

NEWS RELEASE

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Freehold Royalty Trust Announces Second Quarter Results; Increases Monthly Distribution and Declares Extra Distribution

CALGARY, Alberta/August 11, 2004/CCN/ - Freehold Royalty Trust today announced results for the second quarter ended June 30, 2004. As a result of the continued strength in commodity prices, Freehold is increasing its regular monthly distribution from \$0.10 per Trust Unit to \$0.12 per Trust Unit effective with the September 15, 2004 payment.

SECOND QUARTER HIGHLIGHTS

- ▶ Production averaged 5,757 barrels of oil equivalent (boe) per day, unchanged from the second quarter of 2003
- ▶ Price realizations averaged \$37.37 per boe, up 12% from the second quarter of 2003
- ▶ Operating netback rose 10% over last year to \$33.57 per boe
- ▶ Distributions totalled \$0.40 per Trust Unit compared with \$0.50 for the second quarter of 2003
- ▶ An extra distribution of \$0.13 per Trust Unit related to the second quarter will be paid on September 15, 2004, along with the regular monthly distribution of \$0.12 per Trust Unit (total \$0.25 per Trust Unit).

Freehold posted solid financial results for the second quarter of 2004, achieving gains in revenue, funds generated from operations (cash flow) and net income relative to the second quarter last year, while production volumes remained constant. Commodity prices continued to demonstrate strength in the quarter, although the price differential between light and heavy crude oil widened significantly. Results for the year to date were also good, but lower than the first six months of last year, mainly due to record high commodity prices in the early part of 2003 and a stronger Canadian dollar this year. Our results are largely dependent on the Canadian dollar prices we receive for our oil and gas production and are therefore influenced by both commodity prices and foreign currency exchange rates. We do not have any commodity price or foreign currency hedges in place, which provides the full benefit of current high commodity prices.

RESULTS AT A GLANCE	Three Months Ended			Six Months Ended		
	2004	2003	% Change	2004	2003	% Change
Financial						
Gross revenue (\$000s)	19,878	17,855	+11	37,829	39,609	-4
Net income ¹ (\$000s)	9,515	9,334	+2	17,189	22,263	-23
Per Trust Unit (\$)	0.30	0.30	-	0.55	0.72	-24
Distributions to Unitholders (\$000s)	12,593	15,631	-19	24,233	28,029	-14
Per Trust Unit ² (\$)	0.40	0.50	-20	0.77	0.90	-14
Long-term debt (\$000s)	17,000	18,500	-8	17,000	18,500	-8
Trust Units outstanding	31,499,236	31,279,236	+1	31,499,236	31,279,236	+1
Weighted average	31,476,983	31,256,983	+1	31,465,733	30,941,184	+2
Operating						
Average daily production						
Oil (bbls/d)	3,526	3,523	-	3,611	3,614	-
NGLs (bbls/d)	311	330	-6	280	319	-12
Natural gas (mcf/d)	11,520	11,356	+1	10,659	11,174	-5
Oil equivalent (boe/d)	5,757	5,746	-	5,667	5,796	-2
Average price realizations (\$/boe)	37.37	33.49	+12	36.20	37.24	-3
Operating netback (\$/boe)	33.57	30.47	+10	32.39	33.84	-4

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 June 30, 2004 and previous periods, and the outlook for Freehold based on information available as at August 11, 2004. 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 June 30, 2004 and June 30, 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 combined 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 August 11, 2004, 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 Combined 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.

RESULTS OF OPERATIONS

The table below provides a summary of our results for the second quarter of 2004 and the preceding seven quarters. Looking at our results over this 24-month period, the impact of commodity prices and foreign currency exchange rates is clearly evident. Financial results for the second quarter were among the best in the history of Freehold, buoyed by commodity prices at the high end of the historical range. Relative to the same period last year, we achieved solid gains in revenue, cash flow and net income, while production volumes remained level. This performance was surpassed only in the first quarter of 2003. In that quarter, strong demand in North America pushed natural gas prices to record highs and the Canadian dollar had just begun to strengthen. These factors also influenced our year-to-date results.

