

Freehold Royalty Trust Announces 2007 Third Quarter Results

THIRD QUARTER HIGHLIGHTS

- Revenue was \$37 million, down 3% from the third quarter of 2006.
- Production averaged 8,219 barrels of oil equivalent (boe) per day, down 1% quarter over quarter.
- Price realizations averaged \$48.28 per boe, 1% lower than the third quarter a year ago.
- Operating netback was \$43.65 per boe, down 3% from last year.
- Funds generated from operations decreased 6% to \$30 million (\$0.61 per Trust Unit).
- Distributions declared in the third quarter amounted to \$0.45 per Trust Unit, down 17% quarter over quarter.
- Completed two previously announced acquisitions of royalty interests for \$90 million net of adjustments.

The next regular monthly distribution of \$0.15 per Trust Unit will be paid on December 15, 2007, to Unitholders of record on November 30, 2007 (ex-distribution date November 28, 2007). In addition, the Board of Directors has declared an additional payment of \$0.12 per Trust Unit to be paid on December 15, 2007, to Unitholders of record on November 30, 2007 (ex-distribution date November 28, 2007). The additional payment is based on expected excess cash in 2007 due to high commodity prices and higher production volumes as a result of recently completed acquisitions. The \$0.12 payment will be made concurrently with the regular \$0.15 monthly distribution payable to Unitholders on December 15, 2007. Including the December 15, 2007 payments, 12-month trailing cash distributions total \$1.92 per Trust Unit.

Results at a Glance	Three Months Ended			Nine Months Ended		
	September 30			September 30		
	2007	2006	Change	2007	2006	Change
Financial (\$000s, except as noted)						
Gross revenue	36,931	37,994	-3%	111,951	110,853	1%
Operating income	33,005	34,439	-4%	98,384	101,421	-3%
Net income (loss)	12,487	12,728	-2%	(20,259)	35,636	-157%
Per Trust Unit, basic and diluted (\$)	0.25	0.26	-4%	(0.41)	0.73	-156%
Funds generated from operations	29,907	31,692	-6%	88,417	92,455	-4%
Per Trust Unit (\$)	0.61	0.65	-6%	1.80	1.88	-4%
Capital expenditures	1,960	4,649	-58%	8,266	7,680	8%
Distributions declared	22,165	26,521	-16%	66,449	79,506	-16%
Per Trust Unit (\$) ⁽¹⁾	0.45	0.54	-17%	1.35	1.62	-17%
Long-term debt, period end	179,000	98,000	83%	179,000	98,000	83%
Unitholders' equity, period end	259,562	357,963	-27%	259,562	357,963	-27%
Trust Units (000s) ⁽²⁾	49,246	49,103	—	49,211	49,068	—
Operating						
Average daily production (boe/d)	8,219	8,335	-1%	8,448	8,445	—
Average price realizations (\$/boe)	48.28	48.95	-1%	47.96	47.61	1%
Operating netback (\$/boe)	43.65	44.92	-3%	42.66	43.99	-3%

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

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

Message to Unitholders

I am pleased to report Freehold's operating and financial results for the third quarter and first nine months of 2007. Although overall industry drilling declined 4% in the third quarter, the number of wells drilled on our royalty lands rose 5%. Operating netbacks remained strong, at \$43.65 per boe, despite lower natural gas prices, higher heavy oil differentials, and a stronger Canadian dollar.

Net income for the third quarter was down 2% to \$12.5 million. For the first nine months of the year, net income was reduced to a loss of \$20.3 million (\$0.41 per Trust Unit) with the recording of a non-cash future income tax expense in the second quarter related to the substantive enactment of the trust taxation legislation. With the passing of Bill C-52 by the Senate in June 2007, the Canadian trust taxation legislation has now become law. While Freehold will not be subject to the tax until 2011, we have recorded an additional future income tax expense of \$53.4 million for the year. This provision is a non-cash expense relating to temporary differences between accounting versus tax depreciation rates: it is an accounting entry and has no current impact on our cash flows or our cash available for distribution.

ROYALTY ACQUISITIONS

We continue to pursue acquisition opportunities that support our strategy of acquiring royalty interests. During the third quarter, we completed two royalty acquisitions that will increase production in the fourth quarter by about 9%. This production receives high netbacks as there are no associated operating and capital costs or third party royalty expenses. The acquisitions totalled \$90 million net of adjustments and were funded through Freehold's credit facilities, which have been increased to \$210 million. As a result, our long-term debt at the end of the third quarter was \$179 million, equal to 1.4 times our cash flow for the last twelve months. While this ratio is below average for our peer group, we believe that having a strong balance sheet provides maximum flexibility for future transactions. Therefore, we plan to reduce debt as we are able with cash available after funding monthly distributions, reclamation fund contributions, and capital expenditures.

REVIEW OF ALBERTA ROYALTY AND TAX REGIME

On October 25, 2007, the Government of Alberta announced its "New Royalty Framework" for Crown oil and gas royalty policy. The new royalty regime, which takes effect January 1, 2009, will be a sliding scale formula based on both commodity prices and well productivity. Overall, the government accepted many of the changes proposed by the Alberta Royalty Review Panel on September 18, 2007, for conventional assets, with some modifications to consider the maturity of conventional reserves and to reflect the growing importance of unconventional oil and gas resources. The government did not accept the recommendation to increase the freehold mineral tax, but did announce it will review the freehold mineral rights tax to ensure it is fulfilling its intended objective; that is, to cover the province's costs of administering the regulatory system.

The royalty rate changes will see the oil and gas industry paying higher Alberta Crown royalties beginning in 2009, which will have a negative impact on producers' future cash flows generated after the new regime takes effect. However, we expect to see little impact on Freehold's current producing wells, given the mature nature of most of our producing assets. As well, the new royalty rates will only apply to our working interest production on Alberta Crown lands, which is about 900 boe per day or 11% of our total production. Our royalty interest production in Alberta is not affected.

INCOME TRUST TAXATION

Just over one year ago, the federal government unexpectedly announced its plan to impose a tax on distributions from publicly-traded income trusts beginning January 1, 2011. We continue to analyze the various alternative structures available to us although further clarification of the implementation of new rules is still needed. As such, we have no plans to convert from our current structure at this time. We continue to see value for our Unitholders over the next three years, during which time cash distributions will remain protected from taxes at the corporate level. Instead, we intend to focus on the successful execution of our business strategy. We remain committed to maximizing sustainable cash distributions over the long term by actively managing our large portfolio oil and gas royalty interests, successfully developing our working interest properties to sustain production and extend reserve life, and acquiring appropriate assets to provide long-term growth in the value of the Trust.

OUTLOOK

With our recent acquisitions contributing to our results in the fourth quarter, production should average 8,550 boe per day (8,450 boe per day for the year), while we expect production in 2008 to average 8,200 boe per day due to natural production declines. Additional opportunities on our working interest properties has led us to increase our capital budget for 2007 by \$2.5 million to \$12.0 million – the largest capital program in our history. The 26% increase is due to partner activity, primarily in Southeast Saskatchewan, where recent drilling successes have identified additional infill opportunities. Consequently, our capital spending in the fourth quarter will be approximately \$3.7 million. In 2008, capital expenditures on our working interest properties are anticipated to be \$10.6 million.

To date in the fourth quarter, WTI crude oil prices have reached record highs with supply struggling to keep pace with demand growth. At the same time, the Canadian dollar has moved past parity with the U.S. dollar, reducing Canadian dollar realizations. Mild weather has moderated natural gas demand, and the markets have been kept well supplied by liquefied natural gas imports and an active land drilling program in the United States. As a result, natural gas storage levels are above the five year average as the winter heating season begins.

