Freehold
ROYALTY TRUST

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NEWS RELEASE

Freehold Royalty Trust Announces 2006 First Quarter Results

CALGARY, ALBERTA, (CCNMatthews – May 10, 2006) – Freehold Royalty Trust (Freehold or the Trust) (TSX:FRU.UN) today announced results for the period ended March 31, 2006. Freehold's full exposure to high commodity prices, combined with increased royalty production from the Petrovera acquisition completed in May 2005, resulted in robust financial and operating results.

FIRST QUARTER HIGHLIGHTS

- Production averaged 8,794 barrels of oil equivalent (boe) per day, up 60% from the first quarter of 2005.
- Price realizations averaged $43.78 per boe, 11% higher than a year ago.
- Operating netback averaged $40.18 per boe, up 11% from the same period last year.
- Funds generated from operations were $0.58 per Trust Unit, up 14% from the first quarter of 2005.
- Distributions to Unitholders in the first quarter totalled $0.54 per Trust Unit, 32% higher than last year.
- The regular monthly distribution remains fixed at $0.18 per Trust Unit.

The regular monthly distribution in the amount of $0.18 per Trust Unit will be paid on June 15, 2006 to Unitholders of record on May 31, 2006 (ex-distribution date May 29, 2006). Including the June 15, 2006 payment, 12-month trailing cash distributions total $2.12 per Trust Unit.

Results at a Glance	Three Months Ended March 31		
	2006	2005	Change
Financial ($000s, except as noted)			
Gross revenue	**35,007**	19,859	76%
Operating income	**31,802**	17,916	78%
Net income	**8,766**	9,368	-6%
Per Trust Unit, basic and diluted ($)	**0.18**	0.30	-40%
Funds generated from operations	**28,198**	16,103	75%
Per Trust Unit ($)	**0.58**	0.51	14%
Distributions to Unitholders	**26,483**	12,936	105%
Per Trust Unit ($) (1)	**0.54**	0.41	32%
Long-term debt	**105,000**	27,000	289%
Unitholders' equity	**382,449**	161,616	137%
Operating			
Average daily production (boe/d)	**8,794**	5,502	60%
Average price realizations ($/boe)	**43.78**	39.47	11%
Operating netback ($/boe)	**40.18**	36.18	11%

(1) Based on the number of Trust Units issued and outstanding at each record date.

Message to Unitholders

Freehold generated strong financial and operating results in the first quarter of 2006, as the Trust benefited from the growth in royalty production as a result of the Petrovera acquisition completed in the second quarter of 2005. Results were fuelled by a 60% increase in oil and gas production and an 11% increase in average price realizations compared with the first quarter of 2005. As a result, distributions with respect to operations in the first quarter of 2006 totalled $0.54 per Trust Unit, up 32% from a year ago.

We are very pleased with the continued performance of the Petrovera acquisition, which has added to the strength of the Trust. Petrovera contributed about 37% of our gross revenues in the first quarter. The strong performance of these royalty assets is reflected in the ongoing drilling activity on our royalty lands. In the first quarter, 218 gross (4.9 equivalent net) royalty wells were drilled on our lands at no cost to us. Even more encouraging, there are currently 106 (5.8 equivalent net) licensed drilling locations on our royalty lands, the highest number in our history.

Crude oil prices continue to demonstrate strength. However, as a result of a global surplus of heavy crude and lack of upgrading capacity, the price differential between light and heavy crude oil remained at record levels, averaging $28.57 per barrel in the first quarter. The differential was $6.00 per barrel higher than the first quarter of last year, and this had a significant negative impact on our price realizations due to our heavier product mix (heavy oil accounts for 39% of our total boe production). We have seen a significant narrowing of the differential in the second quarter due to start-up of the Enbridge Spearhead pipeline on March 1, and a pipeline reversal enabling Alberta heavy oil to be shipped from Cushing, Oklahoma to Irving, Texas for processing. The differential improved from $33.93 per barrel in February to $15.19 in April. This short-term moderation is expected to bring relief for the next four to five months, but differentials are expected to widen again in the fourth quarter as seasonal demand softens.

Natural gas prices have weakened significantly since the beginning of the year, as a warmer than normal winter enabled gas storage levels to build above seasonal levels. With more than adequate supplies, prices are expected to remain weak through the summer, but may exhibit volatility if hurricanes once again hit the U.S. Gulf Coast, which is still recovering from the ravages of Hurricanes Katrina and Rita in 2005.

Since inception Freehold has not funded any of the incentive plans of the Manager. Effective January 1, 2006, Freehold will fund its proportionate share of a short term incentive plan (bonus) and a long term incentive plan for employees of Rife Resources, the Manager of the Trust. This will increase our general and administrative expenses in 2006 by $450,000 related to the short term incentive plan. In consideration for assuming a funding role in the incentive programs, the Manager has agreed to amend the Management Agreement to remove the 1.5% acquisition fee. This fee has amounted to $6.6 million since inception, of which $5.3 million was incurred in 2005 in relation to the Petrovera acquisition.

In light of current market conditions, we have increased the oil prices and lowered the natural gas prices in our 2006 forecast. Based on the assumptions provided in the accompanying MD&A, we expect to maintain our current monthly distribution rate at $0.18 per Trust Unit for the remainder of the year, and our 2006 distribution guidance of $2.16 per Trust Unit remains achievable. Any excess income will be directed to repayment of long-term debt and improvements in working capital, in keeping with our goal to maintain a strong balance sheet to pursue additional acquisition opportunities.

