

## Freehold Royalty Trust Announces 2006 Fourth Quarter and Year End Results and 2006 Year End Reserves

### **FOURTH QUARTER HIGHLIGHTS**

- Production averaged 8,313 barrels of oil equivalent (boe) per day, down 5% from the fourth quarter of 2005.
- Price realizations averaged \$41.44 per boe, 25% lower than a year ago.
- Operating netback averaged \$38.57 per boe, down 25% from the same period last year.
- Funds generated from operations were \$0.56 per Trust Unit, down 29% from the fourth quarter of 2005.
- Distributions declared in the fourth quarter totalled \$0.48 per Trust Unit, 25% lower than last year.
- Proved plus probable net reserves declined 8% to 28.0 million boe at December 31, 2006.
- Reserve additions of 1.5 million boe replaced 49% of annual production at an average cost of \$9.38 per boe.
- At forecast 2007 production levels, our reserve life index is 9.6 years.

The regular monthly distribution remains fixed at \$0.15 per Trust Unit until further notice. Production levels, operating costs and other expenses remain in line with our expectations and the Trust's financial condition is healthy.

<b>Results at a Glance</b>	Three Months Ended			Twelve Months Ended		
	December 31			December 31		
	2006	2005	Change	2006	2005	Change
<b>Financial</b> (\$000s, except as noted)						
Gross revenue	<b>32,214</b>	44,555	-28%	<b>143,067</b>	136,914	4%
Operating income	<b>29,506</b>	41,452	-29%	<b>130,927</b>	126,793	3%
Net income	<b>9,545</b>	18,747	-49%	<b>45,181</b>	58,346	-23%
Per Trust Unit, basic and diluted (\$)	<b>0.19</b>	0.38	-50%	<b>0.92</b>	1.36	-32%
Funds generated from operations	<b>27,394</b>	38,694	-29%	<b>119,849</b>	118,034	2%
Per Trust Unit (\$)	<b>0.56</b>	0.79	-29%	<b>2.44</b>	2.76	-12%
Property and royalty acquisitions	—	—	—	<b>5,382</b>	351,705	-98%
Development expenditures <sup>(1)</sup>	<b>3,766</b>	1,631	131%	<b>11,446</b>	7,982	43%
Distributions declared	<b>23,594</b>	31,366	-25%	<b>103,100</b>	84,810	22%
Per Trust Unit (\$) <sup>(2)</sup>	<b>0.48</b>	0.64	-25%	<b>2.10</b>	1.92	9%
Long-term debt	<b>100,000</b>	107,000	-7%	<b>100,000</b>	107,000	-7%
Unitholders' equity	<b>344,448</b>	399,471	-14%	<b>344,448</b>	399,471	-14%
<b>Operating</b>						
Average daily production (boe/d)	<b>8,313</b>	8,739	-5%	<b>8,412</b>	7,636	10%
Average price realizations (\$/boe)	<b>41.44</b>	54.95	-25%	<b>46.07</b>	48.53	-5%
Operating netback (\$/boe)	<b>38.57</b>	51.56	-25%	<b>42.64</b>	45.49	-6%

(1) Capital expended relates to working interest properties.

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

## Message to Unitholders

In the fourth quarter of 2006, Freehold declared distributions of \$23.6 million, or \$0.48 per Trust Unit, representing 86% of funds generated from operations. Distributions for the full year reached a record \$2.10 per Trust Unit; however, fourth quarter distributions were down 25%, mainly due to a 25% decline in realized prices compared with the fourth quarter of 2005.

### COMMODITY PRICES

While West Texas Intermediate oil prices were flat quarter-over-quarter, natural gas prices were 46% lower than the fourth quarter of 2005. In 2005, prices spiked in the fourth quarter with the temporary loss of supply following hurricanes Katrina and Rita in the Gulf of Mexico. Since the beginning of 2006, however, natural gas prices have weakened from the record highs of 2005 and gas storage levels remain above the five year average. Longer-term, industry fundamentals remain positive; however, ample inventories, a mild winter, and a slowing U.S. economy could further depress commodity prices in the near-term. Of particular relevance for Freehold are the markets for heavy oil and prices for the benchmark Bow River/Hardisty stream, which is a close proxy for our average oil realizations. In March 2006, new pipeline access expanded the market for Alberta heavy oil, and we benefited from a significant narrowing of the price spread in 2006.

