

Q1

Quarterly Report

THREE MONTHS ENDED MARCH 31, 2008

Freehold Royalty Trust Announces 2008 First Quarter Results

First Quarter Highlights

- Revenues were \$48.6 million, up 31% from the first quarter of 2007.
- Net income increased 142% to \$23.6 million (\$0.48 per Trust Unit) including a \$3.3 million future income tax recovery.
- Funds generated from operations increased 38% to \$39.2 million (\$0.79 per Trust Unit).
- Distributions declared in the first quarter amounted to \$0.45 per Trust Unit.
- Production averaged 8,152 barrels of oil equivalent (boe) per day, down 5%.
- Price realizations averaged \$64.16 per boe, 35% higher than the first quarter of 2007.
- Operating netback increased to \$59.18 per boe, 41% higher than the first quarter of 2007.

On April 21, 2008, Freehold announced a 20% increase in the distribution rate to \$0.18 per Trust Unit effective with the April distribution (payable May 15 to Unitholders of record on April 30, 2008). The May distribution of \$0.18 per Trust Unit will be paid on June 15, 2008 to Unitholders of record on May 31, 2008 (ex-distribution date May 28, 2008). Including the June 15, 2008 payment, Freehold's 12-month trailing cash distributions total \$1.98 per Trust Unit.

RESULTS AT A GLANCE

Financial (\$000s, except as noted)	Three Months Ended March 31		
	2008	2007	Change
Gross revenue	48,574	37,005	31%
Net income	23,647	9,787	142%
Per Trust Unit, basic and diluted (\$)	0.48	0.20	140%
Funds generated from operations	39,182	28,297	38%
Per Trust Unit (\$)	0.79	0.58	36%
Capital expenditures	2,202	3,476	-37%
Property and royalty acquisitions (net)	-	-	-
Distributions declared	22,198	22,133	-
Per Trust Unit (\$) ⁽¹⁾	0.45	0.45	-
Long-term debt, period end	169,000	99,000	71%
Unitholders' equity, period end	253,395	332,836	-24%
Trust Units (000s) ⁽²⁾	49,317	49,175	-
Operating			
Average daily production (boe/d)	8,152	8,564	-5%
Average price realizations (\$/boe)	64.16	47.40	35%
Operating netback (\$/boe)	59.18	42.06	41%

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

(2) Weighted average number of Trust Units outstanding during the period, basic.

Message to Unitholders

Freehold achieved record first quarter cash flow and earnings as our oil-weighted production base benefited from high oil prices. Although the economic benefit was somewhat muted by a stronger Canadian dollar, our operating netback was \$59.18 per boe reflecting both our high percentage of royalty production (which has no associated royalty or operating expenses) and our strategy of not hedging commodity prices.

Production of 8,152 barrels of oil equivalent (boe) per day was slightly lower than anticipated, in large part because we have not yet seen the full impact of production additions from successful drilling in 2007. About 70% of the activity on our royalty lands last year occurred in the last half of the year. In addition, a net profits interest (NPI) was adjusted due to low natural gas prices, which reduced volumes by about 185 boe per day. We also experienced production curtailments at four of our working interest oil properties during the first quarter of 2008. The properties were returned to normal production in April. Overall, we anticipate 2008 production will average about 8,200 boe per day, bolstered by successful development on our lands in 2007 and 2008.

As was widely anticipated, industry drilling declined in the first quarter with 24% fewer wells drilled in western Canada. The slowdown serves as a reminder that commodity prices – and in particular natural gas prices – are a key driver for our industry because natural gas drilling accounts for more than two-thirds of the activity in western Canada. Due to the recent rebound in natural gas prices, industry forecasters are suggesting that the drilling slowdown may not be as dramatic or as prolonged as they had previously predicted. Drilling activity on our royalty lands was up 12% overall (on an equivalent net basis) although there are currently fewer licensed drilling locations on our royalty lands than at this time last year.

We will commence our 2008 development program at Hayter, Alberta, in the second quarter and plan to drill eight (1.9 net) wells. The second quarter will also see a continuation of our development program in Southeast Saskatchewan. Nine (1.3 net) wells were drilled on the Bakken trend last year and a similar program is planned for 2008.

On April 21, 2008, we announced a 20% distribution increase to \$0.18 per Trust Unit effective with the April distribution. Oil prices continue to set new records and natural gas prices have risen steadily through the first four months of 2008 with colder winter weather helping to draw down natural gas inventories. At the same time, imports of liquefied natural gas (LNG) to North America were significantly lower than last year because of strong demand for LNG in European and Asian markets. With storage levels currently in line with the five year average, weather will be a key factor in determining natural gas demand over the next several months. We have chosen to take a conservative view of natural gas prices until we see further evidence of a strengthening in natural gas fundamentals.

Joe Holowsky, Vice-President, Finance and Administration and CFO, has indicated his intention to retire at the end of this year following more than 26 years with Rife Resources, the Manager of the Trust. We appreciate Joe's significant contributions toward the success of Freehold as Chief Financial Officer of the Trust since 1996. Our Board is working with the Manager on the succession planning process to provide for a smooth transition.

On January 31, 2008, Tullio Cedraschi retired as President and CEO of the CN Investment Division. His successor, Russell J. Hiscock, will become one of the two Manager-appointed directors of Freehold at our annual meeting later today. We look forward to welcoming Mr. Hiscock as a director. We are also pleased that Mr. Cedraschi has agreed to stand for election as an independent director.

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 months ended March 31, 2008 and previous periods, and the outlook for Freehold based on information available as at May 7, 2008. The financial information contained herein has been prepared in accordance with Canadian generally accepted accounting principles (GAAP). All comparative percentages are between the quarters ended March 31, 2008 and March 31, 2007, 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, 2007 and 2006, together with the accompanying notes.

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

FORWARD-LOOKING STATEMENTS

This MD&A offers our assessment of Freehold's future plans and operations as at May 7, 2008, 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, taxation, royalties, regulation, competition from other industry participants, the lack of availability of qualified personnel or management, stock market volatility, and our ability to access sufficient capital from internal and external sources. Risks are described in more detail in our AIF, 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 these forward-looking statements.

CONVERSION OF NATURAL GAS TO BARREL OF OIL EQUIVALENT (BOE)

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 the boe ratio is useful for comparative measures and observing trends, it may not accurately reflect individual product values and may be misleading if used in isolation.

NON-GAAP MEASURES

Within this MD&A, references are made to terms commonly used as key performance indicators in the oil and gas industry. We believe that operating netback and funds generated from operations are useful supplemental measures to analyze operating performance, leverage, and liquidity. However, these terms do not have any standardized meanings prescribed by GAAP and therefore may not be comparable with the calculations of similar measures for other entities.

Operating netback, which is calculated as average unit sales price less royalties and operating expenses, represents the cash margin for product sold, calculated on a per boe basis. Funds generated from operations is a key measure of our ability to generate cash, finance operations, and pay monthly distributions. Funds generated from operations as presented is not intended to represent operating cash flow or operating profits for the period nor should it be viewed as an alternative to cash provided by operating activities, net income or other measures of financial performance calculated in accordance with Canadian GAAP. All references to funds generated from operations throughout this report are based

on cash provided by operating activities before changes in non-cash working capital as per the Statement of Cash Flows. Funds generated from operations per Trust Unit is calculated based on the weighted average number of Trust Units outstanding consistent with the calculation of net income per Trust Unit.