On behalf of the Board of Directors
of Freehold Resources Ltd.,

David J. Sandmeyer
President and Chief Executive Officer

Management's Discussion and Analysis (MD&A)

The following discussion is management's opinion about Freehold Resources Ltd., Petrovera Resources (a general partnership), and Freehold Royalty Trust's (the "Trust") (collectively "Freehold"), operating and financial results for the three months ended March 31, 2006 and previous periods, and the outlook for Freehold based on information available as at May 10, 2006. The financial information contained herein has been prepared in accordance with Canadian generally accepted accounting principles (GAAP). All comparative percentages are between the quarters ended March 31, 2006 and March 31, 2005, and all dollar amounts are expressed in Canadian currency, unless otherwise noted. This discussion should be read in conjunction with the Trust's annual MD&A and audited financial statements for the years ended December 31, 2005 and 2004, together with the accompanying notes. These are on pages 23 through 59 of the Trust's 2005 annual report to Unitholders.

FORWARD-LOOKING STATEMENTS

This MD&A offers our assessment of Freehold's future plans and operations as at May 10, 2006, and contains forward-looking statements. By their nature, forward-looking statements are subject to numerous risks and uncertainties, some of which are beyond our control, including the impact of general economic conditions, industry conditions, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other industry participants, the lack of availability of qualified personnel or management, stock market volatility and ability to access sufficient capital from internal and external sources. You are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. Our actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements. We can give no assurance that any of the events anticipated will transpire or occur, or if any of them do, what benefits we will derive from them. Except as required by law, we do not undertake to update the forward-looking statements contained herein.

CRITICAL ACCOUNTING ESTIMATES

The assets, liabilities, revenues and expenses reported in our financial statements depend to varying degrees on estimates made by management. These estimates are based on historical experience and reflect certain assumptions about the future that are believed to be both reasonable and conservative. The more significant reporting areas are crude oil and natural gas reserve estimation, depletion, impairment of assets, and oil and gas revenue accruals. Management's judgments and estimates in these areas are based on information available from both internal and external sources, including engineers, geologists, and historical experience in similar matters. Except as discussed in this MD&A, we are not aware of trends, commitments, events, or uncertainties that are expected to materially affect the methodology or assumptions associated with the critical accounting estimates.

The Trust has no operational control over its royalty lands, as it primarily holds small interests in several thousand wells. Thus, obtaining timely production data from the well operators is extremely difficult. As a result, we use government reporting databases and past production receipts to estimate revenue accruals. The substantial increase in royalty interest production with the Petrovera acquisition in May 2005 required a corresponding increase in our revenue accruals. The increase is reflected in higher accounts receivables.

CONVERSION OF NATURAL GAS TO OIL EQUIVALENT

To provide a single unit of production for analytical purposes, natural gas production and reserves volumes are converted mathematically to equivalent barrels of oil (boe). We use the international standard conversion 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.

SUPPLEMENTAL DISCLOSURE

We believe that operating income, netback and funds generated from operations are useful supplemental measures to analyze operating performance, leverage and liquidity. Operating income, which is gross revenue less royalty expense and operating expense, represents the results of operations before general and administrative, interest, taxes and non-cash expenses. Operating netback, which is calculated as average unit sales price less royalties and operating expenses; and investor netback, which deducts administrative and interest expense and income and capital taxes, represent the cash margin for product sold, calculated on a per boe basis. Funds generated from operations is derived from our Consolidated Statements of Cash Flows. It represents cash provided by operating activities, before changes in non-cash working capital. Operating income, netback, funds generated from operations and funds generated from operations per Trust Unit do not have any standardized meanings prescribed by GAAP and therefore may not be comparable with the calculations of similar measures for other entities.

TRUST UNITS OUTSTANDING

On March 31, 2006, we issued 35,654 Trust Units in payment of the quarterly management fee. As at March 31, 2006 and May 10, 2006, there were 49,067,235 Trust Units outstanding, an increase of 55% over last year. In May 2005, the Trust issued 17.4 million Trust Units in association with the Petrovera acquisition, which accounts for the majority of the increase. There are no options outstanding under the Trust Unit Option Plan.

Trust Units Outstanding	Three Months Ended March 31		
	2006	2005	Change
Weighted average	**49,031,977**	31,544,486	55%
At period end	**49,067,235**	31,566,736	55%

THE ROYALTY ADVANTAGE

The following table demonstrates the advantage of our royalty lands. In the first quarter of 2006, royalty interest properties accounted for 77% of gross revenue and 90% of distributions to Unitholders. We do not incur royalty expenses, operating expenses or site restoration expenses on our royalty production.

Components of Distributions to Unitholders **Three months ended March 31, 2006** ($000s)	Royalty Interest Properties	Working Interest Properties	**Total Trust**
Gross revenue	27,054	7,953	**35,007**
Royalty expense	—	(1,084)	**(1,084)**
Net revenue	27,054	6,869	**33,923**
Operating expense	—	(2,121)	**(2,121)**
Net operating income	27,054	4,748	**31,802**
General and administrative expense	(1,626)	(507)	**(2,133)**
Interest expense	(1,068)	(123)	**(1,191)**
Income and capital taxes	—	(276)	**(276)**
Expenditures on reclamation	—	(4)	**(4)**
Funds generated from operations	24,360	3,838	**28,198**
Reclamation fund contributions	—	(105)	**(105)**
Development expenditures	—	(1,601)	**(1,601)**
Changes in debt	(2,000)	—	**(2,000)**
Changes in working capital	1,518	473	**1,991**
Distributions declared	23,878	2,605	**26,483**

HISTORICAL PERFORMANCE SUMMARY

The following table summarizes our performance for the first quarter of 2006 and for the preceding seven quarters. This presentation illustrates the fluctuations in pricing experienced over the past eight quarters, and the resultant effect on our financial results. In recent quarters, our results have benefited from strong oil and natural gas prices, despite increasingly wide price differentials between light and heavy oil and a rising Canadian dollar.

