

## Quarterly Report

THREE AND SIX MONTHS ENDED JUNE 30, 2008

# Freehold Royalty Trust Announces 2008 Second Quarter Results

## Second Quarter Highlights

- Revenues were \$61.3 million, up 61% from the second quarter of 2007.
- Net income was \$36.2 million (\$0.73 per Trust Unit) compared with a loss of \$42.5 million (\$0.86 per Trust Unit) in the second quarter of 2007 (which included a \$54.3 million non-cash provision for future income tax following the enactment of the Canadian income trust taxation legislation).
- Cash provided by operating activities increased 50% to \$46.4 million (\$0.94 per Trust Unit).
- Funds generated from operations increased 76% to \$53.2 million (\$1.08 per Trust Unit).
- Distributions declared in the second quarter were 36% higher at \$0.61 per Trust Unit.
- Production averaged 7,674 barrels of oil equivalent (boe) per day, down 10%.
- Price realizations averaged \$86.43 per boe, 79% higher than the second quarter of 2007.
- Operating netback increased 92% to \$81.21 per boe.

On June 12, 2008, we announced a 39% increase in the distribution rate to \$0.25 per Trust Unit from \$0.18 per Trust Unit effective with the June distribution (payable on July 15, 2008). Our monthly distributions have increased twice this year in response to higher commodity prices. The August distribution of \$0.25 per Trust Unit will be paid on September 15, 2008 to Unitholders of record on August 31, 2008 (ex-distribution date August 27, 2008). Including the September 15, 2008 payment, our 12-month trailing cash distributions total \$2.18 per Trust Unit.

### RESULTS AT A GLANCE

Financial (\$000s, except as noted)	Three Months Ended June 30			Six Months Ended June 30		
	2008	2007	Change	2008	2007	Change
Gross revenue	61,301	38,015	61%	109,875	75,020	46%
Net income (loss)	36,163	(42,533)	—	59,810	(32,746)	—
Per Trust Unit, basic and diluted (\$)	0.73	(0.86)	—	1.21	(0.67)	—
Cash provided by operating activities	46,379	30,829	50%	80,200	57,342	40%
Per Trust Unit (\$)	0.94	0.63	77%	1.17	1.19	57%
Funds generated from operations <sup>(1)</sup>	53,183	30,213	76%	92,365	58,510	58%
Per Trust Unit (\$)	1.08	0.61	77%	1.87	1.19	57%
Capital expenditures	2,135	2,830	-25%	4,337	6,306	-31%
Distributions declared	30,114	22,151	36%	52,312	44,284	18%
Per Trust Unit (\$) <sup>(2)</sup>	0.61	0.45	36%	1.06	0.90	18%
Long-term debt, period end	151,000	100,000	51%	151,000	100,000	51%
Unitholders' equity, period end	260,250	268,683	-3%	260,250	268,683	-3%
Trust Units (000s) <sup>(3)</sup>	49,353	49,210	0%	49,335	49,193	0%
<b>Operating</b>						
Average daily production (boe/d)	7,674	8,566	-10%	7,914	8,565	-8%
Average price realizations (\$/boe)	86.43	48.21	79%	74.96	47.81	57%
Operating netback (\$/boe)	81.21	42.28	92%	69.86	42.17	66%

(1) See Non-GAAP measures.

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

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

## Message to Unitholders

Buoyed by significantly higher commodity prices, Freehold achieved record revenue, cash flow and earnings for the second quarter of 2008. Revenue rose 61%, cash provided by operating activities rose 50%, and funds generated from operations rose 76% from the second quarter last year. Net income was \$36.2 million compared with a loss of \$42.5 million in the second quarter 2007. The second quarter loss last year included a \$54.3 million non-cash provision for future income tax following the enactment of tax legislation related to Canadian income trusts.

Our average operating netback was \$81.21 per boe, reflecting our unhedged production, which received the full benefit of the higher prices. However, these results were marred by lower production volumes, mainly due to wet spring conditions, which hampered drilling and maintenance operations, and the scheduled maintenance at the Hayter facility. Consequently, the full impact of production additions from recent drilling is not yet reflected in our results. Production for the first half of the year was 7,914 barrels of oil equivalent (boe) per day, and our previous guidance of 7,900 boe per day for the full year remains unchanged with production additions in the second half expected to offset natural production declines.

### COMMODITY PRICES REMAIN VOLATILE

West Texas Intermediate (WTI) crude oil prices continued to set new records in the second quarter, with the average price up 91% from a year ago. Edmonton Par prices rose 75% and Bow River/Hardisty prices rose 106%. To date in the third quarter, oil prices have remained volatile due to the fluctuating U.S. dollar and political instability in the Middle East and Africa, two key oil-producing regions. Natural gas prices have increased steadily through the first seven months of 2008. With natural gas storage inventories currently below last year's level, weather will be a key factor in determining the rate at which storage is refilled during the summer. We are currently forecasting that WTI prices will average US\$116 per barrel for the year and AECO natural gas prices will average \$8.90 per Mcf.

### DISTRIBUTIONS INCREASED IN 2008 ON HIGHER COMMODITY PRICES

Our monthly distributions have increased twice in 2008 in response to higher commodity prices. On April 21, 2008, we announced a 20% increase in the distribution rate to \$0.18 per Trust Unit effective with the April distribution, and on June 12, 2008, we announced a 39% increase in the distribution rate to \$0.25 per Trust Unit from \$0.18 per Trust Unit effective with the June distribution. Based on our current operating assumptions (as outlined in Management's Discussion and Analysis for the three and six months ended June 30, 2008), we may be required to consider a special distribution at year-end. However, excess cash from operating activities in the second half of the year might also be used to fund additional acquisitions or increases in our capital program should appropriate opportunities arise. We will continue to monitor prices and activity levels closely, and our guidance will be reviewed and updated quarterly.

### COST PRESSURES CONSTRAIN GROWTH IN INDUSTRY ACTIVITY

According to statistics published by the Canadian Association of Oilwell Drilling Contractors, 3,148 wells were drilled in western Canada during the second quarter of 2008, down 3% from the second quarter last year (and down 17% for the year to date). This slowdown was expected, as 2008 drilling budgets were scaled-back in response to low natural gas prices throughout 2007 and uncertainty regarding the Alberta royalty regime. The price rebound of natural gas in the first half of 2008 has raised expectations for higher drilling activity in western Canada. However, spring break-up and wet weather in the second quarter delayed any significant uplift in activity. As well, cost pressures throughout the industry are having an equalizing effect on activity levels, constraining further growth. The Petroleum Services Association of Canada is predicting that, despite higher commodity prices, drilling in the second half of 2008 will remain consistent with the levels experienced in the first half of the year.

Drilling on our royalty lands generally mirrors industry drilling. On an equivalent net basis, royalty drilling was down 6% in the second quarter but was up 8% for the six-month period. There are currently 95 (3.7 equivalent net) licensed drilling locations on our royalty lands, compared with 79 (4.6 equivalent net) locations at this time last year.

#### **DEVELOPMENT ACTIVITIES TO ACCELERATE IN SECOND HALF**

Capital expenditures on our working interest properties for the first half of 2008 were \$4.3 million. Second quarter drilling was lower in 2008 due to wet weather and timing differences of planned drilling programs, but activity will accelerate in the second half of the year. Capital expenditures are expected to top \$6.3 million with the bulk of this directed to our major properties at Hayter, Alberta, and in Southeast Saskatchewan. In the third quarter, we will complete our 2008 development program at Hayter, Alberta, and continue our development program in Southeast Saskatchewan. Since 2006, we have participated in the drilling of 18 (2.8 net) Bakken oil wells. Production from the Bakken trend will increase as more wells are fracture stimulated and new wells are drilled during the second half of 2008.

#### **ACQUISITION SUPPORTS ROYALTY STRATEGY**

On July 7, 2008, we acquired certain royalty interests in Alberta for \$8.5 million, prior to closing adjustments. The acquisition of these properties supports our strategy of acquiring royalty interests. As there are no operating and capital costs or third party royalties associated with the royalty production acquired, this production receives high netbacks. The properties include royalties in units at Seven Persons, Bellshill Lake, Viking Kinsella, Beaverhill Lake, and Plain, as well as royalty interests in oil and natural gas properties at Medicine Hat, Killam, Wainwright, Viking Kinsella, and Skaro/Redwater. Proved plus probable reserves attributed to the properties were evaluated effective December 31, 2007, by an independent reserves evaluator at 202,000 boe.