In addition, we refer to various per boe figures, such as revenues and costs, which are also considered non-GAAP measures but provide meaningful information on our operational performance. We derive per boe figures by dividing the relevant revenue or cost figure by the total volume of oil and gas production during the period, with natural gas converted to equivalent barrels of oil as described above.

The Royalty Advantage

We manage one of the largest portfolios of oil and gas royalties in Canada. Our royalty lands are comprised of a large and widely diversified portfolio of properties extending from northeastern British Columbia to southern Ontario, including interests in 346 oil and gas production units that provide small royalty interests in more than 14,500 wells.

Our focus on royalties represents a conservative departure from owning traditional oil and gas assets. A royalty interest offers the benefit of sharing in production revenue without the operational costs, risks and responsibilities typically associated with oil and gas operations. The following table demonstrates the advantage of our royalty lands from which we receive revenue but do not incur royalty expenses, operating expenses, site restoration expenses, or capital expenditures.

COMPONENTS OF DISTRIBUTIONS TO UNITHOLDERS

(\$000s)	Three months ended March 31, 2008		
	Royalty Interest	Working Interest	Total Trust
	Lands	Properties	
Gross revenue	33,623	14,951	48,574
Royalty expense	-	(1,425)	(1,425)
Freehold mineral tax	(469)	(127)	(596)
Net revenue	33,154	13,399	46,553
Operating expense	-	(2,657)	(2,657)
	33,154	10,742	43,896
General and administrative expense	(2,065)	(826)	(2,891)
Interest expense	(1,933)	(279)	(2,212)
Income and capital taxes	-	(86)	(86)
Unit based compensation	392	156	548
Expenditures on reclamation	-	(73)	(73)
Funds generated from operations	29,548	9,634	39,182
Reclamation fund contribution	-	(90)	(90)
Capital expenditures	-	(2,202)	(2,202)
Acquisitions	-	-	-
Changes in debt	(9,000)	-	(9,000)
Changes in working capital	(4,066)	(1,626)	(5,692)
Distributions declared	16,482	5,716	22,198

Quarterly Performance and Trends

Our results are directly influenced by commodity prices, which are determined by supply and demand factors, weather, seasonality, global political events, general economic conditions, and changes in Canadian/U.S. dollar exchange rates. Quarterly variances in revenues, net income, and funds generated from operations are caused mainly by fluctuations in commodity prices, production volumes, and operating costs. Crude oil prices are generally determined by global supply and demand factors, but the variances do not have seasonable predictability. Natural gas prices are typically higher in winter months as heating demand rises, but this seasonality is significantly influenced by weather conditions and North American natural gas inventories.

The following significant changes have occurred over the last eight quarters that have influenced the Trust's financial results.

- The substantive enactment in June 2007 of Bill C-52 *Budget Implementation Act, 2007*, resulted in the initial recording of a \$54.3 million future income tax expense in the second quarter of 2007. We are now required to record future income tax related to temporary differences at the Trust level, which represents the difference between the accounting and tax basis of the Trust's net assets. In addition, corporate tax rate reductions enacted in the fourth quarter of 2007 resulted in a future income tax recovery of \$5.9 million.
- On August 31, 2007, we acquired gross overriding royalty (GORR) interests on 309,800 gross acres of land in Alberta and Saskatchewan for \$57.6 million. On September 5, 2007, we acquired a 7% GORR interest on 9,078 gross acres of land at Dixonville, Alberta, for \$32.8 million. Both acquisitions were funded through Freehold's credit facilities, which were increased to \$210 million. The acquisitions contributed approximately 675 boe per day in the fourth quarter of 2007.
- Over the past eight quarters, the Canadian dollar strengthened considerably relative to the U.S. dollar, which influenced our Canadian dollar price realizations for crude oil.
- Over the past eight quarters, WTI crude prices have risen significantly, reaching record highs in the first quarter of 2008. This significant rise in benchmark pricing boosted our revenues; however, the revenue increase was somewhat offset by the increase in the value of the Canadian dollar relative to its U.S. counterpart.
- Over the past several quarters we have experienced higher operating expenses on our working interest properties, which currently comprise about 29% of our total production volumes. Rising costs have been experienced industry wide and particularly in Alberta where strong economic growth and oil sands development have created increased demand for people and services. However, the effect of higher costs on our overall results is mitigated by our large proportion of royalty interest production, which is unencumbered by operating expenses.
- Quarterly fluctuations in the percentage of our total boe production that is derived from royalty interests will result in corresponding fluctuations in operating expenses and third party royalty expenses. Over the past eight quarters, royalty production volumes have varied between 63% and 79% of total boe production.

The accompanying table illustrates the fluctuations in pricing experienced over the past eight quarters and the resulting effect on our financial results.

QUARTERLY REVIEW	2008	2007				2006		
	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Financial (\$000s, except as noted)								
Revenue, net of royalty expense	46,553	39,218	36,086	35,907	34,988	31,765	36,550	36,998
Funds generated from operations	39,182	32,591	29,907	30,213	28,297	27,394	31,692	32,565
Per Trust Unit (\$)	0.79	0.66	0.61	0.61	0.58	0.56	0.65	0.66
Distributions to Unitholders	22,198	28,096	22,165	22,151	22,133	23,594	26,521	26,502
Per Trust Unit (\$) ⁽¹⁾	0.45	0.57	0.45	0.45	0.45	0.48	0.54	0.54
Payout ratio (%)	57	86	74	73	78	86	84	81
Net income (loss)	23,647	19,067	12,487	(42,533)	9,787	9,545	12,728	14,142
Per Trust Unit, basic and diluted (\$)	0.48	0.39	0.25	(0.86)	0.20	0.19	0.26	0.29
Property and royalty acquisitions	-	26	90,430	-	-	-	5,382	-
Capital expenditures	2,202	3,901	1,960	2,830	3,476	3,766	4,649	1,430
Long-term debt	169,000	178,000	179,000	100,000	99,000	100,000	98,000	96,000
Trust Units outstanding								
Weighted average (000s)	49,317	49,282	49,246	49,210	49,175	49,139	49,103	49,068
At quarter end (000s)	49,352	49,317	49,281	49,246	49,210	49,174	49,139	49,103
Operating (\$/boe, except as noted)								
Daily production (boe/d)	8,152	8,591	8,219	8,566	8,564	8,313	8,335	8,212
Royalty interest production (%)	71	70	69	63	72	79	77	79
Average selling price	64.16	50.57	48.28	48.21	47.40	41.44	48.95	50.27
Operating netback	59.18	46.47	43.65	42.28	42.06	38.57	44.92	47.08
Operating expenses	3.58	3.14	4.07	3.79	3.33	2.95	2.75	2.43
Working Interest properties	12.54	10.56	13.17	10.34	11.82	13.86	11.88	11.51
General and administrative expenses	3.90	2.11	1.35	1.67	3.24	1.44	1.32	1.79
Benchmark Prices								
WTI crude oil (US\$/bbl)	97.86	90.68	75.38	65.04	58.16	60.26	70.48	70.70
Exchange rate (Cdn\$/US\$)	1.00	1.02	0.96	0.91	0.85	0.89	0.89	0.89
Edmonton Par crude oil (Cdn\$)	97.50	86.42	79.95	71.93	67.09	64.48	79.08	78.55
Light/heavy oil differential (Cdn\$/bbl)	19.47	29.37	23.95	21.02	16.98	18.80	20.14	17.43
Bow River/Hardisty (Cdn\$/bbl)	78.04	57.05	56.00	50.91	50.11	45.69	58.94	61.11
AECO natural gas (Cdn\$/Mcf)	7.13	6.00	5.61	7.37	7.45	6.36	6.03	6.27
Unit Trading Performance								
High (\$)	19.29	15.85	15.85	15.85	15.30	19.80	23.06	21.70
Low (\$)	14.55	14.46	12.51	13.77	13.00	12.43	18.50	18.02
Close (\$)	18.04	15.60	15.26	14.53	14.35	14.81	19.00	21.00
Volume (000s)	6,740	7,036	5,172	6,853	6,040	13,867	5,153	5,336

