

NEWS RELEASE

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Freehold Royalty Trust Announces 2006 Second Quarter Results

CALGARY, ALBERTA, (CCNMatthews – August 9, 2006) – Freehold Royalty Trust (Freehold or the Trust) (TSX:FRU.UN) today announced revenue and earnings for the period ended June 30, 2006. Freehold's oil-weighted production mix, together with higher royalty production yielded strong financial and operating results.

SECOND QUARTER HIGHLIGHTS

- Production averaged 8,212 barrels of oil equivalent (boe) per day, up 13% from the second quarter of 2005.
- Price realizations averaged \$50.27 per boe, 19% higher than a year ago.
- Operating netback averaged \$47.08 per boe, up 19% from the same period last year.
- Funds generated from operations were \$0.66 per Trust Unit, up 12% from the second quarter of 2005.
- Distributions declared in the second quarter totalled \$0.54 per Trust Unit, 32% higher than last year.
- The regular monthly distribution remains fixed at \$0.18 per Trust Unit.

The regular monthly distribution of \$0.18 per Trust Unit will be paid on September 15, 2006 to Unitholders of record on August 31, 2006 (ex-distribution date August 29, 2006). Including the September 15, 2006 payment, 12-month trailing cash distributions total \$2.22 per Trust Unit.

Results at a Glance	Three Months Ended June 30			Six Months Ended June 30		
	2006	2005	Change	2006	2005	Change
Financial (\$000s, except as noted)						
Gross revenue	37,852	28,564	33%	72,859	48,423	50%
Operating income	35,180	26,237	34%	66,982	44,153	52%
Net income	14,142	10,858	30%	22,908	20,226	13%
Per Trust Unit, basic and diluted (\$)	0.29	0.26	12%	0.47	0.55	-15%
Funds generated from operations	32,565	24,344	34%	60,763	40,447	50%
Per Trust Unit (\$)	0.66	0.59	12%	1.24	1.11	12%
Distributions declared	26,502	17,981	47%	52,985	30,917	71%
Per Trust Unit (\$) ⁽¹⁾	0.54	0.41	32%	1.08	0.82	32%
Long-term debt	96,000	120,000	-20%	96,000	120,000	-20%
Unitholders' equity	371,072	413,908	-10%	371,072	413,908	-10%
Operating						
Average daily production (boe/d)	8,212	7,279	13%	8,502	6,395	33%
Average price realizations (\$/boe)	50.27	42.42	19%	46.93	41.16	14%
Operating netback (\$/boe)	47.08	39.61	19%	43.53	38.14	14%

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

Message to Unitholders

Freehold achieved strong financial and operating results in the second quarter of 2006, as the Trust benefited from high oil prices and growth in royalty production as a result of the Petrovera acquisition completed in the second quarter of 2005. Our operating netback in the second quarter was \$47.08 per boe, reflecting our high percentage of royalty production (which has no associated royalty or operating expenses) as well as our full exposure to commodity prices. These factors contributed to a 32% increase in distributions over the second quarter last year.

The overall pace of industry drilling slowed in the second quarter of 2006, as lower natural gas prices prompted some producers to trim back drilling programs, and in particular shallow gas drilling. While drilling on our royalty lands was also down (mirroring industry), there are currently 138 locations currently licensed to be drilled, evidence of the ongoing development potential on our lands. On our working interest properties, we anticipate a very active development program in the second half of this year. As a result of additional opportunities, we have increased our 2006 development budget from \$6 million to \$11 million.

Effective July 1, 2006, we purchased a 5.2% working interest in the Wildmere Lloydminster 'A' Pool Unit No. 1, in which we also have a 2.6% royalty interest. The property has an 11-year reserve life and this acquisition is expected to contribute 100 boe per day for the balance of 2006. The \$5.5 million acquisition will be funded from working capital.

At the Annual and Special Meeting of Unitholders held on May 10, 2006, Unitholders approved a deferred trust unit plan for non-management directors. Under the plan, fully vested deferred trust units are granted annually, which are redeemable for an equal number of Trust Units any time after the director's retirement.

Effective January 1, 2006, the Trust will fund its proportionate share of the costs associated with short-term and long-term incentive compensation for employees of Rife Resources (the Manager). In consideration for assuming a funding role in the incentive programs, the Manager has eliminated the 1.5% acquisition fee. Our share of these expenses are reflected in our General and Administrative costs for the year to date.

Crude oil prices continue to demonstrate strength as global markets remain in a tight supply and demand balance, and conflict in the Middle East continues to create uncertainty. As a result of a global surplus of heavy crude and lack of upgrading capacity in North America, we have witnessed considerable volatility in light/heavy oil differentials over the past few quarters as only certain refineries are configured to process heavy oil and their processing capacity is limited. However, new pipeline access, including the start-up of the Enbridge Spearhead pipeline on March 1, and a pipeline reversal enabling Alberta heavy oil to be shipped from Cushing, Oklahoma to Irving, Texas for processing, has expanded the market for Alberta heavy oil. Natural gas prices continue to weaken, as gas storage levels remain above seasonal levels. With more than adequate supplies, prices are expected to remain weak in the near term, but may exhibit weather-related volatility. However, given current high oil prices and our oil-weighted production mix, this softening in natural gas prices is not expected to have a negative impact on 2006 distributions.

Considering all of the above factors (and based on the assumptions provided in the accompanying Management Discussion & Analysis) our distribution guidance of \$2.16 per Trust Unit for 2006 remains achievable and we expect to maintain our current monthly distribution rate at \$0.18 per Trust Unit for the remainder of the year. In keeping with our goal to maintain a strong balance sheet to pursue additional acquisition opportunities, any excess income will be directed to repayment of long-term debt and improvements in working capital.

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



David J. Sandmeyer
President and Chief Executive Officer

Management's Discussion and Analysis (MD&A)

The following discussion is management's opinion about the operating and financial results of Freehold Resources Ltd., Petrovera Resources (a general partnership), and Freehold Royalty Trust (collectively, Freehold or the Trust), for the three and six months ended June 30, 2006 and previous periods, and the outlook for Freehold based on information available as at August 9, 2006. The financial information contained herein has been prepared in accordance with Canadian generally accepted accounting principles (GAAP). All comparative percentages are between the quarters ended June 30, 2006 and June 30, 2005, and all dollar amounts are expressed in Canadian currency, unless otherwise noted. This discussion should be read in conjunction with the Trust's annual MD&A and audited financial statements for the years ended December 31, 2005 and 2004, together with the accompanying notes. These are on pages 23 through 59 of the Trust's 2005 annual report to Unitholders.

