾
Jun. 30, 2004	Jul. 15, 2004	0.1000
Jul. 31, 2004	Aug. 15, 2004	0.1000
Aug. 31, 2004	Sep. 15, 2004	0.2500 ⁽¹⁾
Sep. 30, 2004	Oct. 15, 2004	0.1200
Oct. 31, 2004	Nov 15, 2004	0.1200
Nov. 30, 2004	Dec. 15, 2004	0.2500 ⁽¹⁾
		1.7100

Note:

(1) Regular monthly distributions are supplemented by quarterly top-ups when excess income is available. Payment includes quarterly top up.

Unitholder Income Tax Information

Canadian Tax Information for Unitholders Resident in Canada

The following information is intended to assist individual Canadian Unitholders in the preparation of their 2004 T1 Income Tax Return. This summary is directed to a Unitholder who, for the purposes of the Tax Act, is a resident of Canada and holds the Trust Units as capital property. The information provided below is based on our understanding of the Tax Act and the regulations thereunder and is provided for general information only. Unitholders are advised to consult their personal tax advisors with respect to their particular circumstances.

For income tax purposes, only cash payments received in each calendar year are subject to Canadian income tax. All cash distributions paid to Unitholders from inception of the Trust to the end of 2000 were 100% tax deferred and have been treated as a return of capital. Beginning in 2001, distributions became taxable. Distributions paid to Unitholders in 2002 were 58% taxable (42% tax deferred), Distributions paid in 2003 were 69% taxable (31% tax deferred). Distributions paid in 2004 were 68% taxable (32% tax deferred).

The tax-deferred portion of the distributions is deemed a return of capital (i.e. a repayment of a portion of the initial investment) and the remainder is considered a return on capital (i.e. income). The calculation of return of capital and return on capital for the purposes of the Tax Act does not represent an economic calculation of return of capital and return on capital. The allocation between these two streams is dependent upon the tax deductions that we are entitled to claim against the income it earns from Royalty Income received from Freehold Resources. (the operating company) and income the Trust earns directly. The level of these tax deductions is primarily driven by COGPE (Canadian Oil and Gas Property Expense) representing the cost of acquiring the royalty from Freehold Resources or the Trust's direct investment in revenue-producing property.

For purposes of the Tax Act, we are treated as a mutual fund trust. Each year, we file a T3 income tax return with the taxable income allocated to and made taxable in the hands of Unitholders. This taxable income is allocated, on T3 supplementary forms, to each Unitholder who received distributions in that taxation year. The T3 slip will report only the other income component in Box 26. This income is taxed as ordinary income. The portion deemed return of capital reduces the Unitholder's adjusted cost base in the Units and should be included in the computation of capital gain (or loss) at the time of disposition (see "Adjusted Cost Base Calculation for Capital Gains Purposes").

Trust Units held within an RRSP, RRIF, DPSP or RESP

Trust Units are qualified investments for registered plans such as a Registered Retirement Savings Plan (RRSP), Registered Retirement Income Fund (RRIF), Deferred Profit Sharing Plan (DPSP) or Registered Educational Savings Plan (RESP). Trust Units held inside such registered plans are completely tax-sheltered and no amounts are required to be reported on the 2004 T1 Income Tax Return.

Trust Units held outside of a Registered Plan

For cash distributions received by a Canadian resident outside of an RRSP, RRIF, DPSP, or RESP, 68% of 2004 cash distributions are taxable (other income). The amount reported in Box 26 on the T3 slip should be reported on the 2004 T1 Income Tax Return as "Other Income". The remaining 32% is tax deferred and deemed a return of capital as outlined in the following schedule.

Record Date	Payment Date	Taxable Amount Box 26 (Other Income)	Tax-Deferred Amount	Total Distribution Paid Cdn \$
December 31, 2003	January 15, 2004	\$0.0680	\$0.0320	\$0.1000
January 31, 2004	February 15, 2004	0.0680	0.0320	0.1000
February 29, 2004	March 15, 2004	0.1156	0.0544	0.1700
March 31, 2004	April 15, 2004	0.0680	0.0320	0.1000
April 30, 2004	May 15, 2004	0.0680	0.0320	0.1000
May 31, 2004	June 15, 2004	0.1360	0.0640	0.2000
June 30, 2004	July 15, 2004	0.0680	0.0320	0.1000
July 31, 2004	August 15, 2004	0.0680	0.0320	0.1000
August 31, 2004	September 15, 2004	0.1700	0.0800	0.2500
September 30, 2004	October 15, 2004	0.0816	0.0384	0.1200
October 31, 2004	November 15, 2004	0.0816	0.0384	0.1200
November 30, 2004	December 15, 2004	0.1700	0.0800	0.2500
Total paid during the 2004 taxation year		\$1.1628	\$0.5472	\$1.7100

The December 31, 2004 distribution was paid on January 15, 2005 (2005 taxation year) and is therefore not included in the 2004 T3 amounts.