Quarterly Results (\$000s, except as noted)	2004			2003			2002		
	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	
Revenue, net of royalty expense	19,066	17,250	15,230	16,865	17,070	20,804	16,711	15,806	
Funds generated from operations	16,428	14,380	12,691	14,714	14,922	18,365	14,495	13,684	
Distributions to Unitholders	12,593	11,640	12,575	12,545	15,631	12,398	11,477	11,169	
Per Trust Unit (\$)	0.40	0.37	0.40	0.40	0.50	0.40	0.38	0.37	
Payout ratio (%)	77%	81%	99%	85%	105%	68%	79%	82%	
Net income ¹	9,515	7,674	5,947	8,868	9,334	12,929	7,324	8,010	
Per Trust Unit, diluted (\$)	0.30	0.24	0.19	0.28	0.30	0.42	0.24	0.27	
Long-term debt	17,000	18,000	18,000	17,500	18,500	17,500	30,000	30,500	
Daily production (boe/d)	5,757	5,577	5,768	5,909	5,746	5,847	6,033	5,922	
Average selling price (\$/boe)	37.37	35.00	29.51	32.15	33.49	40.97	31.27	29.81	
Operating netback (\$/boe)	33.57	31.18	25.88	28.61	30.47	37.18	28.08	26.78	
U.S./Cdn.\$ exchange rate	0.7357	0.7590	0.7600	0.7247	0.7158	0.6626	0.6372	0.6398	
WTI crude oil (US\$/bbl)	38.31	35.14	31.18	30.20	28.91	33.86	28.14	28.27	
Bow River heavy oil (C\$/bbl)	37.31	34.93	28.53	30.64	31.61	39.79	32.21	35.80	
AECO natural gas (C\$/mcf)	6.80	6.61	5.59	6.29	6.99	7.92	5.46	3.25	

¹ 2002 and 2003 restated.

PRODUCTION

Our production profile is currently weighted 69% to oil and NGLs and 31% to natural gas. Average daily production volumes in the second quarter of 2004 were relatively unchanged from the same period last year. Production from working interest properties rose 9% quarter over quarter, largely due to new oil wells drilled at Hayter during the last half of 2003. Royalty volumes declined 3%, as drilling on our royalty lands largely offset normal production declines. On a year-to-date basis, average production declined 2% to 5,667 boe per day. While drilling on our royalty lands has helped to minimize the rate of our production decline, in the absence of acquisition activity, we expect our production to average about this level for the remainder of the year.

Production for the second quarter of 2004 includes a one-time positive adjustment totalling 200 boe per day, dating back to September 1999. The adjustment relates to the re-classification of a Medicine River well into a zone where Freehold holds a royalty interest. We also had a positive adjustment of 100 boe per day on a well at Epping where Freehold holds both a royalty and working interest. On an annual basis, these wells contribute approximately 15 boe per day of production to Freehold.

Average Daily Production	Three Months Ended June 30			Six Months Ended June 30		
	2004	2003	% Change	2004	2003	% Change
Royalty lands						
Oil (bbls/d)	2,157	2,405	-10	2,175	2,450	-11
NGLs (bbls/d)	232	243	-5	216	227	-5
Natural gas (mcf/d)	9,092	8,383	+8	8,181	8,350	-2
Oil equivalent (boe/d)	3,904	4,045	-3	3,755	4,069	-8
Working interest properties						
Oil (bbls/d)	1,368	1,118	+22	1,436	1,164	+23
NGLs (bbls/d)	80	87	-8	63	92	-32
Natural gas (mcf/d)	2,428	2,973	-18	2,477	2,824	-12
Oil equivalent (boe/d)	1,853	1,700	+9	1,912	1,727	+11
Total Trust						
Oil (bbls/d)	3,526	3,523	-	3,611	3,614	-
NGLs (bbls/d)	311	330	-6	280	319	-12
Natural gas (mcf/d)	11,520	11,356	+1	10,659	11,174	-5
Oil equivalent (boe/d)	5,757	5,746	-	5,667	5,796	-2
Number of days in period (days)	91	91	-	182	181	+1
Total volumes during period (mboe)	523.9	522.9	-	1031.4	1049.1	-2
Potash (tonnes/d)	9.9	8.3	+19	8.4	8.7	-3

SUBSEQUENT EVENT

Effective July 31, 2004, Freehold Resources Ltd. acquired all of the outstanding shares of Ventana Ventures Inc. for approximately \$3.2 million, (includes \$0.4 million in adjustments). The corporation was dissolved and the assets transferred to Freehold Resources Ltd. The primary assets are royalties in connection with oil and gas properties in the Peace River area of Alberta. The properties are expected to contribute royalty production of approximately 60 boe per day during the next twelve months.

BENCHMARK PRICES

Compared with last year, WTI crude oil prices rose 33% in the second quarter and 17% for the year to date. Light/heavy oil differential prices widened to \$13.29 per barrel in the second quarter, up 37% from the second quarter last year. The average price for Bow River heavy oil increased 18% in the second quarter and 1% in the first six months of 2004. AECO natural gas prices, which were exceptionally high in the first quarter of 2003, declined 3% quarter over quarter and 10% year over year.