FORWARD-LOOKING STATEMENTS

This MD&A offers our assessment of Freehold's future plans and operations as at August 9, 2006, and contains forward-looking statements. By their nature, forward-looking statements are subject to numerous risks and uncertainties, some of which are beyond our control, including the impact of general economic conditions, industry conditions, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other industry participants, the lack of availability of qualified personnel or management, stock market volatility and ability to access sufficient capital from internal and external sources. Risks are described in more detail in our Annual Information Form, which is available on our website. You are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. Our actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements. We can give no assurance that any of the events anticipated will transpire or occur, or if any of them do, what benefits we will derive from them. Except as required by law, we do not undertake to update the forward-looking statements contained herein.

NEW ACCOUNTING POLICIES

Unit Based Compensation

A deferred trust unit plan has been established for the non-management directors of Freehold whereby fully vested deferred trust units are granted annually. Distributions to Unitholders declared prior to redemption are assumed to be reinvested in notional units on the date of distribution. Compensation expense is recognized at market value at the time of grant or distribution with a corresponding increase to contributed surplus. Upon redemption of the deferred trust units for Trust Units, the amount previously recognized in contributed surplus is recorded as an increase to Unitholders' capital. (See Trust Units Outstanding and General and Administrative Expenses.)

Effective January 1, 2006, the Trust will fund its proportionate share of the costs associated with a bonus plan and a long-term incentive compensation plan for employees of Rife Resources, the Manager of the Trust (the Manager's LTIP). The Manager's LTIP uses a combination of the value of phantom Rife shares and Trust Units as the basis for Rights, which are granted annually at the discretion of the directors of Rife and vest at the end of a three-year period. Distributions to Unitholders declared by the Trust during the vesting period are assumed to be reinvested in notional Rights on the date of distribution. As participants in the Manager's LTIP receive a cash payment on a fixed vesting date, compensation expense is determined based on the intrinsic value of the Rights at each period end. The valuation incorporates the period end Trust Unit price, the number of Rights outstanding at each period end, and certain management assumptions. Compensation expense is recognized over the vesting period with a corresponding increase or decrease in liabilities. The Trust has not incorporated an estimated forfeiture rate for Rights that will not vest; rather, the Trust accounts for actual forfeitures as they occur. (See General and Administrative Expenses.)

CRITICAL ACCOUNTING ESTIMATES

The assets, liabilities, revenues and expenses reported in our financial statements depend to varying degrees on estimates made by management. These estimates are based on historical experience and reflect certain assumptions about the future that are believed to be both reasonable and conservative. The more significant reporting areas are crude oil and natural gas

reserve estimation, depletion, impairment of assets, and oil and gas revenue accruals. Management's judgments and estimates in these areas are based on information available from both internal and external sources, including engineers, geologists, and historical experience in similar matters. Except as discussed in this MD&A, we are not aware of trends, commitments, events, or uncertainties that are expected to materially affect the methodology or assumptions associated with the critical accounting estimates.

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

CONVERSION OF NATURAL GAS TO OIL EQUIVALENT

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

SUPPLEMENTAL DISCLOSURE

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

TRUST UNITS OUTSTANDING

As at June 30, 2006 and August 9, 2006, there were 49.1 million Trust Units outstanding. In May 2005, the Trust issued 17.4 million Trust Units in association with the Petrovera acquisition.

At the Annual and Special Meeting of Unitholders held on May 10, 2006, Unitholders approved a deferred trust unit plan for non-management directors whereby fully vested deferred trust units are granted annually. Distributions to Unitholders declared by the Trust prior to redemption are assumed to be reinvested in notional units on the date of distribution. Subsequently, the Board allocated 1,595 deferred trust units to each eligible director and 3,190 deferred trust units to the Chair of the Board. As at June 30, 2006, there were 11,848 deferred trust units outstanding, which are redeemable for an equal number of Trust Units any time after the director's retirement.

Trust Units Outstanding	Three Months Ended			Six Months Ended		
	June 30			June 30		
	2006	2005	Change	2006	2005	Change
Weighted average						
Basic	49,067,627	41,489,077	18%	49,049,900	36,544,253	34%
Diluted	49,074,356	41,489,077	18%	49,053,279	36,544,253	34%
At period end	49,102,889	48,960,273	0%	49,102,889	48,960,273	0%

THE ROYALTY ADVANTAGE

The following table demonstrates the advantage of our royalty lands on which we do not incur royalty expenses, operating expenses or site restoration expenses. In the second quarter of 2006, royalty interest properties accounted for 77% of gross revenue and 85% of distributions to Unitholders.

Components of Distributions to Unitholders			
Three months ended June 30, 2006			
(\$000s)	Royalty Interest Properties	Working Interest Properties	Total Trust
Gross revenue	29,018	8,834	37,852
Royalty expense	—	(854)	(854)
Net revenue	29,018	7,980	36,998
Operating expense	—	(1,818)	(1,818)
Net operating income	29,018	6,162	35,180
General and administrative expense ⁽¹⁾	(713)	(283)	(996)
Interest expense	(1,162)	(137)	(1,299)
Income and capital taxes	—	(309)	(309)
Expenditures on reclamation	—	(11)	(11)
Funds generated from operations	27,143	5,422	32,565
Reclamation fund contributions	—	(103)	(103)
Development expenditures	—	(1,430)	(1,430)
Changes in debt	(9,000)	—	(9,000)
Changes in working capital	4,470	—	4,470
Distributions declared	22,613	3,889	26,502

(1) Excludes non-cash expenses.

HISTORICAL PERFORMANCE SUMMARY

Our results are largely influenced by commodity prices, which are determined by supply and demand factors, including weather, general economic conditions, and changes in the Canadian/U.S. dollar currency exchange rate. Oil and natural gas prices have shown significant volatility in recent years. The accompanying table illustrates the fluctuations in pricing experienced over the past eight quarters, and the resultant effect on our financial results.

The acquisition of Petrovera Resources had a positive impact on our results from the date of closing on May 10, 2005. The Petrovera contribution is partially reflected in the second quarter of 2005 (52 days of production) and is fully reflected in the following periods.

Another factor that has influenced our results over the past several quarters is higher operating expenses on our working interest properties, which currently comprise about 21% of our total production volumes. Rising costs are being experienced throughout the oil and gas industry. However, the effect on our overall results is lessened by our large proportion of royalty interest production, which has no associated operating expenses.