The commodity price fluctuations we have witnessed throughout 2006 serve to reinforce that our cash flows, and thus our distributions, are largely dependent on supply and demand factors that are beyond our control. Due to the unpredictable nature of commodity markets, we continue to believe our 'no hedging' policy is the right strategy for Freehold.

### RESERVES AND LAND VALUES

Our 2006 capital program was successful in adding low-cost reserves. We spent \$16.8 million on development activities and acquisitions, adding 1.5 million boe of net proved plus probable reserves at an average cost of \$9.38 per boe. While these activities replaced only 49% of our 2006 production, they produced a very profitable recycle ratio of 4.5, contributing to a three-year average recycle ratio of 1.8. Our oil and gas reserves were independently evaluated as at December 31, 2006, with reserves assigned to 20,488 wells. Net proved plus probable reserves declined 8% year-over-year. Technical revisions reduced proved plus probable reserves by 1.0 million boe. These revisions resulted from changes in the producing characteristics of a large number of properties. Two thirds of the affected properties were oil, the majority of which were in heavy oil areas of Alberta and Saskatchewan. Our calculated reserve life index is 9.6 years, compared with 9.9 years at the end of 2005.

At December 31, 2006, our land holdings encompassed 2.1 million gross acres. Our undeveloped land, totalling 598,235 gross acres, was independently valued at \$19.4 million. The present value of our net proved plus probable oil and gas reserves, discounted at 10%, was \$636.3 million, contributing to a net asset value of \$11.74 per Trust Unit.

### DRILLING ACTIVITY

Industry wide, just over 22,000 wells were completed in western Canada during 2006, up 1% from 2005. We anticipate that lower commodity prices will reduce drilling activity in 2007, particularly in natural gas regions. Drilling has already shifted to more oil-weighted targets as lower natural gas prices have made the economics of shallow gas and coal bed methane activity less attractive for producers. Nonetheless, industry activity in western Canada, particularly in the oil sands, remains robust and the demand for people and oilfield services is unprecedented. The oil and gas industry continues to experience higher costs, as well as a severe shortage of experienced professionals and skilled tradespeople.

Drilling on Freehold's lands was down from 2005's record, although 2006 was still the second best year in our 10-year history with 851 gross (26.2 equivalent net) wells drilled on our lands. Of note, there are currently 119 (6.1 equivalent net) licensed drilling locations on our royalty lands, up from 92 (4.6 equivalent net) locations at this time last year. The higher number of drilling licences is evidence of the ongoing development potential of our royalty lands.

## DISTRIBUTION GUIDANCE

Our distribution guidance for 2007 remains unchanged at \$1.80 per Trust Unit based on monthly distributions of \$0.15 per Trust Unit. We will continue to monitor prices and activity levels closely, and our guidance will be reviewed and updated quarterly.

## PROPOSED FEDERAL TAX CHANGES

On October 31, 2006, the Minister of Finance surprised the market by announcing the federal government's intention to impose a tax on the cash distributions of income trusts by 2011. The announcement reflects a fundamental shift in the tax system and departs from the government's earlier commitment to leave the tax rules for income trusts unchanged.

In the days after the announcement, nearly \$35 billion of Canadians' wealth was destroyed. We believe there was absolutely no need to penalize existing trusts to prevent future conversions. Freehold Royalty Trust is a member of the Canadian Association of Income Funds ([www.caif.ca](http://www.caif.ca)) and part of the Coalition of Canadian Energy Trusts ([www.canadianenergytrusts.ca](http://www.canadianenergytrusts.ca)). Through these organizations, we are continuing to express our concerns and objections to the federal government regarding the proposed income trust tax changes in order to realize a better solution than what is currently being proposed.

Income trusts comprise a significant portion of the public issuers in Canada, and trusts provide an important income stream for individuals, especially retirees and those planning retirement. We urge our Unitholders to contact the Canadian government to ensure that their voices are also heard in this important issue. We also encourage our Unitholders to become members of the Canadian Association of Income Trust Investors ([www.caiti.info](http://www.caiti.info)). This organization has been formed with a mission to preserve the ongoing viability and sustainability of the Canadian income trust market and is an effective vehicle through which individual investors can voice their opinions regarding trust taxation.