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

Development Activities

INDUSTRY ACTIVITY

According to statistics published by the Canadian Association of Oilwell Drilling Contractors, a total of 4,986 wells were drilled in western Canada during the first quarter of 2008, down 24% from the first quarter last year. This slowdown was expected as 2008 drilling budgets were scaled-back in response to low natural gas prices throughout 2007. Industry forecasters, however, are suggesting that the slowdown may not be as dramatic or as prolonged as they had previously predicted due to the recent rebound in natural gas prices.

ROYALTY INTEREST LANDS

Although drilling on our royalty lands generally mirrors industry drilling, this was not the case in the first quarter of 2008. We had a strong start to the year, with royalty drilling up 12% overall (on an equivalent net basis). There are currently 65 (1.9 equivalent net) licensed drilling locations on our royalty lands, compared with 70 (3.8 equivalent net) locations at this time last year.

DRILLING ON ROYALTY LANDS

	Three Months Ended March 31		
	2008	2007	Change
Unitized wells			
Gross	119	83	43%
Equivalent net ⁽¹⁾	0.5	0.3	67%
Non-unitized wells			
Gross	111	107	4%
Equivalent net ⁽¹⁾	5.0	4.6	9%
Total			
Gross	230	190	21%
Equivalent net ⁽¹⁾	5.5	4.9	12%

(1) Equivalent net wells are the aggregate of the numbers obtained by multiplying each gross well by our royalty interest percentage.

WORKING INTEREST PROPERTIES

In the first quarter of 2008, we drilled two (0.4 net) wells in Southeast Saskatchewan and ten (0.4 net) wells in Alberta with a 100% net success rate. First quarter drilling was lower in 2008 due to timing differences of planned drilling programs. We will commence our 2008 development program at Hayter, Alberta, in the second quarter and plan to drill eight (1.9 net) wells. The second quarter will also see a continuation of our development program in Southeast Saskatchewan where nine (1.9 net) Bakken wells are planned for 2008.

DRILLING ON WORKING INTEREST PROPERTIES

	Three Months Ended March 31			
	2008		2007	
	Gross	Net	Gross	Net
Oil	4	0.5	5	2.0
Natural gas	7	0.2	12	0.1
Other	1	0.1	0	0.0
Total	12	0.8	17	2.1

Results of Operations

PRODUCTION

On a boe basis, our production profile for the three months ended March 31, 2008 was 34% heavy oil, 36% natural gas, 26% light and medium oil, and 4% NGL.

We have no operational control over our royalty lands, as we primarily hold small royalty interests in several thousand wells. Obtaining timely production data from the well operators is extremely difficult. Thus, we use government reporting databases and past production receipts to estimate revenue accruals.

Royalty interests, which contributed 71% (2007 Q1 – 72%) of total volumes produced in the quarter declined 5% from last year. The full impact of production additions from drilling in 2007 is not yet reflected in our results, as more than two-thirds of the activity on our royalty lands last year occurred in the last half of the year. Royalty volumes in the first quarter of 2007 included production from two natural gas wells and one oil well that were converted, upon payout, from royalty interests to working interests – these volumes are now reflected in working interest production. In addition, a net profits interest (NPI) well at Lambert, Alberta, was adjusted due to low natural gas prices experienced during 2007, which reduced volumes in the first quarter of 2008 by about 185 boe per day. Continued higher natural gas prices in 2008 should allow the NPI interest to regain a positive balance and allow booking of volumes to recommence later in the year.

Working interest production declined 3% largely due to production curtailments experienced on four oil properties during the first quarter of 2008. The properties were returned to normal production in April. In addition, of the nine wells drilled and completed during 2007 on the Bakken trend in Southeast Saskatchewan, only four have been fracture stimulated. Production from this area will increase as more wells are fracture stimulated and new wells are drilled during 2008.

Overall, we anticipate 2008 production will average about 8,200 boe per day, bolstered by successful drilling and completion operations on our lands in 2007 and 2008.

AVERAGE DAILY PRODUCTION

	Three Months Ended		
	March 31		
	2008	2007	Change
Royalty lands			
Oil (bbls/d)	3,135	3,298	-5%
NGL (bbls/d)	230	298	-23%
Natural gas (Mcf/d)	14,750	15,354	-4%
Oil equivalent (boe/d)	5,823	6,155	-5%
Working interest properties			
Oil (bbls/d)	1,763	1,855	-5%
NGL (bbls/d)	69	80	-14%
Natural gas (Mcf/d)	2,982	2,841	5%
Oil equivalent (boe/d)	2,329	2,409	-3%
Total Trust			
Oil (bbls/d)	4,898	5,153	-5%
NGL (bbls/d)	299	378	-21%
Natural gas (Mcf/d)	17,732	18,195	-3%
Oil equivalent (boe/d)	8,152	8,564	-5%
Number of days in period (days)	91	90	1%
Total volumes during period (Mboe)	742	771	-4%
Potash production (tonnes/d)	16.1	15.2	6%

BENCHMARK PRICES

West Texas Intermediate (WTI) crude oil prices in the first quarter were 68% higher in 2008, and new records continue to be set in the second quarter. However, the economic benefit has been somewhat muted by a stronger Canadian dollar. Nevertheless, Edmonton Par prices increased 45% and Bow River/Hardisty prices rose a spectacular 56%. Historically, differentials have been the widest in the first quarter of the year. However, we believe improved access to U.S. markets via pipelines added in 2006 has created an ongoing demand for Canadian heavy crude from U.S. heavy oil refiners.

Although average AECO natural gas prices declined 4% in the first quarter, prices have steadily increased through the first four months of 2008. Colder winter weather across North America created significant demand for natural gas for heating and power generation, drawing down natural gas storage levels. At the same time, imports of liquefied natural gas (LNG) to North America have been significantly lower than last year due to strong demand for LNG in European and Asian markets. With natural gas storage levels currently in line with the five year average, weather will be a key factor in determining the rate at which storage is refilled during the summer. Warmer weather typically increases demand for space cooling and because natural gas is used to generate a large portion of electricity in the United States, increased electrical demand often means increased natural gas demand.

AVERAGE BENCHMARK PRICES

	Three Months Ended		
	March 31		
	2008	2007	Change
WTI crude oil (US\$/bbl)	97.86	58.16	68%
US\$/Cdn\$ exchange rate	0.9960	0.8535	17%
Edmonton Par crude oil (Cdn\$/bbl)	97.50	67.09	45%
Light/heavy oil differential (Cdn\$/bbl)	19.47	16.98	15%
Bow River/Hardisty (Cdn\$/bbl)	78.04	50.11	56%
AECO natural gas (Cdn\$/Mcf)	7.13	7.45	-4%

Source for commodity prices: Canadian Association of Petroleum Producers.