Quarterly Review	2006		2005				2004	
	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Financial (\$000s, except as noted)								
Revenue, net of royalty expense	36,998	33,923	43,364	42,867	27,922	19,170	19,204	19,994
Funds generated from operations	32,565	28,198	38,694	38,893	24,344	16,103	16,139	17,392
Per Trust Unit (\$)	0.66	0.58	0.79	0.79	0.59	0.51	0.51	0.55
Distributions to Unitholders	26,502	26,483	31,366	22,527	17,981	12,936	15,449	14,808
Per Trust Unit (\$) ⁽¹⁾	0.54	0.54	0.64	0.46	0.41	0.41	0.49	0.47
Payout ratio (%)	81	94	81	58	74	80	96	85
Net income	14,142	8,766	18,747	19,373	10,858	9,368	9,397	10,306
Per Trust Unit, basic and diluted (\$)	0.29	0.18	0.38	0.40	0.26	0.30	0.30	0.33
Development expenditures								
Property and royalty acquisitions								
Long-term debt	96,000	105,000	107,000	118,000	120,000	27,000	27,000	17,000
Trust Units outstanding (000s) ⁽²⁾	49,068	49,032	48,996	48,961	41,489	31,544	31,522	31,499
Operating (\$/boe, except as noted)								
Daily production (boe/d)	8,212	8,794	8,739	8,974	7,279	5,502	5,575	5,447
Average selling price	50.27	43.78	54.95	52.61	42.42	39.47	38.37	40.96
Operating netback	47.08	40.18	51.56	49.89	39.61	36.18	34.67	36.85
Operating expenses	2.43	2.68	2.38	2.03	2.54	2.53	2.77	3.05
Working Interest properties	11.51	11.26	12.06	10.35	11.00	7.59	8.16	9.29
General and administrative expenses	1.79	2.69	1.52	1.17	1.42	2.55	1.68	1.46
Benchmark Prices								
WTI crude oil (US\$/bbl)	70.70	63.45	60.02	63.19	53.20	49.84	48.28	43.88
Exchange rate (Cdn\$/US\$)	0.89	0.87	0.85	0.83	0.80	0.82	0.82	0.77
Edmonton Par (Cdn\$)	78.55	68.96	71.17	76.51	65.76	61.45	57.70	56.25
Light/heavy oil differential (Cdn\$/bbl)	17.43	28.57	28.14	20.79	24.17	22.48	21.60	14.29
Bow River/Hardisty (Cdn\$/bbl)	61.11	40.39	43.03	55.72	41.59	38.97	36.10	41.96
AECO natural gas (Cdn\$/Mcf)	6.27	9.27	11.68	8.17	7.38	6.69	7.08	6.66
Unit Trading Performance								
High (\$)	21.70	22.20	18.98	19.30	17.63	18.49	18.42	16.97
Low (\$)	18.02	18.44	15.15	15.99	14.25	15.50	15.75	14.57
Close (\$)	21.00	19.50	18.81	18.68	15.99	16.10	17.45	16.25
Volume (000s)	5,336	11,155	7,611	9,980	8,311	2,418	4,252	1,768

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

(2) Weighted average during the quarter.

DEVELOPMENT ACTIVITIES

The overall pace of industry drilling slowed in the second quarter of 2006, as lower natural gas prices prompted some producers to trim back drilling programs, and in particular shallow gas drilling. The Petroleum Services Association of Canada (PSAC) reported a total of 2,900 wells drilled in the second quarter, down from 3,900 wells drilled in the second quarter last year, and down sharply from the 4,430 wells originally forecast last October. PSAC expects continued downward pressure on natural gas prices until mid to late November. In the current pricing environment, industry drilling in 2006 is anticipated to be about 7.5% lower than last year's record level.

ROYALTY INTEREST LANDS

Drilling on our royalty lands occurs at no cost to Freehold and generally mirrors industry activity. A total of 136 wells were drilled on our royalty lands in the second quarter, including 76 unitized wells. On an equivalent net basis, this is 3.0 wells, down 32% from the second quarter of 2005 as the industry reduced drilling for natural gas. However, we continue to see

development potential on our lands, as evidenced by the number of licensed drilling locations. There are currently 138 (9.4 equivalent net) licensed drilling locations on our royalty lands, compared with 151 (7.7 equivalent net) locations at this time last year.

Royalty Interest Lands Drilling Summary ⁽¹⁾ (includes unitized wells)	Three Months Ended			Six Months Ended		
	June 30			June 30		
	2006	2005	Change	2006	2005	Change
Gross wells	136	141	-4%	354	465	-24%
Equivalent net wells ⁽²⁾	3.0	4.4	-32%	7.9	10.4	-24%
Net success rate	99.0%	100%	-1%	99.3%	95.8%	4%

(1) Includes drilling on the Petrovera lands from January 1, 2005 (the effective date of the acquisition).

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

WORKING INTEREST PROPERTIES

In the second quarter of 2006, we spent \$1.4 million (\$3.0 million for the year to date) on development of working interest properties, including the drilling of 8 (1.2 net) wells. The major areas of activity were in Southeast Saskatchewan and Hayter, Alberta.

Working Interest Properties Drilling Summary	Three Months Ended June 30				Six Months Ended June 30			
	2006		2005		2006		2005	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Oil	5	0.9	3	0.7	14	1.2	10	0.8
Natural gas	3	0.3	3	0.0	23	0.7	21	0.2
Other	0	0.0	—	—	2	0.2	—	—
Total	8	1.2	6	0.7	39	2.1	31	1.0

We anticipate a very active development program in the second half of this year. As a result of additional opportunities on our working interest properties, we have increased our 2006 capital budget from \$6 million to \$11 million which will be funded from funds generated from operations. Two-thirds of the increase relates to Southeast Saskatchewan, where 17 (4.4 net) additional locations are planned, targeting light oil. We have also expanded our infill drilling program at Hayter to 11 (2.6 net) wells, all of which are expected to commence production in the third quarter. A battery expansion is also planned at Hayter in the fourth quarter, which will further increase production. Approximately 15% of the increased capital budget relates to cost increases.

Effective July 1, 2006, Freehold purchased a 5.2% working interest in the Wildmere Lloydminster 'A' Pool Unit No. 1 in which we also have a 2.6% gross overriding royalty interest. Production from the pool, which has been under waterflood since 1977, is primarily medium heavy crude (20 degree API). The property has an 11-year reserve life and is expected to contribute production of approximately 100 boe per day for the balance of 2006. The \$5.5 million acquisition will be funded from working capital.

RESULTS OF OPERATIONS

PRODUCTION

Reflecting the Petrovera acquisition that occurred midway through the second quarter of 2005, average daily production volumes were higher in both the second quarter and 2006 year to date compared with last year. Royalty production rose 16%, contributing 79% of total volumes in the second quarter of 2006. Working interest production increased 3%. Working interest oil production declined 8% in the second quarter, while natural gas production increased 38% due to the conversion of some royalty interests to working interests upon reaching payout. Second quarter production was about 4% lower than anticipated as a result of weather related access issues that restricted sales, drilling and repairs. Considering planned activity levels in the second half of this year, we still expect that production for the full year will average 8,500 boe per day.

