Freehold
ROYALTY TRUST

Q4 quarterly report 2004

FOR THE PERIOD ENDED DECEMBER 31, 2004

The board of directors has declared an extra distribution (quarterly top-up) of $0.05 per Trust Unit relating to the fourth quarter. The regular monthly distribution remains fixed at $0.12 per Trust Unit.

FOURTH QUARTER HIGHLIGHTS

- Production averaged 5,575 boe per day, down 3% from the fourth quarter of 2003
- Price realizations averaged $38.37 per boe, up 30% from the fourth quarter of 2003
- Operating netback averaged $34.67 per boe, up 34% from the fourth quarter of 2003
- Acquired 175 boe per day of royalty production for $10.0 million
- Distributions totalled $0.49 per Trust Unit, up 23% from the fourth quarter of 2003
- An extra distribution of $0.05 per Trust Unit related to the fourth quarter will be paid on March 15, 2005, along with the regular monthly distribution of $0.12 (total $0.17 per Trust Unit – record date February 28, 2005, ex-distribution date February 24, 2005)

Financial results for the fourth quarter of 2004 were strong, buoyed by oil and gas prices that remain near record highs. Relative to the fourth quarter of last year, we achieved substantial gains in revenue, funds generated from operations (cash flow) and net income, despite a significant widening in the differential prices between light and heavy crude oil and a moderate 3% decline in production volumes. Similarly, results for the year were also solid, but were relatively flat compared with last year, mainly due to record high prices for natural gas in the first quarter of 2003.

A record $1.73 per Trust Unit was paid to Unitholders for the financial year 2004. For Canadian tax purposes, cash distributions received during the taxation year ($1.71 per Trust Unit) were 68% taxable (as other income) and 32% tax deferred (return of capital).

	Three Months Ended December 31			Twelve Months Ended December 31		
RESULTS AT A GLANCE	**2004**	2003	% Change	**2004**	2003	% Change
Financial						
Gross revenue ($000s)	**19,936**	15,869	+26	**78,491**	73,166	+7
Net income[1] ($000s)	**9,397**	5,947	+58	**36,892**	37,078	-1
Per Trust Unit ($)	**0.30**	0.19	+58	**1.17**	1.19	-2
Distributions to Unitholders ($000s)	**15,449**	12,575	+23	**54,490**	53,149	+3
Per Trust Unit[2] ($)	**0.49**	0.40	+23	**1.73**	1.70	+2
Long-term debt ($000s)	**27,000**	18,000	+50	**27,000**	18,000	+50
Trust Units outstanding	**31,544,236**	31,454,236	-	**31,544,236**	31,454,236	-
Weighted average	**31,521,981**	31,431,981	-	**31,488,355**	31,164,161	+1
Operating						
Average daily production						
Oil (bbls/d)	**3,680**	3,740	-2	**3,594**	3,688	-3
NGLs (bbls/d)	**298**	294	+1	**283**	317	-11
Natural gas (Mcf/d)	**9,582**	10,406	-8	**10,270**	10,872	-6
Oil equivalent (boe/d)	**5,575**	5,768	-3	**5,588**	5,817	-4
Average price realizations ($/boe)	**38.37**	29.51	+30	**37.91**	34.01	+11
Operating netback ($/boe)	**34.67**	25.88	+34	**34.05**	30.51	+12

1 2003 restated.

2 Based on the number of Trust Units issued and outstanding at each record date.

MANAGEMENT'S DISCUSSION AND ANALYSIS (MD&A)

The following discussion is management's opinion about Freehold Resources Ltd. and Freehold Royalty Trust's (the Trust) (collectively Freehold), operating and financial results for the three months ended December 31, 2004 and previous periods, and the outlook for Freehold based on information available as at February 16, 2005. 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 December 31, 2004 and December 31, 2003 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, 2003 and 2002, together with the accompanying notes. These are included on pages 15 through 44 of the Trust's 2003 annual report to Unitholders.

FORWARD-LOOKING STATEMENTS

This MD&A offers our assessment of Freehold's future plans and operations as at February 16, 2005, 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. No assurance can be given that any of the events anticipated will transpire or occur, or if any of them do, what benefits we will derive from them. We disclaim any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

SUPPLEMENTAL DISCLOSURE

We believe that distributions to Unitholders, cash flow and netbacks are useful supplemental measures. You are cautioned that distributions to Unitholders should not be construed as an alternate to net income as determined by GAAP. Cash flow, as used in this report, refers to funds generated from operations derived from our Consolidated Statements of Cash Flows. Cash flow represents cash provided by operating activities, before changes in non-cash working capital. We use cash flow to analyze operating performance, leverage and liquidity. 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. Distributions to Unitholders, cash flow and netback do not have any standardized meanings prescribed by GAAP and therefore may not be comparable with the calculations of similar measure for other entities.

CONVERSION OF NATURAL GAS TO OIL EQUIVALENT

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). We use the international 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.

CHANGE IN ACCOUNTING POLICIES

ASSET RETIREMENT OBLIGATIONS

On January 1, 2004, we adopted new Canadian accounting standards for asset retirement obligations. This change in accounting policy has been applied retroactively with restatement of prior periods presented for comparative purposes.

We now recognize the fair value of an Asset Retirement Obligation (ARO) in the period in which it is incurred when a reasonable estimate of the fair value can be made. The fair value of the estimated ARO is recorded as a long-term liability, with a corresponding increase in the carrying value of the asset. The capitalized amount is depleted on a unit-of-production method over the life of the reserves. In periods subsequent to initial measurement, the passage of time results in liability changes and the amount of accretion is charged against current period income. The liability is also adjusted for revisions to previously used estimates.

Previously, we recognized a provision for estimated future abandonment and site restoration costs provided for on the unit-of-production method over the remaining proved reserves. The annual charge was expensed as provision for future site restoration, with abandonment and site restoration expenditures charged to the accumulated provision as incurred.

This change in accounting policy resulted in the following increases (decreases) to our 2003 financial results:

($000s)	December 31, 2003 (three months)	December 31, 2003 (year)
Net income	$ 57	$ 52
Petroleum and natural gas interests, net of accumulated depletion and depreciation	1,732	1,732
Asset retirement obligation	3,606	3,606
Provision for future site restoration	(1,773)	(1,773)

The opening adjustment to 2004 Unitholders' equity was a reduction of $101,000 (2003 - $153,000). This reflects the cumulative impact of accretion and depletion expense, net of the previously recorded cumulative site restoration provision.