The deadline for mailing all T3 Supplementary information slips as required by Canada Revenue Agency is March 31, 2005.

- Registered Unitholders who received cash distributions during the 2004 taxation year from the Transfer Agent, Computershare Trust Company of Canada (and not from a brokerage firm or other intermediary) will receive a "T3 Supplementary" slip directly from Computershare.
- Non-Registered Unitholders who received cash distributions during the taxation year 2004 from a brokerage firm or other intermediary will receive a "T3 Supplementary" slip directly from the brokerage firm or other intermediary, not from the Transfer Agent or the Trust.

Adjusted Cost Base Calculation for Capital Gains Purposes

Unitholders are required to reduce the adjusted cost base (ACB) of their Trust Units by the amount equal to any distributions received in the form of return of capital (the tax-deferred portion of distributions received). Unitholders should maintain a record of all distributions that are classified as partially or entirely a return of capital distribution while holding Trust Units.

For investors in the \$10.00 per Trust Unit initial public offering in November 1996, the ACB of Trust Units still held as at December 31, 2004 is \$3.5284 per Trust Unit, taking into account the cumulative return of capital of \$6.4716 as provided in the following table:

HISTORICAL TAX INFORMATION

Taxation Year¹	Taxable Amount (Other Income) Per Unit²	Tax Deferred Amount (Return of Capital) Per Unit³	Taxable Percentage	Tax Deferred Percentage	Total Paid Distribution Cdn\$
2004	\$1.1628	\$0.5472	68%	32%	\$1.71
2003	1.1730	0.5270	69%	31%	1.70
2002	0.7598	0.5502	58%	42%	1.31
2001	0.5928	0.9672	38%	62%	1.56
2000	0.0000	1.2900	0%	100%	1.29
1999	0.0000	0.7600	0%	100%	0.76
1998	0.0000	0.8500	0%	100%	0.85
1997	0.0000	0.9800	0%	100%	0.98
Total	\$3.6884	\$6.4716			\$10.16

Notes:

- (1) For income tax purposes, only cash payments received in each calendar year are subject to Canadian income tax.
- (2) As at December 31, 2004, we have the benefit of \$161 million of income tax accounts to reduce the taxable portion of future distributions.
- (3) The tax-deferred amount reduces the adjusted cost base of a Unitholder's investment in Trust Units.

2005 Taxability

The Trust estimates that approximately 25% of Distributions to Unitholders received in 2005 will be tax deferred and 75% will be taxable. The actual level of taxability is dependent upon commodity prices received and company activities undertaken to year-end.

Canadian Tax Information for Non-Resident Unitholders

The following information is provided for general information only. Unitholders who are not residents of Canada for income tax purposes are encouraged to seek advice from a qualified tax advisor in their country of residence for the tax treatment of distributions.

NR4 Summary and Slips

For the purposes of preparing the NR4 Return the amount of the distribution considered taxable for Canadian purposes is included in the gross income reported in Box 16 of the NR4 slip. The full amount of the tax withheld is reported in Box 17 of the NR4 slip.

Non-Resident Withholding Tax

Monthly income distributions payable to non-residents of Canada are normally subject to a withholding tax of 25% as prescribed by the Tax Act. This withholding tax may be reduced in accordance with reciprocal tax treaties.

Refund of Excess Part XIII Tax Withheld

The non-resident Unitholder will have been subject to tax withholdings in excess of that required based on the taxable portion of their distribution for Canadian purposes. A non-resident can apply for a refund of this excess tax paid by completing Form NR7-R, *Application of Refund of Non-Resident Tax Withheld*. This form has to be received by the Canada Revenue Agency ("CRA") no later than two years from the end of the calendar year in which the tax was remitted.

United States Tax Information for Unitholders Resident in the United States

For U.S. purposes only, we are considered a corporation and therefore the full amount of the distribution is considered a dividend.

U.S. tax rules state that no portion of the distribution will be considered a tax-deferred return of capital unless the Trust computes its current and accumulated earnings and profits in accordance with U.S. income tax principles. At this time, we do not perform a current and accumulated earnings and profits calculation; therefore distributions are 100% taxable to U.S. residents as a dividend. However, such dividends may be eligible for the lower U.S. tax rate allowed on dividends from certain foreign corporations. Please consult your U.S. tax advisor.