On a boe basis, our production profile for the first six months of 2006 was 39% natural gas, 4% natural gas liquids (NGL), 19% light and medium oil and 38% heavy oil.

Average Daily Production	Three Months Ended June 30			Six Months Ended June 30		
	2006	2005	Change	2006	2005	Change
Royalty lands						
Oil (bbls/d)	3,450	3,156	9%	3,544	2,633	35%
NGL (bbls/d)	287	288	0%	293	261	12%
Natural gas (Mcf/d)	16,428	12,915	27%	16,505	10,462	58%
Oil equivalent (boe/d)	6,475	5,596	16%	6,588	4,637	42%
Working interest properties						
Oil (bbls/d)	1,176	1,279	-8%	1,322	1,332	-1%
NGL (bbls/d)	78	53	47%	67	58	16%
Natural gas (Mcf/d)	2,899	2,104	38%	3,153	2,210	43%
Oil equivalent (boe/d)	1,737	1,683	3%	1,914	1,758	9%
Total Trust						
Oil (bbls/d)	4,626	4,435	4%	4,865	3,965	23%
NGL (bbls/d)	365	341	7%	360	319	13%
Natural gas (Mcf/d)	19,327	15,019	29%	19,659	12,672	55%
Oil equivalent (boe/d)	8,212	7,279	13%	8,502	6,395	33%
Number of days in period (days)	91	91	—	181	181	—
Total volumes during period (Mboe)	747	662	13%	1,539	1,158	33%
Potash production (tonnes/d)	8.4	9.8	-14%	9.5	9.6	-1%

BENCHMARK PRICES

Crude oil prices remained robust in the second quarter, with West Texas Intermediate (WTI) prices increasing 33% over last year. Reflecting a stronger Canadian dollar, Edmonton Par crude oil prices rose 19% compared with last year. As a result of a global surplus of heavy crude and lack of upgrading capacity, we have witnessed considerable volatility in light/heavy oil differentials over the past few quarters. The differential was wider than normal (\$28.57 per barrel) in the first quarter of 2006, but we saw a significant narrowing of the price spread in the second quarter, as new pipeline access has expanded the market for Alberta heavy oil. The differential improved to \$15.19 per barrel for the month of April, before widening again to average \$21.02 per barrel for the month of June. Differentials are expected to remain in this range for the third quarter but widen again in the fourth quarter as seasonal demand softens.

In North America, natural gas demand is typically lower in the second quarter in advance of the summer cooling season and prices continued to weaken throughout the second quarter. While the longer term outlook for natural gas remains positive, near-term weakness is expected to persist over the coming months, due to high inventory levels.

Average Benchmark Prices	Three Months Ended June 30			Six Months Ended June 30		
	2006	2005	Change	2006	2005	Change
WTI crude oil (US\$/bbl)	70.70	53.20	33%	67.09	51.52	30%
US\$/Cdn\$ exchange rate	0.8911	0.8039	11%	0.8787	0.8095	9%
Edmonton Par crude oil (Cdn\$/bbl)	78.55	65.76	19%	73.75	63.61	16%
Light/heavy oil differential (Cdn\$/bbl)	17.43	24.17	-28%	23.00	23.33	-1%
Bow River/Hardisty (Cdn\$/bbl)	61.11	41.59	47%	50.75	40.28	26%
AECO natural gas (Cdn\$/Mcf)	6.27	7.38	-15%	7.77	7.03	11%

FREEHOLD'S REALIZED PRICES

On a boe basis, our average price realizations were 19% higher in the second quarter of 2006. Freehold's realized prices reflect product quality and transportation differences. As oil and natural gas prices are denominated in U.S. dollars, realized selling prices were negatively affected by a stronger Canadian dollar compared with last year.

Average Selling Prices	Three Months Ended			Six Months Ended		
	June 30			June 30		
	2006	2005	Change	2006	2005	Change
Oil (\$/bbl)	60.01	41.92	43%	49.17	40.90	20%
NGL (\$/bbl)	52.82	44.29	19%	53.71	43.69	23%
Oil and NGL (\$/bbl)	59.48	42.09	41%	49.49	41.10	20%
Natural gas (\$/Mcf)	6.00	7.17	-16%	7.14	6.88	4%
Oil equivalent (\$/boe)	50.27	42.42	19%	46.93	41.16	14%
Potash (\$/tonne)	202.94	212.65	-5%	215.95	207.89	4%

REVENUE

We receive revenue from about 200 industry operators. Gross revenue rose 33% in the second quarter. Higher commodity prices accounted for 64% of the increase, with the remainder attributable to increased production volumes, mainly from the Petrovera acquisition.

Revenue	Three Months Ended			Six Months Ended		
	June 30			June 30		
	2006	2005	Change	2006	2005	Change
Gross revenue	37,852	28,564	33%	72,859	48,423	50%
Royalty expense ⁽¹⁾	(854)	(642)	33%	(1,938)	(1,331)	46%
Net revenue	36,998	27,922	33%	70,921	47,092	51%

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

The accompanying table demonstrates the net effect of price and volume variances on gross revenues. "Other" includes potash revenue, sulphur revenue, lease rentals, processing fees and interest income. Despite a 29% increase in natural gas production in the second quarter, revenue from natural gas production was \$1.6 million lower, due to lower natural gas prices.

Gross Revenue Variances (\$000s)	Three Months Ended		Six Months Ended	
	June 30		June 30	
	2006 vs. 2005	2005 vs. 2004	2006 vs. 2005	2005 vs. 2004
Oil and NGL				
Production increase (decrease)	1,161	3,598	8,433	2,764
Price increase (decrease)	7,558	1,766	6,499	3,974
Net increase (decrease)	8,719	5,364	14,932	6,738
Natural gas				
Production increase (decrease)	2,352	2,284	9,034	2,434
Price increase (decrease)	(1,603)	871	610	1,132
Net increase (decrease)	749	3,155	9,644	3,566
Other	(179)	167	(139)	290
Gross revenue increase (decrease)	9,288	8,686	24,436	10,594

EXPENSES**ROYALTIES PAID**

Royalty expense rates on our working interest properties are tied to commodity prices and production volumes. In the second quarter, royalty expenses rose 33% due to higher production volumes and higher oil prices. On a per boe basis, royalty expenses rose only 18% quarter over quarter, reflecting the increase in royalty production volumes, which have no royalty expenses.