Average Benchmark Prices	Three Months Ended June 30			Six Months Ended June 30		
	2004	2003	% Change	2004	2003	% Change
WTI crude oil (US\$/bbl)	38.31	28.91	+33	36.73	31.39	+17
Bow River heavy oil (C\$/bbl)	37.31	31.61	+18	36.12	35.70	+1
Light/heavy oil differential	13.29	9.71	+37	11.98	10.43	+15
AECO natural gas (C\$/mcf)	6.80	6.99	-3	6.71	7.46	-10
U.S./Cdn. \$ exchange rate	0.7357	0.7158	+3	0.7474	0.6894	+8

REALIZED PRICES

Our average selling price in the second quarter was \$37.37 per boe, up 12% over the second quarter of last 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 35% of our total boe production is heavy oil. Light/heavy differential prices also had an impact on our year-to-date results. For the first six months of 2004, our average selling price was down 3%, as natural gas prices were higher in the prior period. Higher currency exchange rates also had a negative impact on our Canadian dollar realizations for the year to date.

Average Selling Prices	Three Months Ended June 30			Six Months Ended June 30		
	2004	2003	% Change	2004	2003	% Change
Oil (\$/bbl)	37.23	31.26	+19	35.60	35.71	-
NGLs (\$/bbl)	34.78	29.40	+18	34.12	32.75	+4
Oil and NGLs (\$/bbl)	37.03	31.10	+19	35.49	35.47	-
Natural gas (\$/mcf)	6.34	6.39	-1	6.29	6.83	-8
Oil equivalent (\$/boe)	37.37	33.49	+12	36.20	37.24	-3
Potash (\$/tonne)	162.81	134.96	+21	157.35	133.17	+18

REVENUE

We receive revenue from more than 200 industry operators. Gross revenue of \$19.9 million for the second quarter of 2004 was up 11% from a year ago. Year-to-date, gross revenue is down 4% on lower prices and production volumes. Revenue for the second quarter of 2004 includes one-time positive adjustments of 300 boe per day of royalty and working interest production, as discussed above.

The accompanying table demonstrates the net effect of price and volume variances on gross revenues.

Gross Revenue Variances (\$000s)	Three Months Ended June 30		Six Months Ended June 30	
	2004 vs. 2003	2003 vs. 2002	2004 vs. 2003	2003 vs. 2002
Oil and NGLs				
Production increase (decrease)	(54)	(602)	(139)	(1,630)
Price increase (decrease)	2,079	(474)	16	5,108
Net increase (decrease)	2,025	(1,076)	(123)	3,478
Natural gas				
Production increase (decrease)	95	(198)	(520)	144
Price increase (decrease)	(54)	2,764	(1,086)	6,717
Net increase (decrease)	41	2,566	(1,606)	6,861
Other	(43)	130	(51)	191
Gross revenue increase (decrease)	2,023	1,620	(1,780)	10,530

ROYALTIES PAID

Royalties are paid on production relating to ownership in working interest production. These expenses, which are directly tied to commodity prices and production volumes, were 3% higher (on a per boe basis) than the second quarter of last year. For the six months ended June 30, 2004, royalty expenses declined 11%.

Royalty Expenses (net of ARC)	Three Months Ended June 30			Six Months Ended June 30		
	2004	2003	% Change	2004	2003	% Change
Working interest properties (\$000s)	812	785	+3	1,513	1,735	-13
Per boe (\$)	4.82	5.07	-5	4.35	5.55	-22
Total royalty expenses (\$000s)	812	785	+3	1,513	1,735	-13
Total Trust ¹ (\$/boe)	1.55	1.50	+3	1.47	1.65	-11

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

A majority of our working interest properties are operated by other parties. With industry activity at record levels, the energy sector continues to experience rising costs as a result of increased competition for oilfield goods and services. The cost of purchased power has also risen. Operating expenses on our working interest properties were \$8.78 per boe for the second quarter, up 19% from the second quarter of 2003. Major plant maintenance activities are typically scheduled to occur in the second quarter. On a total Trust basis, operating costs per boe were 30% higher, reflecting lower royalty production volumes year over year.