We have no asset retirement obligations (ARO) on our royalty income properties. Our ARO results from our responsibility to abandon and reclaim our net share of all working interest properties. The net present value of our total ARO is estimated to be $3.9 million, with the undiscounted value being $9.9 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. A credit adjusted, risk-free rate of 6.25% was used to calculate the present value of the ARO.

($000s)	December 31, 2004	December 31, 2003
Balance, beginning of period	$ 3,606	$ 3,289
Liabilities incurred	156	137
Liabilities settled	(57)	(34)
Accretion expense	232	214
Balance, end of period	$ 3,937	$ 3,606

PETROLEUM AND NATURAL GAS INTERESTS

On January 1, 2004, we adopted CICA Accounting Guideline 16, *Oil and Gas Accounting – Full Cost*. This guideline modifies the ceiling test calculation, requiring that an impairment loss be recognized when the carrying amount of assets is greater than the sum of the undiscounted cash flows. Our calculation, performed at January 1, 2004, resulted in no impairment loss. The future prices we used in estimating cash flows were based on forecasts by an independent reserves evaluator, adjusted for our quality, transportation, and contract differences.

DEVELOPMENT ACTIVITIES

ROYALTY LANDS

Lessees drilled 146 (2.9 net) wells on our royalty lands in the fourth quarter, compared with 143 (3.1 net) wells in the fourth quarter of last year. During 2004, 671 (12.3 net) royalty wells were drilled, compared with 576 (16.0 net) in 2003. While the gross number of wells drilled is up significantly year over year, the net contribution is down. This relates to the location and type of wells being drilled, including a high number of shallow gas wells and unitized wells. These royalty wells were drilled at no cost to Freehold.

Currently 41 (1.3 net) drilling licences have been issued on our royalty lands, compared with 41 (2.4 net) at this time last year.

Royalty Lands Drilling Summary (includes unitized wells)	Three Months Ended December 31 **2004**	2003	% Change	Twelve Months Ended December 31 **2004**	2003	% Change
Gross	**146**	143	+2	**671**	576	+16
Net royalty interest basis	**2.9**	3.1	-6	**12.3**	16.0	-23
Net success rate %	**99**	94	+5	**99**	98	+1

WORKING INTEREST PROPERTIES

In the fourth quarter of 2004, we spent $1.9 million on facilities and the drilling of 41 (1.6 net) wells. This resulted in 31 (1.3 net) natural gas wells and 9 (0.3 net) oil wells, for a 98% success rate. In addition, facilities at Hayter were expanded to handle increased volumes. In total, 22 (0.3 net) gas wells were drilled at the Brownfield Gas Unit, 6 (0.4 net) gas wells at Eyremore, 6 (0.1 net) oil wells at Pembina Cardium Unit No. 31, 1 (0.2 net) gas well at LaGlace, and 2 (0.3 net) wells at Viking. Production volumes will be added during 2005 as a result of this spending.

Plans for 2005 include additional drilling and facilities expansion at Hayter with 10 (2.4 net) wells being considered. At Pembina Cardium Unit #9, water injection into the pool has been successfully increased. Twenty (2.0 net) wells have been approved, of which 7 (0.7 net) are to be injection wells.

Working Interest Properties Drilling Summary	Three Months Ended December 31 **2004** **(gross)**	**(net)**	2003 (gross)	(net)	Twelve Months Ended December 31 **2004** **(gross)**	**(net)**	2003 (gross)	(net)
Oil	**9**	**0.3**	2	0.7	**32**	**3.6**	39	6.6
Natural gas	**31**	**1.3**	4	0.0	**57**	**1.8**	35	0.3
D&A	**1**	**0.0**	0	0.0	**1**	**0.0**	0	0.0
Total	**41**	**1.6**	6	0.7	**90**	**5.4**	74	6.9
Net success rate %		**98**		100		99		100

SUMMARY OF RESERVES

The Trust's oil and gas reserves, as at December 31, 2004, were independently evaluated by Trimble Engineering Associates Ltd. The evaluation was conducted in accordance with National Instrument 51-101 (NI 51-101). Freehold's Reserves Committee met with the reserve evaluators to review their findings and procedures and the reserve report has been accepted by the Board of Directors.

At December 31, 2004, reserves were assigned to 14,637 wells. Net reserves totalled 21.2 million boe, down 4% from year-end 2003. Freehold replaced 65% (2003 – 53%) of annual production through acquisitions and development activities (excluding technical revisions and economic factors). The average cost of reserve replacement was $12.91 per boe in 2004, compared with $11.35 per boe in 2003, as the acquired reserves are mainly royalties which have a greater economic value than working interests and therefore command a higher market price. The three-year average cost of reserve replacement is $10.15 per boe.

Based on 2004 net interest reserves and the evaluator's forecast of 2005 net interest production, Freehold's reserve life index is 10.6 years.

Summary of Net Interest Reserves as at December 31, 2004	Proved				Proved
	Developed Producing	Developed Non-producing	Undeveloped	Total Proved	Plus Probable
Light and medium oil (Mbbls)	4,587	2	10	4,599	6,078
Heavy oil (Mbbls)	4,544	0	267	4,811	7,483
Natural gas (MMcf)	24,649	591	13	25,253	37,313
NGLs (Mbbls)	1,045	16	(1)	1,059	1,384
Total (Mboe)	14,284	116	278	14,678	21,163
Reserve life index (years)	7.9	-	-	7.9	10.6
Potash [1] (Mtonnes)	57,553	-	-	-	57,553

1 Potash reserves, evaluated by Rife Resources Ltd., are not subject to NI 51-101.

The present value of Freehold's future net revenue, discounted at 10%, is $292.2 million, plus $5.1 million for potash, evaluated by the Manager. This represents a 14% increase from 2003, which is primarily related to increased future price expectations and the addition of reserves during 2004. Future net revenue estimates are based on the December 31, 2004 escalated oil and gas price and exchange rate forecasts by an independent qualified reserves evaluator.