#### **CORPORATE SIFT TAX STRATEGY COMMITTEE FORMED**

On July 14, 2008, the Department of Finance released draft amendments to the Canadian Income Tax Act to facilitate the conversion of SIFT entities into corporations. We are currently assessing the draft rules as they relate to our particular circumstances. In addition, our board has established a special committee comprised of independent board members with a mandate to determine a course of action that best maximizes Unitholder value when the SIFT tax comes into effect in 2011. In the interim, we plan to retain the flow-through advantages of our current structure.

#### **OFFICER APPOINTMENTS TO FACILITATE SUCCESSION PLANNING**

I am pleased to announce a number of officer appointments, effective August 13, 2008. Bill Ingram has been promoted to Executive Vice-President and Chief Operating Officer. Joe Holowisky, who has indicated his intention to retire at the end of this year, has been promoted to Senior Vice-President, Special Projects. Darren Gunderson, formerly our Controller, has been promoted to Vice-President, Finance and Chief Financial Officer. Garry Bieber has been promoted to Vice-President, Production, and Michael Mogan has been promoted to Controller. These appointments were approved by the Board to facilitate management succession for the Trust.

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 June 30, 2008 and previous periods, and the outlook for Freehold based on information available as at August 13, 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 June 30, 2008 and June 30, 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](http://www.sedar.com).

### FORWARD-LOOKING STATEMENTS

This MD&A offers our assessment of Freehold's future plans and operations as at August 13, 2008, and contains forward-looking statements including our expectations for production referred to in the "Message to Unitholders" on page 2; our expected sources of funds for distributions and capital expenditures referred to under "Liquidity and Capital Resources – Capital Expenditures" on page 16; future income tax on page 20; and our drilling plans, production guidance, distribution policy and our key operating assumptions referred to under the "Outlook" on page 18.

Such statements are generally identified by the use of words such as "anticipate", "continue", "estimate", "expect", "forecast", "may", "will", "project", "should", "plan", "intend", "believe", and similar expressions (including the negatives thereof). 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.

With respect to forward-looking statements contained in this MD&A, we have made assumptions regarding, among other things, future oil and natural gas prices; future capital expenditure levels; future production levels; future exchange rates; the cost of developing and expanding our assets; our ability and the ability of our lessees to obtain equipment in a timely manner to carry out development activities; our ability to market our oil and natural gas successfully to current and new customers; the impact of increasing competition; our ability to obtain financing on acceptable terms; and our ability to add production and reserves through our development and acquisition activities. The Outlook section on page 19 sets forth our key operating assumptions with respect to the forward-looking statements referred to above.

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. The forward-looking information contained in the MD&A is expressly qualified by this cautionary statement. Our policy for updating forward-looking statements is to update our key operating assumptions quarterly and, except as required by law, we do not undertake to update any other 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, funds generated from operations, and net debt to funds generated from operations are useful supplemental measures for management and investors to analyze operating performance, financial leverage, and liquidity, and we use these terms to facilitate the understanding and comparability of our results of operations and financial position. 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. See Operating Netback on page 15.

Funds generated from operations is a financial term commonly used in the oil and gas industry. It represents cash provided by operating activities before changes in non-cash working capital and 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. The key difference between cash provided by operating activities and funds generated from operations is changes in non-cash working capital, which is affected by accounts receivable. Accounts receivable, and therefore working capital, can fluctuate greatly between reporting periods due to timing of receipt of payments. In the event that commodity prices and/or volumes have changed significantly from the previous reporting period, a significant difference could occur between cash provided by operating activities and funds generated from operations. 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. See Funds Generated From Operations and Net Income on page 16.

Net debt to funds generated from operations is calculated as net debt (total debt less positive working capital) as a proportion of funds generated from operations for the previous 12 months. See Debt Analysis on page 18.

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.

## **Related Party Transactions**

We do not operate any of our oil and gas assets, nor do we have any employees. The Manager of the Trust is a wholly owned subsidiary of Rife Resources Ltd., which is 100% owned by the CN Pension Trust Funds (the pension funds for the employees of Canadian National Railway Company). The Manager recovers its costs (see General and Administrative Expenses) and receives a quarterly management fee paid in Trust Units (see Management Fees).

## 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, cash provided by operating activities, 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 reasonable 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 our results.

- WTI crude prices have exhibited significant volatility, climbing to record highs in the second quarter of 2008. This significant rise in benchmark pricing has boosted our revenues; however, the increase has been somewhat offset by the increase in the value of the Canadian dollar relative to its U.S. counterpart.
- The Canadian dollar has strengthened considerably relative to the U.S. dollar, reducing our Canadian dollar price realizations for crude oil.
- Natural gas prices have exhibited significant volatility, dipping below \$6.00 per Mcf in the third quarter of 2007. Natural gas markets began to strengthen in the first quarter of 2008, and we have benefited from higher natural gas prices in the first half of 2008.
- Our monthly distributions have increased twice in 2008 in response to higher commodity prices. On April 21, 2008, we announced a 20% increase in the distribution rate to \$0.18 per Trust Unit effective with the April distribution, and on June 12, 2008, we announced a 39% increase in the distribution rate to \$0.25 per Trust Unit from \$0.18 per Trust Unit effective with the June distribution.
- 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 our credit facilities, which were increased to \$210 million.
- 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. We have experienced higher operating expenses on our working interest properties, which currently comprise about 28% of our total production volumes. 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.
- The increase in our Trust Unit price during 2008 has resulted in a corresponding increase in unit based incentive compensation.
- In the second quarter of 2007, two natural gas wells in British Columbia were converted from royalty interests to working interests upon payout. To account for the change in status of the two wells, royalty volumes and revenues were adjusted, and in their place working interest volumes and revenues were booked, along with associated operating and royalty 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.

## QUARTERLY REVIEW

	2008		2007				2006	
	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
<b>Financial</b> (\$000s, except as noted)								
Revenue, net of royalty expense	59,563	46,553	39,218	36,086	35,907	34,988	31,765	36,550
Distributions declared	30,114	22,198	28,096	22,165	22,151	22,133	23,594	26,521
Per Trust Unit (\$) <sup>(1)</sup>	0.61	0.45	0.57	0.45	0.45	0.45	0.48	0.54
Net income (loss)	36,163	23,647	19,067	12,487	(42,533)	9,787	9,545	12,728
Per Trust Unit, basic and diluted (\$)	0.73	0.48	0.39	0.25	(0.86)	0.20	0.19	0.26
Cash provided by operating activities	46,379	33,821	32,503	30,155	30,829	26,513	26,437	32,462
Per Trust Unit (\$)	0.94	0.69	0.66	0.61	0.63	0.54	0.54	0.66
Funds generated from operations <sup>(2)</sup>	53,183	39,182	32,591	29,907	30,213	28,297	27,394	31,692
Per Trust Unit (\$)	1.08	0.79	0.66	0.61	0.61	0.58	0.56	0.65
Property and royalty acquisitions	-	-	26	90,430	-	-	-	5,382
Capital expenditures	2,135	2,202	3,901	1,960	2,830	3,476	3,766	4,649
Long-term debt	151,000	169,000	178,000	179,000	100,000	99,000	100,000	98,000
Trust Units outstanding								
Weighted average (000s)	49,353	49,317	49,282	49,246	49,210	49,175	49,139	49,103
At quarter end (000s)	49,388	49,352	49,317	49,281	49,246	49,210	49,174	49,139
<b>Operating</b> (\$/boe, except as noted)								
Daily production (boe/d)	7,674	8,152	8,591	8,219	8,566	8,564	8,313	8,335
Royalty interest production (%)	72	71	70	69	63	72	79	77
Average selling price	86.43	64.16	50.57	48.28	48.21	47.40	41.44	48.95
Operating netback <sup>(2)</sup>	81.21	59.18	46.47	43.65	42.28	42.06	38.57	44.92
Operating expenses	4.08	3.58	3.14	4.07	3.79	3.33	2.95	2.75
Working interest properties	14.37	12.54	10.56	13.17	10.34	11.82	13.86	11.88
General and administrative expenses	2.15	3.16	1.80	1.28	1.59	2.89	1.60	1.22
<b>Benchmark Prices</b>								
WTI crude oil (US\$/bbl)	123.98	97.86	90.68	75.38	65.04	58.16	60.26	70.48
Exchange rate (Cdn\$/US\$)	0.99	1.00	1.02	0.96	0.91	0.85	0.89	0.89
Edmonton Par crude oil (Cdn\$)	126.07	97.50	86.42	79.95	71.93	67.09	64.48	79.08
Light/heavy oil differential (Cdn\$/bbl)	21.43	19.47	29.37	23.95	21.02	16.98	18.80	20.14
Bow River/Hardisty (Cdn\$/bbl)	104.64	78.04	57.05	56.00	50.91	50.11	45.69	58.94
AECO natural gas (Cdn\$/Mcf)	9.35	7.13	6.00	5.61	7.37	7.45	6.36	6.03
<b>Unit Trading Performance</b>								
High (\$)	24.40	19.29	15.85	15.85	15.85	15.30	19.80	23.06
Low (\$)	17.51	14.55	14.46	12.51	13.77	13.00	12.43	18.50
Close (\$)	23.99	18.04	15.60	15.26	14.53	14.35	14.81	19.00
Volume (000s)	8,993	6,740	7,036	5,172	6,853	6,040	13,867	5,153