REALIZED PRICES

Freehold's average selling prices reflect product quality and transportation differences from benchmark prices. On a boe basis, our average price realizations were 35% higher in the first quarter of 2008. As approximately 34% of our total production mix is heavy oil, the markets for heavy oil are of particular relevance for us, and prices for the benchmark Bow River/Hardisty stream are generally a close proxy for our average oil realizations.

AVERAGE SELLING PRICES

	Three Months Ended		
	March 31		
	2008	2007	Change
Oil (\$/bbl)	75.23	49.39	52%
NGL (\$/bbl)	67.43	45.02	50%
Oil and NGL (\$/bbl)	74.78	49.09	52%
Natural gas (\$/Mcf)	7.58	7.39	3%
Oil equivalent (\$/boe)	64.16	47.40	35%
Potash (\$/tonne)	340.73	235.15	45%

Revenue

Gross revenue increased 31% on higher oil prices, partly offset by lower oil and gas volumes in the first quarter of 2008. Potash royalty revenue (included in other revenue) increased to \$500,000 in the first quarter of 2008 from \$323,000 last year, as volumes rose 6% and prices rose 45%. Despite higher prices, potash royalties are expected to comprise only 1% of our revenue in 2008.

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

GROSS REVENUE VARIANCES

(\$000s)	Three Months Ended March 31	
	2008 vs. 2007	2007 vs. 2006
Oil and NGL		
Production increase (decrease)	(1,865)	306
Price increase (decrease)	12,787	4,346
Net increase (decrease)	10,922	4,652
Natural gas		
Production increase (decrease)	(181)	(1,196)
Price increase (decrease)	324	(1,578)
Net increase (decrease)	143	(2,774)
Other ⁽¹⁾	504	120
Gross revenue increase (decrease)	11,569	1,998

(1) Other includes potash revenue, sulphur revenue, lease rentals, processing fees, and interest income.

NET REVENUE

(\$000s)	Three Months Ended March 31		
	2008	2007	Change
Gross revenue	48,574	37,005	31%
Royalty and freehold mineral tax expense ⁽¹⁾	(2,021)	(2,017)	0%
Net revenue	46,553	34,988	33%

(1) Royalty expenses and freehold mineral tax include all Crown charges and royalty payments to third parties.

Expenses

ROYALTY EXPENSE AND FREEHOLD MINERAL TAX

Royalty expense includes all Crown charges (including freehold mineral taxes) and royalty payments to third parties. Crown royalty rates are tied to commodity prices and production volumes. The majority of our freehold mineral taxes, payable annually to the Crown, pertain to two sections of land in the Hayter area that were acquired in the Petrovera acquisition in May 2005. Prior to the Petrovera acquisition, our freehold mineral taxes were not material and were recorded under working interest expenses. Freehold mineral taxes recorded in the first quarter of 2007 included approximately \$250,000 that related to 2006.

Total royalty expense remained consistent at \$2.0 million, but increased 4% on a per boe basis in the first quarter of 2008 due to higher oil prices, partly offset by lower volumes.

ROYALTY EXPENSE AND FREEHOLD MINERAL TAX ⁽¹⁾ (\$000s, except as noted)	Three Months Ended March 31		
	2008	2007	Change
Working interest properties			
Crown royalties	1,096	771	42%
Freehold royalties ⁽²⁾	329	228	44%
Freehold mineral taxes	127	68	87%
Working interest properties	1,552	1,067	45%
Per boe (\$)	7.32	4.92	49%
Royalty lands			
Crown royalties	—	—	—
Freehold royalties ⁽²⁾	—	—	—
Freehold mineral taxes	469	950	-51%
Royalty lands	469	950	-51%
Per boe (\$)	0.89	1.71	-48%
Total Trust	2,021	2,017	0%
Per boe (\$)	2.72	2.62	4%

(1) Royalty expenses and freehold mineral tax include all Crown charges and royalty payments to third parties.

(2) Freehold royalties include mineral title and gross overriding royalty payments to third parties.

OPERATING EXPENSES

Certain portions of operating expenses are fixed costs and, as such, per boe operating costs are highly variable to production volumes. On working interest properties, operating costs per boe rose 6% in the first quarter because of lower production as well as inflationary pressures. On a total Trust basis, operating costs per boe rose 8%. Factoring in 2008 maintenance activities and property taxes, operating costs are forecast to average \$3.85 per boe in 2008.

OPERATING EXPENSES	Three Months Ended March 31		
	2008	2007	Change
Working interest properties (\$000s)	2,657	2,563	4%
Per boe (\$)	12.54	11.82	6%
Royalty lands ⁽¹⁾ (\$000s)	—	—	—
Per boe (\$)	—	—	—
Total operating expenses (\$000s)	2,657	2,563	4%
Total Trust (\$/boe)	3.58	3.33	8%

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

GENERAL AND ADMINISTRATIVE EXPENSES (G&A)

In the first quarter of 2008, G&A expenses totalled \$2.9 million, including \$1.8 million charged by the Manager for time and direct costs incurred on behalf of the Trust. On a per boe basis, G&A expenses were 20% higher in the first quarter of 2008. The rise in G&A costs reflects higher staff levels and general inflationary pressures in Calgary, including a tight employment market that has increased compensation for the Manager's staff. G&A costs are forecast to average \$2.44 per boe in 2008.

First quarter expenses also reflect higher deferred compensation expenses. In the first quarter, we recorded a non-cash expense of \$197,000 (2007 – \$222,000), with a corresponding increase to contributed surplus, as unit based compensation relating to the deferred trust unit plan for non-management directors. We also recorded a non-cash expense of \$351,000 (2007 – \$52,000) in the first quarter for the Trust's proportionate share of the Manager's long-term incentive plan for

2008. As at March 31, 2008, we had recorded \$965,000 as a deferred compensation asset and accrued \$1,726,000 as a liability.

G&A EXPENSES

	Three Months Ended		
	March 31		
	2008	2007	Change
G&A expenses (\$000s)	2,891	2,500	16%
Per boe (\$)	3.90	3.24	20%
As a percentage of revenue	6%	7%	-14%

INTEREST EXPENSES

Interest expenses increased 65% in the first quarter of 2008. In the third quarter of 2007, we increased debt by \$78 million to fund royalty acquisitions totalling \$90.5 million, inclusive of acquisition costs.

INTEREST EXPENSES

	Three Months Ended		
	March 31		
	2008	2007	Change
Net interest expense (000s)	2,212	1,338	65%
Per boe (\$)	2.98	1.74	71%

DEPLETION AND 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 are provided for on a unit-of-production basis using estimated proved reserves.

DEPLETION, DEPRECIATION AND ACCRETION EXPENSES

	Three Months Ended		Year Ended
	March 31		December 31
(\$000s, except as noted)	2008	2007	2007
Depletion and depreciation	17,573	17,626	72,400
Accretion of asset retirement obligation	95	69	266
Total depletion, depreciation and accretion expenses	17,668	17,695	72,666
Per boe (\$)	23.82	22.96	23.47

MANAGEMENT FEES

The quarterly management fee, which is paid in Trust Units, was 35,654 Trust Units for the first quarter of 2008, unchanged from 2007. The ascribed value was 26% higher because of a higher Trust Unit price at the end of the first quarter of 2008.