In addition, the acquisition of Petrovera Resources had a positive impact on our results from the date of closing on May 10, 2005. The Petrovera contribution is partially reflected in the second quarter of 2005 (52 days of production) and is fully reflected in the following periods. Another factor that has influenced our results over the past several quarters is higher operating expenses on our working interest properties, which currently contribute about one-quarter of our total production volumes. Increasing costs is a trend being experienced throughout the oil and gas industry. However, the effect on our overall results is lessened by our royalty interest production, which does not incur operating expenses.

Quarterly Review	**2006**	2005				2004		
	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Financial ($000s, except as noted)								
Revenue, net of royalty expense	**33,923**	43,364	42,867	27,922	19,170	19,204	19,994	19,066
Funds generated from operations	**28,198**	38,694	38,893	24,344	16,103	16,139	17,392	16,407
Per Trust Unit ($)	**0.58**	0.79	0.79	0.59	0.51	0.51	0.55	0.52
Distributions to Unitholders	**26,483**	31,366	22,527	17,981	12,936	15,449	14,808	12,593
Per Trust Unit ($) (1)	**0.54**	0.64	0.46	0.41	0.41	0.49	0.47	0.40
Payout ratio (%)	**94**	81	58	74	80	96	85	77
Net income	**8,766**	18,747	19,373	10,858	9,368	9,397	10,306	9,515
Per Trust Unit, basic and diluted ($)	**0.18**	0.38	0.40	0.26	0.30	0.30	0.33	0.30
Long-term debt	**105,000**	107,000	118,000	120,000	27,000	27,000	17,000	17,000
Trust Units outstanding (000s) (2)	**49,032**	48,996	48,961	41,489	31,544	31,522	31,499	31,477
Operating ($/boe)								
Daily production	**8,794**	8,739	8,974	7,279	5,502	5,575	5,447	5,757
Average selling price	**43.78**	54.95	52.61	42.42	39.47	38.37	40.96	37.37
Operating netback	**40.18**	51.56	49.89	39.61	36.18	34.67	36.85	33.57
Operating expenses	**2.68**	2.38	2.03	2.54	2.53	2.77	3.05	2.83
Working Interest properties	**11.26**	12.06	10.35	11.00	7.59	8.16	9.29	8.78
General and administrative expenses	**2.69**	1.52	1.17	1.42	2.55	1.68	1.46	1.41
Benchmark Prices								
WTI crude oil (US$/bbl)	**63.45**	60.02	63.19	53.20	49.84	48.28	43.88	38.31
Exchange rate (Cdn$/US$)	**0.87**	0.85	0.83	0.80	0.82	0.82	0.77	0.74
Edmonton Par (Cdn$)	**68.96**	71.17	76.51	65.76	61.45	57.70	56.25	50.60
Light/heavy oil differential (Cdn$/bbl)	**28.57**	28.14	20.79	24.17	22.48	21.60	14.29	13.29
Bow River/Hardisty (Cdn$/bbl)	**40.39**	43.03	55.72	41.59	38.97	36.10	41.96	37.31
AECO natural gas (Cdn$/Mcf)	**9.27**	11.68	8.17	7.38	6.69	7.08	6.66	6.80
Unit Trading Performance								
High ($)	**22.20**	18.98	19.30	17.63	18.49	18.42	16.97	15.80
Low ($)	**18.44**	15.15	15.99	14.25	15.50	15.75	14.57	14.65
Close ($)	**19.50**	18.81	18.68	15.99	16.10	17.45	16.25	15.00
Volume (000s)	**11,155**	7,611	9,980	8,311	2,418	4,252	1,768	3,149

(1) Based on the number of Trust Units issued and outstanding at each record date.
(2) Weighted average during the quarter.

DEVELOPMENT ACTIVITIES

The record pace of drilling continued in the first quarter of 2006. The industry as a whole drilled more than 6,000 wells in western Canada, 22% more wells than in the first quarter of 2005. Mirroring this activity, 250 gross wells were drilled on our lands. In 2006, access has not been hampered by an early spring break-up and wet weather as was the situation last year.

In the current pricing environment, industry activity levels are anticipated to remain robust. The Petroleum Services Association of Canada (PSAC) predicts a total count of 26,725 wells in 2006, which would set yet another record for the industry. Driving these activity levels are continued strong oil prices, a growing emphasis on natural gas from coal, and a focus on shallow gas drilling.

ROYALTY INTEREST LANDS

A total of 218 wells were drilled on our royalty lands in the first quarter, including 132 unitized wells. On an equivalent net basis, this is 4.9 wells, up 58% from the first quarter of 2005. Drilling on our royalty lands occurs at no cost to Freehold. We continue to see development potential on our lands, as evidenced by a record number of drilling locations. There are currently 106 (5.8 equivalent net) licensed drilling locations on our royalty lands, compared with 61 (2.2 equivalent net) locations at this time last year.