The U.S. Jobs and Growth Tax Relief Reconciliation Act of 2003 (the “Act”) was signed into law on May 28, 2003. The Act effectively reduces the U.S. federal income tax rate on qualified dividend income, received January 1, 2003 through December 31, 2008, to a maximum of 15%. Qualified dividend income is defined as dividends received during the taxation year from domestic U.S. corporations and “qualified foreign corporations”. The term “qualified foreign corporation” excludes, among other things, a passive foreign investment company (“PFIC”). Therefore, dividends from a PFIC are not eligible for the above-noted lower rate of tax. Based on legal and tax advice we have obtained, as the majority of our revenue is derived from non-operated royalty interests, We may be considered a PFIC for U.S. tax purposes and therefore may not be a qualified foreign corporation for U.S. federal income tax purposes under the Act. As such, our distributions may not be eligible for the lower U.S. tax rate outlined above.

In the case of the Tax Treaty between Canada and the U.S., the withholding tax for U.S. residents is prescribed at 15%. U.S. taxpayers may be eligible for a foreign tax credit with respect to the Canadian withholding taxes paid. U.S. investors should seek a refund of Canadian withholding tax related to amounts withheld on non-taxable distributions (from a Canadian tax perspective) from Canada Revenue Agency by filing Form NR7-R, Application for Refund of Non-Resident Tax Withheld. Under this circumstance, these taxes should not be claimed as a credit against any U.S. tax liability.

2004 DISTRIBUTIONS IN U.S. DOLLARS

Record Date	Payment Date	Total Distribution Paid in Cdn\$	Cdn\$/US\$ Exchange Rate	Total Distribution Paid in US\$
December 31, 2003	January 15, 2004	0.10	1.2924	\$0.077375
January 31, 2004	February 15, 2004	0.10	1.3264	\$0.075392
February 29, 2004	March 15, 2004	0.17	1.3401	\$0.126856
March 31, 2004	April 15, 2004	0.10	1.3105	\$0.076307
April 30, 2004	May 15, 2004	0.10	1.3707	\$0.072955
May 31, 2004	June 15, 2004	0.20	1.3634	\$0.146692
June 30, 2004	July 15, 2004	0.10	1.3404	\$0.074605
July 31, 2004	August 15, 2004	0.10	1.3292	\$0.075233
August 31, 2004	September 15, 2004	0.25	1.3167	\$0.189869
September 30, 2004	October 15, 2004	0.12	1.2639	\$0.094944
October 31, 2004	November 15, 2004	0.12	1.2207	\$0.098304
November 30, 2004	December 15, 2004	0.25	1.1904	\$0.210013
Total paid during the 2004 taxation year		\$1.71		\$1.318545

The December 31, 2004 distribution was paid on January 15, 2005 (2005 taxation year) and is therefore not included in the 2004 NR4 amounts.

- Distributions are considered a dividend for tax reporting purposes.
- Registered Unitholders will receive a form NR4 from the Transfer Agent, Computershare Trust Company of Canada.
- Non-registered Unitholders (units held by a brokerage firm or other intermediary) will receive a form NR4 from the brokerage firm or other intermediary.

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.

Cash Distribution Reinvestment Plan

A Trust Unit Cash Distribution Reinvestment Plan (the "DRIP Plan") 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.

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.

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 Shareholders 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 Shareholders Agreement dated December 31, 2004 among the Manager, Freehold Resources and the Trustee as trustee for and on behalf of the Trust, the Unitholders are entitled to attend all meetings of shareholders of Freehold Resources and except as set forth below, to direct the manner in which the Trust will vote its shares in Freehold Resources at all such meetings. Prior to the 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 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 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 Shareholders Agreement, which is currently two), approving its financial statements and appointing auditors of Freehold Resources. In addition, Unitholders will be entitled to direct the Trust as to how to vote its shares in Freehold Resources on any proposed amendment to the Unanimous Shareholders Agreement, where such amendment is required to be approved by Special Resolution. The 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 Shareholders 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 Shareholders 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 Distributions to Unitholders, 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 appointed by the Manager and five of whom are independent directors elected by the Unitholders.