MANAGEMENT FEES

	Three Months Ended		
	March 31		
(Paid in Trust Units)	2008	2007	Change
Trust Units issued in payment of management fees	35,654	35,654	0%
Ascribed value (\$000s) ⁽¹⁾	643	512	26%
Per boe (\$)	0.87	0.66	32%

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

Operating Netback

In the first quarter of 2008, our operating netback was \$59.18 per boe, up 41% mainly due to higher oil prices. As our production is unhedged, we have received the full benefit of higher commodity prices.

OPERATING NETBACK

(\$/boe)	Three Months Ended March 31		
	2008	2007	Change
Gross revenue ⁽¹⁾	65.48	48.01	36%
Royalty and freehold mineral tax expense ⁽²⁾	(2.72)	(2.62)	4%
Operating expenses	(3.58)	(3.33)	8%
Operating netback	59.18	42.06	41%

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

(2) Royalty expenses and freehold mineral tax include all Crown charges and royalty payments to third parties.

Funds Generated From Operations and Net Income

Funds generated from operations totalled \$39.2 million (\$0.79 per Trust Unit), up 38% from the first quarter last year, reflecting higher oil prices. Net income for the first quarter rose 142% to \$23.6 million. A future income tax recovery, related to corporate tax rate reductions enacted in the first quarter, resulted in a \$3.3 million increase to net income.

FUNDS GENERATED FROM OPERATIONS AND NET INCOME

(\$000s, except as noted)	Three Months Ended March 31		
	2008	2007	Change
Cash provided by operating activities	33,821	26,513	28%
Changes in non-cash working capital	5,361	1,784	201%
Funds generated from operations	39,182	28,297	38%
Per Trust Unit (\$)	0.79	0.58	36%
Net income	23,647	9,787	142%
Per Trust Unit, basic and diluted (\$)	0.48	0.20	140%

Distributions

Distributions to Unitholders totalled \$0.45 per Trust Unit for the first quarter. Royalty income contributed 74% of distributions for the quarter. Since inception, the Trust has distributed \$602.9 million (\$16.67 per Trust Unit) to Unitholders.

ACCUMULATED DISTRIBUTIONS

	Three Months Ended March 31	
	2008	2007
Distributions to Unitholders (\$000s)	22,198	22,133
Accumulated, beginning of period	580,669	486,124
Accumulated, end of period	602,867	508,257
Distributions per Trust Unit (\$) ⁽¹⁾	0.45	0.45
Accumulated, beginning of period	16.22	14.30
Accumulated, end of period	16.67	14.75

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

The following table illustrates the relationship between cash provided from operating activities and historical distributions, as well as net income and historical distributions. Net income includes significant non-cash charges that do not affect cash flow. These charges amounted to \$15.6 million for the first quarter of 2008 (2007 – \$18.9 million). Net earnings also include fluctuations in future income taxes due to changes in tax rates and tax rules. In addition, other non-cash charges, such as depletion and depreciation on property, plant and equipment and accretion on the asset retirement obligations, do not represent the actual cost of maintaining our productive capacity given the natural declines associated with oil and gas assets. In these instances, where distributions exceed net earnings, a portion of the cash distribution paid to Unitholders may represent an economic return of the Unitholders' capital.

DISTRIBUTION ANALYSIS

(\$000s)	Three Months Ended March 31	
	2008	2007
Cash provided by operating activities	33,821	26,513
Net income	23,647	9,787
Cash distributions paid or payable	22,198	22,133
Excess of cash provided by operating activities over cash distributions	52%	20%
Excess (shortfall) of net income over cash distributions	7%	(56%)

DISTRIBUTION POLICY

Our distribution policy takes into consideration forecasted cash provided by operating activities, debt levels, and capital expenditures. We have a declining asset base, and ongoing development activities and acquisitions are necessary to replace production and add additional reserves. The success of these activities, along with commodity prices, are the main factors influencing the sustainability of our distributions.

On April 21, 2008, we announced a 20% increase in the distribution rate to \$0.18 per Trust Unit effective with the April distribution (payable May 15 to Unitholders of record on April 30, 2008). The May distribution of \$0.18 per Trust Unit will be paid on June 15, 2008 to Unitholders of record on May 31, 2008 (ex-distribution date May 28, 2008). Including the June 15, 2008 payment, Freehold's 12-month trailing cash distributions total \$1.98 per Trust Unit.

This distribution increase results from higher revenues due to strong commodity prices for the year to date. The following table provides our key operating assumptions for 2008 based on actual results for the first quarter and our forecast for the rest of the year. We have chosen to take a conservative view of natural prices until we see further evidence of a strengthening in natural gas fundamentals. We will continue to monitor prices and activity levels closely, and our guidance will be reviewed and updated quarterly.

Recognizing the cyclical nature of our industry, we caution that significant changes (positive or negative) in commodity prices (including light/heavy oil price differentials), foreign exchange rates, or production rates will result in adjustments to the distribution level. It is also inherently difficult to predict activity levels on our royalty lands since we do not know the future plans of the various operators. Freehold is particularly vulnerable to swings in the light/heavy oil price differential, as approximately 34% of our total boe production is heavy oil.

2008 KEY OPERATING ASSUMPTIONS

	MD&A Dated	
	May 7 2008	February 27 2008
Average daily production (boe/d)	8,200	8,200
Average WTI oil price (US\$/bbl)	100.00	85.00
Average light/heavy oil price differential (Cdn\$/bbl)	26.00	25.00
Average Bow River Hardisty oil price (Cdn\$/bbl)	73.00	60.00
Average AECO natural gas price (Cdn\$/Mcf)	6.85	6.65
Average exchange rate (Cdn\$/US\$)	0.99	1.00
Average operating costs (\$/boe)	3.85	3.85
Average general and administrative costs (\$/boe)	2.44	2.44
Capital expenditures (\$ millions)	10.6	10.6
Long-term debt at year end (\$ millions)	155	155
Weighted average Trust Units outstanding (thousands)	49,371	49,371
Estimated portion of distributions taxable as income (%)	90-100%	90-100%

A sensitivity analysis of the potential impact of key variables on distributions to Unitholders is provided in the Trust's annual MD&A.

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 20, 2008 (the record date for our 2008 annual meeting of Unitholders), we estimate that approximately 75% of the Trust's Units are held by Canadian residents, with the remaining 25% 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

Our capital expenditure obligations (with respect to our working interest properties) are deducted from funds generated from operations prior to the determination of distributions to Unitholders. Capital expenditures on working interest properties totalled \$2.2 million in the first quarter of 2008. In total, we spent \$1.7 million in Southeast Saskatchewan and the remainder on various projects in Alberta. Capital expenditures in 2008 are anticipated to be \$10.6 million, the majority of which will be spent at Hayter and Southeast Saskatchewan.

**ACQUISITIONS AND
CAPITAL EXPENDITURES**

(\$000s, except as noted)	Three Months Ended March 31		
	2008	2007	Change
Property and royalty acquisitions (net)	—	—	—
Capital expenditures	2,202	3,476	-37%
Change in reclamation fund	90	(302)	-130%
	2,292	3,174	-28%

We expect to fund distributions and capital expenditures from cash provided by operating activities. However, we will continue to fund acquisitions and growth through additional debt and equity. In the oil and gas sector, because of the nature of reserve reporting, the natural reservoir declines, and the risks involved in capital investment, it is not possible to distinguish between capital spent on maintaining productive capacity and capital spent on growth opportunities. Therefore, maintenance capital is not disclosed separately from development capital spending.