Operating Expenses	Three Months Ended			Six Months Ended		
	2004	2003	%	2004	2003	%
Working interest properties (\$000s)	1,480	1,138	+30	2,907	2,376	+22
Per boe (\$)	8.78	7.35	+19	8.35	7.60	+10
Total operating expenses (\$000s)	1,480	1,138	+30	2,907	2,376	+22
Total Trust ¹ (\$/boe)	2.83	2.18	+30	2.82	2.26	+25

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

GENERAL AND ADMINISTRATIVE EXPENSES (G&A)

While we incur expenses to administer our interests in more than 16,000 wells in western Canada, our G&A expenses are less than 5% of gross revenue. Our overhead recoveries are minimal as we do not operate any of our royalty production. G&A expenses for the second quarter of 2004 rose modestly from the same period in 2003. Year-to-date, G&A expenses were 17% higher, primarily due to increased costs associated with regulatory compliance and financial reporting obligations.

G&A Expenses	Three Months Ended			Six Months Ended		
	2004	2003	%	2004	2003	%
G&A expenses (\$000s)	740	734	+1	1,907	1,629	+17
Per boe (\$)	1.41	1.40	+1	1.85	1.55	+19

MANAGEMENT FEES

The Manager of the Trust receives its management fee in Trust Units. For the second quarter, the Manager received 22,500 Trust Units, with an ascribed value of \$337,500 (\$15.00 per Trust Unit) compared with the same number of Trust Units with an ascribed value of \$293,625 (\$13.05 per Trust Unit) in the second quarter of 2003. The 15% change in the dollar value of management fees reflects the 15% price appreciation of the Trust Units between the two periods.

Management Fees (\$000s, except as noted)	Three Months Ended			Six Months Ended		
	2004	2003	%	2004	2003	%
Management fees (paid in Trust Units)	337	294	+15	669	559	+20
Acquisition fees (1.5%)	5	25	-80	5	25	-80
Total	342	319	+7	674	584	+15
Per boe (\$)	0.65	0.61	+7	0.65	0.56	+16
Trust Unit closing price	15.00	13.05	+15	15.00	13.05	+15

NETBACKS

Our operating netback rose 10% to \$33.57 per boe, compared to the second quarter last year. Year-to date, our operating netback was \$32.39, down 4% from the prior period. 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 June 30			Six Months Ended June 30		
	2004	2003	% Change	2004	2003	% Change
Gross revenue ¹	37.95	34.15	+11	36.68	37.75	-3
Royalty expenses (net of ARC)	1.55	1.50	+3	1.47	1.65	-11
Operating expenses	2.83	2.18	+30	2.82	2.26	+25
Operating netback	33.57	30.47	+10	32.39	33.84	-4

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

NET INCOME AND FUNDS GENERATED FROM OPERATIONS

Higher average selling prices led to an increase in net income and funds generated from operations (cash flow) for the second quarter of 2004 relative to the second quarter of 2003. For the six months ended June 30, 2004, lower average selling prices and a stronger Canadian dollar resulted in lower net income and funds generated from operations compared with the same period last year.

Net Income and Funds Generated from Operations (\$000s, except as noted)	Three Months Ended June 30			Six Months Ended June 30		
	2004	2003	% Change	2004	2003	% Change
Net income	9,515	9,334	+2	17,189	22,263	-23
Per Trust Unit (\$)	0.30	0.30	-	0.55	0.72	-24
Funds generated from operations	16,428	14,922	+10	30,808	33,287	-7
Per Trust Unit (\$)	0.52	0.48	+8	0.98	1.08	-9

DISTRIBUTIONS TO UNITHOLDERS

Regular monthly distributions are supplemented by quarterly top-ups, when excess income is available. The level of distributions is closely related to the price we receive for our oil and gas production. Distributions to Unitholders for the second quarter of 2004 were 20% lower than the same period last year. Distributions represented a payout of 77% of funds generated, as cash was withheld to fund acquisition and development expenditures, reduce long term debt and improve working capital. For the first six months of 2004, we distributed \$24.2 million or \$0.77 per Trust Unit, down 14% from last year.

The continued strength in commodity prices during the second quarter of 2004 has enabled the board of directors to declare an extra distribution of \$0.13 per Trust Unit. The distribution is payable on September 15, 2004 to Unitholders of record on August 31, 2004 (ex-distribution date August 27, 2004). As well, the board has increased the regular monthly distribution from \$0.10 per Trust Unit to \$0.12 per Trust Unit effective with the September 15, 2004 payment. Combined, the September 15th payment (regular monthly distribution and the top-up for the second quarter), will total \$0.25 per Trust Unit. Including the September distribution, the trailing 12-month-distributions paid totals \$1.62 per Trust Unit. Since inception in November 1996, the Trust has distributed a total of \$9.67 per Trust Unit and paid out a total of 83% of cash flow.