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

Name and Province of Residence	Position with Freehold Resources	Principal Occupation	Director/ Officer Since
William W. Siebens ⁽²⁾⁽⁴⁾ Alberta, Canada	Chairman and Director	President and Chief Executive Officer, Candor Investments Ltd. (private energy and investment corporation)	July 29, 1996
David J. Sandmeyer ⁽⁵⁾ Alberta, Canada	Director, President and Chief Executive Officer	President of Rife Resources Ltd. (private oil and gas exploration and production company)	July 29, 1996
D. Nolan Blades ⁽¹⁾⁽²⁾⁽³⁾⁽⁴⁾ Alberta, Canada	Director	President, Sunny Gables Holdings Ltd. (private holding company)	July 29, 1996
Harry S. Campbell, Q.C. ⁽³⁾⁽⁴⁾ Alberta, Canada	Director	Managing Partner, Burnet, Duckworth & Palmer LLP (barristers and solicitors)	July 29, 1996
Tullio Cedraschi ⁽⁵⁾ Quebec, Canada	Director	President and Chief Executive Officer, CN Investment Division (manages the pension funds for employees of the Canadian National Railway Company)	January 21, 1998
Peter T. Harrison ⁽¹⁾⁽³⁾⁽⁴⁾ Quebec, Canada	Director	Senior Vice-President, Montrusco Bolton Inc. (investment counsel)	July 29, 1996
Dr. P. Michael Maher ⁽¹⁾⁽²⁾⁽⁴⁾ Calgary, Alberta	Director	Professor, Haskayne School of Business, University of Calgary	July 29, 1996
J. Frank George Alberta, Canada	Vice-President, Exploitation	Vice President, Exploration of Rife Resources Ltd. (private oil and gas exploration and production company)	July 29, 1996
Darren G. Gunderson Alberta, Canada	Controller	Controller, Freehold Resources Ltd. (private oil and gas exploitation and production company)	November 13, 2003
Joseph N. Holowisky Alberta, Canada	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
William O. Ingram Alberta, Canada	Vice-President, Production	Vice-President, Production of Rife Resources Ltd. (private oil and gas exploration and production company)	July 29, 1996
Michael J. Okrusko Alberta, Canada	Vice-President, Land	Vice-President, Land of Rife Resources Ltd. (private oil and gas exploration and production company)	July 29, 1996

Notes:

- (1) Member of Audit Committee.
- (2) Member of Governance & Nominating Committee.
- (3) Member of Reserves Committee.
- (4) Independent directors of Freehold Resources who were elected by the Unitholders at the last annual meeting of the Trust on May 5, 2004.
- (5) Directors appointed by the Manager.

Each of the directors has been engaged in his principal occupation or in other capacities with the same firm or organization for the past five years.

As at March 15, 2005, the directors and senior officers of Freehold Resources, as a group, beneficially owned, directly or indirectly, or exercised control or direction over 130,978 Trust Units or less than 1% of the issued and outstanding Trust Units. CN Pension Trust Funds, including the Trust Units owned by the Manager, owns 9,982,036 Trust Units (32%) of the Trust as at March 15, 2005. The Manager, which is a wholly owned subsidiary of Rife, owns 1,684,236 Trust Units as at March 15, 2005. Rife is 100% owned by the CN Pension Trust Funds.

The following is a brief description of the backgrounds of the directors and officers of Freehold Resources:

William W. Siebens

Bill Siebens is President and Chief Executive Officer of Candor Investments Ltd. (Calgary), a private energy and investment corporation. He currently serves as a Director of Petro-Canada and the Fraser Institute. He brings special expertise to the Trust with his knowledge of the Royalty Lands as a portion of these lands were previously owned by Siebens Oil & Gas Ltd.

David. J. Sandmeyer

David Sandmeyer is President, Chief Executive Officer and a Director of Freehold Resources (Calgary), and President of Rife (Calgary). Prior to joining Rife in 1982, he held senior positions with Amoco Canada Petroleum Company Limited for 18 years. He is a former Governor of the Canadian Association of Petroleum Producers. A graduate of the University of Saskatchewan, he holds a Bachelor of Science degree in Mechanical Engineering and is a Professional Engineer.

D. Nolan Blades

Nolan Blades is President of Sunny Gables Holdings Ltd. (Calgary) and a Professional Engineer with extensive experience in the oil and gas industry. Mr. Blades was President and Chief Executive Officer of Pursuit Resources Corp. from 1993 to 2000, and is currently a Director of Real Resources Inc., Gemini Corporation and Canoro Resources Ltd.

Harry S. Campbell

Harry Campbell is Managing Partner of the law firm Burnet, Duckworth & Palmer LLP (Calgary). He was admitted to the Alberta Bar in 1974 and has extensive experience with Canadian oil and gas transactions and international petroleum and natural gas matters. Mr. Campbell is currently a Director of Delphi Energy Corp. and The Cathay Investment Fund Limited.

Tullio Cedraschi

Tullio Cedraschi is President and Chief Executive Officer of the CN Investment Division (Montreal). He is currently a Director of the Toronto Stock Exchange, Western Oil Sands Inc. and Helix Investments (Canada) Inc. He is a Governor and Past President of the National Theatre School of Canada, and a Governor Emeritus of McGill University, where he received his MBA.

Peter T. Harrison

Peter Harrison is Senior Vice-President of Montrusco Bolton Inc. (Montreal). Mr. Harrison has over 24 years of investment experience and previously managed Canadian Equities for the CN Investment Division. Mr. Harrison is currently a Director of Daylight Energy Trust. He holds a Bachelor of Commerce degree from McGill University, an MBA from the University of Western Ontario and is a Chartered Financial Analyst.