Assuming the proposed changes are enacted, the new tax will apply to our distributions starting in 2011, which is expected to result in adverse tax consequences to Freehold and certain Unitholders (including most particularly Unitholders that are tax deferred or non-residents of Canada). In the coming months, we will examine our strategy to determine what changes are required, if any, to continue to provide the best possible return for our Unitholders. However, greater clarity on the new rules is needed and a great deal of analysis is required within the legal and tax communities before we will make any decisions. In the meantime, we have been given a four-year grace period before the new tax will apply, and the fundamentals of our business remain strong. The proposed limits on cumulative increases in equity capital (40% in 2007 and 20% in each of the subsequent three years) will not significantly limit our near-term growth opportunities.

## OUR TENTH ANNIVERSARY

We celebrated the tenth anniversary of the Trust on November 25, 2006. Over the past decade, we have funded 100% of our development expenditures, financed our minor acquisitions, and maintained a very conservative balance sheet by paying down debt. These results were accomplished even though we distributed 82% of cash flow to our Unitholders. To date, we have returned \$14.30 per Trust Unit in cumulative distributions, yielding a total return (distributions reinvested) of 423%.

Our royalty interests have helped us to deliver this strong performance and, despite the uncertainty caused by the proposed tax changes, we look forward to continuing to provide our Unitholders with solid investment returns for many years to come.

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



David J. Sandmeyer  
President and Chief Executive Officer

## SUMMARY OF RESERVES

Our oil and gas reserves were independently evaluated by Trimble Engineering Associates Ltd. as at December 31, 2006. The evaluation was conducted in accordance with National Instrument 51-101. Our Reserves Committee met with the reserve evaluators to review their findings and procedures and the reserve report has been accepted by the Board.

Under National Instrument 51-101, we report reserves on a net basis (our share of working interest properties minus royalties payable to others, plus royalties receivable on our royalty lands). As a result, Freehold's reserves may not be directly comparable. In the majority of cases, we lack specific operational knowledge of our royalty interest properties and rely primarily on decline analysis to estimate reserves. Under this method, changes in producing characteristics that are caused by access restrictions such as weather or competition for services may be reflected in a reduction to reserves.

In 2006, reserves were assigned to 20,488 wells. Net proved plus probable reserves totalled 28.0 million boe, down 8% from year-end 2005. Approximately 98.6% of our total proved reserves are producing, which is high by industry standards. Freehold's reserve life index is 9.6 years, compared with 9.9 years at the end of 2005.

Net Oil and Gas Reserves <sup>(1)</sup> as at December 31, 2006	Proved			Total Proved	Proved Plus Probable
	Developed Producing	Developed Non-producing	Undeveloped		
Light and medium oil (Mbbbls)	4,373	19	0	4,393	6,206
Heavy oil (Mbbbls)	6,213	0	231	6,445	10,038
Natural gas (MMcf)	41,015	97	10	41,121	62,019
NGLs (Mbbbls)	1,029	2	0	1,031	1,431
<b>Total (Mboe)</b>	<b>18,452</b>	<b>37</b>	<b>233</b>	<b>18,722</b>	<b>28,012</b>
Reserve life index (years) <sup>(2)</sup>	7.2	—	—	7.2	9.6

(1) Columns may not add due to rounding.

(2) Calculated by dividing Trimble Engineering Associates Ltd.'s forecast of 2007 net production into the remaining net reserves.

During 2006, development activities and acquisitions added 1.5 million boe of proved plus probable reserves. Of these additions, 0.8 million boe were on our royalty lands, 0.3 million boe were on our working interest properties, and 0.4 million boe were from acquisitions. Negative technical revisions of 1.0 million boe resulted primarily from changes in the producing characteristics of a large number of properties. Two thirds of the affected properties were oil, the majority of which were in heavy oil areas of Alberta and Saskatchewan.