Royalty Interest Lands Drilling Summary (1) (includes unitized wells)	Three Months Ended March 31		
	2006	2005	Change
Gross wells	**218**	287	-24%
Equivalent net wells (2)	**4.9**	3.1	58%
Net success rate	**99.5%**	100%	-1%

(1) Includes drilling on the Petrovera lands from January 1, 2005 (the effective date of the acquisition), except wells drilled in Ontario.

(2) Equivalent net wells are the aggregate of the numbers obtained by multiplying each gross well by the Trust's royalty interest percentage.

WORKING INTEREST PROPERTIES

In the first quarter of 2006, we spent $1.6 million completing and equipping fourth quarter 2005 wells and the drilling of 32 (0.9 net) wells, for a 100% success rate. The major areas of activity were Willesden Green, Pembina Cardium Unit No. 9 and Southeast Saskatchewan. We anticipate active second and third quarters, with the Hayter and Southeast Saskatchewan drilling programs to commence after spring breakup.

Working Interest Properties Drilling Summary	Three Months Ended March 31			
	2006		2005	
	Gross	**Net**	Gross	Net
Oil	**9**	**0.3**	7	0.1
Natural gas	**20**	**0.4**	18	0.2
Other	**3**	**0.2**	0	0.0
Total	**32**	**0.9**	25	0.3

RESULTS OF OPERATIONS

PRODUCTION

Average daily production volumes were 60% higher in the first quarter compared with the same period last year. Reflecting the Petrovera acquisition, royalty production volumes contributed 76% of volumes in the first quarter, up from 67% a year ago. Our production profile in the first quarter of 2006 was 38% natural gas, 4% natural gas liquids (NGL), 19% light and medium oil, and 39% heavy oil (on a boe basis).

Working interest production rose 14% as production from fourth quarter drilling came on stream in the first quarter of 2006. As well, a natural gas well at Ojay, in Northeast British Columbia reached payout during the first quarter and converted from a 12.5% royalty interest (68 boe per day) to a 40% working interest (215 boe per day). Without having incurred any of the upfront capital costs we are now receiving 40% of the production from this well. We will also be responsible for our 40% share of future capital and operating expenses. This well is one of a number of convertible royalty wells acquired in the Petrovera acquisition.

Average Daily Production	Three Months Ended March 31		
	2006	2005	Change
Royalty lands			
Oil (bbls/d)	**3,639**	2,104	73%
NGL (bbls/d)	**299**	233	28%
Natural gas (Mcf/d)	**16,583**	7,981	108%
Oil equivalent (boe/d)	**6,702**	3,667	83%
Working interest properties			
Oil (bbls/d)	**1,469**	1,385	6%
NGL (bbls/d)	**55**	63	-13%
Natural gas (Mcf/d)	**3,411**	2,318	47%
Oil equivalent (boe/d)	**2,092**	1,835	14%
Total Trust			
Oil (bbls/d)	**5,108**	3,489	46%
NGL (bbls/d)	**354**	296	20%
Natural gas (Mcf/d)	**19,994**	10,299	94%
Oil equivalent (boe/d)	**8,794**	5,502	60%
Number of days in period (days)	**90**	90	—
Total volumes during period (Mboe)	**791**	495	60%
Potash production (tonnes/d)	**10.5**	9.4	12%

BENCHMARK PRICES

Commodity prices remained high in the first quarter, and the Canadian dollar was also higher compared with last year. However, light/heavy oil differentials were $6.09 per barrel higher than the first quarter of last year. The differential is significant for Freehold, as two-thirds of our oil production (39% of our total boe production) is heavy oil. We have seen a significant narrowing of the price spread in the second quarter, with the differential improving to $16.77 for the month of April. Differentials are expected to remain in this lower range for the next four to five months, but are expected to widen again in the fourth quarter as seasonal demand softens.

Average Benchmark Prices	Three Months Ended March 31		
	2006	2005	Change
WTI crude oil (US$/bbl)	**63.45**	49.84	27%
US$/Cdn$ exchange rate	**0.8662**	0.8150	6%
Edmonton Par crude oil (Cdn$/bbl)	**68.96**	61.45	12%
Light/heavy oil differential (Cdn$/bbl)	**28.57**	22.48	27%
Bow River/Hardisty (Cdn$/bbl)	**40.39**	38.97	4%
AECO natural gas (Cdn$/Mcf)	**9.27**	6.69	39%

FREEHOLD'S REALIZED PRICES

As oil and natural gas prices are denominated in U.S. dollars, realized selling prices in Canadian dollars were negatively affected by currency exchange rates in the first quarter. Freehold's realized prices also reflect product quality and transportation differences. On a boe basis, our average price realizations were 11% higher in the first quarter of 2006.

Average Selling Prices	Three Months Ended March 31		
	2006	2005	Change
Oil ($/bbl)	**39.25**	39.57	-1%
NGL ($/bbl)	**54.65**	43.00	27%
Oil and NGL ($/bbl)	**40.25**	39.84	1%
Natural gas ($/Mcf)	**8.26**	6.44	28%
Oil equivalent ($/boe)	**43.78**	39.47	11%
Potash ($/tonne)	**226.56**	202.94	12%

REVENUE

We receive revenue from about 200 industry operators. Gross revenue rose 76% in the first quarter. Higher production volumes, mainly from the Petrovera acquisition, accounted for 88% of the increase, with the remainder due to higher commodity prices.

Revenue	Three Months Ended March 31		
	2006	2005	Change
Gross revenue	**35,007**	19,859	76%
Royalty expense (1)	**(1,084)**	(689)	57%
Net revenue	**33,923**	19,170	77%

(1) Net of Alberta Royalty Tax Credit. Royalty expenses are incurred only on working interest production.