Dr. P. Michael Maher

Michael Maher is a Professor and former Dean of the Haskayne School of Business, University of Calgary. He currently serves as a Director of Nicer Technologies and Wellpoint Systems Inc. He has a Bachelor of Science degree in Engineering from the University of Saskatchewan; an MBA from the University of Western Ontario; a Ph.D. from Northwestern University; a Doctor of Commerce (honoris causa) degree from St. Mary's University and is a Professional Engineer.

J. Frank George

Frank George, Vice President, Exploitation of Freehold Resources (Calgary), joined Rife (Calgary) in 1983 as Chief Geologist and became Vice President, Exploration in 1994. He is responsible for the management and coordination of all exploration and geological evaluation activities of Rife. A graduate of the University of Calgary, Mr. George is a registered Professional Geologist in Alberta and a member of the Canadian Society of Petroleum Geologists.

Darren G. Gunderson

Darren Gunderson, Controller of Freehold Resources (Calgary), joined Rife in 1991 in the accounting department and became Controller in 1999. Mr. Gunderson holds a Bachelor of Commerce degree from the University of Saskatchewan and is a Certified General Accountant.

Joseph N. Holowisky

Joe Holowisky, Vice President, Finance and Administration, Chief Financial Officer and Secretary of Freehold Resources (Calgary), joined Rife (Calgary) in 1982 as Audit Manager and is currently Vice President, Finance and Administration and Secretary of Rife. Mr. Holowisky is a member of the Petroleum Accounting Society of Canada and the Institute of Internal Auditors. Mr. Holowisky is Chairman of the advisory board of directors of the Energy Insurance Reciprocal.

William O. Ingram

Bill Ingram joined Rife (Calgary) in 1984. As Vice-President, Production, of each of Rife and Freehold Resources, Mr. Ingram is responsible for production and drilling operations, marketing, acquisitions, reserve analysis and economic evaluations. Mr. Ingram is a Professional Engineer and holds a Bachelor of Science degree in Chemical Engineering from the University of Alberta. He is a member of The Association of Professional Engineers, Geologists and Geophysicists of Alberta (APPEGA).

Michael J. Okrusko

Mike Okrusko, Vice President, Land of each of Freehold Resources (Calgary) and Rife (Calgary), joined Rife in 1982 as Manager of Land. Mr. Okrusko is a graduate of the Southern Alberta Institute of Technology (Petroleum Technology) and holds a Bachelor of Commerce (Finance) degree from the University of Calgary. Mr. Okrusko is an active member of the Canadian Association of Petroleum Landman and has obtained the P. Land designation.

Corporate Cease Trade Orders or Bankruptcies

During the past 10 years, none of the directors of Freehold Resources is or has been a director or executive officer of any company that, while that person was acting in that capacity: (i) was the subject of a cease trade order or similar order or an order that denied that company access to any exemption under securities legislation for a period of more than 30 consecutive days; (ii) was subject to an event that resulted, after the director or executive officer ceased to be a director or executive officer, in the company being the subject of a cease trade or similar order or an order that denied the relevant company access to any exemption under securities legislation, for a period of more than 30 consecutive days; or (iii) within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets.

Personal Bankruptcies

None of the directors of Freehold Resources has, within the past 10 years, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the proposed director.

Audit Committee

The full text of the audit committee mandate is included in Appendix C of this Annual Information Form.

Composition of Audit Committee

Freehold's audit committee consists of Mr. D. Nolan Blades (Chair), Mr. Peter T. Harrison and Dr. P. Michael Maher. All members of the audit committee are independent and financially literate as those terms are used under Multilateral Instrument 52-110. See "Governance - Board of Directors of Freehold Resources".

Pre-Approval Policies and Procedures

The audit committee pre-approves all non-audit services to be provided to the Trust by the external auditors. Prior to the commencement of the Trust's fiscal year, the audit committee pre-approves expenditures with a dollar limit for services related to consultations as to the accounting or disclosure treatment of transactions, and for expenditures with a dollar limit for services related to taxation matters. The audit committee must pre-approve any costs that exceed these limits.

EXTERNAL AUDITOR SERVICE FEES

	Year ended December 31	
	2004	2003
Audit fees ⁽¹⁾	\$ 36,921	\$ 33,150
Audit-related fees ⁽²⁾	30,984	-
Tax fees ⁽³⁾	10,190	2,750
All other fees ⁽⁴⁾	-	975
Total	\$ 77,995	\$ 36,875

Notes:

- (1) Audit fees consist of fees for the audit of the Trust's annual financial statements or services that are normally provided in connection with statutory and regulatory filings or engagements.
- (2) Audit-related fees consist of fees for assurance and related services that are reasonably related to the performance of the audit or review of the Trust's financial statements and are not reported as Audit Fees. During 2004 and 2003, the services provided in this category included due diligence reviews in connection with acquisitions and dispositions, research of accounting and audit-related issues, review of reserves disclosure and the completion of audits required by contracts to which the Trust is a party.
- (3) Tax fees consist of fees for tax compliance services, tax advice and tax planning. During 2004 and 2003, the services provided in this category included assistance and advice in relation to Unitholder taxation issues and the preparation of corporate income tax returns.
- (4) During 2003, the services provided in this category included professional services rendered relating to the renegotiation of the Trust's long-term debt facility.