Analysis of Distributions to Unitholders (\$000s, except as noted)	Three Months Ended June 30			Six Months Ended June 30		
	2004	2003	% Change	2004	2003	% Change
Funds generated from operations	16,428	14,922	+10	30,808	33,287	-7
Deduct:						
Site reclamation fund contributions	(103)	(79)	+30	(207)	(158)	+31
Provision for capital expenditures	(650)	(1,550)	-58	(1,650)	(2,800)	-41
Debt additions (repayment)	(1,000)	1,000	-200	(1,000)	(2,200)	-55
Property and royalty acquisitions	(330)	(1,522)	-78	(330)	(1,522)	-78
Working capital changes	(1,752)	2,860	-161	(3,388)	1,422	-338
Distributions to Unitholders	12,593	15,631	-19	24,233	28,029	-14
Per Trust Unit ¹ (\$)	0.40	0.50	-20	0.77	0.90	-14

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

On August 11, 2004, there were 31,499,236 Trust Units outstanding, unchanged from the balance outstanding at the end of the second quarter.

UNITHOLDER TAXATION

Due to continued high commodity prices, we currently estimate that, for residents of Canada, approximately 75% of distributions to Unitholders in 2004 will be taxable as other income and 25% will be a tax-deferred return of capital.

On August 11, 2004 Freehold released tax information for residents of the United States. The U.S. Jobs and Growth Tax Relief Reconciliation Act of 2003 (the "Act") was signed into law on May 28, 2003. The Act effectively reduces the U.S. federal income tax rate on qualified dividend income, received January 1, 2003 through December 31, 2008, to a maximum of 15%. Qualified dividend income is defined as dividends received during the taxation year from domestic U.S. corporations and "qualified foreign corporations". The term "qualified foreign corporation" excludes, among other things, a passive foreign investment company ("PFIC"). Therefore, dividends from a PFIC are not eligible for the above-noted lower rate of tax. Based on recent legal and tax advice obtained by Freehold, as the majority of Freehold's revenue is derived from non-operated royalty interests, Freehold may be considered a PFIC for U.S. tax purposes and therefore would not be a qualified foreign corporation for U.S. federal income tax purposes. As such, our distributions would not be eligible for the lower U.S. tax rate outlined above.

The above information is provided for general information only. Unitholders should consult their own legal and tax advisors regarding their individual tax consequences.

LIQUIDITY AND CAPITAL RESOURCES

During the second quarter, we reduced long-term debt by \$1.0 million. At the end of the second quarter, we had no short-term debt outstanding and long-term debt was \$17.0 million. At 0.2:1, Freehold'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. We have approximately \$47.0 million of available capacity under our credit facilities.

CAPITAL EXPENDITURES

We are not responsible for capital expenditures to develop our royalty properties. Therefore our capital requirements are modest, relative to most energy trusts. Our development expenditures for working interest properties are estimated to be \$4.7 million in 2004, most of which will be incurred in the second half. Of this amount, \$2.0 million is planned for the drilling of 11 (2.6 net) wells at our Hayter property and the expansion of water handling facilities. At present, the budget includes \$1.0 million for drilling activities at Pembina Cardium Unit No. 9, however, this activity may be deferred until 2005. Provision for capital expenditures in the second quarter amounted to \$0.7 million (2003 - \$1.6 million).

CHANGE IN ACCOUNTING POLICIES

ASSET RETIREMENT OBLIGATIONS

On January 1, 2004, we adopted CICA Handbook Section 3110, *Asset Retirement Obligations* (ARO). 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 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 the asset. 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 calculated 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 financial results:

(\$000s)	June 30, 2003 (three months)	June 30, 2003 (six months)	December 31, 2003 (year)
Net income	(6)	(10)	(52)
Petroleum and natural gas interests, net of accumulated depletion and depreciation	1,749	1,749	1,732
Asset retirement obligation	3,440	3,440	3,606
Provision for future site restoration	(1,528)	(1,528)	(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.

Our ARO results from our responsibility to abandon and reclaim our net share of all working interest properties. We have no ARO on our royalty income properties. The net present value of our total ARO obligations is estimated to be \$3.7 million (\$9.8 million, undiscounted). Payments to settle the obligations are expected to occur continually over the next 50 years, with the majority of obligations being over 15 years away.

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. Freehold's calculation, performed at January 1, 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.

DEVELOPMENT ACTIVITIES

ROYALTY LANDS

Industry-wide, more than 10,000 wells were drilled in western Canada during the first six months of 2004. In the second quarter, 4,000 wells were drilled, as wet weather slowed the pace of drilling activity. However, industry forecasters anticipate a strong second half, with the total drilling count surpassing 22,000 wells by the end of the year.