Royalty Expenses (net of Alberta Royalty Credit)	Three Months Ended			Six Months Ended		
	June 30			June 30		
	2006	2005	Change	2006	2005	Change
Working interest properties (\$000s)	854	642	33%	1,938	1,331	46%
Per boe (\$)	5.41	4.19	29%	5.60	4.18	34%
Royalty interest lands ⁽¹⁾ (\$000s)	—	—	—	—	—	—
Per boe (\$)	—	—	—	—	—	—
Total royalty expenses (\$000s)	854	642	33%	1,938	1,331	46%
Total Trust (\$/boe)	1.14	0.97	18%	1.26	1.15	10%

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

OPERATING EXPENSES

On a per boe basis, operating costs on working interest properties were 5% higher than the second quarter last year, but are in line with costs experienced over the last three quarters. In the second quarter last year, the industry began to experience rising power costs (natural gas and electricity). Cost inflation is a trend being experienced throughout the oil and gas industry. However, the effect on our overall results is lessened by our large component of royalty interest production (79% of production in the second quarter), which does not incur operating expenses. Overall, operating costs for the quarter were \$2.43 per boe, down 4% from a year ago. We still anticipate operating expenses will average \$2.48 per boe for the full year.

Operating Expenses	Three Months Ended			Six Months Ended		
	June 30			June 30		
	2006	2005	Change	2006	2005	Change
Working interest properties (\$000s)	1,818	1,685	8%	3,939	2,939	34%
Per boe (\$)	11.51	11.00	5%	11.38	9.23	23%
Royalty interest lands ⁽¹⁾ (\$000s)	—	—	—	—	—	—
Per boe (\$)	—	—	—	—	—	—
Total operating expenses (\$000s)	1,818	1,685	8%	3,939	2,939	34%
Total Trust (\$/boe)	2.43	2.54	-4%	2.56	2.54	1%

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

DEPLETION, DEPRECIATION AND ACCRETION OF ASSET RETIREMENT OBLIGATION

Depletion of oil and natural gas properties, including the capitalized portion of the asset retirement obligation, and depreciation of equipment is provided for on a unit-of-production basis using estimated proved reserves volumes. Depletion on property, plant and equipment and accretion on the asset retirement obligation totalled \$36.2 million (\$23.54 per boe), compared with \$19.4 million (\$16.79 per boe) in the first half of last year. The increase reflects higher volumes produced and the addition of petroleum and natural gas interests from the Petrovera acquisition at a higher cost than our historical average.

Depletion, Depreciation and Accretion Expenses	Six Months Ended		Year Ended
	June 30	June 30	December 31
	2006	2005	2005
Depletion and depreciation (\$000s)	36,108	19,326	56,938
Accretion of asset retirement obligation (\$000s)	126	122	252
Total depletion, depreciation and accretion expenses (\$000s)	36,234	19,448	57,190
Per boe (\$)	23.54	16.79	20.52

GENERAL AND ADMINISTRATIVE EXPENSES (G&A)

The Manager is entitled to reimbursement for G&A costs based on time spent and direct costs incurred. For the three months ended June 30, 2006, the Manager charged the Trust \$0.8 million in G&A costs (2005 – \$0.7 million). At June 30, 2006, there was \$0.2 million in accounts payable relating to these costs.

On a per boe basis, G&A expenses for the second quarter of 2006 were 26% higher than last year, reflecting an increase in the Manager's staff levels, higher stock exchange listing fees due to additional Trust Units outstanding, and rising costs associated with regulatory compliance and financial reporting. In addition, the annual retainer for non-management directors was increased for 2006. We also recorded a non-cash expense of \$234,000 in the second quarter (with a corresponding increase to contributed surplus) as unit based compensation relating to the grant of 11,848 deferred trust units pursuant to the deferred trust unit plan for non-management directors.

G&A Expenses	Three Months Ended June 30			Six Months Ended June 30		
	2006	2005	Change	2006	2005	Change
G&A expenses (\$000s)	1,336	943	42%	3,469	2,206	57%
Per boe (\$)	1.79	1.42	26%	2.25	1.91	18%
As a percentage of revenue	4.0%	3%	33%	5%	5%	0%

As approved by our Board, effective January 1, 2006, the Trust will fund its proportionate share of the costs associated with the short-term and long-term incentive compensation for employees of the Manager. In consideration for assuming a funding role in the incentive programs, the Manager has eliminated the 1.5% acquisition fee, effective January 1, 2006. G&A for the second quarter of 2006 includes a non-cash charge of \$106,000 for the Trust's proportionate share of the Manager's LTIP for the first half of 2006. G&A for the six months ended June 30, 2006 includes \$450,000 expensed in the first quarter for the Trust's proportionate share of the Manager's short term incentive plan for 2006.

MANAGEMENT FEES

The Manager of the Trust receives its management fee in Trust Units. The issue of 17.4 million Trust Units in May 2005 resulted in a pro-rata increase in the management fee, in accordance with the management agreement. The management fee for the second quarter of 2006 was 35,654 Trust Units (2005 – 30,017 Trust Units).

Management Fees (paid in Trust Units) (\$000s, except as noted)	Three Months Ended June 30			Six Months Ended June 30		
	2006	2005	Change	2006	2005	Change
Ascribed value of management fees ⁽¹⁾	749	480	56%	1,444	842	71%
Per boe (\$)	1.00	0.73	37%	0.94	0.73	29%

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

INTEREST EXPENSES

Additional debt assumed in May 2005 to finance the Petrovera acquisition resulted in increased interest expense. In the second quarter, interest expense totalled \$1.3 million, or \$1.74 per boe.

Interest Expenses (\$000s, except as noted)	Three Months Ended June 30			Six Months Ended June 30		
	2006	2005	Change	2006	2005	Change
Net interest expense	1,299	690	88%	2,490	935	166%
Per boe (\$)	1.74	1.04	67%	1.62	0.81	100%

OPERATING NETBACK

Our operating netback in the second quarter was \$47.08 per boe, 19% higher than last year, reflecting higher oil prices, and a higher percentage of royalty production, which has no associated royalty or operating expenses. We do not have any

commodity price or foreign currency hedges in place, and we have no plans to enter into any foreign currency or commodity price hedges at this time. This policy is subject to quarterly review by our Board.

Operating Netback (\$/boe)	Three Months Ended			Six Months Ended		
	June 30			June 30		
	2006	2005	Change	2006	2005	Change
Gross revenue ⁽¹⁾	50.65	43.12	17%	47.35	41.83	13%
Royalty expenses ⁽²⁾	1.14	0.97	18%	1.26	1.15	10%
Operating expenses	2.43	2.54	-4%	2.56	2.54	1%
Operating netback	47.08	39.61	19%	43.53	38.14	14%

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

(2) Net of Alberta Royalty Credit.