Reconciliation of Net Interest Oil and Gas Reserves	Net Proved (Mboe)	Net Probable (Mboe)	Proved Plus Probable (Mboe)	Proved Plus Probable Net Present Value of Future Net Revenue Discounted at 10%, Before Tax ($000s, forecast prices and costs)
December 31, 2003	15,437	6,615	22,052	255,791
Extensions, improved recovery	446	347	793	16,588
Technical revisons	364	(579)	(216)	(4,317)
Discoveries	13	11	24	473
Acquisitions	321	113	434	12,033
Dispositions	-	-	-	-
Economic factors	(1)	(5)	(6)	57,053
2004 production	(1,901)	(16)	(1,917)	(45,374)
December 31, 2004	14,678	6,485	21,163	292,247
Change over prior year	(759)	(130)	(889)	36,456

Freehold's net asset value as of December 31, 2004 (discounted at 10%, before tax) was $8.92 per Trust Unit, compared with $8.08 at year-end 2003. Year over year, the major variances in the composition of asset value were increased bank debt and the value of oil and gas reserves discussed above.

Net Asset Value, as at December 31, 2004	Discounted at		
($000s, except unit data)	10%	12%	15%
Present value of oil and gas reserves [1]	292,247	268,070	239,793
Present value of potash reserves [2]	5,138	4,408	3,650
Undeveloped land [3]	5,129	5,129	5,129
Reclamation fund	1,646	1,646	1,646
Working capital	4,128	4,128	4,128
Bank debt	(27,000)	(27,000)	(27,000)
Net asset value	281,287	256,381	227,346
Trust units outstanding	31,544,236	31,544,236	31,544,236
Net asset value per Trust Unit	8.92	8.13	7.21

1 Evaluated by Trimble Engineering Associates Ltd. and includes ARC.

2 Evaluated by Rife Resources Ltd.

3 Evaluated by Seaton-Jordan & Associates Ltd., effective December 31, 2003.

RESULTS OF OPERATIONS

The table below is a summary of our performance for the fourth quarter of 2004 compared with the preceding seven quarters. This presentation illustrates the fluctuations in pricing experienced since the beginning of 2003, and the resultant effect on our quarterly financial results. As oil and gas prices are denominated in U.S. dollars, realized selling prices in Canadian dollars are influenced by currency exchange rates. The Canadian dollar began to strengthen in the second quarter of 2003, reducing Canadian dollar price realizations. The Canadian dollar is expected to remain strong in 2005. Natural gas prices, which were exceptionally high in the first quarter of 2003, moderated somewhat in subsequent quarters before rising to average above $7.00 per Mcf again in the fourth quarter of 2004. Heavy grades of crude oil sell at a discount to light oil. The light/heavy differential price began to widen towards the end of the third quarter of 2004, reaching unprecedented levels in the fourth quarter that have persisted into 2005.

Quarterly Results	**2004**				2003			
($000s, except as noted)	**Q4**	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Revenue, net of royalty expense	**19,204**	19,994	19,066	17,250	15,230	16,865	17,070	20,804
Funds generated from operations	**16,153**	17,409	16,428	14,380	12,691	14,714	14,922	18,365
Per Trust Unit ($)	**0.51**	0.55	0.52	0.46	0.40	0.47	0.48	0.60
Distributions to Unitholders	**15,449**	14,808	12,593	11,640	12,575	12,545	15,631	12,398
Per Trust Unit ($)	**0.49**	0.47	0.40	0.37	0.40	0.40	0.50	0.40
Payout ratio (%)	**96%**	85%	77%	81%	99%	85%	105%	68%
Net income[1]	**9,397**	10,306	9,515	7,674	5,947	8,868	9,334	12,929
Per Trust Unit, diluted ($)	**0.30**	0.33	0.30	0.24	0.19	0.28	0.30	0.42
Long-term debt	**27,000**	17,000	17,000	18,000	18,000	17,500	18,500	17,500
Daily production (boe/d)	**5,575**	5,447	5,757	5,577	5,768	5,909	5,746	5,847
Average selling price ($/boe)	**38.37**	40.96	37.37	35.00	29.51	32.15	33.49	40.97
Operating netback ($/boe)	**34.67**	36.85	33.57	31.18	25.88	28.61	30.47	37.18
U.S./Cdn.$ exchange rate	**0.8195**	0.7651	0.7357	0.7590	0.7600	0.7247	0.7158	0.6626
WTI crude oil (US$/bbl)	**48.28**	43.88	38.31	35.14	31.18	30.20	28.91	33.86
Bow River heavy oil (Cdn.$/bbl)	**36.10**	41.96	37.31	34.93	28.53	30.79	31.61	39.79
Light/heavy oil differential (Cdn.$/bbl)	**21.60**	14.29	13.29	10.67	11.02	10.13	9.51	11.16
AECO natural gas (Cdn.$/Mcf)	**7.08**	6.66	6.80	6.61	5.59	6.29	6.99	7.92
Trading Performance TSX: FRU.UN								
High ($ per Trust Unit)	**18.42**	16.97	15.80	16.30	17.19	13.85	13.48	11.85
Low ($ per Trust Unit)	**15.75**	14.57	14.65	14.02	13.11	12.81	11.20	10.50
Close ($ per Trust Unit)	**17.45**	16.25	15.00	14.75	16.35	13.70	13.05	11.78
Volume (000s)	**4,252**	1,768	3,149	2,399	2,506	2,991	2,447	3,025

1 2003 restated.

PRODUCTION

Production was down 3% quarter-over-quarter and 4% year-over-year, due to normal productivity declines. Production from working interest wells increased 2% in 2004, mainly due to the successful 2004 drilling program at Hayter and a prior period adjustment, while royalty production declined 7%. On a boe basis, our production mix is currently 28% light and medium oil, 36% heavy oil, 5% NGLs and 31% natural gas.

Approximately 40% of the royalty interest wells drilled during 2004 have not yet been placed on production. These wells are expected to add to production volumes during the first and second quarters of 2005.