Reconciliation of Net Oil and Gas Reserves <sup>(1)</sup>	Proved	Probable	Proved Plus Probable	Net Present Value <sup>(2)</sup>
	(Mboe)	(Mboe)	(Mboe)	(\$000s)
December 31, 2005	20,412	10,118	30,530	742,832
Production <sup>(3)</sup>	(3,017)	(58)	(3,074)	(69,912)
Development additions	651	496	1,146	37,163
Acquisitions <sup>(4)</sup>	256	119	376	5,123
Revisions:				
Operating Costs	—	—	—	(7,259)
Pricing	—	—	—	(24,503)
Royalties	—	—	—	(3,341)
Future capital, ARTC	—	—	—	(5,285)
Reserves	420	(1,385)	(966)	(38,551)
<b>December 31, 2006</b>	<b>18,722</b>	<b>9,290</b>	<b>28,012</b>	<b>636,267</b>
Change over prior year	(1,690)	(828)	(2,518)	(106,565)

(1) Columns may not add due to rounding.

(2) Net present value of proved plus probable reserves based on forecast prices and costs, discounted at 10% before tax. Based on the December 31, 2006 escalated oil and gas price forecasts by an independent qualified reserves evaluator.

(3) Estimated by Trimble Engineering Associates Ltd.

(4) Wildmere Unit interest acquired July 1, 2006.

## ACQUISITION AND DEVELOPMENT COSTS

In 2006, we spent \$16.8 million on development activities and acquisitions, adding 1.5 million boe of reserves at an average cost of \$9.38 per boe. While these activities replaced only 49% of our 2006 production, they produced a very profitable recycle ratio of 4.5, contributing to a three-year average recycle ratio of 1.8.

<b>Analysis of Development and Acquisition Costs</b>	<b>2006</b>	<b>2005</b>	<b>2004</b>	<b>Three-Year Results</b>
Development expenditures (\$000s)	11,446	7,982	5,823	25,251
Change in future development capital estimates (\$000s)	(2,549)	235	(2,593)	(4,907)
Net reserve additions by development (Mboe)	1,146	945	817	2,908
<b>Development costs (\$/boe)<sup>(1)</sup></b>	<b>7.76</b>	<b>8.70</b>	<b>3.95</b>	<b>7.00</b>
Acquisition expenditures (\$000s)	5,382	351,705	12,881	369,968
Net reserve additions by acquisition (Mboe)	376	12,889	434	13,699
<b>Acquisition costs (\$/boe)</b>	<b>14.33</b>	<b>27.29</b>	<b>29.68</b>	<b>27.01</b>
Total expenditures (\$000s)	16,828	359,687	18,704	395,219
Change in future development capital estimates (\$000s)	(2,549)	235	(2,593)	(4,907)
Net reserve additions (Mboe)	1,522	13,834	1,251	16,607
<b>Development and acquisition costs (\$/boe)</b>	<b>9.38</b>	<b>26.02</b>	<b>12.88</b>	<b>23.50</b>

(1) Development expenditures plus change in future capital, divided by reserves added.

<b>Recycle Statistics</b> (\$ per boe, except as noted)	<b>2006</b>	<b>2005</b>	<b>2004</b>	<b>Three-Year Results</b>
Operating netback <sup>(1)(4)</sup>	42.64	45.49	34.05	41.43
Development and acquisition costs <sup>(2)(4)</sup>	9.38	26.02	12.88	23.50
Recycle ratio (times) <sup>(3)</sup>	4.5	1.7	2.6	1.8

(1) Total revenue, less operating costs and royalty expenses net of Alberta Royalty Credit.

(2) Development expenditures, plus change in future capital, plus acquisition costs, divided by net reserves added through development and acquisition activities.

(3) Operating netback divided by the average cost of acquiring and developing new reserves.

(4) Operating netback is based on gross production, while development and acquisition costs are based on net reserves.

## SUMMARY OF LAND HOLDINGS

At December 31, 2006, our land holdings encompassed approximately 2.1 million gross acres, comprised mainly of mineral title and gross overriding royalties.