FUNDS GENERATED FROM OPERATIONS AND NET INCOME

Additional royalty production and higher average selling prices led to a 34% increase in funds generated from operations in the second quarter of 2006. On a per Trust Unit basis, the increase was only 12%, due to additional Trust Units outstanding following the Petrovera acquisition. Non-cash expenses, primarily higher depletion and depreciation, reduced net income.

Funds Generated From Operations and Net Income	Three Months Ended			Six Months Ended		
	June 30			June 30		
	2006	2005	Change	2006	2005	Change
Funds generated from operations (\$000s)	32,565	24,344	34%	60,763	40,447	50%
Per Trust Unit (\$)	0.66	0.59	12%	1.24	1.11	12%
Net income (\$000s)	14,142	10,858	30%	22,908	20,226	13%
Per Trust Unit, basic and diluted (\$)	0.29	0.26	12%	0.47	0.55	-15%

DISTRIBUTIONS AND UNITHOLDER TAXATION

Higher prices and production volumes resulted in increased distributions to Unitholders for the second quarter and first half of 2006 relative to the same periods last year. Royalty income contributed approximately 85% of distributions in the second quarter. Since inception, the Trust has distributed \$436 million (\$13.28 per Trust Unit) to Unitholders.

Distributions to Unitholders (\$000s, except as noted)	Three Months Ended		Six Months Ended	
	June 30		June 30	
	2006	2005	2006	2005
Funds generated from operations	32,565	24,344	60,763	40,447
Net reclamation fund contribution	(103)	(93)	(208)	(141)
Development expenditures	(1,430)	(1,215)	(3,031)	(2,292)
Debt additions (repayment)	(9,000)	93,000	(11,000)	93,000
Proceeds from Trust Unit issuance	—	258,935	—	258,935
Property and Royalty acquisitions	—	(351,705)	—	(351,705)
Changes in working capital	4,470	(5,285)	6,461	(7,327)
Distributions to Unitholders	26,502	17,981	52,985	30,917
Accumulated, beginning of period	409,507	311,150	383,024	298,214
Accumulated, end of period	436,009	329,131	436,009	329,131
Distributions per Trust Unit ⁽¹⁾ (\$)	0.54	0.41	1.08	0.82
Accumulated, beginning of period	12.74	10.69	12.20	10.28
Accumulated, end of period	13.28	11.10	13.28	11.10

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

Second quarter distributions represented a payout of 81% of funds generated from operations in 2006, versus 74% in 2005. Since inception, our payout ratio has averaged 82%.

Payout Ratio ⁽¹⁾ (\$ per Trust Unit, except as noted)	Three Months Ended			Six Months Ended		
	June 30			June 30		
	2006	2005	Change	2006	2005	Change
Funds generated from operations	32,565	24,344	34%	60,763	40,447	50%
Distributions to Unitholders	26,502	17,981	47%	52,985	30,917	71%
Payout ratio	81%	74%	9%	87%	76%	14%

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

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

FOREIGN OWNERSHIP UPDATE

Our Trust Indenture provides that not more than 49% of the Trust's Units can be held by non-residents. We monitor foreign ownership levels on a regular basis through declarations from Unitholders and geographical searches. Based on geographical data as of March 22, 2006 (the record date for our 2006 annual and special meeting of Unitholders), we estimate that approximately 77% of the Trust's Units are held by Canadian residents, with the remaining 23% held by non-residents. While we believe that these results are reasonable estimations, the inability of all public issuers to obtain the residency information of their beneficial holders means that issuers must rely upon the information provided to the transfer agent. As a result, the residency information is subject to the accuracy provided by third party data and by system limitations. Accordingly, the reported level of Canadian ownership is subject to these limitations, and the level of Canadian ownership can change at any time without notice.

LIQUIDITY AND CAPITAL RESOURCES

In conjunction with the Petrovera acquisition in 2005, we expanded our credit facilities from \$65 million to \$165 million. These credit facilities were used to fund \$93 million of the purchase price for the acquisition, inclusive of transaction costs. During the last 12 months, we have repaid \$24 million of long-term debt with funds generated from operations. At June 30, 2006, we had no short-term debt outstanding and long-term debt was \$96 million. We had working capital of \$10.4 million, resulting in net debt of \$85.7 million. In addition, we had accrued \$635,000 of charges relating to incentive compensation pursuant to the Manager's LTIP as a long term liability (See General and Administrative Expenses).

Debt Analysis (\$000s)	As at June 30		
	2006	2005	Change
Long-term debt	96,000	120,000	-20%
Short-term debt	—	—	—
Total debt	96,000	120,000	-20%
Less: working capital	10,350	11,454	-10%
Net debt obligations	85,650	108,546	-21%

The Trust's ratio of net debt (long-term debt less positive working capital) to trailing funds generated from operations improved slightly to 0.6 to 1, from 0.7 to 1 at the end of the first quarter, reflecting the repayment of \$9 million in long-term debt during the second quarter, and higher cash flows during the last 12 months.

Financial Leverage and Coverage Ratios ⁽¹⁾	As at June 30		
	2006	2005	Change
Net debt to funds generated from operations (times)	0.6	1.5	-60%
Net debt to distributions (times)	0.8	1.8	-56%
Distributions to interest expense (times)	22.7	48.8	-53%
Net debt to net debt plus equity (%)	19%	21%	-10%

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

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

Components of Working Capital (\$000s)	June 30 2006	Mar. 31 2006	Dec. 31 2005	Sept. 30 2005	June 30 2005
Cash	245	38	192	17	215
Accounts receivable	28,051	32,125	35,728	35,211	21,707
Current assets	28,296	32,163	35,920	35,228	21,922
Distributions payable to Unitholders	(8,839)	(8,832)	(12,748)	(6,859)	(5,875)
Accounts payable and accrued liabilities	(9,107)	(9,042)	(6,891)	(6,713)	(4,593)
Current liabilities	(17,946)	(17,874)	(19,639)	(13,572)	(10,468)
Working capital ⁽¹⁾	10,350	14,289	16,281	21,656	11,454

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

DISTRIBUTION OUTLOOK

The fundamental outlook for oil and gas producers remains positive through the remainder of the decade. The global oil market remains tight and geopolitical issues in the Middle East continue to create uncertainty in world markets. Despite recent price weakness, natural gas supply remains a concern with Canadian conventional production declining.