On a gross basis, lessees drilled 176 wells on our royalty lands in the second quarter, up slightly from 169 wells in the second quarter of last year. On a net royalty interest basis, this is the equivalent of 2.1 net wells, compared with 2.4 net wells in the second quarter of 2003. These wells were drilled at no cost to Freehold. In the first half of this year, 413 (4.3 net) royalty wells were drilled, compared with 311 (6.6 net) in the same period last year. 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 an industry focus on natural gas opportunities.

We monitor drilling licences to track wells planned on our royalty lands. The current number of locations almost equals the drilling during the first half of 2004 (on a net basis), signalling a very strong third quarter for royalty drilling. Oil-prone locations have increased, with six (0.8 net) in S.E. Saskatchewan and nine (0.5 net) at Hayter. There are also 30 (2.0 net) shallow gas locations, in which our royalty interest is small.

Royalty Lands Drilling Summary (includes unitized wells)	Three Months Ended June 30			Six Months Ended June 30		
	2004	2003	% Change	2004	2003	% Change
Gross	176	169	+4	413	311	+33
Net royalty interest basis	2.1	2.5	-16	4.3	6.6	-35

WORKING INTEREST PROPERTIES

In the second quarter of 2004, we spent \$1.0 million on facilities and the drilling of four (0.2 net) wells. This resulted in three (0.1 net) natural gas wells and one (0.1 net) oil wells, for a 100% success rate. Eleven (2.6 net) wells are approved at Hayter for the second half of 2004, of which four have been drilled and two completed to date in the third quarter.

At Pembina Cardium Unit No. 9, the focus is to improve water injection into the pool to increase reservoir pressure and ultimately production and reserves. This is necessary due to the large number of wells drilled over the past three years. Following this repressurization, PennWest Petroleum Ltd., who is the operator of the unit, plans further oil development drilling. This drilling activity was originally planned for the second half of this year, but may be deferred until 2005.

Working Interest Properties Drilling Summary	Three Months Ended June 30				Six Months Ended June 30			
	2004		2003		2004		2003	
	(gross)	(net)	(gross)	(net)	(gross)	(net)	(gross)	(net)
Oil	1	0.1	8	0.7	10	0.3	21	2.6
Natural gas	3	0.1	0	0.0	24	0.5	26	0.0
Total	4	0.2	8	0.7	34	0.8	47	2.6

OUTLOOK

Oil and gas commodity pricing continues to be very strong. Gains in global consumption, combined with rapid economic growth in China and India, continue to fuel high demand for all forms of energy, including crude oil and natural gas. World oil inventories remain tight and recent reports suggest OPEC will not be able to increase production significantly in the near term. Against this backdrop, industry predictions are that a record number of wells will be drilled in western Canada this year, which bodes well for a strong second half. We would expect that drilling on our royalty lands would likewise be at high levels.

DISTRIBUTION GUIDANCE

Recognizing the cyclical nature of our industry, we continue to maintain a conservative outlook on commodity pricing. When we provided our initial guidance last November, we estimated that distributions would total \$1.30 per Trust Unit in 2004. That guidance was updated to \$1.40 in February and increased to \$1.50 in May. As a result of higher than expected commodity prices, we are once again increasing our distribution estimate for 2004.

As a result of performance year to date, we are adjusting our annual production estimate downward by 90 boe per day to 5,665 boe per day. Based on the assumptions below, we estimate that cash distributions for 2004 will total \$1.67 per Trust Unit. Our outlook includes \$3.0 million (\$0.10 per Trust Unit) for acquisitions completed to date in 2004 but does not take into account any acquisitions that may occur during the remainder of the year. The board of directors will evaluate the distribution outlook throughout the year and we will provide additional guidance as warranted.

2004 Distribution Outlook	August 11, 2004	May 5, 2004
Estimated cash distributions (\$ per Trust Unit)	1.67	1.50
2004 Assumptions		
Average daily production, excluding acquisitions (boe/d)	5,665	5,755
Average WTI oil price (US\$/bbl)	37.80	31.80
Average AECO natural gas price (C\$/mcf)	6.45	5.45
Average light/heavy oil price differential (C\$/bbl)	12.40	10.60
Average Canadian/U.S. dollar exchange rate (C\$)	0.75	0.76
Capital expenditures (\$ millions)	4.7	4.7

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 may be declared from time to time at the board's discretion. We caution that significant changes in production rates, commodity prices or foreign exchange rates (positive or negative) will result in adjustments to the distribution level. For example, if commodity prices weaken in 2004, and the Canadian dollar remains strong, revenues and distributions will be negatively affected. Freehold is particularly vulnerable to swings in the light/heavy oil differential price, as approximately 35% of our total boe production is heavy oil. An analysis of the potential impact of key variables on distributable income is provided on page 31 of the Trust's 2003 annual report to Unitholders.