Average Daily Production	Three Months Ended December 31 2004	2003	% Change	Twelve Months Ended December 31 2004	2003	% Change
Royalty lands						
Oil (bbls/d)	**2,274**	2,261	+1	**2,206**	2,396	-8
NGLs (bbls/d)	**228**	206	+11	**217**	228	-5
Natural gas (Mcf/d)	**7,054**	7,721	-9	**7,726**	8,089	-4
Oil equivalent (boe/d)	**3,678**	3,754	-2	**3,711**	3,972	-7
Working interest properties						
Oil (bbls/d)	**1,406**	1,479	-5	**1,388**	1,292	+7
NGLs (bbls/d)	**70**	87	-20	**66**	89	-26
Natural gas (Mcf/d)	**2,528**	2,685	-6	**2,544**	2,783	-9
Oil equivalent (boe/d)	**1,897**	2,014	-6	**1,877**	1,845	+2
Total Trust						
Oil (bbls/d)	**3,680**	3,740	-2	**3,594**	3,688	-3
NGLs (bbls/d)	**298**	294	+1	**283**	317	-11
Natural gas (Mcf/d)	**9,582**	10,406	-8	**10,270**	10,872	-6
Oil equivalent (boe/d)	**5,575**	5,768	-3	**5,588**	5,817	-4
Number of days in period (days)	**92**	92	-	**366**	365	-
Total volumes during period (mboe)	**512,855**	530,644	-3	**2,045,345**	2,123,293	-4
Potash (tonnes/d)	**8.5**	7.6	+12	**7.6**	7.6	-

BENCHMARK PRICES

WTI crude oil prices averaged U.S. $48.28 per barrel in the fourth quarter and U.S.$41.40 per barrel for the year. However, a global surplus of heavy crude and a lack of upgrading capacity caused light/heavy oil differential prices to widen significantly in the fourth quarter, averaging $21.60 per barrel, 95% higher than the fourth quarter last year and 43% higher year-over-year. The average price for Bow River heavy oil rose 27% in the fourth quarter and 15% for the year. AECO natural gas prices rose 27% quarter-over-quarter and were 1% higher year-over-year.

Average Benchmark Prices	Three Months Ended December 31 2004	2003	% Change	Twelve Months Ended December 31 2004	2003	% Change
WTI crude oil (US $/bbl)	**48.28**	31.18	+55	**41.40**	31.04	+33
Bow River heavy oil (Cdn. $/bbl)	**36.10**	28.53	+27	**37.60**	32.68	+15
Light/heavy oil differential	**21.60**	11.02	+96	**14.94**	10.46	+43
AECO natural gas (Cdn. $/Mcf)	**7.08**	5.59	+27	**6.79**	6.70	+1
U.S./Cdn. $ exchange rate	**0.8195**	0.7600	+8	**0.7698**	0.7158	+8

REALIZED PRICES

Compared with last year, our average selling price rose 30% in the fourth quarter and 11% for the year. The increase in light/heavy oil differential prices resulted in a lower average price for our production relative to the benchmark WTI price. The differential is significant for Freehold, as approximately 56% of our oil production (36% of our total boe production) is heavy oil. In addition, the cost of purchased condensate, used as a diluent and blending agent in heavy oil, has risen dramatically in the last few months.

Average Selling Prices	Three Months Ended December 31 2004	2003	% Change	Twelve Months Ended December 31 2004	2003	% Change
Oil ($/bbl)	**38.09**	28.59	+33	**38.08**	32.77	+16
NGLs ($/bbl)	**40.62**	29.45	+38	**37.29**	30.95	+20
Oil and NGLs ($/bbl)	**38.28**	28.66	+34	**38.03**	32.63	+17
Natural gas ($/Mcf)	**6.44**	5.25	+23	**6.28**	6.18	+2
Oil equivalent ($/boe)	**38.37**	29.51	+30	**37.91**	34.01	+11
Potash ($/tonne)	**182.69**	141.43	+29	**167.37**	133.36	+26

REVENUE

Gross revenue of $19.9 million for the fourth quarter of 2004 was up 26% from a year ago, as higher prices more than offset a moderate decline in production volumes. For the year, gross revenue increased 7%. The accompanying table demonstrates the net effect of price and volume variances on gross revenues.

Gross Revenue Variances ($000s)	Three Months Ended December 31 2004 vs. 2003	2003 vs. 2002	Twelve Months Ended December 31 2004 vs. 2003	2003 vs. 2002
Oil and NGLs				
Production increase (decrease)	**(197)**	(710)	**(1,637)**	(2,471)
Price increase (decrease)	**3,571**	(1,221)	**7,896**	2,765
Net increase (decrease)	**3,374**	(1,931)	**6,259**	294
Natural gas				
Production increase (decrease)	**(488)**	12	**(1,314)**	285
Price increase (decrease)	**1,139**	220	**400**	9,295
Net increase (decrease)	**651**	232	**(914)**	9,580
Other	**42**	7	**(20)**	149
Gross revenue increase (decrease)	**4,067**	(1,692)	**5,325**	10,023

ROYALTIES PAID

We incur royalty expenses relating to ownership in working interest production. These expenses are tied directly to commodity prices and production volumes. Quarter over quarter, royalty expenses were 19% higher (on a per boe basis) and for the year ended December 31, 2004, royalty expenses declined 3%.

Royalty Expenses (net of ARC)	Three Months Ended December 31 2004	2003	% Change	Twelve Months Ended December 31 2004	2003	% Change
Working interest properties ($000s)	**732**	639	+15	**2,977**	3,197	-7
Per boe ($)	**4.20**	3.45	+22	**4.33**	4.75	-9
Total royalty expenses ($000s)	**732**	639	+15	**2,977**	3,197	-7
Total Trust[1] ($/boe)	**1.43**	1.20	+19	**1.46**	1.51	-3

1 We do not incur royalty expenses on production from our royalty lands. As the royalty owner, we receive the royalty as income from other companies.

OPERATING EXPENSES

On a boe basis, operating expenses on our working interest properties were basically unchanged from the fourth quarter of last year and were 11% higher than 2003. Prior period adjustments amounted to the majority of the increase. In addition, with industry activity at record levels, the demand for oilfield goods and services is intense and the energy sector has been experiencing cost inflation. Most of our working interest properties are operated by other parties. For the total Trust, operating costs were $2.77 per boe for the fourth quarter and $2.87 per boe for the year.

Operating Expenses	Three Months Ended December 31 2004	2003	% Change	Twelve Months Ended December 31 2004	2003	% Change
Working interest properties ($000s)	**1,423**	1,502	-5	**5,860**	5,190	+13
Per boe ($)	**8.16**	8.11	+1	**8.53**	7.71	+11
Total operating expenses ($000s)	**1,423**	1,502	-5	**5,860**	5,190	+13
Total Trust[1] ($/boe)	**2.77**	2.83	-2	**2.87**	2.44	+18

1 Freehold does not incur operating costs on its royalty lands.

GENERAL AND ADMINISTRATIVE EXPENSES (G&A)

We incur expenses to administer our interests in more than 16,000 wells in western Canada. G&A expenses for the fourth quarter of 2004 rose 32% from the same period in 2003. For the year, G&A expenses were 22% higher, primarily due to increased staff levels and higher costs associated with regulatory compliance and financial reporting obligations. On a per boe basis, G&A costs were also higher, as production volumes were lower. Since we do not operate any of our royalty production, our overhead recoveries are minimal. Our G&A expenses as a percentage of gross revenue were 4%.