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

(2) See Non-GAAP Measures.

## Development Activities

### INDUSTRY ACTIVITY

According to statistics published by the Canadian Association of Oilwell Drilling Contractors, 3,148 wells were drilled in western Canada during the second quarter of 2008, down 3% from the second quarter last year (and down 17% for the year to date). This slowdown was expected, as 2008 drilling budgets were scaled-back in response to low natural gas prices throughout 2007 and uncertainty regarding the Alberta royalty regime. The price rebound of natural gas in the first half of 2008 has raised expectations for higher drilling activity in western Canada. However, spring break-up and wet weather in the second quarter delayed any significant uplift in activity. As well, cost pressures throughout the industry are having an equalizing effect on activity levels, constraining further growth. The Petroleum Services Association of Canada is predicting that, despite higher commodity prices, drilling in the second half of 2008 will remain consistent with the levels experienced in the first half of the year.

### ROYALTY INTEREST LANDS

Drilling on our royalty lands generally mirrors industry drilling. On an equivalent net basis, royalty drilling was down 6% in the second quarter but was up 8% for the six-month period. There are currently 95 (3.7 equivalent net) licensed drilling locations on our royalty lands, compared with 79 (4.6 equivalent net) locations at this time last year.

#### DRILLING ON ROYALTY LANDS

	Three Months Ended June 30			Six Months Ended June 30		
	2008	2007	Change	2008	2007	Change
<b>Unitized wells</b>						
Wells drilled by lessees	51	80	-36%	170	163	4%
Equivalent net <sup>(1)</sup>	0.2	0.2	0%	0.7	0.5	40%
<b>Non-unitized wells</b>						
Wells drilled by lessees	40	26	54%	151	133	14%
Equivalent net <sup>(1)</sup>	1.3	1.4	-7%	6.3	6.0	5%
<b>Total</b>						
Wells drilled by lessees	91	106	-14%	321	296	8%
Equivalent net <sup>(1)</sup>	1.5	1.6	-6%	7.0	6.5	8%

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

### ACQUISITION OF ROYALTY INTERESTS

On July 7, 2008, we acquired certain royalty interests in Alberta for \$8.5 million, prior to closing adjustments. The properties include royalties in units at Seven Persons, Bellshill Lake, Viking Kinsella, Beaverhill Lake, and Plain, as well as royalty interests in oil and natural gas properties at Medicine Hat, Killam, Wainwright, Viking Kinsella, and Skaro/Redwater. Proved plus probable reserves attributed to the properties were evaluated effective December 31, 2007 by an independent reserves evaluator at 202,000 boe. The acquisition of these properties supports our strategy of acquiring royalty interests. As there are no operating and capital costs or third party royalties associated with the royalty production acquired, this production receives high netbacks.

### WORKING INTEREST PROPERTIES

In the second quarter of 2008, we participated in the drilling of 7 (1.2 net) wells in Alberta and 4 (1.3 net) wells in Saskatchewan with a 100% net success rate. Second quarter drilling was lower in 2008 due to wet weather and timing differences of planned drilling programs.

**DRILLING ON WORKING  
INTEREST PROPERTIES**

	Three Months Ended June 30				Six Months Ended June 30			
	2008		2007		2008		2007	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Oil	10	2.2	13	3.4	14	2.7	18	5.4
Natural gas	-	-	9	0.3	7	0.2	21	0.4
Other	1	0.2	-	-	2	0.3	-	-
Total	11	2.4	22	3.7	23	3.2	39	5.8

## Results of Operations

### PRODUCTION

We have no operational control over our royalty lands, as we primarily hold small royalty interests in over 24,000 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.

In the second quarter of 2007, two natural gas wells in British Columbia were converted from royalty interests to working interests upon payout. To account for the change in status of the two wells, royalty volumes and revenues were adjusted downward, and in their place working interest volumes and revenues were booked, along with associated operating and royalty expenses.

Royalty production rose 1% in the second quarter, with royalty interests contributing 72% (2007 Q2 – 63%) of total volumes produced. The change in status of the two wells in the second quarter last year reduced royalty interest volumes in that quarter by approximately 1.3 MMcf per day of natural gas and 25 barrels per day of natural gas liquids. Weather conditions during the second quarter of 2008 hampered remedial operations on oil wells, and the full impact of production additions from drilling in 2007 and 2008 is not yet reflected in our results. Royalty production for the first six months of 2008 was 2% lower than last year.

Working interest production declined 31% in the second quarter of 2008 and 19% year to date, largely due to the one-time production adjustment in the second quarter of 2007 relating to the payout of two wells mentioned above. The change in status of these two wells inflated working interest volumes in the second quarter last year by approximately 4.4 MMcf per day of natural gas and 110 barrels per day of natural gas liquids. To a lesser extent, the volume decline can be attributable to wet conditions and a scheduled turnaround at the Hayter facility during June 2008.

On a boe basis, our production profile for the six months ended June 30, 2008 was 33% heavy oil, 37% natural gas, 26% light and medium oil, and 4% NGL.

#### AVERAGE DAILY PRODUCTION

	Three Months Ended June 30			Six Months Ended June 30		
	2008	2007	Change	2008	2007	Change
<b>Royalty lands</b>						
Oil (bbls/d)	2,893	3,022	-4%	3,014	3,159	-5%
NGL (bbls/d)	234	256	-9%	232	277	-16%
Natural gas (Mcf/d)	14,211	12,909	10%	14,481	14,125	3%
Oil equivalent (boe/d)	5,496	5,430	1%	5,660	5,790	-2%
<b>Working interest properties</b>						
Oil (bbls/d)	1,506	1,699	-11%	1,635	1,777	-8%
NGL (bbls/d)	73	125	-42%	71	103	-31%
Natural gas (Mcf/d)	3,595	7,874	-54%	3,289	5,372	-39%
Oil equivalent (boe/d)	2,178	3,136	-31%	2,254	2,775	-19%
<b>Total Trust</b>						
Oil (bbls/d)	4,399	4,721	-7%	4,649	4,936	-6%
NGL (bbls/d)	307	381	-19%	303	380	-20%
Natural gas (Mcf/d)	17,806	20,783	-14%	17,770	19,497	-9%
Oil equivalent (boe/d)	7,674	8,566	-10%	7,914	8,565	-8%
Number of days in period (days)	91	91	0%	182	181	1%
Total volumes during period (Mboe)	698	780	-11%	1,440	1,550	-7%
<b>Potash production (tonnes/d)</b>	<b>8.7</b>	14.0	-38%	12.4	14.6	-15%

#### MARKETING AND HEDGING

Our royalty lands consist of a large number of properties, with generally small volumes per property. A provision of the leases calls for our natural gas to be marketed with the lessees' production. Historically, we have chosen to market our oil production in the same manner. Some of our leases allow us to take our oil production in kind, and we have chosen to do so to speed up receipt of royalty income. As at June 30, 2008, approximately 40% of our royalty oil production was being marketed by Freehold using 30-day contracts.