THE MANAGER

The Manager is a wholly-owned subsidiary of Rife, which is 100% owned by the CN Pension Trust Funds.

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.

Employees

The Trust has no employees but rather is managed by the Manager pursuant to the Management Agreement. At December 31, 2004, the Manager had 70 full and part-time employees. These personnel also render services to Rife and Canpar.

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 since automatically renewed for additional three year terms, the current term of which has renewed to November 2007, 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 Distributions to Unitholders, 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 2004, the Manager received 90,000 Trust Units as the Management Fee to the Manager, bringing the total number of Trust Units received by the Manager to 684,236 from inception of the Trust in late 1996 to December 31, 2004.

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 \$2.6 million for General and Administrative Costs for the year ended December 31, 2004.

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 2004, \$197,000 (2003 - \$53,000) 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, province of residence, position held and principal occupation of each director and officer of the Manager are set out below:

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

As at March 15, 2005 the directors and senior officers of the Manager, as a group, beneficially owned, directly or indirectly, or exercised control or direction over 25,017 Trust Units. Rife owns 100% of the outstanding shares in the capital of the Manager. All of the shares of Rife are owned by the CN Pension Trust Funds.

There were no amounts paid by Freehold Resources or the Trust to any person set forth above during the period ended December 31, 2004.

A brief description of the backgrounds of the directors and officers of the Manager is provided under "Board of Directors of Freehold Resources".

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 Distributions to Unitholders.

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.

LEGAL PROCEEDINGS

There are no outstanding legal proceedings which are for claims in excess of 10% of the current Asset Value of the Trust to which the Trust is a party or in respect of which any of its properties are subject, nor are there any such proceedings pending or known to be contemplated.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

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 was used to pay down bank debt. The Manager is a wholly-owned subsidiary of the CN Pension Trust Funds, which held 9,982,036 Trust Units as at March 11, 2005, representing 32% of the outstanding Trust Units.

There were no material interests, direct or indirect, of any directors or executive officers of the Manager, directors or executive officers of Freehold Resources, any Unitholder who beneficially owns more than 10% of the Trust Units or any known associate or affiliate of such persons in any transaction within the three most recently completed financial years or during the current financial year that has materially affected or will materially affect the Trust, other than as disclosed herein.

AUDITORS, TRANSFER AGENT AND REGISTRAR

The auditors of the Trust are KPMG LLP, Chartered Accountants, Calgary, Alberta.

Computershare Trust Company of Canada at its offices in Calgary, Alberta and Toronto, Ontario acts as the transfer agent and registrar for the Trust Units.

MATERIAL CONTRACTS

Except for contracts entered into since January 1, 2002, by the Trust in the ordinary course of business or otherwise disclosed herein, the only material contracts entered into or to be entered into by the Trust which is considered material is the Trust Indenture dated May 1, 2002 as described under the heading "Trust Units – The Trust Indenture", the renewed Management Agreement as described under the heading "The Manager – Management Agreement", and the Unanimous Shareholders Agreement dated December 31, 2004 as described under the heading "Governance – Unanimous Shareholders Agreement".

INTERESTS OF EXPERTS

The Trimble Report, wherein is summarized in this AIF, was prepared by Trimble and certified in the form attached hereto in Appendix A. KPMG LLP are the auditors of the Trust and have prepared a report as the audited financial statements of the Trust for the year ended December 31, 2004.

No person or company whose profession or business gives authority to a statement made by such person or company and who is named in this AIF as having prepared or certified a part of this AIF, or a report or valuation described in this AIF or in a document specifically incorporated by reference into this AIF, has received or shall receive a direct or indirect interest in the property of the Trust or of any associate or affiliate of the Trust. As at the date hereof, the aforementioned persons and companies beneficially own, directly or indirectly, less than 1% of the securities of the Trust and its associates and affiliates. In addition, none of the aforementioned persons or companies, nor any director, officer or employee of any of the aforementioned persons or companies, is or is expected to be elected, appointed or employed as a director, officer or employee of the Trust or of any associates or affiliates of the Trust.

ADDITIONAL FINANCIAL AND OTHER INFORMATION

Additional information about the Trust may be found on SEDAR at www.sedar.com. Information about 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 Management – Proxy Statement of the Trust dated March 15, 2005 which relates to the Annual Meeting of Unitholders to be held on May 11, 2005. Additional financial information is provided in the consolidated financial statements of the Trust and Freehold Resources for the period ended December 31, 2004 and the accompanying Management's Discussion and Analysis.