G&A Expenses	Three Months Ended December 31 2004	2003	% Change	Twelve Months Ended December 31 2004	2003	% Change
G&A expenses ($000s)	**864**	657	+32	**3,502**	2,866	+22
Per boe ($)	**1.68**	1.24	+35	**1.71**	1.35	+27
As a percentage of gross revenue (%)	**4%**	4%	-	**4%**	4%	-

MANAGEMENT FEES

The Manager of the Trust receives 22,500 Trust Units per quarter as its management fee. The ascribed value of the management fee is based on the closing price of the Trust Units on the Toronto Stock Exchange at the end of each quarter. The increase in the dollar value of management fees directly reflects the price appreciation of the Trust Units between the two periods. The closing price of the Trust Units was $17.45 on December 31, 2004, versus $16.35 on December 31, 2003. The Manager also received a fee of $150,000 relating to acquisitions completed during the fourth quarter.

Management Fees ($000s, except as noted)	Three Months December 31 2004	2003	% Change	Twelve Months Ended December 31 2004	2003	% Change
Management fees (paid in Trust Units)	**393**	368	+7	**1,428**	1,235	+16
Acquisition fees (1.5%)	**150**	23	+552	**197**	52	+279
Total	**543**	391	+39	**1,625**	1,287	+26
Per boe ($)	**1.06**	0.74	+43	**0.79**	0.61	+30
Trust Unit closing price	**17.45**	16.35	+7	**17.45**	16.35	+7

NETBACKS

Compared with the fourth quarter last year, our operating netback rose 34% to $34.67 per boe. For the year, our operating netback was $34.05, up 12% from the 2003. These operating netbacks represent nearly 90% of gross revenue. We have consistently delivered a superior netback, relative to our peer group, as we do not incur royalty or operating expenses on our royalty lands.

Operating Netbacks ($/boe)	Three Months Ended December 31 **2004**	2003	% Change	Twelve Months Ended December 31 **2004**	2003	% Change
Gross revenue[1]	**38.87**	29.91	+30	**38.38**	34.46	+11
Royalty expenses (net of ARC)	**(1.43)**	(1.20)	+19	**(1.46)**	(1.51)	-3
Operating expenses	**(2.77)**	(2.83)	-2	**(2.87)**	(2.44)	+18
Operating netback	**34.67**	25.88	+34	**34.05**	30.51	+12
As a percentage of gross revenue (%)	**89%**	87%		**89%**	89%	

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

NET INCOME AND FUNDS GENERATED FROM OPERATIONS

On a per Trust Unit basis, the factors outlined above resulted in higher net income and funds generated from operations (cash flow) quarter–over-quarter, while year-over-year results were relatively flat.

Net Income and Funds Generated from Operations ($000s, except as noted)	Three Months Ended December 31 **2004**	2003	% Change	Twelve Months Ended December 31 **2004**	2003	% Change
Net income	**9,397**	5,947	+58	**36,892**	37,078	-1
Per Trust Unit ($)	**0.30**	0.19	+58	**1.17**	1.19	-2
Funds generated from operations	**16,153**	12,691	+27	**64,370**	60,692	+6
Per Trust Unit ($)	**0.51**	0.40	+28	**2.04**	1.95	+5

DISTRIBUTIONS TO UNITHOLDERS

The level of distributions is closely related to the price we receive for our oil and gas production. Distributions for the fourth quarter of 2004 represented a payout of 96% of funds generated and were 23% higher than the same period last year. For the year, distributions represented a payout of 85% of funds generated and were up 3% from last year.

Analysis of Distributions to Unitholders ($000s, except as noted)	Three Months Ended December 31 **2004**	2003	% Change	Twelve Months Ended December 31 **2004**	2003	% Change
Funds generated from operations	**16,153**	12,691	+27	**64,370**	60,692	+6
Deduct:						
Reclamation fund contributions	**(104)**	(79)	+32	**(414)**	(317)	+31
Provision for capital expenditures	**(1,895)**	(894)	+112	**(5,823)**	(5,894)	-1
Debt addition (repayment)	**10,000**	500	+1,900	**9,000**	(1,499)	+700
Property and royalty acquisitions	**(9,799)**	(1,572)	+523	**(13,061)**	(3,386)	+286
Working capital changes	**1,094**	1,929	-43	**418**	3,553	-88
Distributions to Unitholders	**15,449**	12,575	+23	**54,490**	53,149	+3
Per Trust Unit[1] ($)	**0.49**	0.40	+23	**1.73**	1.70	+2
Payout ratio[2] (%)	**96**	99	-3	**85**	88	-3

1 Based on the number of Trust Units issued and outstanding at each record date.
2 Distributions to Unitholders as a percentage of funds generated from operations.

Regular monthly distributions are supplemented by extra distributions (quarterly top-ups) when excess income is available. The board of directors has declared an extra distribution of $0.05 per Trust Unit related to the fourth quarter. The distribution is payable on March 15, 2005 to Unitholders of record on February 28, 2005 (ex-distribution date February 24, 2005). Combined, the March 15th payment (regular monthly distribution of $0.12 and the $0.05 top-up for the fourth quarter), will total $0.17 per Trust Unit. Including the March 15th payment, the trailing 12-month-distributions paid total $1.75 per Trust Unit. Since inception in November 1996, the Trust has distributed a total of $10.57 per Trust Unit.

On February 16, 2005, there were 31,544,236 Trust Units outstanding, unchanged from the balance outstanding December 31, 2004.

UNITHOLDER TAXATION

For Canadian tax purposes, cash distributions received during the taxation year ($1.71 per Trust Unit) were 68% taxable (as other income) and 32% tax deferred (return of capital). Due to continued high commodity prices, we currently estimate that, for residents of Canada, approximately 75% of distributions to Unitholders in 2005 will be taxable as other income and 25% will be a tax-deferred return of capital.

LIQUIDITY AND CAPITAL RESOURCES

In the fourth quarter of 2004, we increased long-term debt by $9.0 million. At year-end, we had no short-term debt outstanding and long-term debt was $27.0 million. We have approximately $38.0 million of available capacity under our credit facilities. The Trust's ratio of net debt (long-term debt less positive working capital) to trailing cash flow remains among the lowest in the energy trust sector, at 0.4:1. Our healthy financial condition gives us maximum flexibility to pursue opportunities to grow our asset base.