We market most of our working interest oil production using 30-day contracts to ensure the highest competitive pricing. Approximately 4% of our natural gas production is sold under marketing arrangements tied to the Alberta monthly or daily spot price (AECO) or other indexed referenced prices.

On July 22, 2008, SemGroup L.P., a significant purchaser of oil and gas in western Canada, filed a voluntary petition for reorganization under Chapter 11 of the U.S. Bankruptcy Code as well as an application for creditor protection under the *Companies' Creditors Arrangement Act* in Canada for its subsidiary, SemCanada Crude Company. Overall, our potential exposure is not material because we do not market our production through SemCanada. Working interest production and royalty lands production that is taken in-kind has no exposure. Of the remaining 77% of our royalty production, the default provisions of the various contracts and leases from which our royalties are derived should serve to minimize our potential monetary losses where the royalty payor has marketed through SemCanada.

Our production was unhedged for the first six months of 2008, 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 of directors.

**BENCHMARK PRICES**

West Texas Intermediate (WTI) crude oil prices continued to set new records in the second quarter, with the average price up 91% from a year ago. Edmonton Par prices rose 75% and Bow River/Hardisty prices rose 106%. For the first six months of 2008, WTI has average US\$110.94, up 80% from the first half of 2007. Edmonton Par prices were 61% higher, and Bow River/Hardisty prices were 81% higher than the same period in 2007. To date in the third quarter, oil prices have remained volatile due to the fluctuating U.S. dollar and political instability in the Middle East and Africa, two key oil-producing regions.

AECO natural gas prices increased 27% in the second quarter; prices have increased steadily through the first seven months of 2008. Natural gas storage inventories are currently about 15% below last year's level and about 2% lower than 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 June 30			Six Months Ended June 30		
	2008	2007	Change	2008	2007	Change
WTI crude oil (US\$/bbl)	123.98	65.04	91%	110.94	61.60	80%
US\$/Cdn\$ exchange rate	0.9901	0.9112	9%	0.9931	0.8824	13%
Edmonton Par crude oil (Cdn\$/bbl)	126.07	71.93	75%	111.79	69.51	61%
Light/heavy oil differential (Cdn\$/bbl)	21.43	21.02	2%	20.45	19.00	8%
Bow River/Hardisty (Cdn\$/bbl)	104.64	50.91	106%	91.34	50.51	81%
AECO natural gas (Cdn\$/Mcf)	9.35	7.37	27%	8.24	7.41	11%

Source for commodity prices: Canadian Association of Petroleum Producers.

**REALIZED PRICES**

Our average selling prices reflect product quality and transportation differences from benchmark prices. On a boe basis, our average price realizations were 79% higher in the second quarter of 2008, and 57% higher in the first six months of the year. As approximately 33% 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 June 30			Six Months Ended June 30		
	2008	2007	Change	2008	2007	Change
Oil (\$/bbl)	105.63	51.34	106%	89.62	50.33	78%
NGL (\$/bbl)	81.17	60.03	35%	74.40	52.60	41%
Oil and NGL (\$/bbl)	104.04	51.99	100%	88.68	50.49	76%
Natural gas (\$/Mcf)	9.75	7.11	37%	8.67	7.24	20%
Oil equivalent (\$/boe)	86.43	48.21	79%	74.96	47.81	57%
Potash (\$/tonne)	716.98	236.16	204%	472.53	235.63	101%

## Revenue

Gross revenue increased 61% to \$61.3 million in the second quarter of 2008 as higher prices more than offset lower production. Oil prices were the largest contributor.

### REVENUE

(\$000s)	Three Months Ended June 30			Six Months Ended June 30		
	2008	2007	Change	2008	2007	Change
Gross revenue	61,301	38,015	61%	109,875	75,020	46%
Royalty and mineral tax expense <sup>(1)</sup>	(1,738)	(2,108)	-18%	(3,759)	(4,125)	-9%
Net revenue	59,563	35,907	66%	106,116	70,895	50%

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

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

### GROSS REVENUE VARIANCES

(\$000s)	Three Months Ended June 30		Six Months Ended June 30	
	2008 vs. 2007	2007 vs. 2006	2008 vs. 2007	2007 vs. 2006
<b>Oil and NGL</b>				
Production increase (decrease)	(3,745)	528	(5,404)	828
Price increase (decrease)	24,163	(3,401)	36,744	952
Net increase (decrease)	20,418	(2,873)	31,340	1,780
<b>Natural gas</b>				
Production increase (decrease)	(2,642)	942	(2,556)	(213)
Price increase (decrease)	5,006	1,946	5,062	326
Net increase (decrease)	2,364	2,888	2,506	113
<b>Other <sup>(1)</sup></b>	504	148	1,009	268
Gross revenue increase (decrease)	23,286	163	34,855	2,161

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

## Expenses

### ROYALTY EXPENSE AND MINERAL TAX

Royalty expense and mineral tax includes all Crown charges and royalty payments to third parties. Crown royalty rates are tied to commodity prices and production volumes. The majority of our 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 mineral taxes were not material and were recorded under working interest expenses. Mineral taxes recorded in the first half of 2007 included approximately \$250,000 that related to 2006. Royalty expenses in the second quarter last year were inflated due to the one time production adjustment related to the change in status of two wells, along with associated operating and royalty expenses.

ROYALTY EXPENSE AND MINERAL TAX <sup>(1)</sup> (\$000s, except as noted)	Three Months Ended June 30			Six Months Ended June 30		
	2008	2007	Change	2008	2007	Change
<b>Working interest properties</b>						
Crown royalties	1,395	1,871	-25%	2,490	2,641	-6%
Third party royalties	235	165	42%	564	393	44%
Mineral tax	87	69	26%	215	138	56%
Working interest properties	1,717	2,105	-18%	3,269	3,172	3%
Per boe (\$)	8.66	7.37	18%	7.97	6.32	26%
<b>Royalty lands</b>						
Crown royalties	—	—	—	—	—	—
Third party royalties	—	—	—	—	—	—
Mineral tax	21	3	600%	490	953	-49%
Royalty lands	21	3	600%	490	953	-49%
Per boe (\$)	0.04	0.01	300%	0.48	0.91	-47%
<b>Total Trust</b>	1,738	2,108	-18%	3,759	4,125	-9%
Per boe (\$)	2.49	2.70	-8%	2.61	2.66	-2%

(1) Royalty expense and mineral tax includes all Crown charges and 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 39% in the second quarter because of lower production and scheduled maintenance, as well as inflationary pressures. Operating costs in the second quarter last year were inflated due to the one time production adjustment related to the change in status of two wells, along with associated operating and royalty expenses.

OPERATING EXPENSES	Three Months Ended June 30			Six Months Ended June 30		
	2008	2007	Change	2008	2007	Change
Working interest properties (\$000s)	2,849	2,953	-4%	5,506	5,516	0%
Per boe (\$)	14.37	10.34	39%	13.42	10.98	22%
Royalty lands <sup>(1)</sup> (\$000s)	—	—	—	—	—	—
Per boe (\$)	—	—	—	—	—	—
Total operating expenses (\$000s)	2,849	2,953	-4%	5,506	5,516	0%
Total Trust (\$/boe)	4.08	3.79	8%	3.82	3.56	7%

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

**GENERAL AND ADMINISTRATIVE EXPENSES (G&A)**

G&A expenses include direct costs incurred by the Trust and reimbursement of the G&A expenses incurred by the Manager on behalf of the Trust. G&A expenses in 2008 reflect 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 expenses totalled \$1.5 million in the second quarter, including \$1.2 million charged by the Manager for time and direct costs incurred on behalf of the Trust.