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 consolidated financial statements of the Trust and Freehold Resources for the period ended December 31, 2004 together with the accompanying report of the auditor and one copy of any subsequent interim financial statements,
 - (iii) one copy of the Information Circular – Management Proxy Statement of the Trust dated March 15, 2005, 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;
- 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
c/o Freehold Resources Ltd.
400, 144 – 4th Avenue S.W.
Calgary, Alberta T2P 3N4
Telephone: (403) 221-0802
Fax: (403) 221-0888

APPENDIX A

Report on Reserves Data by Independent Qualified Reserves Evaluator FORM 51-101 F2

To the board of directors of Freehold Resources Ltd. and Rife Resources Management Ltd., as manager of Freehold Royalty Trust (the "Trust"):

1. We have evaluated and reviewed the Trust's reserves data as at December 31, 2004. The reserves data consist of the following:
 - (a) (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2004 using forecast prices and costs; and
 - (ii) the related estimated future net revenue; and
 - (b) (i) proved oil and gas reserves estimated as at December 31, 2004 using constant prices and costs; and
 - (ii) the related estimated future net revenue.
2. The reserves data are the responsibility of the Trust's management. Our responsibility is to express an opinion on the reserves data based on our evaluation and review.

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

3. Those standards require that we plan and perform an evaluation and review to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation and review also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.
4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Trust evaluated and reviewed by us for the year ended December 31, 2004, and identifies the respective portions thereof that we have evaluated and reviewed and reported on to the Trust's management.

Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Audited	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate)			Total
				Evaluated	Reviewed		
Trimble Engineering Associates Ltd.	January 19, 2005	Canada	nil	\$ 289,409,000	\$ 2,838,000	\$ 292,247,000	

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

Executed as to our report referred to above:

Calgary, Alberta / Canada, March 15, 2005
Trimble Engineering Associates Ltd.

"signed"

Stephen C. Trimble, P.Eng.
President

APPENDIX B

Report of Management and Directors on Reserves Data and Other Information FORM 51-101 F3

Management of Freehold Royalty Trust (the "Trust") being Freehold Resources Ltd. ("Resources") is responsible for the preparation and disclosure of information with respect to oil and gas activities of Trust in accordance with securities regulatory requirements. This information includes reserves data, which consist of the following:

- (a) (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2004 using forecast prices and costs; and
- (ii) the related estimated future net revenue; and
- (b) (i) proved oil and gas reserves estimated as at December 31, 2004 using constant prices and costs; and
- (ii) the related estimated future net revenue.

An independent qualified reserves evaluator, Trimble Engineering Associates Ltd. ("Trimble"), has evaluated the Trust's reserves data. The report of the independent qualified reserves evaluator will be filed with securities regulatory authorities concurrently with this report.

The Reserves Committee of the board of directors of Resources has:

- (a) reviewed the Trust's procedures for providing information to the independent qualified reserves evaluator;
- (b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and
- (c) reviewed the reserves data with Resources and the independent qualified reserves evaluator.

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

- (a) the content and filing with securities regulatory authorities of the reserves data and other oil and gas information;
- (b) the filing of the report of the independent qualified reserves evaluator on the reserves data; and
- (c) the content and filing of this report.

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

Dated at Calgary, Alberta, this 15th day of March, 2005.

"signed"

David J. Sandmeyer, P.Eng.
President, Chief Executive Officer and Director

"signed"

William O. Ingram, P. Eng.
Vice-President, Production

"signed"

D. Nolan Blades, P. Eng.
Director and Chair, Reserves Committee

"signed"

Peter T. Harrison
Director and Member, Reserves Committee

APPENDIX C

Audit Committee Mandate

Role and Objective

The Audit Committee (the “Committee”) is a committee of the board of directors of Freehold Resources Ltd. (“Resources”) to which the board has delegated certain responsibilities for oversight of the nature and scope of the annual audit, management’s reporting on internal accounting standards and practices, financial information and accounting systems and procedures, financial reporting and statements and recommending, for board of director approval, the audited financial statements and other mandatory disclosure releases containing financial information. The objectives of the Committee, with respect to Resources and (the “Trust”) (hereinafter collectively referred to as “Freehold”), are as follows:

1. To assist directors in meeting their responsibilities (especially for accountability) in respect of the preparation and disclosure of the financial statements of Freehold and related matters;
2. To provide better communication between directors and external auditors;
3. To enhance the external auditor’s independence;
4. To increase the transparency, credibility and objectivity of financial reporting; and
5. To strengthen the role of the outside directors by facilitating in-depth discussions between directors on the Committee, management and external auditors.