While the regular monthly distribution remains fixed at \$0.15 per Trust Unit, distributions for 2007 are expected to total \$1.92 per Trust Unit. This includes an additional payment of \$0.12 per Trust Unit to be paid on December 15, 2007. The additional payment is based on expected excess cash in 2007 due to high commodity prices and higher production volumes in the fourth quarter as a result of recently completed acquisitions.

Looking ahead to 2008, we anticipate that geopolitical uncertainty and strong global demand growth will keep crude oil prices high, while storage levels and weather will be the key demand factors for natural gas prices.

In western Canada, drilling activity is anticipated to decline further in response to weak natural gas markets, high operating costs, and the strength of the Canadian dollar. As well, the new Alberta Crown royalty structure could significantly change the economics of future exploration and development activities in the Province of Alberta. A dramatic reduction in industry drilling would likely be reflected on our royalty lands, but it is too early to say what the potential impact might be on Freehold's future production and reserves. There are currently 98 (11.1 equivalent net) licensed drilling locations on our royalty lands, compared with 88 (6.7 equivalent net) locations at this time last year. Considering the current industry slowdown, we are very encouraged by this evidence of ongoing development potential on our royalty lands.

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 September 30, 2007 and previous periods, and the outlook for Freehold based on information available as at November 7, 2007. 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 September 30, 2007 and September 30, 2006, 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, 2006 and 2005, together with the accompanying notes. These are on pages 13 through 49 of the Trust's 2006 annual report to Unitholders.

FORWARD-LOOKING STATEMENTS

This MD&A offers our assessment of Freehold's future plans and operations as at November 7, 2007, and contains forward-looking statements. By their nature, forward-looking statements are subject to numerous risks and uncertainties, some of which are beyond our control, including the impact of general economic conditions, industry conditions, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, taxation, royalties, regulation, competition from other industry participants, the lack of availability of qualified personnel or management, stock market volatility, and our ability to access sufficient capital from internal and external sources. Risks are described in more detail in our Annual Information Form, which is available on our website. You are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. Our actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements. We can give no assurance that any of the events anticipated will transpire or occur, or if any of them do, what benefits we will derive from them. Except as required by law, we do not undertake to update these forward-looking statements.

CONVERSION OF NATURAL GAS TO OIL EQUIVALENT

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

NON-GAAP MEASURES

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

Operating income, which is gross revenue less royalty expense and operating expense, represents the results of operations before general and administrative, interest, taxes and depletion, accretion and management fees. Operating netback, which is calculated as average unit sales price less royalties and operating expenses; and investor netback, which deducts administrative and interest expense and income and capital taxes, represent the cash margin for product sold, calculated on a per boe basis. Funds generated from operations is a key measure of our ability to generate cash, finance operations, and pay monthly distributions. Funds generated from operations as presented is not intended to represent operating cash flow or operating profits for the period nor should it be viewed as an alternative to cash provided by operating activities, net income or other measures of financial performance calculated in accordance with Canadian GAAP. All references to funds generated from operations throughout this report are based on cash provided by operating activities before changes in non-cash working capital as per the Statement of Cash Flows. Funds generated from operations per Trust Unit is calculated based on the weighted average number of Trust Units outstanding consistent with the calculation of net income per Trust Unit.

THE ROYALTY ADVANTAGE

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 following table demonstrates the advantage of our royalty lands from which we receive revenue but do not incur royalty expenses, operating expenses, site restoration expenses, or capital expenditures.

Components of Distributions to Unitholders			
Nine months ended September 30, 2007 ⁽¹⁾	Royalty Interest	Working Interest	
(\$000s)	Properties	Properties	Total Trust
Gross revenue	74,504	37,447	111,951
Royalty expense	—	(3,762)	(3,762)
Freehold mineral tax	(1,012)	(196)	(1,208)
Net revenue	73,492	33,489	106,981
Operating expense	—	(8,597)	(8,597)
Operating income	73,492	24,892	98,384
General and administrative expense	(3,280)	(1,538)	(4,818)
Interest expense	(4,012)	(439)	(4,451)
Income and capital taxes	—	(98)	(98)
Loss on settlement of litigation	—	(278)	(278)
Unit based compensation	265	124	389
Expenditures on reclamation	—	(711)	(711)
	66,465	21,952	88,417
Reclamation fund withdrawal	—	360	360
Capital expenditures	—	(8,266)	(8,266)
Acquisitions	(90,430)	—	(90,430)
Changes in debt	79,000	—	79,000
Changes in working capital	(1,791)	(841)	(2,632)
Distributions declared	53,244	13,205	66,449

(1) Numbers may not add due to rounding.

DEVELOPMENT ACTIVITIES

Industry wide, a total of 4,128 wells were drilled in western Canada during the third quarter of 2007, down 4% from last year. Year-to-date, industry drilling is down 10% over 2006, with the major of the decline in gas prone areas. Industry forecasters are predicting the slowdown to continue through the balance of 2007 and into 2008.

ROYALTY INTEREST LANDS

Our royalty lands are comprised of a large and widely diversified portfolio of properties extending from northeastern British Columbia to Ontario, and drilling on our royalty lands generally mirrors overall industry activity levels. Although fewer wells were drilled across western Canada in the third quarter of 2007, the number of wells drilled on our royalty lands rose 5%. Consistent with industry, though, we experienced declines in gas prone areas as producers directed drilling towards oil targets. There are currently 98 (11.1 equivalent net) licensed drilling locations on our royalty lands, compared with 88 (6.7 equivalent net) locations at this time last year.

Royalty Interest Lands	Three Months Ended			Nine Months Ended		
	September 30			September 30		
	2007	2006	Change	2007	2006	Change
Drilling Summary						
(includes unitized wells)						
Gross wells	188	168	12%	484	522	-7%
Equivalent net wells ⁽¹⁾	6.8	6.5	5%	13.3	14.4	-8%
Net success rate	100.0%	97.7%	2%	99.5%	98.8%	1%

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

WORKING INTEREST PROPERTIES

Drilling on our working interest lands was significantly lower quarter over quarter, mainly because we concluded our Hayter drilling program in the second quarter this year, whereas delays caused by poor weather pushed the Hayter drilling program into the third quarter last year. In the fourth quarter, we expect to drill an additional 9 (2.0 net) wells in Southeast Saskatchewan that will add to production early in 2008.

Working Interest Properties Drilling Summary	Three Months Ended September 30				Nine Months Ended September 30			
	2007		2006		2007		2006	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Oil	3.0	0.6	14	3.6	21	6.0	33	5.7
Natural gas	3.0	0.2	7	—	24	0.6	58	1.2
Other	—	—	1	—	—	—	2	0.2
Total	6.0	0.8	22	3.6	45	6.6	93	7.1

RESULTS OF OPERATIONS

PRODUCTION

Production volumes in the third quarter averaged 8,219 boe per day, down 1% from the third quarter of 2006. Year over year, production remained level. On a boe basis, our production profile for the period ended September 30, 2007 was 35% natural gas, 4% natural gas liquids (NGL), 23% light and medium oil, and 38% heavy oil. With our recent acquisitions contributing to our results in the fourth quarter, production should average 8,550 boe per day (8,450 boe per day for the year), while we expect production in 2008 to average 8,200 boe per day due to natural production declines.