**G&A EXPENSES**

	Three Months Ended June 30			Six Months Ended June 30		
	2008	2007	Change	2008	2007	Change
G&A expenses (\$000s)	1,504	1,237	22%	3,847	3,463	11%
Per boe (\$)	2.15	1.59	35%	2.67	2.23	20%
As a percentage of revenue	2%	3%	-33%	4%	5%	-20%

**UNIT BASED COMPENSATION**

The Trust pays a portion of the costs associated with a long-term incentive compensation plan for employees of the Manager (the Manager's LTIP). For the three months ended June 30, 2008, Freehold expensed \$1.3 million (2007 – \$51,000) as unit based compensation. The total for the six month period ended June 30, 2008 was \$1.7 million (2007 – \$103,000). The liability is estimated at the end of each quarter based on the quarter end Trust Unit price and performance factors, and the related compensation charges are recognized over the vesting period. The increase in unit based compensation in 2008 reflects an increase in the Trust Unit price and the expected performance factors. At June 30, 2008, Freehold recorded \$2.3 million as a deferred long-term compensation asset and \$194,000 as a current portion of deferred long-term compensation, representing the portion of the LTIP liability not yet charged to earnings. In addition, Freehold accrued \$3.6 million as a long-term liability and \$1.2 million as a current liability.

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 on the date of distribution. For the three months ended June 30, 2008, Freehold expensed \$41,000 of unit based compensation with a corresponding increase to contributed surplus (2007 – \$13,000). The total for the six month period ended June 30, 2008 was \$238,000 (2007 – \$235,000).

**UNIT BASED COMPENSATION**

	Three Months Ended June 30			Six Months Ended June 30		
	2008	2007	Change	2008	2007	Change
Unit based compensation	1,365	64	2033%	1,913	338	466%
Per boe (\$)	1.95	0.08	2238%	1.33	0.22	505%
As a percentage of revenue	2%	0%	—	2%	0%	—

**INTEREST EXPENSES**

Interest expenses increased 36% in the second 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 June 30			Six Months Ended June 30		
	2008	2007	Change	2008	2007	Change
Net interest expense (000s)	1,788	1,312	36%	4,000	2,650	51%
Per boe (\$)	2.56	1.68	52%	2.78	1.71	63%

## 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 (\$000s, except as noted)	Six Months Ended June 30		Year Ended December 31
	2008	2007	2007
Depletion and depreciation	34,579	35,549	72,400
Accretion of asset retirement obligation	191	134	266
Total depletion, depreciation and accretion expenses	34,770	35,683	72,666
Per boe (\$)	24.14	23.02	23.47

## MANAGEMENT FEES

The quarterly management fee, which is paid in Trust Units, was 35,654 Trust Units for the second quarter of 2008, unchanged from 2007. The ascribed value was 65% higher because of a higher Trust Unit price at the end of the second quarter of 2008.

MANAGEMENT FEES (Paid in Trust Units)	Three Months Ended June 30			Six Months Ended June 30		
	2008	2007	Change	2008	2007	Change
Trust Units issued in payment of management fees	35,654	35,654	0%	71,308	71,308	0%
Ascribed value (\$000s) <sup>(1)</sup>	855	518	65%	1,498	1,030	45%
Per boe (\$)	1.22	0.66	85%	1.04	0.66	58%

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

## Operating Netback

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. 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, production from which yields higher netbacks.

NETBACK ANALYSIS (\$000s)	Six months ended June 30, 2008		
	Royalty Interest Lands	Working Interest Properties	Total Trust
Gross revenue <sup>(1)</sup>	76,525	33,350	109,875
Royalty expense and mineral tax <sup>(2)</sup>	(490)	(3,269)	(3,759)
Net revenue	76,035	30,081	106,116
Operating expense	-	(5,506)	(5,506)
	76,035	24,575	100,610

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

(2) Royalty expense and mineral tax includes all Crown charges and royalty payments to third parties.

In the second quarter of 2008, our operating netback was \$81.21 (2007 - \$42.28) per boe, up 92% due to higher commodity prices. As our production is unhedged, we have received the full benefit of the higher prices.

**OPERATING NETBACKS**

(\$ per boe)	Six months ended June 30, 2008		
	Royalty Interest	Working Interest	Total Trust
	Lands	Properties	
Gross revenue <sup>(1)</sup>	74.30	81.31	76.29
Royalty expense and mineral tax <sup>(2)</sup>	(0.48)	(7.97)	(2.61)
Net revenue	73.82	73.34	73.68
Operating expense	-	(13.42)	(3.82)
Operating netback	73.82	59.92	69.86

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

(2) Royalty expense and mineral tax includes all Crown charges and royalty payments to third parties.

**Funds Generated From Operations and Net Income**

Cash provided by operating activities rose 50% and funds generated from operations rose 76% from the second quarter last year, reflecting higher commodity prices, partly offset by lower production. Net income was \$36.2 million compared with a loss of \$42.5 million in the second quarter 2007. The second quarter loss last year included a \$54.3 million non-cash provision for future income tax following the enactment of the Canadian income trust taxation legislation.

**FUNDS GENERATED FROM OPERATIONS AND NET INCOME**

(\$000s, except as noted)	Three Months Ended June 30			Six Months Ended June 30		
	2008	2007	Change	2008	2007	Change
Cash provided by operating activities	46,379	30,829	50%	80,200	57,342	40%
Changes in non-cash working capital	6,804	(616)	-1205%	12,165	1,168	942%
Funds generated from operations	53,183	30,213	76%	92,365	58,510	58%
Per Trust Unit (\$)	1.08	0.61	77%	1.87	1.19	57%
Net income (loss)	36,163	(42,533)	-185%	59,810	(32,746)	-283%
Per Trust Unit, basic and diluted (\$)	0.73	(0.86)	-185%	1.21	(0.67)	-281%

**Distributions**

Our distributions have increased twice in 2008 in response to higher commodity prices. On April 21, 2008, we announced a 20% increase in the distribution rate to \$0.18 per Trust Unit effective with the April distribution, and on June 12, 2008, we announced a 39% increase in the distribution rate to \$0.25 per Trust Unit from \$0.18 per Trust Unit effective with the June distribution.

Distributions to Unitholders totalled \$0.61 per Trust Unit for the second quarter and \$1.06 for the year to date. Since inception, the Trust has distributed \$633 million (\$17.28 per Trust Unit) to Unitholders.

**ACCUMULATED DISTRIBUTIONS**

	Three Months Ended June 30		Six Months Ended June 30	
	2008	2007	2008	2007
Distributions declared (\$000s)	30,114	22,151	52,312	14,284
Accumulated, beginning of period	602,867	508,257	580,669	486,124
Accumulated, end of period	632,981	530,408	632,981	500,408
Distributions per Trust Unit (\$) <sup>(1)</sup>	0.61	0.45	1.06	0.90
Accumulated, beginning of period	16.67	14.75	16.22	14.30
Accumulated, end of period	17.28	15.20	17.28	15.20

(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. The Trust has historically distributed less cash than cash provided by operating activities. This excess cash has been used to fund capital expenditures and repay bank debt as required. Net income includes significant non-cash charges that do not affect cash flow. These charges amounted to \$17.2 million for the second quarter of 2008 (2007 – \$72.9 million) and \$32.8 million (2007 – \$91.8 million) for the first half of 2008. 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 June 30		Six Months Ended June 30	
	2008	2007	2008	2007
Cash provided by operating activities	46,379	30,829	80,200	57,342
Net income (loss)	36,163	(42,533)	59,810	(32,746)
Distributions declared	30,114	22,151	52,312	44,284
Excess of cash provided by operating activities over distributions declared	54%	39%	53%	29%
Excess (shortfall) of net income over distributions declared	20%	(292%)	14%	(174%)

## Liquidity and Capital Resources

Our capital expenditure obligations (with respect to our working interest properties) are deducted from cash provided by operating activities prior to the determination of distributions to Unitholders. Capital expenditures on working interest properties totalled \$2.1 million in the second quarter and \$4.3 million for the year to date.

### CAPITAL EXPENDITURES

(\$000s, except as noted)	Three Months Ended June 30			Six Months Ended June 30		
	2008	2007	Change	2008	2007	Change
Capital expenditures	2,135	2,830	-25%	4,337	6,306	-31%
Change in reclamation fund	(9)	(39)	-77%	81	(341)	-124%
	2,126	2,791	-24%	4,418	5,965	-26%

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.

### RECLAMATION FUND

We are liable for our share of ongoing environmental obligations and the ultimate reclamation of our working interest properties upon abandonment. We have no reclamation responsibilities on our royalty assets, as these are the responsibility of the working interest owners. Ongoing environmental obligations are funded from cash provided by operating activities. Our reclamation fund consists of cash invested in an interest-bearing account and is funded by quarterly cash payments of \$150,000. We contributed \$319,000 in cash and interest to the fund during the first half of

2008 and withdrew \$238,000, which was spent on reclamation activities. At June 30, 2008, the fund had a balance of \$1.9 million.