The accompanying table demonstrates the net effect of price and volume variances on gross revenues. "Other" includes potash revenue, sulphur revenue, lease rentals, processing fees and interest income.

Gross Revenue Variances ($000s)	Three Months Ended March 31	
	2006 vs. 2005	2005 vs. 2004
Oil and NGL		
Production increase (decrease)	**6,074**	(727)
Price increase (decrease)	**139**	2,101
Net increase (decrease)	**6,213**	1,374
Natural gas		
Production increase (decrease)	**7,209**	228
Price increase (decrease)	**1,686**	183
Net increase (decrease)	**8,895**	411
Other	**40**	122
Gross revenue increase (decrease)	**15,148**	1,907

EXPENSES

ROYALTIES PAID

Royalty expense rates on our working interest properties are tied to commodity prices and production volumes. In the first quarter, royalty expenses rose 57% due to higher production volumes and higher commodity prices. On a per boe basis, royalty expenses declined 1% quarter over quarter, reflecting the increase in royalty production volumes, which have no royalty expenses.

Royalty Expenses (net of Alberta Royalty Tax Credit)	Three Months Ended March 31		
	2006	2005	Change
Working interest properties ($000s)	**1,084**	689	57%
Per boe ($)	**5.76**	4.17	38%
Royalty interest lands [(1)] ($000s)	**0**	0	—
Per boe ($)	**0**	0	—
Total royalty expenses ($000s)	**1,084**	689	57%
Total Trust ($/boe)	**1.37**	1.39	-1%

(1) We do not incur royalty expenses on production from our royalty lands.

OPERATING EXPENSES

On a per boe basis, operating costs on working interest properties were 48% higher than the first quarter last year, but are in line with costs experienced over the last nine months of 2005. In the second quarter last year, the industry began to experience rising power costs (natural gas and electricity). With the recent softening in natural gas prices, we anticipate that operating costs will be moderately lower in the second quarter of this year.

Increasing costs is a trend being experienced throughout the oil and gas industry. However, the effect on our overall results is lessened by our large component of royalty interest production (76% of production), which does not incur operating expenses. Overall, operating costs for the first quarter were $2.68 per boe, up 6% from a year ago.

Operating Expenses	Three Months Ended March 31		
	2006	2005	Change
Working interest properties ($000s)	**2,121**	1,254	69%
Per boe ($)	**11.26**	7.59	48%
Royalty interest lands [(1)] ($000s)	**0**	0	—
Per boe ($)	**0**	0	—
Total operating expenses ($000s)	**2,121**	1,254	69%
Total Trust ($/boe)	**2.68**	2.53	6%

(1) We do not incur operating expenses on production from our royalty lands.

DEPLETION, DEPRECIATION AND ACCRETION OF ASSET RETIREMENT OBLIGATION

Depletion of oil and natural gas properties, including the capitalized portion of the asset retirement obligation, and depreciation of equipment is provided for on a unit-of-production basis using estimated proved reserves volumes. Depletion on property, plant and equipment and accretion on the asset retirement obligation totalled $18.6 million ($23.52 per boe), compared with $6.4 million ($12.99 per boe) in the first quarter last year. The increase reflects higher volumes produced and the addition of petroleum and natural gas interests from the Petrovera acquisition at a higher cost than our historical average. In addition, the higher asset retirement obligation recorded in 2005 has resulted in higher accretion expense in 2006.

Depletion, Depreciation and Accretion Expenses	Three Months Ended		Year Ended
	March 31 2006	March 31 2005	December 31 2005
Depletion and depreciation ($000s)	**18,557**	6,369	56,938
Accretion of asset retirement obligation ($000s)	**62**	61	252
Total depletion, depreciation and accretion expenses ($000s)	**18,619**	6,430	57,190
Per boe ($)	**23.52**	12.99	20.52

GENERAL AND ADMINISTRATIVE EXPENSES (G&A)

On a per boe basis, G&A expenses for the first quarter of 2006 were 5% higher than last year, reflecting an increase in the Manager's staff levels and rising costs associated with regulatory compliance and financial reporting. In addition, the Board increased the annual retainer for directors effective January 2, 2006. G&A expenses are typically higher in the first quarter of the year, as a number of annual expenses must be paid at the beginning of the year.

G&A Expenses	Three Months Ended March 31		
	2006	2005	Change
G&A expenses ($000s)	**2,133**	1,263	69%
Per boe ($)	**2.69**	2.55	5%
As a percentage of revenue	**6%**	6%	—

As approved by Freehold's Board of Directors, effective January 1, 2006, Freehold will fund its proportionate share of a short term incentive plan (bonus) and a long term incentive plan for employees of Rife Resources, the Manager of the Trust. In consideration for assuming a funding role in the incentive programs, the Manager has eliminated the 1.5% acquisition fee, effective January 1, 2006.

For the three months ended March 31, 2006, the Manager charged the Trust $1.5 million in G&A costs (2004 – $835,000), including $450,000 for the Trust's share of the Manager's short-term incentive plan for 2006. At March 31, 2006, there was $1.0 million in accounts payable relating to these costs.

MANAGEMENT FEES

The management fee for the first quarter of 2006 was 35,654 Trust Units (2005 – 22,500 Trust Units).