Average Daily Production	Three Months Ended			Nine Months Ended		
	September 30			September 30		
	2007	2006	Change	2007	2006	Change
Royalty lands						
Oil (bbls/d)	3,104	3,346	-7%	3,140	3,477	-10%
NGL (bbls/d)	251	301	-17%	268	296	-9%
Natural gas (Mcf/d)	13,929	16,542	-16%	14,059	16,518	-15%
Oil equivalent (boe/d)	5,677	6,404	-11%	5,752	6,526	-12%
Working interest properties						
Oil (bbls/d)	1,922	1,394	38%	1,826	1,346	36%
NGL (bbls/d)	63	72	-13%	89	69	29%
Natural gas (Mcf/d)	3,345	2,793	20%	4,689	3,032	55%
Oil equivalent (boe/d)	2,542	1,932	32%	2,696	1,920	40%
Total Trust						
Oil (bbls/d)	5,026	4,740	6%	4,966	4,823	3%
NGL (bbls/d)	314	373	-16%	357	364	-2%
Natural gas (Mcf/d)	17,274	19,335	-11%	18,748	19,550	-4%
Oil equivalent (boe/d)	8,219	8,335	-1%	8,448	8,446	—
Number of days in period (days)	92	92	—	273	273	—
Total volumes during period (Mboe)	756	767	-1%	2,306	2,306	—
Potash production (tonnes/d)	12.3	9.3	32%	13.8	9.4	47%

Royalty interests contributed 69% of total volumes produced during the quarter. Royalty interest production declined 10% due to the reclassification upon payout of two royalty wells in Northeast British Columbia to working interest status and, to a lesser extent, due to reduced industry drilling. Working interest production rose 33% on drilling successes at Hayter and Southeast Saskatchewan and the production adjustment mentioned above.

On August 31, 2007, we acquired gross overriding royalty (GORR) interests on 345,000 gross acres of land in Alberta and Saskatchewan for \$57.6 million net of adjustments. These properties contributed 165 boe per day for the third quarter. Currently, 1,200 wells are producing (56% natural gas, 35% light oil and NGLs and 9% heavy oil) and further drilling on the lands is anticipated. Proved plus probable reserves were evaluated by Freehold at 1.5 million boe (37% natural gas). Based on forecast production, the reserve life index is approximately 7.4 years.

On September 5, 2007, we acquired a 7.2% GORR interest on 7,330 gross acres of land at Dixonville, Alberta, for \$32.8 million net of adjustments. The property contributed 55 boe per day for the third quarter. Proved plus probable reserves were evaluated by Freehold at 0.8 million boe (86% oil, 29° API). Based on the Operator's announced plans, we expect our share of production to grow to approximately 325 boe per day by 2009 through drilling opportunities. There are approximately 75 identified horizontal well locations designed to optimize pool recovery. As a royalty owner, Freehold will not incur any capital or operating costs related to this activity.

BENCHMARK PRICES

The average price for West Texas Intermediate (WTI) crude oil rose 7% in the third quarter of 2007, while the U.S. dollar continued to lose value. Lack of refining capacity for heavier grades of crude caused the price spread between light and heavy oil to widen and Bow River/Hardisty prices to soften by 5% quarter over quarter.

AECO natural gas prices declined 7% quarter over quarter. Liquefied natural gas imports and elevated levels of natural gas drilling in the United States have kept the North American market well supplied through the summer. The level of natural gas in storage remains above the five-year average, causing continued price uncertainty in natural gas markets.

Average Benchmark Prices	Three Months Ended			Nine Months Ended		
	September 30			September 30		
	2007	2006	Change	2007	2006	Change
WTI crude oil (US\$/bbl)	75.38	70.48	7%	66.19	68.21	-3%
US\$/Cdn\$ exchange rate	0.9575	0.8919	7%	0.9074	0.8831	3%
Edmonton Par crude oil (Cdn\$/bbl)	79.95	79.08	1%	72.99	75.53	-3%
Light/heavy oil differential (Cdn\$/bbl)	23.95	20.14	19%	20.65	22.04	-6%
Bow River/Hardisty (Cdn\$/bbl)	56.00	58.94	-5%	52.34	53.48	-2%
AECO natural gas (Cdn\$/Mcf)	5.61	6.03	-7%	6.81	7.19	-5%

Source for commodity prices: Canadian Association of Petroleum Producers.

REALIZED PRICES

Freehold's average selling prices reflect product quality and transportation differences from benchmark prices. As approximately 37% 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. On a boe basis, our average price realizations were 1% lower in the third quarter of 2007 and 1% higher for the year to date.

Average Selling Prices	Three Months Ended			Nine Months Ended		
	September 30			September 30		
	2007	2006	Change	2007	2006	Change
Oil (\$/bbl)	57.45	58.62	-2%	52.76	52.30	1%
NGL (\$/bbl)	57.97	53.80	8%	54.19	53.74	1%
Oil and NGL (\$/bbl)	57.48	58.27	-1%	52.85	52.40	1%
Natural gas (\$/Mcf)	5.20	5.70	-9%	6.60	6.66	-1%
Oil equivalent (\$/boe)	48.28	48.95	-1%	47.96	47.61	1%
Potash (\$/tonne)	195.73	215.57	-9%	223.70	215.83	4%

REVENUE

Gross revenue in the third quarter was \$36.9 million, down 3% from the third quarter of 2006 as a result of lower natural gas prices, higher heavy oil differentials, a stronger Canadian dollar, and a reduction in industry drilling activity. Year to date gross revenue was up 1%.

Revenue	Three Months Ended			Nine Months Ended		
	September 30			September 30		
	2007	2006	Change	2007	2006	Change
Gross revenue	36,931	37,994	-3%	111,951	110,853	1%
Royalty and freehold mineral tax expense ⁽¹⁾	(845)	(1,444)	-41%	(4,970)	(3,382)	47%
Net revenue	36,086	36,550	-1%	106,981	107,471	—

(1) Net of Alberta Royalty Credit in 2006. Royalty expenses are incurred only on working interest production.

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

Gross Revenue Variances (\$000s)	Three Months Ended		Nine Months Ended	
	September 30		September 30	
	2007 vs. 2006	2006 vs. 2005	2007 vs. 2006	2006 vs. 2005
Oil and NGL				
Production increase (decrease)	1,201	(1,476)	1,971	7,603
Price increase (decrease)	(368)	971	641	6,824
Net increase (decrease)	833	(505)	2,612	14,427
Natural gas				
Production increase (decrease)	(987)	(1,142)	(1,446)	7,088
Price increase (decrease)	(881)	(4,244)	(308)	(2,830)
Net increase (decrease)	(1,868)	(5,386)	(1,754)	4,258
Other ⁽¹⁾	(28)	(52)	240	(191)
Gross revenue increase (decrease)	(1,063)	(5,943)	1,098	18,494

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

EXPENSES

ROYALTY EXPENSE AND FREEHOLD MINERAL TAX

Royalty rates are tied to commodity prices and production volumes. In the third quarter, royalty expenses on our working interest properties declined 38% due to price and volume variances.

Royalty Expense and Freehold Mineral Tax ⁽¹⁾ (net of Alberta Royalty Credit) ⁽²⁾	Three Months Ended			Nine Months Ended		
	September 30			September 30		
	2007	2006	Change	2007	2006	Change
Working interest properties (\$000s)	786	1,275	-38%	3,958	3,096	28%
Per boe (\$)	3.36	7.16	-53%	5.38	5.91	-9%
Royalty interest lands (\$000s)	59	169	-65%	1,012	286	254%
Per boe (\$)	0.11	0.29	-62%	0.64	0.16	300%
Total royalty expenses (\$000s)	845	1,444	-41%	4,970	3,382	47%
Total Trust (\$/boe)	1.12	1.88	-40%	2.15	1.47	46%

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

(2) Effective January 1, 2007, the Alberta Government discontinued the Alberta Royalty Credit.

OPERATING EXPENSES

On working interest properties, operating costs per boe were 11% higher during the quarter. On a total Trust basis, operating costs per boe were 48% higher. The increase was primarily attributable to a higher proportionate share of working interest volumes during the quarter. With additional royalty interest production in the fourth quarter, operating costs for the full year are expected to average \$3.60 per boe.