### DEBT ANALYSIS

We increased debt to fund acquisitions in the third quarter of 2007. During the second quarter, we reduced debt by \$18 million. At June 30, 2008, we had no short-term debt outstanding and long-term debt was \$151 million. We had positive working capital of \$18 million, resulting in net debt of \$133 million. In addition, we had accrued a \$4.7 million liability relating to incentive compensation pursuant to the Manager's LTIP. We currently have \$59 million of available capacity under our credit facilities.

We added to our debt in the third quarter of 2008 with the acquisition of certain royalty interests in Alberta for \$8.5 million, prior to closing adjustments. The purchase price was funded through Freehold's existing credit facilities.

DEBT ANALYSIS (\$000s)	June 30		December 31
	2008	2007	2007
Long-term debt	151,000	100,000	178,000
Short-term debt	-	-	-
Total debt	151,000	100,000	178,000
Less: working capital	18,032	11,241	11,219
Net debt obligations	132,968	88,759	166,781

At June 30, 2008, our ratio of net debt (total debt less positive working capital) to trailing funds generated from operations was 0.9 to 1, reflecting the Trust's healthy financial condition.

FINANCIAL LEVERAGE AND COVERAGE RATIOS <sup>(1)</sup>	June 30		December 31
	2008	2007	2007
Net debt to funds generated from operations (times)	0.9	0.8	1.4
Net debt to distributions (times)	1.3	0.9	1.8
Distributions to interest expense (times)	12.3	17.6	13.5
Net debt to net debt plus equity (%)	33%	25%	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 second quarter mainly due to higher commodity prices, which increased the dollar value of accounts receivable.

**COMPONENTS OF  
WORKING CAPITAL**

	June 30	Mar. 31	Dec. 31	Sept. 30	June 30
(\$000s)	2008	2008	2007	2007	2007
Cash	521	617	393	82	254
Current portion of deferred compensation	194	106	-	-	-
Accounts receivable	42,538	35,131	26,802	26,883	25,865
Current assets	43,253	35,854	27,195	26,965	26,119
Distributions declared	(12,347)	(7,403)	(7,398)	(7,392)	(7,387)
Current portion of unit based compensation	(1,166)	(423)	-	-	-
Accounts payable and accrued liabilities	(11,708)	(11,433)	(8,578)	(7,891)	(7,491)
Current liabilities	(25,221)	(19,259)	(15,976)	(15,283)	(14,878)
Working capital <sup>(1)</sup>	18,032	16,595	11,219	11,682	11,241

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

**FUTURE INCOME TAX**

The future income tax liability on our Consolidated Balance Sheet as at June 30, 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.

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.

In June 2008, Bill C-50, which contains legislation to adjust the deemed provincial component on the SIFT tax rate, received Royal Assent. Under this legislation, the provincial component will be based on actual provincial corporate tax rates under a formula giving equal weight to province-by-province payrolls and revenues rather than a flat provincial rate of 13% as previously announced. This is a positive development for Alberta-based income trusts, as the provincial tax rate is currently 10%. However, we have not adjusted our provision for future income tax, as the specific income tax regulations for the adjustment have not been finalized.

On July 14, 2008, the Department of Finance released draft amendments to the Canadian Income Tax Act to facilitate the conversion of SIFT entities into corporations. We are currently assessing the draft rules as they relate to our particular circumstances. In addition, our board has established a special committee comprised of independent board members with a mandate to determine a course of action that best maximizes Unitholder value when the SIFT tax comes into effect in 2011. In the interim, we plan to retain the flow-through advantages of our current structure.

**Outlook**

Drilling activity on our working interest properties are expected to accelerate in the second half of the year. Capital expenditures are expected to top \$6.3 million with the bulk of this directed to our major properties at Hayter, Alberta, and in Southeast Saskatchewan. In the third quarter, we will complete our 2008 development program at Hayter, Alberta and continue our development program in Southeast Saskatchewan. Since 2006, we have participated in the drilling of 18 gross (2.8 net) Bakken oil wells of which 3 (0.8 net) were in the second quarter. Of these, 12 (2.0 net) have been fracture stimulated. Production from the Bakken trend will increase as more wells are fracture stimulated and new wells are drilled during the second half of 2008. Our previous production guidance of 7,900 boe per day for the full year remains unchanged with production additions in the second half expected to offset natural production declines.

Our distribution policy takes into consideration forecasted cash provided by operating activities, debt levels, debt covenants, capital expenditures, and reclamation fund requirements. 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. Under our credit facility, we are restricted from making distributions if we are or would be in default under the credit facility or if our borrowings thereunder exceed our borrowing base, currently set at \$210 million. As at June 30, 2008, we were in compliance with all of our debt covenants.

The following table contains our key operating assumptions for 2008 based on actual results for the first half of the year and our current outlook for the second half. Based on these operating assumptions, we may be required to consider a special distribution at year-end. However, excess cash provided by operating activities in the second half of the year might also be used to fund additional acquisitions or increases in our capital program should appropriate opportunities arise. We will continue to monitor prices and activity levels closely, and our guidance will be reviewed and updated quarterly.

#### 2008 KEY OPERATING ASSUMPTIONS

	MD&A	News Release	MD&A Dated	
	Dated	Dated	May 7	Feb. 27
	August 13	June 12	2008	2008
	2008	2008	2008	2008
Average daily production (boe/d)	7,900	7,900	8,200	8,200
Average WTI oil price (US\$/bbl)	116.00	114.00	100.00	85.00
Average light/heavy oil price differential (Cdn\$/bbl)	23.00	24.00	26.00	25.00
Average Bow River Hardisty oil price (Cdn\$/bbl)	94.00	90.00	73.00	60.00
Average AECO natural gas price (Cdn\$/Mcf)	8.90	8.60	6.85	6.65
Average exchange rate (Cdn\$/US\$)	0.99	0.99	0.99	1.00
Average operating costs (\$/boe)	3.85	3.85	3.85	3.85
Average G&A costs	2.55	2.55	2.44	2.44
Capital expenditures (\$ millions)	10.6	10.6	10.6	10.6
Long-term debt at year end (\$ millions)	155	155	155	155
Weighted average Trust Units outstanding (thousands)	49,371	49,371	49,371	49,371
Estimated portion of distributions taxable as income (%)	90-100%	90-100%	90-100%	90-100%

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 33% of our total boe production is heavy oil.

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

## Trust Units Outstanding

As at June 30, 2008 and August 13, 2008, there were 49,388,121 Trust Units outstanding. At the end of the second quarter, the Trust issued 35,654 Trust Units to the Manager in payment of the quarterly management fee.

On May 7, 2008, the Board granted 1,002 deferred trust units to Tullio Cedraschi, who was elected as an independent director at our Annual Meeting of Unitholders on May 7, 2008. As at June 30, 2008, there were 40,288 deferred trust units outstanding and at August 13, 2008, there were 40,727 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		
	2008	2007	Change	2008	2007	Change
Weighted average						
Basic	49,352,859	49,210,243	—	49,335,032	49,192,516	—
Diluted	49,394,038	49,210,243	—	49,376,726	49,192,516	—
At period end	49,388,121	49,245,505	—	49,388,121	49,245,505	—

## Environmental Regulation and Risk

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation under a variety of federal, provincial, and local laws and regulations. Compliance with these regulations can require significant expenditures and a breach may result in fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability, and potentially increased capital expenditures and operating costs.

On January 24, 2008, the Alberta Government announced its plan to reduce projected emissions in the province by 50% by 2050. This will result in real reductions of 14% below 2005 levels. The Alberta Government stated it would form a government-industry council to determine a go-forward plan for implementing technologies, which will significantly reduce greenhouse gas emissions by capturing air emissions from industrial sources and locking them permanently underground in deep rock formations (carbon capture). In addition, the plan calls for energy conservation by individuals and for increased investment in clean energy technologies and incentives for expanding the use of renewable and alternative energy sources such as bioenergy, wind, solar, hydrogen, and geothermal. Initiatives under this theme will account for 18% of Alberta's reductions.