Membership of Committee

1. The Committee shall be comprised of at least three (3) directors of Resources, all of whom are “independent” (as such term is used in Multilateral Instrument 52-110 – Audit Committees (“MI 52-110”).
2. The board of directors shall have the power to appoint the Committee Chairman.
3. All of the members of the Committee shall be “financially literate”. The board of directors of Resources has adopted the definition for “financial literacy” used in MI 52-110.

Meetings

1. At all meetings of the Committee every question shall be decided by a majority of the votes cast. In case of an equality of votes, the chairman of the meeting shall not be entitled to a second or deciding vote.
2. A quorum for meetings of the Committee shall be a majority of its members, and the rules for calling, holding, conducting and adjourning meetings of the Committee shall be the same as those governing the board.
3. Meetings of the Committee should be scheduled to take place at least four times per year. Minutes of all meetings of the Committee shall be taken. The Chief Financial Officer shall attend meetings of the Committee, unless otherwise excused from all or part of any such meeting by the Chairman.
4. The Committee shall forthwith report the results of meetings and reviews undertaken and any associated recommendations to the board.
5. The Committee shall meet with the external auditor at least once per year (in connection with the preparation of the year end financial statements) and at such other times as the external auditor and the Committee consider appropriate.
6. The Committee shall meet with the external reserve evaluators at least once per year (in connection with the preparation of the year end reserves).

Mandate and Responsibilities of Committee

1. It is the responsibility of the Committee to oversee the work of the external auditors, including resolution of disagreements between management and the external auditors regarding financial reporting.
2. It is the responsibility of the Committee to satisfy itself on behalf of the board with respect to Freehold's internal control systems:
 - identifying, monitoring and mitigating business risks; and
 - ensuring compliance with legal, ethical and regulatory requirements.
3. It is a primary responsibility of the Committee to review the annual financial statements of Freehold prior to their submission to the board of directors for approval. The process should include but not be limited to:
 - reviewing changes in accounting principles, or in their application, which may have a material impact on the current or future years' financial statements;
 - reviewing significant accruals, reserves or other estimates such as the ceiling test calculation;
 - reviewing accounting treatment of unusual or non-recurring transactions;
 - reviewing the Trust's status as a "mutual fund trust" under the *Income Tax Act* (Canada);
 - ascertaining compliance with covenants under loan agreements and Trust Indenture;
 - reviewing adequacy of the reclamation fund;
 - reviewing disclosure requirements for commitments and contingencies;
 - reviewing adjustments raised by the external auditors, whether or not included in the financial statements;
 - reviewing unresolved differences between management and the external auditors; and
 - obtaining explanations of significant variances with comparative reporting periods.
4. The Committee is to review the financial statements, prospectuses, management discussion and analysis (MD&A), annual information forms (AIF) and all public disclosure containing audited or unaudited financial information before release and prior to board approval. The Committee must be satisfied that adequate procedures are in place for the review of Freehold's disclosure of all other financial information and shall periodically access the accuracy of those procedures.
5. With respect to the appointment of external auditors by the board, the Committee shall:
 - recommend to the board the appointment of external auditors;
 - recommend to the board the terms of engagement of the auditor, including the compensation of the auditors and confirmation that the auditors shall report directly to the Committee;
 - when there is to be a change in auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change; and
 - review and approve any non-audit services to be provided by the auditors' firm and consider the impact on the independence of the auditors.
6. The Committee shall review with external auditors (and internal auditor if one is appointed by Freehold) their assessment of the internal controls of Freehold, their written reports containing recommendations for improvement, and management's response and follow-up to any identified weaknesses. The Committee shall also review annually with the external auditors their audit plan and, upon completion of the audit, their reports upon the financial statements of Freehold and its subsidiaries.

7. The Committee must pre-approve all non-audit services to be provided to Freehold or its subsidiaries by the external auditors. The Committee may delegate to one or more members the authority to pre-approve non-audit services, provided that the member report to the Committee at the next scheduled meeting such pre-approval and the member comply with such other procedures as may be established by the Committee from time to time.
8. The Committee shall review on an annual basis the reserves as evaluated by the external reserve evaluators. This annual process shall include a face-to-face meeting with management and the reserve evaluators.
9. The Committee shall review risk management policies and procedures of Freehold (i.e. hedging, litigation and insurance).
10. The Committee shall review and approve management's hiring policies regarding current and former partners and employees of the present and former external auditor.
11. The Committee shall establish a procedure for:
 - the receipt, retention and treatment of complaints received by Freehold regarding accounting, internal accounting controls or auditing matters; and
 - the confidential, anonymous submission by employees of Freehold of concerns regarding questionable accounting or auditing matters.
12. The Committee shall have the authority to investigate any financial activity of Freehold. All employees of Rife are to cooperate as requested by the Committee.
13. The Committee may retain persons having special expertise and/or obtain independent professional advice to assist in filling their responsibilities at the expense of Freehold without any further approval of the board.