Operating Expenses	Three Months Ended			Nine Months Ended		
	September 30			September 30		
	2007	2006	Change	2007	2006	Change
Working interest properties (\$000s)	3,081	2,111	46%	8,597	6,050	42%
Per boe (\$)	13.17	11.88	11%	11.68	11.54	1%
Royalty interest lands ⁽¹⁾ (\$000s)	—	—	—	—	—	—
Per boe (\$)	—	—	—	—	—	—
Total operating expenses (\$000s)	3,081	2,111	46%	8,597	6,050	42%
Total Trust (\$/boe)	4.07	2.75	48%	3.73	2.62	42%

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

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. On a per boe basis, depletion and depreciation on property, plant and equipment and accretion on the asset retirement obligation decreased slightly due to higher working interest production volumes.

Depletion, Depreciation and Accretion Expenses	Nine Months Ended		Year Ended
	Sept. 30 2007	Sept. 30 2006	December 31 2006
Depletion and depreciation (\$000s)	53,799	54,497	71,874
Accretion of asset retirement obligation (\$000s)	200	192	257
Total depletion, depreciation and accretion expenses (\$000s)	53,999	54,689	72,131
Per boe (\$)	23.42	23.72	23.50

GENERAL AND ADMINISTRATIVE EXPENSES (G&A)

In the third quarter of 2007, G&A expenses totalled \$1.0 million, including \$0.8 million charged by the Manager for time and direct costs incurred on behalf of the Trust. On a per boe basis, G&A expenses were 2% higher quarter over quarter.

In the third quarter, we recorded a non-cash expense of \$13,000 (2006 – \$7,000), with a corresponding increase to contributed surplus, as unit based compensation relating to the deferred trust unit plan to non-management directors. The total for the nine months ended September 30, 2007 was \$248,000 (2006 – \$241,000). We also recorded a non-cash expense of \$38,000 (2006 – \$68,000) for the Trust's proportionate share of the Manager's long term incentive plan for 2007. The total for the nine month period ended September 30, 2007 was \$141,000 (2006 – \$174,000). As at September 30, 2007, we had recorded \$397,000 as a deferred long-term compensation asset and accrued \$581,000 as a long term liability.

G&A Expenses	Three Months Ended			Nine Months Ended		
	September 30			September 30		
	2007	2006	Change	2007	2006	Change
G&A expenses (\$000s)	1,017	1,012	—	4,818	4,481	8%
Per boe (\$)	1.35	1.32	2%	2.09	1.94	8%
As a percentage of revenue	2.8%	2.7%	4%	4.3%	4.0%	8%

MANAGEMENT FEES

The quarterly management fee, which is paid in Trust Units, was 35,654 Trust Units for the third quarter of 2007, unchanged from last year. The ascribed value was 20% lower due to a lower Trust Unit price at the end of the third quarter of 2007.

Management Fees (Paid in Trust Units)	Three Months Ended			Nine Months Ended		
	September 30			September 30		
	2007	2006	Change	2007	2006	Change
Trust Units issued in payment of management fees	35,654	35,654	—	106,962	106,962	—
Ascribed value (\$000s) ⁽¹⁾	544	677	-20%	1,574	2,121	-26%
Per boe (\$)	0.72	0.88	-18%	0.68	0.92	-26%

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

INTEREST EXPENSES

Interest expenses increased 34% quarter over quarter, due to increased debt and higher effective interest rates.

Interest Expenses ((\$000s, except as noted)	Three Months Ended			Nine Months Ended		
	September 30			September 30		
	2007	2006	Change	2007	2006	Change
Net interest expense	1,801	1,346	34%	4,451	3,836	16%
Per boe (\$)	2.38	1.75	36%	1.93	1.66	16%

OPERATING NETBACK

Our operating netback in the third quarter of 2007 was \$43.65 per boe, down 3% mainly due to lower commodity prices and a higher proportion of working interest production with associated royalty and operating expenses.

We did not hedge any of our production in the third quarter. This policy is subject to review by our Board.

Operating Netback (\$/boe)	Three Months Ended			Nine Months Ended		
	September 30			September 30		
	2007	2006	Change	2007	2006	Change
Gross revenue ⁽¹⁾	48.84	49.55	-1%	48.54	48.08	1%
Royalty and freehold mineral tax expense ⁽²⁾	1.12	1.88	-40%	2.15	1.47	46%
Operating expenses	4.07	2.75	48%	3.73	2.62	42%
Operating netback	43.65	44.92	-3%	42.66	43.99	-3%

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

(2) Net of Alberta Royalty Credit in 2006.

FUNDS GENERATED FROM OPERATIONS AND NET INCOME

Funds generated from operations totalled \$29.9 million, down 6% from the third quarter last year, reflecting lower average selling prices. Year to date funds decreased 4% to \$88.4 million.

Net income for the third quarter was down 2% to \$12.5 million. For the first nine months of the year, net income was reduced to a loss of \$20.3 million (\$0.41 per Trust Unit) with the recording of a non-cash future income tax expense in the second quarter related to the substantive enactment of the trust taxation legislation. With the passing of Bill C-52 by the Senate in June, the Canadian trust taxation legislation has now become law. While Freehold will not be subject to the tax until 2011, we have recorded an additional future income tax expense of \$53.4 million for the year. This provision is a non-cash expense relating to temporary differences between accounting versus tax depreciation rates: it is an accounting entry and has no current impact on our cash flows or our cash available for distribution.

Funds Generated From Operations and Net Income	Three Months Ended			Nine Months Ended		
	September 30			September 30		
	2007	2006	Change	2007	2006	Change
Cash provided by operating activities	30,155	32,462	-7%	87,427	104,533	-16%
Changes in non-cash working capital	(248)	(770)	-68%	990	(12,078)	-108%
Funds generated from operations (\$000s)	29,907	31,692	-6%	88,417	92,455	-4%
Per Trust Unit (\$)	0.61	0.65	-6%	1.80	1.88	-4%
Net income (loss) (\$000s)	12,487	12,728	-2%	(20,259)	35,636	-157%
Per Trust Unit, basic and diluted (\$)	0.25	0.26	-4%	(0.41)	0.73	-156%

DISTRIBUTIONS

Distributions to Unitholders totalled \$0.45 per Trust Unit for the third quarter. Royalty income contributed 80% of distributions for the quarter. Since inception, the Trust has distributed \$552.6 million (\$15.65 per Trust Unit) to Unitholders.

Accumulated Distributions (\$000s, except as noted)	Three Months Ended		Nine Months Ended	
	September 30		September 30	
	2007	2006	2007	2006
Distributions to Unitholders	22,165	26,521	66,449	79,506
Accumulated, beginning of period	530,408	436,009	486,124	383,024
Accumulated, end of period	552,573	462,530	552,573	462,530
Distributions per Trust Unit (\$) ⁽¹⁾	0.45	0.54	1.35	1.62
Accumulated, beginning of period	15.20	13.28	14.30	12.20
Accumulated, end of period	15.65	13.82	15.65	13.82

(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 (loss) and historical distributions. Net income includes significant non-cash charges that do not impact cash flow. In 2007, these charges amounted to \$17.6 million for the third quarter and \$109.4 million for the year to date. 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	Nine Months	Twelve Months	Twelve Months
	Ended Sept, 30, 2007	Ended Sept. 30, 2007	Ended Dec. 31, 2006	Ended Dec. 31, 2005
Cash provided by operating activities	30,155	88,417	130,934	97,067
Net income (loss)	12,487	(20,259)	45,181	58,346
Cash distributions paid or payable	22,165	66,449	103,100	84,810
Excess of cash provided by operating activities over cash distributions	36%	33%	27%	14%
Excess (shortfall) of net income over cash distributions	-44%	-130%	-56%	-31%

DISTRIBUTION OUTLOOK

Our distribution policy takes into consideration forecasted cash provided by operating activities, debt levels, and capital expenditures. We have a declining asset base, and on 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.