CAPITAL EXPENDITURES

The Trust's capital expenditure obligations are deducted from funds generated from operations, prior to the determination of distributions to Unitholders. As we do not incur any capital expenditures relating to our royalty properties, our capital requirements are modest, relative to most energy trusts. For our working interest properties, capital expenditures totalled $1.9 million in the fourth quarter and $5.8 million for the year. Capital expenditures in 2005 are estimated to be $6.6 million and will be funded from cash flow.

ACQUISITIONS

On December 16, 2004, Freehold acquired certain royalty interests in 12,160 acres of land in the Willesden Green area of Alberta for $10.0 million (prior to adjustments). The acquisition was effective October 1, 2004 and was funded through Freehold's existing bank facilities. The properties are expected to add approximately 175 boe per day of royalty production in 2005, mostly natural gas.

OUTLOOK

Several trends in the oil and gas industry are shaping the near term future of our business.

In 2004, $6.8 billion in new market capital flowed into the oil and gas royalty trust sector from trust unit issues, conversions and convertible debenture issues. The energy trust sector continues to exhibit strong market performance, as low interest rates and a lack of income-generating investment alternatives continue to attract investors to the sector. However, rising interest rates in 2005 would put downward pressure on unit prices.

Efforts by the trusts to replace annual production declines through acquisitions have resulted in increased competition for oil and natural gas properties and related assets. This increased competition and strong commodity prices have resulted in high transaction prices. We continue to pursue opportunities to augment our production and reserves, primarily targeting royalty interests, while maintaining a disciplined valuation approach to ensure that any acquisition we complete will be accretive to our present and future Unitholders.

We view continuing development on our royalty lands as an essential part of our future success. To date, we have seen no evidence to suggest that this activity is slowing. Although the western Canadian sedimentary basin is maturing, drilling activity continues at a record pace. We expect that drilling on our royalty lands will likewise remain at high levels.

DISTRIBUTION GUIDANCE

Crude oil markets continue to be very strong. Demand remains robust, especially from China, and the outlook for 2005 is positive. Although natural gas prices tend to be more volatile than oil prices due to supply and demand factors within North America, the outlook for natural gas prices is also positive. However, the higher Canadian currency will offset a portion of the economic benefit of higher commodity prices.

Of great concern to Freehold is the growing surplus of heavy crude and lack of upgrading capacity, which may have a significant negative impact on our price realizations due to our heavier product mix. The price differential between light and heavy crude oil depends on the relative supply and demand fundamentals of each commodity, and at times is quite significant. 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.

Primarily due to these concerns, we have lowered our 2005 distribution estimate to $1.55 per Trust Unit. Our current assumptions, which are provided in the accompanying table, include a $6.6 million capital program on our working interest properties and long-term debt of $27.0 million at December 31, 2005.

This guidance will be updated quarterly throughout the year. Recognizing the cyclical nature of our industry, we caution that significant changes (positive or negative) in commodity prices (including heavy/light oil price differential), foreign exchange rates or production rates will result in adjustments to the distribution level. It is also inherently difficult to predict activity levels on our royalty lands, since we do not know the future plans of the various operators.

The regular monthly cash distribution is set at $0.12 per Trust Unit. In keeping with our stated practice, a portion of any excess income available for distribution may be directed toward repayment of long-term debt and/or working capital improvement where the board of directors consider it appropriate or necessary and extra distributions (quarterly top-ups) may be declared from time to time at the board's discretion.

2005 Distribution Outlook	**February 16, 2005**	November 10, 2004
Cash distributions ($ per Trust Unit)	**1.55**	1.80
Assumptions		
Average daily production, excluding acquisitions (boe/d)	**5,600**	5,480
Average WTI oil price (US$/bbl)	**41.00**	40.00
Average AECO natural gas price (C$/Mcf)	**6.50**	6.45
Average light/heavy oil price differential (C$/bbl)	**17.50**	14.00
Average US/Cdn. dollar exchange rate	**0.80**	0.80
Capital expenditures ($ millions)	**6.6**	5.0
Long term debt at year-end ($ millions)	**27.0**	17.0

Our commitment to generate superior returns remains our number one priority, but we are not driven by absolute growth objectives. Our primary goal is to extend cash distributions over the long term by actively managing our assets to sustain reserves and productivity without diluting our Unitholders. Our strategy to achieve this is to maintain an aggressive audit program, pursue development opportunities on our working interest properties, acquire appropriate assets with a bias towards royalty interests, and maintain a conservative approach to debt management.

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

David J. Sandmeyer
President & Chief Executive Officer

February 16, 2005

CONSOLIDATED BALANCE SHEETS

($000s)		December 31 2004		December 31 2003
				(restated–note 2)
Assets				
Current assets:				
Cash	$	**66**	$	57
Accounts receivable		**12,797**		11,629
		12,863		11,686
Reclamation fund		**1,646**		1,289
Petroleum and natural gas interests, net of accumulated depletion and depreciation of $180,919 (2003 – $155,258)		**193,492**		198,897
	$	**208,001**	$	211,872
Liabilities and Unitholders’ Equity				
Current liabilities:				
Distributions payable to Unitholders	$	**3,785**	$	3,145
Accounts payable and accrued liabilities		**4,950**		4,174
		8,735		7,319
Asset retirement obligation (notes 2 and 5)		**3,937**		3,606
Long-term debt (note 3)		**27,000**		18,000
Future income tax liability		**3,507**		1,955
Unitholders’ equity:				
Unitholders’ capital		**298,936**		297,508
Accumulated earnings		**164,100**		127,208
Accumulated distributions		**(298,214)**		(243,724)
	$	**208,001**	$	211,872