On January 31, 2008, the Government of Canada and the Province of Alberta released the final report of the Canada-Alberta ecoENERGY Carbon Capture and Storage Task Force, which recommends among others: (i) incorporating carbon capture and storage into Canada's clean air regulations; (ii) allocating new funding into projects through competitive process; and (iii) targeting research to lower the cost of technology.

On March 10, 2008, the Government of Canada released "Turning the Corner – Taking Action to Fight Climate Change" which provides some additional guidance with respect to the Government of Canada's plan to reduce greenhouse gas emissions by 20% by 2020 and by 60% to 70% by 2050. The updated action plan is primarily directed towards industrial emissions from certain specified industries including the oil sands, oil and gas, and refining industries. The updated action plan is intended to force industry to reduce greenhouse gas emissions and to create a carbon emissions trading market, including an offset system, to provide incentive to reduce greenhouse gas emission and establish a market price for carbon. The updated action plan provides for: (i) mandatory reductions of 18% from the 2006 baseline starting in 2010 and by an addition 2% in subsequent years for existing facilities; (ii) new facilities built between 2004 and 2011 will have mandatory emissions standards based upon clean fuel standards (natural gas) with a 2% reduction below the third years intensity levels; and (iii) oil sands plants built in 2012 and later which use heavier hydrocarbons and upgraders and in situ production will have mandatory standards in 2018 based carbon capture and

storage or other green technologies intensity. For the upstream oil and gas industry, the updated action plan also provides for a company threshold of 10,000 boe per day and facility threshold of 3,000 tonnes of CO<sub>2</sub>.

Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact of those requirements on the Trust and its operations and financial condition.

## 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 disclosure of 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 and six months ended June 30, 2008.

## New Accounting Standards

In January 2006, the Canadian Accounting Standards Board (AcSB) adopted a strategic plan for the direction of accounting standards in Canada. As part of the AcSB's strategic plan, Canadian publicly accountable entities will be required to report under International Financial Reporting Standards (IFRS), which will replace Canadian GAAP for years beginning on or after January 1, 2011. An omnibus exposure draft was issued by the AcSB in the second quarter of 2008, which incorporates IFRS into the CICA Handbook and prescribes the transitional provisions for adopting IFRS. Currently, we are assessing the effects of adoption and developing a plan accordingly. We will continue to monitor any changes in the adoption of IFRS and will update plans as necessary.

## Internal Controls

During the three months ended June 30, 2008, there were no changes in internal control over financial reporting that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

On April 18, 2008, the Canadian Securities Administrators published a notice and request for comments on the proposed repeal and replacement of Multilateral Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings. The proposed changes would include the requirement to provide certification of the effectiveness of internal controls over financial reporting for years ending after December 15, 2008. On July 11, 2008, the Canadian Securities Administrators issued Staff Notice 52-322 recommending securities commissions proceed with the December 15, 2008 effective date. We are advancing our plans to test the operating effectiveness of internal controls over financial reporting and provide the required certification.

## Consolidated Balance Sheets

(\$000s) (unaudited)	June 30 2008	December 31 2007
<b>Assets</b>		
Current assets:		
Cash	\$ 521	\$ 393
Accounts receivable	42,538	26,802
Current portion of deferred long-term compensation (note 5)	194	-
	<b>43,253</b>	<b>27,195</b>
Reclamation fund	1,869	1,788
Deposit on acquisition (note 2)	850	-
Deferred long-term compensation (note 5)	2,349	697
Petroleum and natural gas interests, net of accumulated depletion and depreciation of \$416,710 (2007 - \$382,131)	444,416	474,520
	<b>\$ 492,737</b>	<b>\$ 504,200</b>
<b>Liabilities and Unitholders' Equity</b>		
Current liabilities:		
Distributions payable to Unitholders	\$ 12,347	\$ 7,398
Accounts payable and accrued liabilities	11,708	8,578
Current portion of unit based compensation payable (note 5)	1,166	-
	<b>25,221</b>	<b>15,976</b>
Asset retirement obligation	6,700	6,608
Unit based compensation payable (note 5)	3,550	1,106
Long-term debt (note 3)	151,000	178,000
Future income tax liability	46,016	51,404
Unitholders' equity:		
Unitholders' capital (note 4)	566,326	564,828
Contributed surplus (note 5)	660	512
Deficit	(306,736)	(314,234)
	<b>260,250</b>	<b>251,106</b>
	<b>\$ 492,737</b>	<b>\$ 504,200</b>

See accompanying notes to interim consolidated financial statements.

## Consolidated Statements of Income (Loss), Comprehensive Income (Loss) and Deficit

(Unaudited) (\$000s, except per unit and weighted average data)	Three Months Ended June 30		Six Months Ended June 30	
	2008	2007	2008	2007
Revenue:				
Royalty income and working interest sales	\$ 61,301	\$ 38,015	\$ 109,875	\$ 75,020
Royalty expense and mineral tax	(1,738)	(2,108)	(3,759)	(4,125)
	<b>59,563</b>	<b>35,907</b>	<b>106,116</b>	<b>70,895</b>
Expenses:				
Operating	2,849	2,953	5,506	5,516
General and administrative	1,504	1,237	3,847	3,463
Unit based compensation (note 5)	1,365	64	1,913	338
Interest on long-term debt	1,788	1,312	4,000	2,650
Depletion and depreciation	17,006	17,923	34,579	35,549
Accretion of asset retirement obligation	96	65	191	134
Management fee	855	518	1,498	1,030
	<b>25,463</b>	<b>24,072</b>	<b>51,534</b>	<b>48,680</b>
Net income before taxes	34,100	11,835	54,582	22,215
Income and capital taxes	74	37	160	182
Future income tax expense (reduction)	(2,137)	54,331	(5,388)	54,779
	<b>(2,063)</b>	<b>54,368</b>	<b>(5,228)</b>	<b>54,961</b>
Net income (loss) and comprehensive income (loss)	\$ 36,163	\$ (42,533)	\$ 59,810	\$ (32,746)
Deficit, beginning of period	(312,785)	(230,843)	(314,234)	(218,497)
Distributions declared	(30,114)	(22,151)	(52,312)	(44,284)
Deficit, end of period	\$ (306,736)	\$ (295,527)	\$ (306,736)	\$ (295,527)
Net income (loss) per Trust Unit, basic and diluted	\$ 0.73	\$ (0.86)	\$ 1.21	\$ (0.67)
Weighted average number of Trust Units:				
Basic	49,352,859	49,210,243	49,335,032	49,192,516
Diluted	49,394,038	49,210,243	49,376,726	49,192,516

See accompanying notes to interim consolidated financial statements.

## Consolidated Statements of Cash Flows

(Unaudited) (\$000s)	Three Months Ended June 30		Six Months Ended June 30	
	2008	2007	2008	2007
Cash provided by (used in):				
Operating:				
Net income (loss)	\$ 36,163	\$ (42,533)	\$ 59,810	\$ (32,746)
Items not involving cash:				
Depletion and depreciation	17,006	17,923	34,579	35,549
Trust Unit incentive compensation (note 5)	1,365	64	1,913	338
Future income tax expense (reduction)	(2,137)	54,331	(5,388)	54,779
Accretion of asset retirement obligation	96	65	191	134
Trust Units issued in lieu of management fee	855	518	1,498	1,030
Expenditures on reclamation	(165)	(155)	(238)	(574)
	53,183	30,213	92,365	58,510
Changes in non-cash working capital	(6,804)	616	(12,165)	(1,168)
	46,379	30,829	80,200	57,342
Financing:				
Long-term debt	(18,000)	1,000	(27,000)	-
Distributions paid	(25,169)	(22,144)	(47,362)	(44,272)
	(43,169)	(21,144)	(74,362)	(44,272)
Investing:				
Capital expenditures	(2,135)	(2,830)	(4,337)	(6,306)
Deposit on acquisition	(850)	(6,070)	(850)	(6,070)
Change in reclamation fund	9	39	(81)	341
Changes in non-cash working capital	(330)	(1,247)	(442)	(1,202)
	(3,306)	(10,108)	(5,710)	(13,237)
Increase (decrease) in cash	(96)	(423)	128	(167)
Cash, beginning of period	617	677	393	421
Cash, end of period	\$ 521	\$ 254	\$ 521	\$ 254

See accompanying notes to interim consolidated financial statements.