Management Fees ($000s, except as noted)	Three Months Ended March 31		
	2006	2005	Change
Management fees (paid in Trust Units) (1)	**695**	362	92%
Per boe ($)	**0.88**	0.73	21%

(1) The ascribed value of the management fees is based on the closing Trust Unit price at the end of each quarter.

INTEREST EXPENSES

Additional debt assumed in May 2005 to finance the Petrovera acquisition resulted in increased interest expense. In the first quarter, interest expense totalled $1.2 million, or $1.50 per boe.

Interest Expenses ($000s, except as noted)	Three Months Ended March 31		
	2006	2005	Change
Net interest expense	**1,191**	245	386%
Per boe ($)	**1.50**	0.49	206%

OPERATING NETBACK

Our operating netback in the first quarter was $40.18 per boe, 11% higher than last year, reflecting higher commodity prices, and a higher percentage of royalty production, which has no associated royalty or operating expenses. We do not have any commodity price or foreign currency hedges in place, and we have no plans to enter into any foreign currency or commodity price hedges at this time. This policy is subject to quarterly review by our Board.

Operating Netback ($/boe)	Three Months Ended March 31		
	2006	2005	Change
Gross revenue (1)	**44.23**	40.10	10%
Royalty expenses (2)	**(1.37)**	(1.39)	-1%
Operating expenses	**(2.68)**	(2.53)	6%
Operating netback	**40.18**	36.18	11%

(1) Gross revenue includes potash revenue, sulphur revenue and other.

(2) Net of Alberta Royalty Credit.

FUNDS GENERATED FROM OPERATIONS AND NET INCOME

Additional royalty production and higher average selling prices led to a 75% increase in funds generated from operations in the first quarter of 2006. On a per Trust Unit basis, the increase was 14% due to additional Trust Units outstanding following the Petrovera acquisition. Non-cash expenses, primarily higher depletion, depreciation and accretion expenses, reduced net income.

Funds Generated From Operations and Net Income	Three Months Ended March 31		
	2006	2005	Change
Funds generated from operations ($000s)	**28,198**	16,103	75%
Per Trust Unit ($)	**0.58**	0.51	14%
Net income ($000s)	**8,766**	9,368	-6%
Per Trust Unit, basic and diluted ($)	**0.18**	0.30	-40%

DISTRIBUTIONS AND UNITHOLDER TAXATION

Distributions to Unitholders for the first quarter of 2006 totalled $0.54 per Trust Unit, up 32% from the first quarter of 2005. Royalty income contributed approximately 90% of distributions in both periods. Since inception, the Trust has distributed $409.5 million ($12.74 per Trust Unit) to Unitholders.

Distributions to Unitholders ($000s, except as noted)	Three Months Ended March 31	
	2006	2005
Funds generated from operations	**28,198**	16,103
Net reclamation fund contribution	**(105)**	(48)
Development expenditures	**(1,601)**	(1,077)
Debt repayment	**(2,000)**	—
Changes in working capital	**1,991**	(2,042)
Distributions to Unitholders	**26,483**	12,936
Accumulated, beginning of period	**383,024**	298,214
Accumulated, end of period	**409,507**	311,150
Distributions per Trust Unit ($) (1)	**0.54**	0.41
Accumulated, beginning of period	**12.20**	10.28
Accumulated, end of period	**12.74**	10.69

(1) Based on the number of Trust Units issued and outstanding at each record date.

First quarter distributions represented a payout of 94% of funds generated from operations in 2006, versus 80% in 2005. Since inception, our payout ratio has averaged 82%.

Payout Ratio (1) ($ per Trust Unit, except as noted)	Three Months Ended March 31		
	2006	2005	Change
Funds generated from operations	**28,198**	16,103	75%
Distributions to Unitholders	**26,483**	12,936	105%
Payout ratio	**94%**	80%	18%

(1) Distributions to Unitholders as a percentage of funds generated from operations.

For Canadian tax purposes, 100% of distributions paid or payable in 2006 are expected to be taxable as income, unless held in a registered plan, such as a Registered Retirement Savings Plan, a Registered Retirement Income, a Deferred Profit Sharing Plan or a Registered Education Savings Plan.

LIQUIDITY AND CAPITAL RESOURCES

In conjunction with the Petrovera acquisition in 2005, we expanded our credit facilities from $65 million to $165 million. These credit facilities were used to fund $93 million of the purchase price for the acquisition, inclusive of transaction costs. During the first quarter, we reduced long-term debt by $2 million. At March 31, 2006, we had no short-term debt outstanding and long-term debt was $105 million. We had working capital of $14.3 million, resulting in net debt of $90.7 million.

Debt Analysis ($000s)	As at March 31		
	2006	2005	Change
Long-term debt	**105,000**	27,000	289%
Short-term debt	—	—	—
Total debt	**105,000**	27,000	289%
Less: working capital	**14,289**	6,171	132%
Net debt obligations	**90,711**	20,829	336%

At March 31, 2006, the Trust's ratio of net debt (long-term debt less positive working capital) to trailing funds generated from operations improved slightly to 0.7 to 1, from 0.8 to 1 at the end of 2005, reflecting the repayment of $2.0 million in long-term debt during the first quarter, and higher cash flows during the last 12 months.

Financial Leverage and Coverage Ratios (1)	As at March 31		
	2006	2005	Change
Net debt to funds generated from operations (times)	**0.7**	0.3	133%
Net debt to distributions (times)	**0.9**	0.4	125%
Distributions to interest expense (times)	**24.0**	78.7	-70%
Net debt to net debt plus equity (%)	**19%**	11%	73%

(1) Funds generated from operations, distributions and interest expense are 12-months trailing.