CONSOLIDATED STATEMENTS OF INCOME AND ACCUMULATED EARNINGS

(quarterly results unaudited) ($000s, Except per Unit Data)	Three Months Ended December 31 **2004**	2003	Year Ended December 31 **2004**	2003
		(restated-note 2)		(restated-note 2)
Revenue:				
Royalty income and working interest sales	**$ 19,936**	$ 15,869	$ 78,491	$ 73,166
Royalty expense (net of ARC)	**(732)**	(639)	(2,977)	(3,197)
	19,204	15,230	75,514	69,969
Expenses:				
Operating	**1,423**	1,502	5,860	5,190
General and administrative	**864**	657	3,502	2,866
Interest on long-term debt	**172**	175	635	778
Depletion and depreciation	**6,522**	6,610	25,661	21,860
Accretion of asset retirement obligation	**60**	57	232	214
Management fee	**393**	368	1,428	1,235
	9,434	9,369	37,318	32,143
Net income before taxes	**9,770**	5,861	38,196	37,826
Income and capital taxes	**592**	205	1,147	443
Future income tax provision (recovery)	**(219)**	(291)	157	305
Net income	**$ 9,397**	$ 5,947	$ 36,892	$ 37,078
Accumulated earnings – beginning of period, as previously reported	**$ 154,703**	$ 121,419	$ 127,309	$ 90,283
Retroactive effect of change in accounting policy (note 2)	**-**	(158)	(101)	(153)
Accumulated earnings – beginning of period, as restated	**154,703**	121,261	127,208	90,130
Accumulated earnings – end of period, as restated	**$ 164,100**	$ 127,208	$ 164,100	$ 127,208
Net income per Trust Unit, basic and diluted	**$ 0.30**	$ 0.19	$ 1.17	$ 1.19

CONSOLIDATED STATEMENTS OF CASH FLOWS

(quarterly results unaudited) ($000s)	Three Months Ended December 31 2004	Three Months Ended December 31 2003	Year Ended December 31 2004	Year Ended December 31 2003
		(restated-note 2)		(restated-note 2)
Cash provided by (used in):				
Operating:				
Net income	**$ 9,397**	$ 5,947	$ 36,892	$ 37,078
Items not involving cash:				
Depletion and depreciation	**6,522**	6,610	25,661	21,860
Future income tax provision (recovery)	**(219)**	(291)	157	305
Accretion of asset retirement obligation	**60**	57	232	214
Trust Units issued in lieu of management fee	**393**	368	1,428	1,235
Funds generated from operations	**16,153**	12,691	64,370	60,692
Expenditures on reclamation	**(14)**	(27)	(57)	(34)
Changes in non-cash working capital	**1,075**	1,713	(212)	3,169
	17,214	14,377	64,101	63,827
Financing:				
Trust Units issued upon exercise of options	**-**	-	-	10,501
Long-term debt	**10,000**	500	9,000	(12,000)
Distributions paid	**(15,447)**	(12,574)	(53,851)	(53,024)
	(5,447)	(12,074)	(44,851)	(54,523)
Investing:				
Corporate acquisition (note 7)	**-**	-	(3,048)	-
Property and royalty acquisitions	**(9,799)**	(1,572)	(10,013)	(3,386)
Development expenditures	**(1,895)**	(864)	(5,823)	(5,894)
Increase in reclamation fund	**(90)**	(52)	(357)	(283)
	(11,784)	(2,488)	(19,241)	(9,563)
Increase (decrease) in cash	**(17)**	(185)	9	(259)
Cash, beginning of period	**83**	242	57	316
Cash, end of period	**$ 66**	$ 57	$ 66	$ 57

NOTES TO INTERIM CONSOLIDATED FINANCIAL STATEMENTS

For the period ended December 31, 2004

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 financial statements for the fiscal year ended December 31, 2003, unless otherwise identified. The interim consolidated financial statements should be read in conjunction with the financial statements and the notes thereto in Freehold's annual report for the year ended December 31, 2003.

2. CHANGE IN ACCOUNTING POLICY

Asset Retirement Obligations

On January 1, 2004, Freehold adopted new Canadian accounting standards for asset retirement obligations. This change in accounting policy has been applied retroactively with restatement of prior periods presented for comparative purposes.

Freehold now recognizes the fair value of an Asset Retirement Obligation (ARO) in the period in which it is incurred when a reasonable estimate of the fair value can be made. The fair value of the estimated ARO is recorded as a long-term liability, with a corresponding increase in the carrying value of the asset. The capitalized amount is depleted on a unit-of-production method over the life of the reserves. In periods subsequent to initial measurement, the passage of time results in liability changes and the amount of accretion is charged against current period income. The liability is also adjusted for revisions to previously used estimates.

Previously, Freehold recognized a provision for estimated future abandonment and site restoration costs provided for on the unit-of-production method over the remaining proved reserves. The annual charge was expensed as provision for future site restoration, with abandonment and site restoration expenditures charged to the accumulated provision as incurred.

This change in accounting policy resulted in the following increases (decreases) to Freehold's 2003 financial results:

($000s)	December 31, 2003 (three months)	December 31, 2003 (year)
Net income	$ 57	$ 52
Petroleum and natural gas interests, net of accumulated depletion and depreciation	1,732	1,732
Asset retirement obligation	3,606	3,606
Provision for future site restoration	(1,773)	(1,773)

The opening adjustment to 2004 Unitholders' equity was a reduction of $101,000 (2003 - $153,000). This reflects the cumulative impact of accretion and depletion expense, net of the previously recorded cumulative site restoration provision.

Petroleum and Natural Gas Interests

Effective January 1, 2004 Freehold has adopted the recommendations of the revised Canadian guideline for the full cost method of oil and gas accounting. Petroleum and natural gas interests are evaluated in each reporting period to determine that the carrying amount is recoverable and does not exceed the fair value of the properties.

The carrying amount is assessed to be recoverable when the sum of the undiscounted cash flows expected from the production of proved reserves, the lower of cost and market of unproved properties and the cost of major development projects exceeds the carrying amount. When the carrying amount is not assessed to be recoverable, an impairment loss is recognized to the extent that the carrying amount exceeds the sum of the discounted cash flows expected from the production of proved and probable reserves, the lower of cost and market of unproved interests and the cost of major development projects. The cash flows are estimated using expected future product prices and costs and are discounted using a risk-free interest rate.

Prior to January 1, 2004, the ceiling test amount was the sum of the undiscounted cash flows expected from the production of proved reserves, the lower of cost or market of unproved properties and the cost of major development projects less estimated future costs for administration, financing and site restoration. The cash flows were estimated using period end prices and costs.

Freehold's calculation, performed at December 31, 2004, resulted in no impairment loss. The future prices Freehold used in estimating cash flows were based on forecasts by an independent reserves evaluator, adjusted for Freehold's quality, transportation, and contract differences.