The regularly monthly distribution remains fixed at \$0.15 per Trust Unit. Total distributions for 2007 are expected to amount to \$1.92 per Trust Unit, including an additional payment of \$0.12 per Trust Unit to be paid on December 15, 2007. The additional payment is based on expected excess cash in 2007 due to high commodity prices and higher production volumes as a result of recently completed acquisitions.

2007 Distribution Outlook and Key Assumptions	November 7	August 9	May 9	February 28
	2007	2007	2007	2007
Estimated cash distributions (\$ per Trust Unit)	1.92	1.80	1.80	1.80
Key assumptions:				
Average daily production ⁽¹⁾ (boe/d)	8,450	8,100	7,950	7,950
Average WTI oil price (US\$/bbl)	68.50	62.00	61.50	62.50
Average Bow River Hardisty oil price (Cdn\$/bbl)	52.50	46.00	45.00	43.30
Average AECO natural gas price (Cdn\$/Mcf)	6.40	7.25	7.25	7.25
Average light/heavy oil price differential (Cdn\$/bbl)	20.80	22.00	23.00	25.00
Average exchange rate (Cdn\$/US\$)	0.92	0.92	0.90	0.90
Average operating costs (\$/boe)	3.60	3.30	3.10	3.00
Average general and administrative costs (\$/boe)	2.00	2.10	2.10	2.10
Capital expenditures (\$ millions)	12.0	9.5	9.5	8.0
Long-term debt at year end ⁽¹⁾ (\$ millions)	182	100	97	97
Weighted average Trust Units outstanding (thousands)	49,371	49,228	49,228	49,228
Estimated portion of distributions taxable as income (%)	100	100	100	100

Recognizing the cyclical nature of our industry, we caution that significant changes in production rates, commodity prices, interest rates, or foreign exchange rates (positive or negative) will result in adjustments to the distribution level. Freehold is particularly vulnerable to swings in the light/heavy oil price differential, as approximately 38% of our total boe production is heavy oil. A sensitivity analysis of potential impact of key variables on distributions to Unitholders is provided on page 34 of our 2006 annual report.

QUARTERLY PERFORMANCE SUMMARY

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. Another factor that has influenced our results over the past several quarters is higher operating expenses on our working interest properties, which comprise about 30% of our total production volumes. Rising costs have been experienced industry wide and particularly in Alberta where strong economic growth and oil sands development have created increased demand for people and services. However, the effect of higher costs on our overall results is mitigated by our large proportion of royalty interest production, which is unencumbered by operating expenses.

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

Quarterly Review	2007			2006			2005	
	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Financial (\$000s, except as noted)								
Revenue, net of royalty expense	36,086	35,907	34,988	31,765	36,550	36,998	33,923	43,364
Funds generated from operations	29,907	30,213	28,297	27,394	31,692	32,565	28,198	38,694
Per Trust Unit (\$)	0.61	0.61	0.58	0.56	0.65	0.66	0.58	0.79
Distributions to Unitholders	22,165	22,151	22,133	23,594	26,521	26,502	26,483	31,366
Per Trust Unit (\$) ⁽¹⁾	0.45	0.45	0.45	0.48	0.54	0.54	0.54	0.64
Payout ratio (%)	74	73	78	86	84	81	94	81
Net income (loss)	12,487	(42,533)	9,787	9,545	12,728	14,142	8,766	18,747
Per Trust Unit, basic and diluted (\$)	0.25	(0.86)	0.20	0.19	0.26	0.29	0.18	0.38
Property and royalty acquisitions	90,430	—	—	—	5,382	—	—	—
Capital expenditures	1,960	2,830	3,476	3,766	4,649	1,430	1,601	1,631
Long-term debt	179,000	100,000	99,000	100,000	98,000	96,000	105,000	107,000
Trust Units outstanding								
Weighted average (000s)	49,246	49,210	49,175	49,139	49,103	49,068	49,032	48,996
At quarter end (000s)	49,281	49,246	49,210	49,174	49,139	49,103	49,067	49,032
Operating (\$/boe, except as noted)								
Daily production (boe/d)	8,219	8,566	8,564	8,313	8,335	8,212	8,794	8,739
Average selling price	48.28	48.21	47.40	41.44	48.95	50.27	43.78	54.95
Operating netback	43.65	42.28	42.06	38.57	44.92	47.08	40.18	51.56
Operating expenses	4.07	3.79	3.33	2.95	2.75	2.43	2.68	2.38
Working Interest properties	13.17	10.34	11.82	13.86	11.88	11.51	11.26	12.06
General and administrative expenses	1.35	1.67	3.24	1.44	1.32	1.79	2.69	1.52
Benchmark Prices								
WTI crude oil (US\$/bbl)	75.38	65.04	58.16	60.26	70.48	70.70	63.45	60.02
Exchange rate (Cdn\$/US\$)	0.96	0.91	0.85	0.89	0.89	0.89	0.87	0.85
Edmonton Par crude oil (Cdn\$)	79.95	71.93	67.09	64.48	79.08	78.55	68.96	71.17
Light/heavy oil differential (Cdn\$/bbl)	23.95	21.02	16.98	18.80	20.14	17.43	28.57	28.14
Bow River/Hardisty (Cdn\$/bbl)	56.00	50.91	50.11	45.69	58.94	61.11	40.39	43.03
AECO natural gas (Cdn\$/Mcf)	5.61	7.37	7.45	6.36	6.03	6.27	9.27	11.68
Unit Trading Performance								
High (\$)	15.85	15.85	15.30	19.80	23.06	21.70	22.20	18.98
Low (\$)	12.51	13.77	13.00	12.43	18.50	18.02	18.44	15.15
Close (\$)	15.26	14.53	14.35	14.81	19.00	21.00	19.50	18.81
Volume (000s)	5,172	6,853	6,040	13,867	5,153	5,336	11,155	7,611

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

LIQUIDITY AND CAPITAL RESOURCES

On August 31, 2007, we acquired certain overriding royalty interests in Alberta and Saskatchewan for \$57.6 million net of adjustments. The acquisition is effective March 1, 2007 with results of operations being included from September 1, 2007. On September 5, 2007, we acquired a 7.2% gross overriding royalty interest on a property in Alberta for \$32.8 million net of adjustments. The acquisition is effective August 1, 2007 with results of operations being included from September 5, 2007. Both acquisitions were funded through Freehold's credit facilities.

Development expenditures on working interest properties totalled \$2.0 million in the third quarter (\$8.3 million for the year to date). Due to partner activity, primarily in Southeast Saskatchewan, we have increased our 2007 capital budget by \$2.5 million to \$12.0 million. As a result, we expect an active fourth quarter, with expenditures of \$3.6 million. Capital expenditures in 2008 are anticipated to be \$10.6 million.

Capital Expenditures (\$000s, except as noted)	Three Months Ended			Nine Months Ended		
	September 30			September 30		
	2007	2006	Change	2007	2006	Change
Property and royalty acquisitions (net)	90,430	5,382	1580%	90,430	5,382	1580%
Development expenditures	1,960	4,649	-58%	8,266	7,680	8%
Change in reclamation fund	(19)	(70)	-73%	(360)	138	-361%
	92,371	9,961	827%	98,336	13,200	645%

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.

During the third quarter, we increased our credit facility by \$45 million to \$210 million. All other terms, including interest rates and security of the facilities, remain unchanged.