The increased royalty interest production from the Petrovera acquisition has required a corresponding increase in our accounts receivables, caused by the normal time lag in receiving royalty revenue. The dollar amount of receivables also increased due to higher commodity prices.

Components of Working Capital ($000s)	**Mar. 31 2006**	Dec. 31 2005	Sept. 30 2005	June 30 2005	Mar. 31 2005
Cash	**38**	192	17	215	146
Accounts receivable	**32,125**	35,728	35,211	21,707	13,642
Current assets	**32,163**	35,920	35,228	21,922	13,788
Distributions payable to Unitholders	**(8,832)**	(12,748)	(6,859)	(5,875)	(3,788)
Accounts payable and accrued liabilities	**(9,042)**	(6,891)	(6,713)	(4,593)	(3,829)
Current liabilities	**(17,874)**	(19,639)	(13,572)	(10,468)	(7,617)
Working capital (1)	**14,289**	16,281	21,656	11,454	6,171

(1) Working capital is comprised of current assets minus current liabilities.

DISTRIBUTION OUTLOOK

In light of current market conditions, we have increased the oil prices and lowered the natural gas prices in our 2006 forecast. Based on the assumptions provided in the accompanying table, we expect to maintain our current monthly distribution rate at $0.18 per Trust Unit for the remainder of the year, and our 2006 distribution guidance of $2.16 per Trust Unit remains achievable. At the Board's discretion, any excess income will be directed to repayment of long-term debt and improvements in working capital, in keeping with our goal to maintain a strong balance sheet to pursue additional acquisition opportunities.

2006 Distribution Outlook and Key Assumptions

	May 10, 2006	Feb. 22, 2006	Nov. 9, 2005
Estimated cash distributions ($ per Trust Unit)	**2.16**	2.16	2.16
Key assumptions			
Average daily production, excluding acquisitions (boe/d)	**8,500**	8,500	8,600
Average WTI oil price (US$/bbl)	**65.85**	60.75	60.00
Average AECO natural gas price (Cdn$/Mcf)	**7.10**	8.80	10.00
Average light/heavy oil price differential (Cdn$/bbl)	**23.25**	30.00	28.00
Average exchange rate (Cdn$/US$)	**0.88**	0.86	0.85
Average operating costs ($/boe)	**2.48**	2.25	2.25
Average general and administrative costs ($/boe)	**1.75**	1.65	1.65
Development expenditures ($ millions)	**6.0**	6.0	6.0
Long-term debt at year end ($ millions)	**98**	100	94
Weighted average Trust Units outstanding (thousands)	**49,100**	49,100	49,086
Payout ratio (%)	**89**	89	80
Estimated taxability of distributions, as other income (%)	**100**	100	85

Recognizing the cyclical nature of our industry, we caution that significant changes in production rates, commodity prices, interest rates or foreign exchange rates (positive or negative) will result in adjustments to the distribution level. Freehold is particularly vulnerable to swings in the light/heavy oil price differential, as approximately 39% of our total boe production is heavy oil. Within North America, only certain refineries are configured to process heavy oil and their processing capacity is limited. In addition, bitumen production from Alberta's oil sands is expected to increase significantly over the next several years. As a result, markets for heavy oil and bitumen will be somewhat uncertain in the future. Supply and demand imbalances could result in the heavy oil price differential remaining well above historical averages.

An analysis of the potential impact of key variables on distributions to Unitholders is provided on page 47 of the Trust's 2005 annual report to Unitholders.

Upcoming Distributions **Record Date**	**Payment Date**	**Distribution Amount** ($/Trust Unit)
April 30, 2006	May 15, 2006	0.18
May 31, 2006	June 15, 2006	0.18
June 30, 2006	July 15, 2006	0.18 (1)
July 31, 2006	August 15, 2006	0.18 (1)

(1) Estimated distribution is based on current market outlook and is subject to change.

Additional information about Freehold, including our annual information form, is available on SEDAR at www.sedar.com.

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Consolidated Balance Sheets

($000s)	March 31, 2006 (Unaudited)	December 31, 2005
Assets		
Current assets:		
Cash	**$ 38**	$ 192
Accounts receivable	**32,125**	35,728
	32,163	35,920
Reclamation fund	**2,069**	1,964
Petroleum and natural gas interests, net of accumulated depletion and depreciation of $256,414 (2005 - $237,857)	**479,257**	496,194
	$ 513,489	$ 534,078
Liabilities and Unitholders' Equity		
Current liabilities:		
Distributions payable to Unitholders	**$ 8,832**	$ 12,748
Accounts payable and accrued liabilities	**9,042**	6,891
	17,874	19,639
Asset retirement obligation (note 4)	**4,112**	4,036
Long-term debt (note 2)	**105,000**	107,000
Future income tax liability	**4,054**	3,932
Unitholders' equity:		
Unitholders' capital (note 3)	**560,744**	560,049
Deficit	**(178,295)**	(160,578)
	382,449	399,471
	$ 513,489	$ 534,078