Some trusts in our sector have recently reported foreign ownership levels approaching 50%, which may affect their status as a mutual fund trust. This is not currently a concern for Freehold, as non-resident ownership is approximately 18%.

Effective July 31, 2004, Freehold Resources Ltd. acquired all of the outstanding shares of Ventana Ventures Inc. for approximately \$3.2 million, net of adjustments. The primary assets are royalties in connection with oil and gas properties in the Peace River area of Alberta. The major property is a Doe Creek light oil pool at Clair operated by Enterra Energy Trust. The acquisition meets our threshold requirements in terms of cash flow, return on investment, reserve life and future development potential. We estimate these properties will contribute production of 60 boe per day and generate approximately \$1.0 million annually, based on current price expectations.

This recent acquisition, while small, demonstrates our efforts to pursue opportunities to add high quality assets to the Trust. We continue to evaluate acquisition prospects but find them generally very expensive. Ongoing development by our lessees on our royalty lands helps minimize our production rate decline while we look for acquisitions that will be accretive to our present and future Unitholders.

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COMBINED BALANCE SHEETS

(\$000s)	June 30 2004	December 31 2003
	(unaudited)	(restated-note 2)
Assets		
Current assets:		
Cash	466	57
Accounts receivable	13,751	11,629
	14,217	11,686
Reclamation fund	1,470	1,289
Petroleum and natural gas interests, net of accumulated depletion and depreciation of \$168,030 (2003 – \$155,258)	188,127	198,897
	203,814	211,872
Liabilities and Unitholders' Equity		
Current liabilities:		
Distributions payable to Unitholders	3,150	3,145
Accounts payable and accrued liabilities	3,312	4,174
	6,462	7,319
Asset retirement obligation (notes 2 and 5)	3,715	3,606
Long-term debt (note 3)	17,000	18,000
Future income tax liability	2,020	1,955
Unitholders' equity (note 4)	174,617	180,992
	203,814	211,872

COMBINED STATEMENTS OF INCOME

(unaudited) (\$000s, Except per Unit Data)	Three Months Ended June 30		Six Months Ended June 30	
	2004	2003	2004	2003
		(restated-note 2)		(restated-note 2)
Revenue:				
Royalty income and working interest sales	19,878	17,855	37,829	39,609
Royalty expense (net of ARC)	(812)	(785)	(1,513)	(1,735)
	19,066	17,070	36,316	37,874
Expenses:				
Operating	1,480	1,138	2,907	2,376
General and administrative	740	734	1,907	1,629
Interest on long-term debt	147	177	318	417
Depletion and depreciation	6,479	5,011	12,772	10,011
Accretion of asset retirement obligation	57	52	113	103
Management fee	337	294	669	559
	9,240	7,406	18,686	15,095
Net income before taxes	9,826	9,664	17,630	22,779
Income and capital taxes	271	99	376	165
Future income tax provision	40	231	65	351
Net income	9,515	9,334	17,189	22,263
Net income per Trust Unit, basic and diluted	0.30	0.30	0.55	0.72

COMBINED STATEMENTS OF UNITHOLDERS' EQUITY

(unaudited) (\$000s)	June 30 2004	December 31 2003
Unitholders' equity, beginning of period, as previously reported	181,093	185,480
Retroactive adjustment for change in accounting policy (note 2)	(101)	(153)
As restated	180,992	185,327
Net income	17,189	37,078
Distributions to Unitholders	(24,233)	(53,149)
Issue of new Trust Units	669	11,736
Unitholders' equity, end of period	174,617	180,992