# Notes to Interim Consolidated Financial Statements

For the period ended June 30, 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 audited 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, debt covenants, 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.

As a result of the Canadian trust taxation legislation passed in June 2007 and effective January 1, 2011, the Trust is subject to certain capital growth restrictions referred to as "normal growth" equity rules. These rules limit the amount of Unitholders' capital that can be issued by the Trust in each of the next three years, based on the Trust's market capitalization on October 31, 2006. Our market capitalization as of the close of trading on October 31, 2006 was approximately \$929 million, which means our safe harbour equity growth amount for calendar 2008 is \$557 million, and for each of calendar 2009 and 2010 is an additional \$186 million with an ultimate total equity growth amount of no more than \$929 million.

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. Under our credit facility, we are restricted from making distributions if we are or would be in default under the credit facility or if our borrowings thereunder exceed our borrowing base, currently set at \$210 million. As at June 30, 2008, the Trust was in compliance with all such covenants.

<b>CAPITALIZATION</b> (\$000s, except as noted)	June 30 2008	December 31 2007
Unitholders' equity	260,250	251,106
Long term debt	151,000	178,000
Working capital	(18,032)	(11,219)
Net debt	132,968	166,781
Cash provided by operating activities for last 12 months	142,499	119,641
Change in non-cash working capital	12,364	1,367
Trailing 12 months funds generated from operations	154,863	121,008
Net debt to trailing 12 month funds generated from operations (times)	0.9	1.4

#### **(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 June 30, 2008 and December 31, 2007 and did not provide for any doubtful accounts nor were we 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 June 30, 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 June 30, 2008, would have resulted in a corresponding change to net income of approximately \$0.6 million (2007 – \$0.4 million).

## Commodity price risk

- Commodity price risk is the risk that the fair value of future cash flows will fluctuate with 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 June 30, 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 June 30, 2008, would have resulted in a corresponding change to net income of approximately \$0.6 million (2007 – \$0.5 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 June 30, 2008 would have resulted in a corresponding change to net income of approximately \$0.4 million (2007 – \$0.2 million).

**2. Property acquisition**

On July 7, 2008, Freehold closed an acquisition of certain royalty interests in Alberta for \$8.5 million, prior to adjustments. The acquisition was effective June 1, 2008 and was funded through existing credit facilities. In the second quarter of 2008, a deposit of \$850,000 was paid to the vendor, which was subsequently applied against the net acquisition cost.

**3. Long-Term Debt**

Freehold has a \$195 million extendible revolving term credit facility, extendible annually, on which \$151 million was drawn at June 30, 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 2009. 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 100 to 170 basis points and standby fees. The facilities are secured with \$300 million demand debentures over Freehold's petroleum and natural gas assets.

## 4. Unitholders' Capital

	June 30, 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	71,308	1,498	142,616	2,130
Balance, end of period	49,388,121	566,326	49,316,813	564,828

For the purposes of calculating diluted net loss per Trust Unit for the three and six months periods ending June 30, 2007, incremental Trust Units from assumed redemption of deferred trust units are not included due to the anti-dilutive effect. The Trust Units not included were 28,051 and 27,619 for three and six month periods, respectively.

## 5. Unit Based Compensation

### (a) 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 June 30, 2008, Freehold expensed \$1,324,000 (2007 – \$51,000) as unit based compensation. The total for the six month period ended June 30, 2008 was \$1,675,000 (2007 – \$103,000). At June 30, 2008, Freehold recorded \$2,349,000 as a deferred long-term compensation asset and \$194,000 as a current portion of deferred long-term compensation, representing the portion of the liability not yet charged to earnings. In addition, Freehold accrued \$3,550,000 as a long-term liability and \$1,166,000 as a current liability.

### (b) 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 June 30, 2008, there were 40,288 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 June 30, 2008, Freehold expensed \$41,000 of unit based compensation with a corresponding increase to contributed surplus (2007 – \$13,000). The total for the six month period ended June 30, 2008 was \$238,000 (2007 – \$235,000).

CONTRIBUTED SURPLUS (\$000s)	June 30 2008	December 31 2007
Balance, beginning of period	512	247
Trust Unit incentive compensation expense	148	265
Balance, end of period	660	512

## 6. Related Party Transactions

For the three months ended June 30, 2008, Freehold issued 35,654 Trust Units as management fee to the Manager, Rife Resources Ltd., (2007 – 35,654 Trust Units) pursuant to a management agreement. The ascribed value of \$855,000 (2007

– \$518,000) is based on the closing price of the Trust Units on the last trading day of the quarter. The total Trust Units issued for the six month period ended June 30, 2008 was 71,308 Trust Units (2007 – 71,308) with an ascribed value of \$1,498,000 (2007 – \$1,030,000).

For the three months ended June 30, 2008, the Manager charged the Trust \$1,246,000 in general and administrative costs (2007 – \$1,049,000). The total for the six month period ended June 30, 2007 was \$3,038,000 (2007 – \$2,694,000). At June 30, 2008, there was \$375,000 (2007 – \$411,000) in accounts payable and accrued liabilities relating to these costs. The transactions were in the normal course of operations and were measured at the exchange amount, which was 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 June 30		Six Months Ended June 30	
	2008	2007	2008	2007
Interest	1,668	1,272	3,725	2,580
Taxes	13	(685)	203	(407)

## Corporate Information

### BOARD OF DIRECTORS

**William W. Siebens** (5)  
President and Chief Executive Officer  
Candor Investments Ltd.

**D. Nolan Blades** (1)(3)(4)(5)  
President  
Sunny Gables Holdings Ltd.

**Harry S. Campbell, Q.C.** (2)(3)(5)  
Vice-Chair  
Burnet, Duckworth & Palmer, LLP

**Tullio Cedraschi** (2)(5)  
Corporate Director

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

**Russell J. Hiscock**  
President and Chief Executive Officer  
CN Investment Division

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

**David J. Sandmeyer**  
President and Chief Executive Officer  
Rife Resources Ltd.

- (1) Audit Committee
- (2) Governance Committee
- (3) Reserves Committee
- (4) Compensation Committee
- (5) Corporate SIFT Tax Strategy Committee

### 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](mailto:service@computershare.com)

### OFFICERS

**William W. Siebens**  
Chair of the Board

**David J. Sandmeyer**  
President and Chief Executive Officer

**William O. Ingram**  
Executive Vice-President and Chief  
Operating Officer

**Joseph N. Holowisky**  
Senior Vice-President, Special Projects

**Garry W. Bieber**  
Vice-President, Production

**J. Frank George**  
Vice-President, Exploitation

**Darren G. Gunderson**  
Vice-President, Finance and Chief  
Financial Officer

**Michael J. Okrusko**  
Vice-President, Land

**Michael J. Mogan**  
Controller

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

### 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

The Toronto-Dominion Bank  
Calgary, Alberta

### RESERVE EVALUATORS

Trimble Engineering Associates Ltd.  
Calgary, Alberta

### HEAD OFFICE

Freehold Resources Ltd.  
Freehold Royalty Trust  
400, 144 – 4th Avenue S.W.  
Calgary, Alberta T2P 3N4  
Telephone: (403) 221-0802  
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### INVESTOR RELATIONS

Karen C. Taylor  
Manager, Investor Relations and  
Corporate Secretary  
Telephone: (403) 221-0891  
Toll Free: 1-888-257-1873  
Email: [ir@freeholdtrust.com](mailto:ir@freeholdtrust.com)

### WEBSITE

[www.freeholdtrust.com](http://www.freeholdtrust.com)

### 2008 SECOND QUARTER TRADING SUMMARY

High – \$24.40  
Low – \$17.51  
Close – \$23.99  
Volume – 9.0 million  
Trust Units Outstanding – 49.4 million  
Market Capitalization – \$1.2 billion  
(June 30)

### 2008 SECOND QUARTER DISTRIBUTIONS DECLARED

Record Date	Payment Date	Per Trust Unit
April 30, 2008	May 15, 2008	\$0.18
May 31, 2008	June 15, 2008	\$0.18
June 30, 2008	July 15, 2008	<u>\$0.25</u>
		<u>\$0.61</u>

Tax information and historical distributions are available on our website.