We increased debt to fund acquisitions in the third quarter of 2007. During the first quarter, we reduced debt by \$9 million. At March 31, 2008, we had no short-term debt outstanding and long-term debt was \$169 million. We had positive working capital of \$16.6 million, resulting in net debt of \$152.4 million. In addition, we had accrued a \$1.3 million liability relating to incentive compensation pursuant to the Manager's LTIP. We currently have \$41 million of available capacity under our credit facilities.

DEBT ANALYSIS (\$000s)	March 31		December 31
	2008	2007	2007
Long-term debt	169,000	99,000	178,000
Short-term debt	-	-	-
Total debt	169,000	99,000	178,000
Less: working capital	16,595	11,042	11,219
Net debt obligations	152,405	87,958	166,781

At March 31, 2008, our ratio of net debt (total debt less positive working capital) to trailing funds generated from operations was 1.2 to 1. In keeping with our conservative approach to debt management, we anticipate that some portion of our cash flow will be directed to debt repayment.

FINANCIAL LEVERAGE AND COVERAGE RATIOS ⁽¹⁾	March 31		December 31
	2008	2007	2007
Net debt to funds generated from operations (times)	1.2	0.7	1.4
Net debt to distributions (times)	1.6	0.9	1.8
Distributions to interest expense (times)	12.0	18.5	13.5
Net debt to net debt plus equity (%)	38%	21%	40%

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

The following table shows the changes in working capital during the past four quarters. In the oil and gas industry, accounts receivable from industry partners are typically settled in the following month. However, due to administrative issues, payments to freehold and gross overriding royalty owners are often delayed longer. Therefore, working capital can fluctuate significantly resulting from volume and prices changes relative to each period end. Working capital was higher at the end of the first quarter mainly due to higher commodity prices, which increased the dollar value of accounts receivable.

**COMPONENTS OF
WORKING CAPITAL**

	Mar. 31	Dec. 31	Sept. 30	June 30	Mar. 31
(\$000s)	2008	2007	2007	2007	2007
Cash	617	393	82	254	677
Current portion of deferred compensation	106	-	-	-	-
Accounts receivable	35,131	26,802	26,883	25,865	27,870
Current assets	35,854	27,195	26,965	26,119	28,547
Distributions payable to Unitholders	(7,403)	(7,398)	(7,392)	(7,387)	(7,381)
Current portion of unit based compensation	(423)	-	-	-	-
Accounts payable and accrued liabilities	(11,433)	(8,578)	(7,891)	(7,491)	(10,124)
Current liabilities	(19,259)	(15,976)	(15,283)	(14,878)	(17,505)
Working capital ⁽¹⁾	16,595	11,219	11,682	11,241	11,042

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

FUTURE INCOME TAX

The implementation of federal legislation to apply a tax at the trust level on distributions of certain income from publicly traded, specified income flow-through (SIFT) entities will result in certain of our distributions that would have otherwise been taxed as ordinary income being characterized as dividends in addition to being subject to tax at corporate rates at Freehold's level. Because our property base consisted primarily of royalties, there were few tax pools associated with our assets when the Trust was created in 1996. At year end 2007, we had approximately \$230.9 million available in tax pools. In 2011, with our current tax pools, our distributions will become fully taxable at the entity level under the new rules.

On February 26, 2008, the Minister of Finance announced the federal government's intention to adjust the SIFT tax rate. Rather than a flat provincial rate of 13% as previously announced, the provincial component would be based on actual provincial corporate tax rates under a formula giving equal weight to province-by-province payrolls and revenues. This is a positive development for Alberta-based income trusts, and the provincial tax rate is currently 10%. However, we have not adjusted our provision for future income tax as the legislation has not yet been enacted.

The future income tax liability on our Consolidated Balance Sheet as at March 31, 2008, represents the net difference between tax values and accounting values (referred to as temporary differences) effected at substantively enacted tax rates expected to apply when the differences reverse.

Trust Units Outstanding

As at March 31, 2008 and May 7, 2008, there were 49,352,467 Trust Units outstanding. At the end of the first quarter, the Trust issued 35,654 Trust Units to the Manager in payment of the quarterly management fee.

As at March 31, 2008, there were 43,056 deferred trust units outstanding and at May 7, 2008, there were 43,526 deferred trust units outstanding, which are redeemable for an equal number of Trust Units any time after the director's retirement. On January 1, 2008, the Board granted 11,538 deferred trust units to eligible directors of Freehold Resources Ltd. as part of the directors' annual compensation. Each eligible director received 1,923 deferred trust units, and the Chair of the Board received 3,846 deferred trust units.

TRUST UNITS OUTSTANDING

	Three Months Ended		
	March 31		
	2008	2007	Change
Weighted average			
Basic	49,317,205	49,174,593	—
Diluted	49,359,757	49,201,773	—
At period end	49,352,467	49,209,851	—

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 any trends, commitments, events, or uncertainties that are expected to materially affect the methodology or assumptions associated with the critical accounting estimates.

Changes in Accounting Policies

On January 1, 2008, we adopted the CICA Handbook Section 1535 Capital Disclosures, Section 3862 Financial Instruments – Disclosures, and Section 3863 Financial Instruments – Presentation.

Section 1535 Capital Disclosures establishes standards for disclosing information about capital and how it is managed. This section specifies the disclosure about:

- (i) our objectives, policies, and processes for managing capital;
- (ii) quantitative data about what we regard as capital; and
- (iii) whether we have complied with any capital requirements and the consequences in the event of non-compliance.

Section 3862 Financial Instruments – Disclosures and Section 3863 Financial Instruments – Presentation replace Handbook Section 3861 Financial Instruments – Disclosure and Presentation and require increased emphasis on the risks associated with both recognized and unrecognized financial instruments and how those risks are managed. The new presentation standard carries forward the former presentation requirements.

The implementation of these new standards had no impact on our financial results; however they did result in additional disclosure in the notes to the interim consolidated financial statements for the three months ended March 31, 2008.

Consolidated Balance Sheets

(\$000s) (unaudited)	March 31 2008	December 31 2007
Assets		
Current assets:		
Cash	\$ 617	\$ 393
Accounts receivable	35,131	26,802
Current portion of deferred long-term compensation (note 4)	106	-
	35,854	27,195
Reclamation fund	1,877	1,788
Deferred long-term compensation (note 4)	859	697
Petroleum and natural gas interests, net of accumulated depletion and depreciation of \$399,704 (2007 - \$382,131)	459,175	474,520
	\$ 497,765	\$ 504,200
Liabilities and Unitholders' Equity		
Current liabilities:		
Distributions payable to Unitholders	\$ 7,403	\$ 7,398
Accounts payable and accrued liabilities	11,433	8,578
Current portion of unit based compensation payable (note 4)	423	-
	19,259	15,976
Asset retirement obligations (note 5)	6,655	6,608
Unit based compensation payable (note 4)	1,303	1,106
Long-term debt (note 2)	169,000	178,000
Future income tax liability	48,153	51,404
Unitholders' equity:		
Unitholders' capital (note 3)	565,471	564,828
Contributed surplus (note 4)	709	512
Deficit	(312,785)	(314,234)
	253,395	251,106
	\$ 497,765	\$ 504,200

See accompanying notes to interim consolidated financial statements.