In light of current market conditions and taking into account actual results for the first six months of the year, we have increased the oil and natural gas prices in our 2006 forecast. We have also increased our development program by \$5 million to take advantage of additional opportunities on our working interest properties. All other assumptions remain unchanged and our 2006 distribution guidance of \$2.16 per Trust Unit remains achievable. Therefore, we expect to maintain our current monthly distribution rate at \$0.18 per Trust Unit for the remainder of the year. At the Board's discretion, any excess income will be directed to repayment of long-term debt and improvements in working capital, in keeping with our goal to maintain a strong balance sheet to pursue additional acquisition opportunities.

2006 Distribution Outlook and Key Assumptions			
	August 9, 2006	May 10, 2006	Feb. 22, 2006
Estimated cash distributions (\$ per Trust Unit)	2.16	2.16	2.16
Key assumptions			
Average daily production, excluding acquisitions (boe/d)	8,500	8,500	8,500
Average WTI oil price (US\$/bbl)	68.85	65.85	60.75
Average AECO natural gas price (Cdn\$/Mcf)	7.25	7.10	8.80
Average light/heavy oil price differential (Cdn\$/bbl)	23.40	23.25	30.00
Average exchange rate (Cdn\$/US\$)	0.88	0.88	0.86
Average operating costs (\$/boe)	2.48	2.48	2.25
Average general and administrative costs (\$/boe)	1.75	1.75	1.65
Development expenditures (\$ millions)	11.0	6.0	6.0
Long-term debt at year end (\$ millions)	98	98	100
Weighted average Trust Units outstanding (thousands)	49,100	49,100	49,100
Payout ratio (%)	84	89	89
Estimated taxability of distributions, as other income (%)	100	100	100

Recognizing the cyclical nature of our industry, we caution that significant changes in production rates, commodity prices, interest rates or foreign exchange rates (positive or negative) will result in adjustments to the distribution level. Freehold is particularly vulnerable to swings in the light/heavy oil price differential, as approximately 39% of our total boe production is heavy oil. Supply and demand imbalances could result in the heavy oil price differential remaining well above historical averages.

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

Upcoming Distributions		
Record Date	Payment Date	Distribution Amount (\$/Trust Unit)
August 31, 2006	September 15, 2006	0.18
September 30, 2006	October 15, 2006	0.18 ⁽¹⁾
October 31, 2006	November 15, 2006	0.18 ⁽¹⁾
November 30, 2006	December 15, 2006	0.18 ⁽¹⁾

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

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

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Consolidated Balance Sheets

(\$000s) (unaudited)	June 30, 2006	December 31, 2005
Assets		
Current assets:		
Cash	\$ 245	\$ 192
Accounts receivable	28,051	35,728
	<u>28,296</u>	<u>35,920</u>
Reclamation fund	2,172	1,964
Petroleum and natural gas interests, net of accumulated depletion and depreciation of \$273,965 (2005 - \$237,857)	463,163	496,194
	<u>\$ 493,631</u>	<u>\$ 534,078</u>
Liabilities and Unitholders' Equity		
Current liabilities:		
Distributions payable to Unitholders	\$ 8,839	\$ 12,748
Accounts payable and accrued liabilities	9,107	6,891
	<u>17,946</u>	<u>19,639</u>
Asset retirement obligations (note 5)	4,194	4,036
Unit based compensation payable (note 4)	635	—
Long-term debt (note 2)	96,000	107,000
Future income tax liability	3,784	3,932
Unitholders' equity:		
Unitholders' capital (note 3)	561,493	560,049
Contributed surplus	234	—
Deficit	(190,655)	(160,578)
	<u>371,072</u>	<u>399,471</u>
	<u>\$ 493,631</u>	<u>\$ 534,078</u>

Consolidated Statements of Income and Deficit

(Unaudited) (\$000s, except per unit and weighted average data)	Three Months Ended June 30		Six Months Ended June 30	
	2006	2005	2006	2005
Revenue:				
Royalty income and working interest sales	\$ 37,852	\$ 28,564	\$ 72,859	\$ 48,423
Royalty expense (net of Alberta Royalty Tax Credit)	(854)	(642)	(1,938)	(1,331)
	36,998	27,922	70,921	47,092
Expenses:				
Operating	1,818	1,685	3,939	2,939
General and administrative	1,336	943	3,469	2,206
Interest on long-term debt	1,299	690	2,490	935
Depletion and depreciation	17,551	12,957	36,108	19,326
Accretion of asset retirement obligation	64	61	126	122
Management fee	749	480	1,444	842
	22,817	16,816	47,576	26,370
Net income before taxes	14,181	11,106	23,345	20,722
Income and capital taxes	309	248	585	496
Future income tax provision	(270)	—	(148)	—
	39	248	437	496
Net income	\$ 14,142	\$ 10,858	\$ 22,908	\$ 20,226
Deficit, beginning of period	(178,295)	(137,682)	(160,578)	(134,114)
Distributions declared	(26,502)	(17,981)	(52,985)	(30,917)
Deficit, end of period	\$ (190,655)	\$ (144,805)	\$ (190,655)	\$ (144,805)
Net income per Trust Unit, basic and diluted	\$ 0.29	\$ 0.26	\$ 0.47	\$ 0.55
Weighted average number of Trust Units:				
Basic	49,067,627	41,489,077	49,049,900	36,544,253
Diluted	49,074,356	41,489,077	49,053,279	36,544,253

Consolidated Statements of Cash Flows

(Unaudited) (\$000s)	Three Months Ended June 30		Six Months Ended June 30	
	2006	2005	2006	2005
Cash provided by (used in):				
Operating:				
Net income	\$ 14,142	\$ 10,858	\$ 22,908	\$ 20,226
Items not involving cash:				
Depletion and depreciation	17,551	12,957	36,108	19,326
Unit based compensation (note 4)	340	—	340	—
Future income tax provision	(270)	—	(148)	—
Accretion of asset retirement obligation	64	61	126	122
Trust Units issued in lieu of management fee	749	480	1,444	842
Expenditures on reclamation	(11)	(12)	(15)	(69)
Funds generated from operations	32,565	24,344	60,763	40,447
Changes in non-cash working capital	6,335	(7,566)	11,308	(9,024)
	38,900	16,778	72,071	31,423
Financing:				
Issue of Trust Units, net of issue costs	—	258,935	—	258,935
Long-term debt	(9,000)	93,000	(11,000)	93,000
Distributions paid	(26,496)	(15,896)	(56,896)	(28,828)
Changes in non-cash working capital	(3)	(174)	(179)	(174)
	(35,499)	335,865	(68,075)	322,933
Investing:				
Property and royalty acquisitions	—	(351,705)	—	(351,705)
Development expenditures	(1,430)	(1,215)	(3,031)	(2,292)
Increase in reclamation fund	(103)	(93)	(208)	(141)
Changes in non-cash working capital	(1,661)	439	(704)	(69)
	(3,194)	(352,574)	(3,943)	(354,207)
Increase in cash	207	69	53	149
Cash, beginning of period	38	146	192	66
Cash, end of period	\$ 245	\$ 215	\$ 245	\$ 215

Notes to Interim Consolidated Financial Statements

For the three and six month periods ended June 30, 2006 and 2005.