At September 30, 2007, we had no short-term debt outstanding and long-term debt was \$179 million. We had positive working capital of \$11.7 million, resulting in net debt of \$167.3 million. We currently have \$31 million of available capacity under our credit facilities.

Debt Analysis (\$000s)	September 30		December 31
	2007	2006	2006
Long-term debt	179,000	98,000	100,000
Short-term debt	—	—	—
Total debt	179,000	98,000	100,000
Less: working capital	(11,682)	(7,553)	9,050
Net debt obligations	167,318	90,447	90,950

As a result of increased debt related to acquisition activities in the third quarter, our ratio of net debt (total debt less positive working capital) to trailing funds generated from operations was 1.4 to 1, at September 30, 2007. In keeping with our conservative approach to debt management, we anticipate that excess cash will be directed to debt repayment.

Financial Leverage and Coverage Ratios ⁽¹⁾	September 30		December 31
	2007	2006	2006
Net debt to funds generated from operations (times)	1.4	0.7	0.8
Net debt to distributions (times)	1.9	0.8	0.9
Distributions to interest expense (times)	15.5	22.3	19.9
Net debt to net debt plus equity (%)	39%	20%	21%

(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.

Components of Working Capital (\$000s)	Sept. 30 2007	June 30 2007	Mar. 31 2007	Dec. 31 2006	Sept. 30 2006
Cash	82	254	677	421	585
Accounts receivable	26,883	25,865	27,870	29,850	28,311
Current assets	26,965	26,119	28,547	30,271	28,896
Distributions payable to Unitholders	(7,392)	(7,387)	(7,381)	(7,376)	(8,845)
Accounts payable and accrued liabilities	(7,891)	(7,491)	(10,124)	(13,845)	(12,498)
Current liabilities	(15,283)	(14,878)	(17,505)	(21,221)	(21,343)
Working capital ⁽¹⁾	11,682	11,241	11,042	9,050	7,553

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

TRUST UNITS OUTSTANDING

As at September 30, 2007 and November 7, 2007, there were 49,281,159 Trust Units outstanding. At the end of the third quarter, the Trust issued 35,654 Trust Units to the Manager in payment of the quarterly management fee.

On January 1, 2007, the Board granted 14,181 deferred trust units to eligible directors of Freehold Resources Ltd. as part of the directors' annual compensation. Each eligible director received 2,026 deferred trust units, and the Chair of the Board received 4,051 deferred trust units. As at September 30, 2007 there were 29,355 deferred trust units outstanding and at November 7, 2007, there were 29,653 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			Nine Months Ended		
	September 30			September 30		
	2007	2006	Change	2007	2006	Change
Weighted average						
Basic	49,245,893	49,103,277	—	49,210,504	49,067,888	—
Diluted	49,274,801	49,115,279	—	49,210,504	49,074,173	—
At period end	49,281,159	49,138,543	—	49,281,159	49,138,543	—

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.

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

CHANGES IN ACCOUNTING POLICIES

On January 1, 2007, the Trust adopted the new Canadian accounting standards for financial instruments - recognition and measurement, hedging and comprehensive income. The new standards require all financial instruments within their scope, including all derivatives, to be recognized on the balance sheet initially at fair value. Subsequent measurement of all financial assets and liabilities except those held-for-trading and available-for-sale are measured at amortized cost determined using the effective interest rate method. Held-for-trading financial assets are measured at fair value with changes in fair value recognized in earnings. Available-for-sale financial assets are measured at fair value with changes in fair value recognized in comprehensive income and reclassified to earnings when derecognized or impaired.

Cash and short-term investments, if any, are held-to-maturity investments, and the fair values approximate their carrying value due to their short-term nature. Accounts receivable and accounts payable and accrued liabilities are classified as loans and receivables and the fair values approximate their carrying value due to the short-term nature of these instruments. The Trust has not designated any financial instruments as available-for-sale or held-for-trading.

On adoption, the Trust elected to recognize, as separate assets and liabilities, only for those embedded derivatives in hybrid instruments issued, acquired or substantively modified after January 1, 2003. The Trust did not identify any material embedded derivatives which required separate recognition and measurement.

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. In 2002, the Government of Canada ratified the Kyoto Protocol, which calls for Canada to reduce its greenhouse gas emissions to specified levels. There has been much public debate about Canada's ability to meet these targets and the Government's strategy or alternative strategies on climate change and the control of greenhouse gases. Implementation of strategies for reducing greenhouse gases, whether to meet the limits required by the Kyoto Protocol or as otherwise determined, could have a material impact on the nature of oil and natural gas operations, including those of the Trust.

On April 26, 2007, the Federal Government released its *Action Plan to Reduce Greenhouse Gases and Air Pollution*, also known as ecoACTION, which includes the Regulatory Framework for Air Emissions. The plan covers not only large industry, but also regulates the fuel efficiency of vehicles and the strengthening of energy standards for a number of energy-using products. Regarding large industry and industry related projects, ecoAction is intended to achieve the following: (i) an absolute reduction of 150 megatonnes in greenhouse gas emissions by 2020 by imposing mandatory targets; and (ii) a 50% reduction in air pollution from industry by 2015 by setting certain targets. New facilities using cleaner fuels and technologies will have a grace period of three years. To facilitate compliance with the plan's requirements, while at the same time allowing companies to be cost-effective, innovative and adopt cleaner technologies, certain options are provided. These are: (i) in-house reductions; (ii) contributions to technology funds; (iii) trading of emissions with below-target emission companies; (iv) offsets; and (v) access to Kyoto's Clean Development Mechanism.

On March 8, 2007, the Alberta Government introduced Bill 3, the *Climate Change and Emissions Management Amendment Act*, which intends to reduce greenhouse gas emission intensity from large industries. Bill 3 states that facilities emitting more than 100,000 tonnes of greenhouse gases a year must reduce their emissions intensity by 12% starting July 1, 2007; if such reduction is not initially possible the companies owning the large emitting facilities will be required to pay \$15 per tonne for every tonne above the 12% target. These payments will be deposited into an Alberta-based technology fund that will be used to develop infrastructure to reduce emissions or to support research into innovative climate change solutions. Alternatively, large emitters can invest in projects outside of their operations that reduce or offset emissions on their behalf provided that these projects are based in Alberta. Prior to investing, the offset reductions offered by a prospective operation must be verified by a third party to ensure that the emission reductions are real.

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.

REVIEW OF ALBERTA ROYALTY AND TAX REGIME

On October 25, the Government of Alberta announced its "New Royalty Framework" for Crown oil and gas royalty policy. The new royalty regime, which takes effect January 1, 2009, will be a sliding scale formula based on both commodity prices and well productivity. Overall, the government accepted many of the changes proposed by the Alberta Royalty Review Panel on September 18 for conventional assets, with some modifications to consider the maturity of conventional reserves and to reflect the growing importance of unconventional oil and gas resources. The government did not accept the recommendation to increase the freehold mineral tax, but did announce it will review the freehold mineral rights tax to ensure it is fulfilling its intended objective; that is, to cover the province's costs of administering the regulatory system.

The royalty rate changes will see the oil and gas industry paying higher Alberta Crown royalties beginning in 2009, which will have a negative impact on producers' future cash flows generated after the new regime takes effect. However, we expect to see little impact on Freehold's current producing wells, given the mature nature of most of our producing assets. As well, the new royalty rates will only apply to our working interest production on Alberta Crown lands, which is currently about 900 boe per day or about 11% of our total production. Our royalty interest production in Alberta is not affected.

The new Alberta Crown royalty structure could significantly change the economics of future exploration and development activities in the Province of Alberta. A dramatic reduction in industry drilling would likely be reflected on our royalty lands, but it is not possible to predict what the potential impact might be on Freehold's future production and reserves.