COMBINED STATEMENTS OF CASH FLOWS

(unaudited) (\$000s)	Three Months Ended June 30		Six Months Ended June 30	
	2004	2003	2004	2003
		(restated-note 2)		(restated-note 2)
Cash provided by (used in):				
Operating:				
Net income	9,515	9,334	17,189	22,263
Items not involving cash:				
Depletion and depreciation	6,479	5,011	12,772	10,011
Future income tax provision	40	231	65	351
Accretion of asset retirement obligation	57	52	113	103
Trust Units issued in lieu of management fee	337	294	669	559
Funds generated from operations	16,428	14,922	30,808	33,287
Expenditures on site reclamation	(21)	(1)	(26)	(4)
Changes in non-cash working capital	(1,235)	2,360	(2,984)	544
	15,172	17,281	27,798	33,827
Financing:				
Trust Units issued upon exercise of options	-	-	-	9,300
Long-term debt	(1,000)	1,000	(1,000)	(11,500)
Distributions paid	(12,590)	(15,629)	(24,228)	(27,921)
	(13,590)	(14,629)	(25,228)	(30,121)
Investing:				
Property and royalty acquisitions	(330)	(1,522)	(330)	(1,522)
Development expenditures	(710)	(989)	(1,650)	(2,224)
Increase in site reclamation fund	(82)	(78)	(181)	(154)
	(1,122)	(2,589)	(2,161)	(3,900)
Increase (decrease) in cash	460	63	409	(194)
Cash, beginning of period	6	59	57	316
Cash, end of period	466	122	466	122

NOTES TO INTERIM COMBINED FINANCIAL STATEMENTS

For the period ended June 30, 2004 (unaudited)

1. SIGNIFICANT ACCOUNTING POLICIES

The interim combined financial statements of Freehold Royalty Trust "Freehold" have been prepared by management in accordance with Canadian generally accepted accounting principles. The interim combined financial statements have been prepared following the same accounting policies and methods of computation as the combined financial statements for the fiscal year ended December 31, 2003, unless otherwise identified. The interim combined financial statements should be read in conjunction with the combined financial statements and the notes thereto in the Trust's annual report for the year ended December 31, 2003.

2. CHANGE IN ACCOUNTING POLICIES

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 the asset. 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 calculated 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 financial results:

(\$000s)	June 30, 2003 (three months)	June 30, 2003 (six months)	December 31, 2003 (year)
Net income	(6)	(10)	(52)
Petroleum and natural gas interests, net of accumulated depletion and depreciation	1,749	1,749	1,732
Asset retirement obligation	3,440	3,440	3,606
Provision for future site restoration	(1,528)	(1,528)	(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

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 properties 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 January 1, 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 \$17.0 million was drawn at June 30, 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 June 30, 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 unused at June 30, 2004. Borrowings under these facilities bear interest at the Bank's prime lending rate.

Cash interest paid during the six months ended June 30, 2004 was \$316,000 (2003 - \$356,000) and for the current quarter was \$145,000 (2003 - \$180,000).

4. UNITHOLDERS' EQUITY

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 outstanding Trust Units at June 30, 2004 was 31,499,236 (2003 - 31,279,236). The weighted average number of Trust Units outstanding for the six months ending June 30, 2004 was 31,465,733 (2003 - 30,941,184) and for the quarter was 31,476,983 (2003 - 31,256,983).

For the six months ended June 30, 2004, the Manager charged the Trust \$1,372,000 in general and administrative costs, of which \$635,000 was for the current quarter. At June 30, 2004, there was \$401,000 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 \$5,000 for the three and six months ended June 30, 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 \$3.7 million, with the undiscounted value being \$9.8 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.

A reconciliation of the asset retirement obligations is provided below:

	Six months ended June 30, 2004	Year ended December 31, 2003
Obligation, beginning of period	\$ 3,606	\$ 3,288
Increase in liabilities during the period	22	138
Settlement of liabilities during the period	(26)	(34)
Accretion expense	113	214
Obligation, end of period	\$ 3,715	\$ 3,606

6. COMPARATIVE FIGURES

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

7. SUBSEQUENT EVENT

On July 31, 2004 Freehold Resources Ltd. acquired all of the outstanding shares of Ventana Ventures Inc. for \$2.8 million (approximately \$3.2 million including adjustments). The primary assets are royalties in connection with both producing and non producing oil and gas properties.

8. DISTRIBUTIONS TO UNITHOLDERS

(unaudited) (\$000s, Except per Unit Data)	Three Months Ended June 30,		Six Months Ended June 30,	
	2004	2003	2004	2003
Funds generated from operations	\$ 16,428	\$ 14,922	\$ 30,808	\$ 33,287
Site reclamation fund contributions	(103)	(79)	(207)	(158)
Provision for capital expenditures	(650)	(1,550)	(1,650)	(2,800)
Debt additions (repayment from cash flow)	(1,000)	1,000	(1,000)	(2,200)
Property and royalty acquisitions	(330)	(1,522)	(330)	(1,522)
Working capital change	(1,752)	2,860	(3,388)	1,422
Distributions to Unitholders	\$ 12,593	\$ 15,631	\$ 24,233	\$ 28,029
Per Trust Unit ¹	\$ 0.40	\$ 0.50	\$ 0.77	\$ 0.90

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