Consolidated Statements of Income and Deficit and Comprehensive Income

(Unaudited) (\$000s, except per unit and weighted average data)	Three Months Ended March 31	
	2008	2007
Revenue:		
Royalty income and working interest sales	\$ 48,574	\$ 37,005
Royalty expense and freehold mineral tax	(2,021)	(2,017)
	46,553	34,988
Expenses:		
Operating	2,657	2,563
General and administrative	2,891	2,500
Interest on long-term debt	2,212	1,338
Depletion and depreciation	17,573	17,626
Accretion of asset retirement obligation	95	69
Management fee	643	512
	26,071	24,608
Net income before taxes	20,482	10,380
Income and capital taxes	86	145
Future income tax expense (reduction)	(3,251)	448
	(3,165)	593
Net income and comprehensive income	\$ 23,647	\$ 9,787
Deficit, beginning of period	(314,234)	(218,497)
Distributions declared	(22,198)	(22,133)
Deficit, end of period	\$ (312,785)	\$ (230,843)
Net income per Trust Unit, basic and diluted	\$ 0.48	\$ 0.20
Weighted average number of Trust Units:		
Basic	49,317,205	49,174,593
Diluted	49,359,757	49,201,773

See accompanying notes to interim consolidated financial statements.

Consolidated Statements of Cash Flows

(Unaudited) (\$000s)	Three Months Ended March 31	
	2008	2007
Cash provided by (used in):		
Operating:		
Net income for the period	\$ 23,647	\$ 9,787
Items not involving cash:		
Depletion and depreciation	17,573	17,626
Trust Unit incentive compensation (note 4)	548	274
Future income tax expense (reduction)	(3,251)	448
Accretion of asset retirement obligation	95	69
Trust Units issued in lieu of management fee	643	512
Expenditures on reclamation	(73)	(419)
	39,182	28,297
Changes in non-cash working capital	(5,361)	(1,784)
	33,821	26,513
Financing:		
Long-term debt	(9,000)	(1,000)
Distributions paid	(22,193)	(22,128)
	(31,193)	(23,128)
Investing:		
Capital expenditures	(2,202)	(3,476)
Change in reclamation fund	(90)	302
Changes in non-cash working capital	(112)	45
	(2,404)	(3,129)
Increase in cash	224	256
Cash, beginning of period	393	421
Cash, end of period	\$ 617	\$ 677

See accompanying notes to interim consolidated financial statements.

Notes to Interim Consolidated Financial Statements

For the period ended March 31, 2008.

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, 2007, except for the new standards regarding financial instruments and capital disclosures, as detailed below. The following disclosure is incremental to the disclosure contained in the notes to the 2007 annual consolidated financial statements. The interim consolidated financial statements should be read in conjunction with the consolidated financial statements and notes for the year ended December 31, 2007.

NEW ACCOUNTING STANDARDS

On January 1, 2008, the Trust adopted the new Canadian accounting standards relating to financial instruments and capital disclosures.

(a) Capital Management

Freehold Royalty Trust is structured as a mutual fund trust under the *Income Tax Act* (Canada). This enables us to return the majority of our income to Unitholders in a tax-effective manner. We receive revenue from oil and gas properties as reserves are produced, which is paid to Unitholders on a regular basis over the economic life of the properties. The Trust's objective for managing capital is to maximize long-term Unitholder value by distributing to Unitholders any cash that is not required for financing our operations or capital investment growth opportunities that may offer Unitholders better value.

We define capital as long-term debt, Unitholders' equity, and working capital based on the consolidated financial statements. We manage our capital structure taking into account operating activities, debt levels, capital expenditures, and distribution levels. We also consider changes in economic conditions and commodity prices as well as the risk characteristics of our assets. We have a declining asset base, and ongoing development activities and acquisitions are necessary to replace production and add additional reserves. From time to time, we may issue Trust Units or adjust capital spending to manage current and projected debt levels.

We retain working capital primarily to fund capital expenditures or acquisitions and reduce bank indebtedness. The Trust's distribution policy includes withholding a portion of cash provided by operating activities for contributions to the Trust's reclamation fund to provide a cash reserve for the eventual abandonment of oil and gas properties.

Our Trust Indenture provides that not more than 49% of the Trust's Units can be held by non-residents of Canada. We monitor foreign ownership levels on a regular basis through declarations from Unitholders and geographical searches. 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.

We are bound by covenants on our credit facilities. The covenants are monitored monthly as part of management's internal review to ensure compliance with the requirements. As at March 31, 2008, the Trust was in compliance with all such covenants.

(b) Financial Instrument Risk Management

The Trust has exposure to credit, liquidity, and market risks from its use of financial instruments. We employ the following strategies to mitigate these risks.

Credit risk:

- Credit risk is the risk of financial loss to the Trust if a customer or counterparty to a financial instrument fails to meet its contractual obligations and arises principally from our receivables. A large part of our accounts receivable are with oil and gas industry operators, either as joint venture partners or as payors of various royalty agreements. Our diversified revenue stream limits the size of any one property or industry operator with respect to total receivables.
- We maintain an aggressive auditing program to ensure that we are paid royalties on our production from our lands in accordance with the prices obtained by the royalty payor and that unwarranted or excessive deductions are not being taken.
- The carrying amount of accounts receivable and cash and cash equivalents represents the maximum credit exposure. We did not have an allowance for doubtful accounts as at March 31, 2008 and December 31, 2007 and did not provide for any doubtful accounts nor was it required to write off any receivables during the years ended December 31, 2007 and 2006.
- The Trust markets approximately 60% of its production along with the operator or royalty payor under the terms of a diverse number of agreements. When it can, the Trust takes its production in kind (currently 40%) and sells to two primary purchasers under normal industry sale and payment terms.

Liquidity risk:

- Liquidity risk is the risk that we will not be able to meet our financial obligations as they come due. We maintain a conservative approach to debt management that aims to provide maximum financial flexibility with respect to acquisitions and development expenditures, while maintaining stable distributions. As circumstances warrant, we allocate a portion of cash provided by operating activities to debt repayment. We prepare annual capital expenditure budgets, which are regularly monitored and updated.

Market risk:

- Market risk is the risk that changes in market prices, such as foreign currency exchange rates, commodity prices, and interest rates, will affect net income or the value of financial instruments. For short-term investments, we select counter parties based on credit ratings and monitor all investments to ensure a stable return, avoiding complex investment vehicles with higher risk such as asset backed commercial paper.

Foreign currency exchange rate risk

- We do not sell or transact in any foreign currency; however, the underlying market prices in Canada for oil and natural gas are influenced by changes in the exchange rate between the Canadian and U.S. dollar. During the three months ended March 31, 2008, we had no foreign exchange related derivative contracts in place. Assuming all other variables held constant, a 0.01 change (plus or minus) in the U.S./Canadian dollar exchange rate for the three months ended March 31, 2008, would have resulted in a corresponding change to net income of approximately \$0.4 million (2007 – \$0.3 million).

Commodity price risk

- Commodity price risk is the risk that the fair value of future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for oil and natural gas are influenced by the relationship between the Canadian and U.S. dollar as well as macroeconomic events that dictate the levels of supply and demand. During the three months ended March 31, 2008, we had no commodity price related derivative contracts in place. Assuming all other variables held constant, a US\$1.00 change (plus or minus) in the WTI crude oil price for the three months ended March 31, 2008, would have resulted in a corresponding change to net income of approximately \$0.3 million (2007 – \$0.4 million). A \$0.25 change (plus or minus) in the AECO natural gas price would have resulted in a corresponding change to net income of approximately \$0.4 million (2007 – \$0.4 million).