ADDITIONAL INFORMATION

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

Consolidated Balance Sheets

(\$000s) (unaudited)	September 30, 2007	December 31, 2006
Assets		
Current assets:		
Cash	\$ 82	\$ 421
Accounts receivable	26,883	29,850
	<u>26,965</u>	<u>30,271</u>
Reclamation fund	1,757	2,117
Deferred long-term compensation (note 5)	397	86
Petroleum and natural gas interests, net of accumulated depletion and depreciation of \$363,530 (2006 - \$309,731)	486,875	441,754
	<u>\$ 515,994</u>	<u>\$ 474,228</u>
Liabilities and Unitholders' Equity		
Current liabilities:		
Distributions payable to Unitholders	\$ 7,392	\$ 7,376
Accounts payable and accrued liabilities	7,891	13,845
	<u>15,283</u>	<u>21,221</u>
Asset retirement obligation (note 6)	4,311	4,598
Unit based compensation payable (note 5)	581	129
Long-term debt (note 3)	179,000	100,000
Future income tax liability (note 9)	57,257	3,832
Unitholders' equity:		
Unitholders' capital (note 3)	564,272	562,698
Contributed surplus (note 5)	495	247
Deficit	(305,205)	(218,497)
	<u>259,562</u>	<u>344,448</u>
	<u>\$ 515,994</u>	<u>\$ 474,228</u>

See accompanying notes to interim consolidated financial statements.

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

(Unaudited) (\$000s, except per unit and weighted average data)	Three Months Ended September 30		Nine Months Ended September 30	
	2007	2006	2007	2006
Revenue:				
Royalty income and working interest sales	\$ 36,931	\$ 37,994	\$ 111,951	\$ 110,853
Royalty expense and freehold mineral tax (net of Alberta Royalty Tax Credit)	(845)	(1,444)	(4,970)	(3,382)
	36,086	36,550	106,981	107,471
Expenses:				
Operating	3,081	2,111	8,597	6,050
General and administrative	1,017	1,012	4,818	4,481
Interest on long-term debt	1,801	1,346	4,451	3,836
Loss on settlement of litigation (note 7)	278	—	278	—
Depletion and depreciation	18,250	18,389	53,799	54,497
Accretion of asset retirement obligation	66	66	200	192
Management fee	544	677	1,574	2,121
	25,037	23,601	73,717	71,177
Net income before taxes	11,049	12,949	33,264	36,294
Income and capital taxes	(84)	277	98	862
Future income tax expense (reduction) (note 9)	(1,354)	(56)	53,425	(204)
	(1,438)	221	53,523	658
Net income (loss) and comprehensive income (loss)	\$ 12,487	\$ 12,728	\$ (20,259)	\$ 35,636
Deficit, beginning of period	(295,527)	(190,655)	(218,497)	(160,578)
Distributions declared	(22,165)	(26,521)	(66,449)	(79,506)
Deficit, end of period	\$ (305,205)	\$ (204,448)	\$ (305,205)	\$ (204,448)
Net income (loss) per Trust Unit, basic and diluted	\$ 0.25	\$ 0.26	\$ (0.41)	\$ 0.73
Weighted average number of Trust Units:				
Basic	49,245,893	49,103,277	49,210,504	49,067,888
Diluted	49,274,801	49,115,279	49,210,504	49,074,173

See accompanying notes to interim consolidated financial statements.

Consolidated Statements of Cash Flows

(Unaudited) (\$000s)	Three Months Ended September 30		Nine Months Ended September 30	
	2007	2006	2007	2006
Cash provided by (used in):				
Operating:				
Net income (loss)	\$ 12,487	\$ 12,728	\$ (20,259)	\$ 35,636
Items not involving cash:				
Depletion and depreciation	18,250	18,389	53,799	54,497
Trust Unit incentive compensation (note 5)	51	74	389	414
Future income tax expense (reduction) (note 9)	(1,354)	(56)	53,425	(204)
Accretion of asset retirement obligation	66	66	200	192
Trust Units issued in lieu of management fee	544	677	1,574	2,121
Expenditures on reclamation	(137)	(186)	(711)	(201)
	29,907	31,692	88,417	92,455
Changes in non-cash working capital	248	770	(990)	12,078
	30,155	32,462	87,427	104,533
Financing:				
Long-term debt	79,000	2,000	79,000	(9,000)
Distributions paid	(22,161)	(26,514)	(66,433)	(83,410)
Changes in non-cash working capital	(359)	44	(289)	(135)
	56,480	(24,470)	12,278	(92,545)
Investing:				
Property and royalty acquisitions	(90,430)	(5,382)	(90,430)	(5,382)
Capital expenditures	(1,960)	(4,649)	(8,266)	(7,680)
Deposit on acquisition	6,070	—	—	—
Change in reclamation fund	19	70	360	(138)
Changes in non-cash working capital	(506)	2,309	(1,708)	1,605
	(86,807)	(7,652)	(100,044)	(11,595)
Increase (decrease) in cash	(172)	340	(339)	393
Cash, beginning of period	254	245	421	192
Cash, end of period	\$ 82	\$ 585	\$ 82	\$ 585

See accompanying notes to interim consolidated financial statements.

Notes to Interim Consolidated Financial Statements

For the period ended September 30, 2007.

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, 2006, except for the new standards regarding financial instruments detailed below. The following disclosure is incremental to the disclosure contained in the notes to the 2006 annual consolidated financial statements. The interim consolidated financial statements should be read in conjunction with the consolidated financial statements and notes for the year ended December 31, 2006.

Two new Canadian accounting standards have been issued that will require additional disclosure in the Trust's financial statements commencing January 1, 2008, regarding financial instruments, as well as capital and how it is managed.

CHANGES IN ACCOUNTING POLICIES

On January 1, 2007, the Trust adopted the new Canadian accounting standards for financial instruments—recognition and measurement, hedging and comprehensive income. The new standards require all financial instruments within their scope, including all derivatives, to be recognized on the balance sheet initially at fair value. Subsequent measurement of all financial assets and liabilities except those held-for-trading and available-for-sale are measured at amortized cost determined using the effective interest rate method. Held-for-trading financial assets are measured at fair value with changes in fair value recognized in earnings. Available-for-sale financial assets are measured at fair value with changes in fair value recognized in comprehensive income and reclassified to earnings when derecognized or impaired.

Cash and short-term investments, if any, are held-to-maturity investments, and the fair values approximate their carrying value due to their short-term nature. Accounts receivable and accounts payable and accrued liabilities are classified as loans and receivables and the fair values approximate their carrying value due to the short-term nature of these instruments. The Trust has not designated any financial instruments as available-for-sale or held-for-trading.

On adoption, the Trust elected to recognize, as separate assets and liabilities, only for those embedded derivatives in hybrid instruments issued, acquired or substantively modified after January 1, 2003. The Trust did not identify any material embedded derivatives which required separate recognition and measurement.

2. PROPERTY ACQUISITIONS

On August 31, 2007, Freehold closed an acquisition of certain overriding royalty interests in Alberta and Saskatchewan for \$57.6 million, net of adjustments. The acquisition is effective March 1, 2007 with results of operations being included from September 1, 2007.

On September 5, 2007, Freehold closed an acquisition of a gross overriding royalty interest on a property in Alberta for \$32.8 million, net of adjustments. The acquisition is effective August 1, 2007 with results of operations being included from September 5, 2007.

Both acquisitions were funded through Freehold's credit facilities.