Consolidated Statements of Income and Deficit

(Unaudited) ($000s, except per unit and weighted average data)	Three Months Ended March 31 **2006**	2005
Revenue:		
Royalty income and working interest sales	$ **35,007**	$ 19,859
Royalty expense (net of Alberta Royalty Tax Credit)	**(1,084)**	(689)
	33,923	19,170
Expenses:		
Operating	**2,121**	1,254
General and administrative	**2,133**	1,263
Interest on long-term debt	**1,191**	245
Depletion and depreciation	**18,557**	6,369
Accretion of asset retirement obligation	**62**	61
Management fee	**695**	362
	24,759	9,554
Net income before taxes	**9,164**	9,616
Income and capital taxes	**276**	248
Future income tax provision	**122**	—
	398	248
Net income	**8,766**	9,368
Deficit, beginning of period	**(160,578)**	(134,114)
Distributions declared	**(26,483)**	(12,936)
Deficit, end of period	$ **(178,295)**	$ (137,682)
Net income per Trust Unit, basic and diluted	$ **0.18**	$ 0.30
Weighted average number of Trust Units	**49,031,977**	31,544,486

Consolidated Statements of Cash Flows

(Unaudited) ($000s)	Three Months Ended March 31 **2006**	2005
Cash provided by (used in):		
Operating:		
Net income	**$ 8,766**	$ 9,368
Items not involving cash:		
Depletion and depreciation	**18,557**	6,369
Future income tax provision	**122**	—
Accretion of asset retirement obligation	**62**	61
Trust Units issued in lieu of management fee	**695**	362
Expenditures on reclamation	**(4)**	(57)
Funds generated from operations	**28,198**	16,103
Changes in non-cash working capital	**4,972**	(1,458)
	33,170	14,645
Financing:		
Long-term debt	**(2,000)**	—
Distributions paid	**(30,400)**	(12,932)
Changes in non-cash working capital	**(175)**	-
	(32,575)	(12,932)
Investing:		
Development expenditures	**(1,601)**	(1,077)
Increase in reclamation fund	**(105)**	(48)
Changes in non-cash working capital	**957**	(508)
	(749)	(1,633)
Increase (decrease) in cash	**(154)**	80
Cash, beginning of period	**192**	66
Cash, end of period	**$ 38**	$ 146

Notes to Interim Consolidated Financial Statements

For the three month periods ended March 31, 2006 and 2005.

1. SIGNIFICANT ACCOUNTING POLICIES

The interim consolidated financial statements of Freehold Royalty Trust ("Freehold") have been prepared by management in accordance with Canadian generally accepted accounting principles. The interim consolidated financial statements have been prepared following the same accounting policies and methods of computation as the consolidated financial statements for the fiscal year ended December 31, 2005, unless otherwise identified. The interim consolidated financial statements should be read in conjunction with the consolidated financial statements and the notes thereto in Freehold's annual report for the year ended December 31, 2005.

2. LONG-TERM DEBT

Freehold has a $150 million extendible revolving term credit facility, extendible annually, on which $105 million was drawn at March 31, 2006. In the event that the lender does not consent to an extension, the revolving credit facility will revert to a two-year, non-revolving term facility with equal quarterly principal repayments. The first quarterly payment would commence on January 1 of the year following the end of the revolving period. In addition Freehold has available a $15 million extendible revolving operating facility. Borrowings under the facilities bear interest at the Bank's prime lending rate, bankers' acceptance or LIBOR rates plus applicable margins, ranging from 85 to 140 basis points and standby fees. The facilities are secured with $300 million demand debentures over Freehold's petroleum and natural gas assets. In May 2006 the lender agreed to extend the terms of the agreement until May 2007.

3. UNITHOLDERS' CAPITAL

	Three Months Ended March 31, 2006		Year Ended December 31, 2005	
	Units	**Amount ($000s)**	Units	Amount ($000s)
Balance, beginning of period	**49,031,581**	**560,049**	31,544,236	298,936
Issued for cash	—	—	17,363,520	270,003
Less: Issue expenses	—	—	—	(11,068)
Issued in lieu of management fee	**35,654**	**695**	123,825	2,178
Balance, end of period	**49,067,235**	**560,744**	49,031,581	560,049

4. ASSET RETIREMENT OBLIGATION

Freehold has no asset retirement obligations (ARO) on its royalty income properties. Freehold's ARO results from its responsibility to abandon and reclaim its net share of all working interest properties. The net present value of Freehold's total ARO is estimated to be $4.1 million (discounted at a weighted average credit adjusted risk free rate of 6.2%), with the undiscounted value being $10.3 million. Payments to settle the obligations are expected to occur continuously over the next 50 years, with the majority of obligations being over 15 years away.

($000s)	**March 31, 2006**	December 31, 2005
Balance, beginning of period	**4,036**	3,937
Liabilities incurred	**18**	210
Liabilities added upon acquisition	**—**	19
Liabilities settled	**(4)**	(104)
Liabilities disposed	**—**	(352)
Revisions in estimates (1)	**—**	74
Accretion expense	**62**	252
Balance, end of period	**4,112**	4,036

(1) Revisions in estimates are mainly a result of changes provided by the Trust's independent reserves evaluator.

5. RELATED PARTY TRANSACTIONS

For the three month period ended March 31, 2006 Freehold issued 35,654 Trust Units as management fee to Rife Resources Management Ltd. ("the Manager").

For the three month period ended March 31, 2006 the Manager charged the Trust $1.5 million in general and administrative costs. At March 31, 2006 there was $1.0 million in accounts payable relating to these costs. Effective January 1, 2006, the Manager cancelled the 1.5% fee on the purchase of petroleum and natural gas properties acquired by Freehold.

6. SUPPLEMENTAL CASH FLOW DISCLOSURE

Cash Expenses Paid	Three Months Ended March 31	
($000s)	**2006**	2005
Interest	**1,367**	246
Taxes	**390**	808