3. LONG-TERM DEBT

Freehold has a $50.0 million committed production facility on which $27.0 million was drawn at December 31, 2004. The facility is structured as a one-year committed revolving credit facility, extendible annually. In the event that the lender does not consent to such extension, the revolving credit facility will revert to a three-year, non-revolving amortizing term loan with equal quarterly principal repayments. At December 31, 2004, the entire amount outstanding under the production facility is presented as long-term based on Freehold's ability to refinance this amount with the undrawn portion of the facility. Borrowings under the facility bear interest at the Bank's prime lending rate, bankers' acceptance or LIBOR rates plus applicable margins, ranging from 90 to 165 basis points.

In addition, Freehold has available a $15.0 million demand operating facility and a U.S. $10.0 million swap facility which was undrawn at December 31, 2004. Borrowings under these facilities bear interest at the Bank's prime lending rate.

Cash interest paid during the year ended December 31, 2004 was $643,000 (2003 - $712,000) and for the current quarter was $185,000 (2003 - $175,000).

4. UNITHOLDERS' CAPITAL

During the quarter the Trust issued 22,500 Trust Units in payment for the management fee to Rife Resources Management Ltd. (the Manager).

The total number of Trust Units outstanding at December 31, 2004 was 31,544,236 (2003 – 31,454,236). The weighted average number of Trust Units outstanding for the year ending December 31, 2004 was 31,488,355 (2003 – 31,164,161) and for the quarter was 31,521,981 (2003 – 31,431,981).

For the year ended December 31, 2004, the Manager charged the Trust $2,579,000 in general and administrative costs, of which $598,000 was for the current quarter. At December 31, 2004, there was $393,000 in accounts payable relating to these costs. As well, the Manager earns a fee of 1.5% of the purchase price of oil and gas properties acquired by Freehold, with the fee being $150,000 for the quarter and $197,000 for the year ended December 31, 2004.

5. ASSET RETIREMENT OBLIGATIONS

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 $3.9 million, with the undiscounted value being $9.9 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. A credit adjusted risk free rate of 6.25% was used to calculate the present value of the ARO.

($000's)	December 31, 2004	December 31, 2003
Balance, beginning of period	$ 3,606	$ 3,289
Liabilities incurred	156	137
Liabilities settled	(57)	(34)
Accretion expense	232	214
Balance, end of period	$ 3,937	$ 3,606

6. COMPARATIVE FIGURES

Certain comparative figures have been restated to conform to the current year's financial statement presentation.

7. BUSINESS COMBINATION

On July 31, 2004 Freehold acquired all of the issued and outstanding shares of Ventana Ventures Inc., a private corporation, for cash. Ventana was the owner of producing royalty income properties in the Peace River area of Alberta. Results of operations for the acquisition have been included in Freehold's financial results for the period from August 1, 2004 onwards.

The transaction was accounted for by the purchase method with fair values as follows:

($000s)	
Net assets acquired	
Petroleum and natural gas interests	$2,868
Working capital	180
	$3,048

8. DISTRIBUTIONS TO UNITHOLDERS

(quarterly results unaudited) ($000s, Except per Unit Data)	Three Months Ended December 31, 2004	Three Months Ended December 31, 2003	Year Ended December 31, 2004	Year Ended December 31, 2003
Funds generated from operations	**$ 16,153**	$ 12,691	$ 64,370	$ 60,692
Reclamation fund contributions	**(104)**	(79)	(414)	(317)
Provision for capital expenditures	**(1,895)**	(894)	(5,823)	(5,894)
Debt additions (repayment from cash flow)	**10,000**	500	9,000	(1,499)
Corporate acquisition	**-**	-	(3,048)	-
Property and royalty acquisitions	**(9,799)**	(1,572)	(10,013)	(3,386)
Changes in working capital	**1,094**	1,929	418	3,553
Distributions to Unitholders	**15,449**	12,575	54,490	53,149
Accumulated distributions, beginning of period	**282,765**	231,149	243,724	190,575
Accumulated distributions, end of period	**$ 298,214**	$ 243,724	$ 298,214	$ 243,724
Distributions per Trust Unit	**$ 0.49**	$ 0.40	$ 1.73	$ 1.70
Accumulated distributions per Trust Unit, beginning of period	**9.79**	8.15	8.55	6.85
Accumulated distributions per Trust Unit, end of period	**$ 10.28**	$ 8.55	$ 10.28	$ 8.55

CORPORATE INFORMATION

DIRECTORS

D. Nolan Blades 1, 2, 3
President
Sunny Gables Holdings Ltd.

Harry S. Campbell, Q.C. 3
Managing Partner
Burnet, Duckworth & Palmer, LLP

Tullio Cedraschi
President & Chief Executive Officer
CN Investment Division

Peter T. Harrison 1, 3
Senior Vice-President,
Montrusco Bolton Inc.

Dr. P. Michael Maher 1, 2
Professor, Haskayne School of Business
University of Calgary

David J. Sandmeyer
President & Chief Executive Officer
Rife Resources Ltd.

William W. Siebens 2
President & Chief Executive Officer
Candor Investments Ltd.

1 Audit Committee
2 Governance & Nominating Committee
3 Reserves Committee

2005 CASH DISTRIBUTIONS[1]

Record Date	Payment Date	Per Trust Unit
December 31, 2004	January 15, 2005	$0.12
January 31, 2005	February 15, 2005	$0.12
February 28, 2005	March 15, 2005	$0.17 [2]

1 Historical distributions and tax information is available on our website at www.freeholdtrust.com.
2 Monthly distributions are supplemented by quarterly top-ups, when excess income is available; payment includes quarterly top-up.

OFFICERS

William W. Siebens
Chairman

David J. Sandmeyer
President & Chief Executive Officer

J. Frank George
Vice-President, Exploitation

Darren G. Gunderson
Controller

Joseph N. Holowisky
Vice-President, Finance & Administration
Chief Financial Officer and Secretary

William O. Ingram
Vice-President, Production

Michael J. Okrusko
Vice-President, Land

HEAD OFFICE

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WEBSITE

www.freeholdtrust.com

STOCK EXCHANGE LISTING

Toronto Stock Exchange
Trading Symbol: FRU.UN
2004 Fourth Quarter Trading Summary
High – $18.42
Low – $15.75
Close – $17.45
Volume – 4,251,714
Trust Units Outstanding – 31.5 million
Market Capitalization – $550 million

TRUSTEE & TRANSFER AGENT

Computershare Trust Company of Canada
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Toronto, Ontario

Computershare Trust Company of Canada
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Calgary, Alberta

BANKER

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EVALUATION ENGINEERS

Trimble Engineering Associates Ltd.
Calgary, Alberta