1. SIGNIFICANT ACCOUNTING POLICIES

The interim consolidated financial statements of Freehold Royalty Trust (Freehold or the Trust) have been prepared by management in accordance with Canadian generally accepted accounting principles. The interim consolidated financial statements have been prepared following the same accounting policies and methods of computation as the consolidated financial statements for the fiscal year ended December 31, 2005, except for the implementation of unit based compensation. The following disclosure is incremental to the disclosure contained in the 2005 annual consolidated financial statement notes. The interim consolidated financial statements should be read in conjunction with the consolidated financial statements and notes for the year ended December 31, 2005.

UNIT BASED COMPENSATION

A deferred trust unit plan has been established for the non-management directors of Freehold whereby fully-vested deferred trust units are granted annually. Distributions to Unitholders declared prior to redemption are assumed to be reinvested in notional units on the date of distribution. Compensation expense is recognized at the market value of the Trust Units at the time of grant or distribution with a corresponding increase to contributed surplus. Upon redemption of the deferred trust units for Trust Units, the amount previously recognized in contributed surplus is recorded as an increase to Unitholders' capital.

Effective January 1, 2006, the Trust will fund its proportionate share of the costs associated with a long-term incentive compensation plan for employees of Rife Resources, the Manager of the Trust (the Manager's LTIP). The Manager's LTIP uses a combination of the value of phantom Rife shares and Trust Units as the basis for Rights, which are granted annually at the discretion of the directors of Rife and vest at the end of a three-year period. Distributions to Unitholders declared by the Trust during the vesting period are assumed to be reinvested in notional Rights on the date of distribution. Since participants in the Manager's LTIP receive a cash payment on a fixed vesting date, compensation expense is determined based on the intrinsic value of the Rights at each period end. The valuation incorporates the period end Trust Unit price, the number of Rights outstanding at each period end, and certain management assumptions. Compensation expense is recognized over the vesting period with a corresponding increase or decrease in liabilities. The Trust has not incorporated an estimated forfeiture rate for Rights that will not vest; rather, the Trust accounts for actual forfeitures as they occur.

2. LONG-TERM DEBT

Freehold has a \$150 million extendible revolving term credit facility, extendible annually, on which \$96 million was drawn at June 30, 2006. In the event that the lender does not consent to an extension, the revolving credit facility will revert to a two-year, non-revolving term facility with equal quarterly principal repayments. The first quarterly payment would commence on January 1 of the year following the end of the revolving period which is May 2007. In addition Freehold has available a \$15 million extendible revolving operating facility. Borrowings under the facilities bear interest at the Bank's prime lending rate, bankers' acceptance or LIBOR rates plus applicable margins, ranging from 85 to 140 basis points and standby fees. The facilities are secured with \$300 million demand debentures over Freehold's petroleum and natural gas assets.

3. UNITHOLDERS' CAPITAL

	June 30, 2006		December 31, 2005	
	Units	Amount (\$000s)	Units	Amount (\$000s)
Balance, beginning of period	49,031,581	560,049	31,544,236	298,936
Issued for cash	—	—	17,363,520	270,003
Less: Issue expenses	—	—	—	(11,068)
Issued in lieu of management fee	71,308	1,444	123,825	2,178
Balance, end of period	49,102,889	561,493	49,031,581	560,049

4. UNIT BASED COMPENSATION

- (a) In May 2006, the Unitholders approved a deferred trust unit plan for non-management directors (the Directors' Plan) with effect from January 1, 2006. The Directors' Plan consists of fully vested deferred trust units which are granted annually. Distributions to Unitholders declared by the Trust prior to redemption are assumed to be reinvested in notional units on the date of distribution.

In the second quarter of 2006, the Trust expensed \$234,000 as unit based compensation for the six month period ended June 30, 2006, with a corresponding increase to contributed surplus.

- (b) In May 2006, the Board of Directors agreed to fund the Trust's proportionate share of a long-term incentive compensation plan for all employees of the Manager (the Manager's LTIP), with effect from January 1, 2006. The Manager's LTIP will result in employees receiving cash compensation in relation to the value of a specified number of notional units. The Manager's LTIP uses a combination of the value of phantom Rife shares and Trust Units as the basis for Rights, which are granted annually at the discretion of the directors of Rife and vest at the end of a three-year period. Distributions made by the Trust during the vesting period are assumed to be reinvested in notional units on the date of distribution. Upon vesting the employee is entitled to a cash payout based on the Trust Unit price. In addition, there is a performance multiplier based in part on the Trust's performance over the vesting period, which may range from 0.25 to 1.5 times the market value.

As at June 30, 2006, the Trust had accrued \$635,000 of charges relating to incentive compensation pursuant to the Manager's LTIP as a long term liability and expensed \$106,000 for the six month period then ended.

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 \$4.2 million (discounted at a weighted average credit adjusted risk free rate of 6.2%), with the undiscounted value being \$10.4 million. Payments to settle the obligations are expected to occur continuously over the next 50 years, with the majority of obligations being over 15 years away.

(\$000s)	June 30, 2006	December 31, 2005
Balance, beginning of period	4,036	3,937
Liabilities incurred	45	210
Liabilities added upon acquisition	—	19
Liabilities settled	(15)	(104)
Liabilities disposed	—	(352)
Revisions in estimates	—	74
Accretion expense	126	252
Balance, end of period	4,194	4,036

6. RELATED PARTY TRANSACTIONS

For the three month period ended June 30, 2006 Freehold issued 35,654 Trust Units as management fee to the Manager. The total for the six month period ended June 30, 2006 was 71,308 units.

For the three month period ended June 30, 2006 the Manager charged the Trust \$0.8 million in general and administrative costs, totaling \$2.3 million for the six month period ended June 30, 2006. At June 30, 2006 there was \$0.2 million in accounts payable relating to these costs.

7. SUPPLEMENTAL CASH FLOW DISCLOSURE

Cash Expenses Paid (\$000s)	Three Months Ended June 30		Six Months Ended June 30	
	2006	2005	2006	2005
Interest	1,320	864	2,687	1,109
Taxes	699	969	309	248