3. LONG-TERM DEBT

Freehold has a \$195 million extendible revolving term credit facility, extendible annually, on which \$179 million was drawn at September 30, 2007. In the event that the lender does not consent to an extension, the revolving credit facility will revert to a two-year, non-revolving term facility with equal quarterly principal repayments. The first quarterly payment would commence on January 1 of the year following the end of the revolving period, which is May 2008. In addition, Freehold has available a \$15 million extendible revolving operating facility. Borrowings under the facilities bear interest at the Bank's prime lending rate, bankers' acceptance or LIBOR rates plus applicable margins, ranging from 85 to 140 basis points and

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

4. UNITHOLDERS' CAPITAL

	September 30, 2007		December 31, 2006	
	Units	Amount (\$000s)	Units	Amount (\$000s)
Balance, beginning of period	49,174,197	562,698	49,031,581	560,049
Issued in lieu of management fee	106,962	1,574	142,616	2,649
Balance, end of period	49,281,159	564,272	49,174,197	562,698

For the purpose of calculating diluted net loss per Trust Unit for the nine month period ended September 30, 2007, 28,053 incremental Trust Units from assumed redemption of deferred trust units are not included due to the anti-dilutive effect.

5. UNIT BASED COMPENSATION

(a) Deferred Trust Unit Plan

Fully vested deferred trust units are granted annually to non-management directors. Distributions to Unitholders declared by Freehold prior to redemption are assumed to be reinvested in notional units of the date of distribution. As at September 30, 2007, there were 29,355 deferred trust units outstanding, which are redeemable for an equal number of Trust Units any time after the director's retirement.

Deferred Trust Units	September 30, 2007	December 31, 2006
Balance, beginning of period	12,559	—
Annual grant	14,181	11,165
Additional units resulting from distributions	2,615	1,394
Balance, end of period	29,355	12,559

For the three month period ended September 30, 2007, Freehold expensed \$13,000 (2006 - \$7,000) as unit based compensation with a corresponding increase to contributed surplus. The total for the nine month period ended September 30, 2007 was \$248,000 (2006 - \$241,000).

Contributed Surplus (\$000s)	September 30, 2007	December 31, 2006
Balance, beginning of period	247	—
Trust Unit incentive compensation expense	248	247
Balance, end of period	495	247

(b) Manager's Long-Term Incentive Plan

Employees of Rife Resources ("the Manager") receive cash compensation in relation to the value of a specified number of notional units after a three year vesting period. Distributions made by Freehold during the vesting period are assumed to be reinvested in notional units on the date of distribution. For the three month period ended September 30, 2007, Freehold expensed \$38,000 (2006 - \$68,000) as unit based compensation. The total for the nine month period ended September 30, 2007 was \$141,000 (2006 - \$174,000). At September 30, 2007, Freehold had recorded \$397,000 as a deferred long-term compensation asset and accrued \$581,000 as a long-term liability.

6. ASSET RETIREMENT OBLIGATIONS

Freehold has no asset retirement obligations on its royalty income properties. Freehold's asset retirement obligation results from its responsibility to abandon and reclaim its net share of all working interest properties. The net present value of Freehold's total asset retirement obligation is estimated to be \$4.3 million (discounted at a weighted average, credit adjusted, risk free rate of 6.1%), the undiscounted value of which is \$12.1 million. Payments to settle the obligations are expected to occur continuously over the next 50 years, with the majority of obligations being over 15 years away.

Asset Retirement Obligations (\$000s)	September 30, 2007	December 31, 2006
Balance, beginning of period	4,598	4,036
Liabilities incurred	223	364
Liabilities settled	(711)	(302)
Revisions in estimates	—	243
Accretion expense	200	257
Balance, end of period	4,310	4,598

7. LOSS ON SETTLEMENT OF LITIGATION

During the quarter, Freehold paid \$278,000 in settlement of litigation with a third party with respect to the ownership of a well.

8. RELATED PARTY TRANSACTIONS

For the three month period ended September 30, 2007, Freehold issued 35,654 Trust Units as management fee to the Manager (2006 – 35,654 Trust Units, pursuant to a management agreement). The total for the nine month period ended September 30, 2007 was 106,962 Trust Units (2006 – 106,962 Trust Units).

For the three month period ended September 30, 2007, the Manager charged the Trust \$0.8 million in general and administrative costs (2006 - \$0.8 million). The total for the nine month period ended September 30, 2007 was \$3.5 million (2006 - \$3.0 million). At September 30, 2007, there was \$0.5 million in accounts payable and accrued liabilities relating to these costs.

9. FUTURE INCOME TAXES

On June 22, 2007, *Bill C-52 Budget Implementation Act, 2007*, which contained legislation to tax certain publicly traded trusts in Canada, received Royal Assent and became law. As a result, a new 31.5% tax will be applied to distributions from Canadian public income trusts. The new tax is not expected to apply to Freehold until 2011 as a transition period applies to trusts that existed prior to November 1, 2006. However, under Canadian GAAP, this enactment of trust taxation requires the recognition of future income tax. Accordingly, in the second quarter of 2007, Freehold recorded an additional \$54.3 million of future income tax expense with a corresponding increase in future income tax liability. The future income tax adjustment represents the temporary differences between the accounting and tax basis of Freehold's assets, effected at 31.5%, which is the rate that will be applicable in 2011 under the current legislation and Freehold's current structure.

10. SUPPLEMENTAL CASH FLOW DISCLOSURE

Cash Expenses Paid (\$000s)	Three Months Ended September 30		Nine Months Ended September 30	
	2007	2006	2007	2006
Interest	1,670	1,302	4,739	3,990
Taxes	(84)	277	(491)	975

Corporate Information

BOARD OF DIRECTORS

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

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

Harry S. Campbell, Q.C.⁽³⁾⁽⁴⁾
Managing Partner
Burnet, Duckworth & Palmer, LLP

Tullio Cedraschi
President and Chief Executive Officer
CN Investment Division

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

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

David J. Sandmeyer
President
Rife Resources Ltd.

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

2007 THIRD QUARTER DISTRIBUTIONS DECLARED

Record Date	Payment Date	Per Trust Unit
July 31, 2007	August 15, 2007	\$0.15
August 31, 2007	September 15, 2007	\$0.15
September 30, 2007	October 15, 2007	<u>\$0.15</u>
		<u>\$0.45</u>

TAX INFORMATION AND HISTORICAL DISTRIBUTIONS

Tax information and historical distributions are available on our website at www.freeholdtrust.com.

OFFICERS

William W. Siebens
Chair of the Board

David J. Sandmeyer
President and Chief Executive Officer

J. Frank George
Vice-President, Exploitation

Darren G. Gunderson
Controller

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

William O. Ingram
Vice-President, Production

Michael J. Okrusko
Vice-President, Land

HEAD OFFICE

Freehold Resources Ltd.
Freehold Royalty Trust
400, 144 – 4th Avenue S.W.
Calgary, Alberta T2P 3N4
Telephone: (403) 221-0802
Fax: (403) 221-0888

INVESTOR RELATIONS CONTACT

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

WEBSITE

www.freeholdtrust.com

STOCK EXCHANGE LISTING

Toronto Stock Exchange
Trading Symbol: FRU.UN

2007 THIRD QUARTER TRADING SUMMARY

High – \$15.85
Low – \$12.51
Close – \$15.26
Volume – 5,172,005
Trust Units Outstanding – 49.2 million
Market Capitalization – \$752 million
(September 30)

TRUSTEE AND TRANSFER AGENT

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

LEGAL COUNSEL

Burnet Duckworth & Palmer, LLP
Calgary, Alberta

AUDITORS

KPMG, LLP
Calgary, Alberta

BANKERS

Canadian Imperial Bank of Commerce
Calgary, Alberta

Royal Bank of Canada
Calgary, Alberta

RESERVE EVALUATORS

Trimble Engineering Associates Ltd.
Calgary, Alberta