Interest rate risk

- We are exposed to interest rate risk on outstanding bank debt, which has a floating interest rate, and fluctuations in interest rates would impact our future cash flows. Assuming all other variables held constant, a 1% change (plus or minus) in the interest rate for the three months period ended March 31, 2008 would have resulted in a corresponding change to net income of approximately \$0.4 million (2007 – \$0.3 million).

2. Long-Term Debt

Freehold has a \$195 million extendible revolving term credit facility, extendible annually, on which \$169 million was drawn at March 31, 2008. 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 2008. In addition, Freehold has available a \$15 million extendible revolving operating facility.

Borrowings under the facilities bear interest at the Bank's prime lending rate, bankers' acceptance or LIBOR rates plus applicable margins, ranging from 85 to 140 basis points and standby fees.

The facilities are secured with \$300 million demand debentures over Freehold's petroleum and natural gas assets.

In May 2008, the lender agreed to extend the terms of the facility until May 2009 on substantially similar terms.

3. Unitholders' Capital

	March 31, 2008		December 31, 2007	
	Units	Amount (\$000s)	Units	Amount (\$000s)
Balance, beginning of period	49,316,813	564,828	49,174,197	562,698
Issued in lieu of management fee	35,654	643	142,616	2,130
Balance, end of period	49,352,467	565,471	49,316,813	564,828

4. Unit Based Compensation

(a) Deferred Trust Unit Plan

Fully-vested deferred trust units are granted annually to non-management directors. Distributions to Unitholders declared by the Trust prior to redemption are assumed to be reinvested in notional units of the date of distribution. As at March 31, 2008, there were 43,056 deferred trust units outstanding, which are redeemable for an equal number of Trust Units any time after the director's retirement.

For the three months ended March 31, 2008, Freehold expensed \$197,000 (2007 – \$222,000) as unit based compensation with a corresponding increase to contributed surplus.

CONTRIBUTED SURPLUS (\$000s)	March 31 2008	December 31 2007
Balance, beginning of period	512	247
Trust Unit incentive compensation expense	197	265
Balance, end of period	709	512

(b) Manager's Long-Term Incentive Plan

Employees of the Manager receive cash compensation in relation to the value of a specified number of notional units after a three year vesting period. Distributions to Unitholders declared by the Trust during the vesting period are assumed to be reinvested in notional units on the date of distribution. For the three months ended March 31, 2008, Freehold expensed \$351,000 (2007 – \$52,000) as unit based compensation. At March 31, 2008, Freehold recorded \$859,000 as a deferred long-term compensation asset and \$106,000 as a current portion of deferred long-term compensation. In addition, Freehold accrued \$1,303,000 as a long-term liability and \$423,000 as a current liability.

5. Asset Retirement Obligations

Freehold has no asset retirement obligations on its royalty income properties. Freehold's asset retirement obligation results from its responsibility to abandon and reclaim its net share of all working interest properties. The net present value of Freehold's total asset retirement obligation is estimated to be \$6.7 million (discounted at a weighted average, credit adjusted risk free rate of 5.8%), the undiscounted value of which is \$23.6 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.

ASSET RETIREMENT OBLIGATIONS (\$000s)	March 31 2008	December 31 2007
Balance, beginning of period	6,608	4,598
Liabilities incurred	25	675
Liabilities settled	(73)	(799)
Revisions in estimates	-	1,868
Accretion expense	95	266
Balance, end of period	6,655	6,608

6. Related Party Transactions

For the three months ended March 31, 2008, Freehold issued 35,654 Trust Units as management fee to the Manager (2007 – 35,654 Trust Units) pursuant to a management agreement. The ascribed value of \$643,000 (2007 – \$512,000) is based on the closing price of the Trust Units on the last trading day of the quarter.

For the three months ended March 31, 2008, the Manager charged the Trust \$1.8 million in general and administrative costs (2007 – \$1.6 million). At March 31, 2008, there was \$0.3 million (2007 – \$1.1 million) in accounts payable and accrued liabilities relating to these costs. The transactions were in the normal course of operations and are measured at the exchange amount, which is the amount of consideration established and agreed to by the Trust and the Manager.

7. Supplemental Cash Flow Disclosure

CASH EXPENSES PAID

(\$000s)	Three Months Ended March 31	
	2008	2007
Interest	2,046	1,308
Taxes	190	278

8. Subsequent Event

On April 21, 2008, the Board of Directors approved an increase in the distribution rate from \$0.15 per Trust Unit to \$0.18 per Trust Unit effective with the April distribution payable May 15 to Unitholders of record on April 30, 2008.

Corporate Information

BOARD OF DIRECTORS

William W. Siebens (2)
President and Chief Executive Officer
Candor Investments Ltd.

D. Nolan Blades (1)(2)(3)(4)
President
Sunny Gables Holdings Ltd.

Harry S. Campbell, Q.C. (3)(4)
Vice-Chair
Burnet, Duckworth & Palmer, LLP

Tullio Cedraschi
Corporate Director

Peter T. Harrison (1)(3)(4)
Senior Vice-President
Montrusco Bolton Investments Inc.

P. Michael Maher (1)(2)(4)
Professor, Haskayne School of Business
University of Calgary

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

- (1) Audit Committee
- (2) Governance Committee
- (3) Reserves Committee
- (4) Compensation Committee

OFFICERS

William W. Siebens
Chair of the Board

David J. Sandmeyer
President and Chief Executive Officer

J. Frank George
Vice-President, Exploitation

Darren G. Gunderson
Controller

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

William O. Ingram
Vice-President, Production

Michael J. Okrusko
Vice-President, Land

Karen C. Taylor
Manager, Investor Relations and
Corporate Secretary

STOCK EXCHANGE

Toronto Stock Exchange
Trading Symbol: FRU.UN

TRUSTEE AND TRANSFER AGENT

Computershare Trust Company of Canada
600, 530 – 8th Avenue S.W.
Calgary, Alberta T2P 3S8
Toll Free: 1-888-267-6555
Fax: (403) 267-6598
Email: service@computershare.com

LEGAL COUNSEL

Burnet Duckworth & Palmer, LLP
Calgary, Alberta

AUDITORS

KPMG, LLP
Calgary, Alberta

BANKERS

Canadian Imperial Bank of Commerce
Calgary, Alberta

Royal Bank of Canada
Calgary, Alberta

RESERVE EVALUATORS

Trimble Engineering Associates Ltd.
Calgary, Alberta

2008 FIRST QUARTER DISTRIBUTIONS DECLARED

Record Date	Payment Date	Per Trust Unit
January 31, 2008	February 15, 2008	\$0.15
February 29, 2008	March 15, 2008	\$0.15
March 31, 2008	April 15, 2008	<u>\$0.15</u>
		<u>\$0.45</u>

Tax information and historical distributions are available on our website.

HEAD OFFICE

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Karen C. Taylor
Manager, Investor Relations and
Corporate Secretary
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WEBSITE

www.freeholdtrust.com

2008 FIRST QUARTER TRADING SUMMARY

High – \$19.29
Low – \$14.55
Close – \$18.04
Volume – 6.7 million
Trust Units Outstanding – 49.3 million
Market Capitalization – \$890 million
(March 31)