<b>Summary of Land Holdings</b> (gross acres) <sup>(1)</sup>	December 31		Change
	<b>2006</b>	<b>2005</b>	
Mineral title and gross overriding royalty land	<b>1,865,418</b>	1,808,704	3%
Working interest land	<b>203,952</b>	197,241	3%
<b>Total</b>	<b>2,069,370</b>	2,005,945	3%
Undeveloped land	<b>598,235</b>	555,171	8%

(1) Total number of acres in which we have an interest.

## NET ASSET VALUE

At December 31, 2006, the present value of our net proved plus probable oil and gas reserves, discounted at 10%, before tax, was \$636.3 million, down from \$742.8 million one year ago. The reduction resulted from a higher operating cost forecast, increased inflation, reduced exchange rate, reduced pricing forecast, and the impact of the technical reserve changes. Our net asset value was \$11.74 per Trust Unit, compared with \$13.85 the prior year. In addition to the reduction in the value of reserves, the major changes year-over-year were a \$7.2 million reduction in working capital, a \$7.0 million reduction in bank debt, and a \$5.3 million increase in the value of undeveloped land.

Net Asset Value as at December 31, 2006 <sup>(1)</sup> (\$000s, except unit data)	Discounted at			
	0%	5%	10%	15%
Present value of oil and gas reserves <sup>(2)</sup>	1,388,973	855,270	636,267	517,185
Present value of potash reserves <sup>(3)</sup>	43,665	18,347	10,530	7,360
Undeveloped land <sup>(4)</sup>	19,412	19,412	19,412	19,412
Reclamation fund	2,117	2,117	2,117	2,117
Working capital	9,050	9,050	9,050	9,050
Bank debt	(100,000)	(100,000)	(100,000)	(100,000)
Net asset value	1,363,217	804,196	577,376	455,124
Trust Units outstanding	49,174,197	49,174,197	49,174,197	49,174,197
<b>Net asset value per Trust Unit</b>	<b>27.72</b>	<b>16.35</b>	<b>11.74</b>	<b>9.26</b>

(1) Columns may not add due to rounding.

(2) Evaluated by Trimble Engineering Associates Ltd.

(3) Potash reserves, evaluated by Rife Resources Ltd., are not subject to NI 51-101.

(4) Evaluated by Seaton-Jordan & Associates Ltd., effective December 31, 2006.

## Management's Discussion and Analysis (MD&A)

The following discussion is management's opinion about the operating and financial results of Freehold Resources Ltd., Petrovera Resources (a general partnership), and Freehold Royalty Trust (collectively, Freehold or the Trust), for the three and twelve months ended December 31, 2006 and previous periods, and the outlook for Freehold based on information available as at February 28, 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 December 31, 2006 and December 31, 2005, and all dollar amounts are expressed in Canadian currency, unless otherwise noted. This discussion should be read in conjunction with the Trust's annual MD&A and audited financial statements for the years ended December 31, 2005 and 2004, together with the accompanying notes. These are on pages 23 through 59 of the Trust's 2005 annual report to Unitholders.

Additional information about Freehold, including our annual information form, 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 February 28, 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, 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.

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. 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.

Operating income, netback, funds generated from operations, and funds generated from operations per Trust Unit do not have any standardized meanings prescribed by GAAP and therefore may not be comparable with the calculations of similar measures for other entities.

## THE ROYALTY ADVANTAGE

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 development expenditures. In 2006, royalty interest properties accounted for 76% of gross revenue, 84% of funds generated from operations, and 89% of distributions declared.

Components of Distributions to Unitholders Twelve months ended December 31, 2006 (\$000s)	Royalty Interest		Working Interest		Total Trust
	Properties	Properties	Properties	Properties	
Gross revenue	109,189	33,878			143,067
Royalty expense	—	(3,831)			(3,831)
Net revenue	109,189	30,047			139,236
Operating expense	—	(8,309)			(8,309)
Net operating income	109,189	21,738			130,927
General and administrative expense	(4,389)	(1,192)			(5,581)
Interest expense	(4,638)	(556)			(5,194)
Income and capital taxes	—	(291)			(291)
Unit based compensation	225	65			290
Expenditures on reclamation	—	(302)			(302)
Funds generated from operations	100,387	19,462			119,849
Reclamation fund contributions	—	(153)			(153)
Development expenditures	—	(11,446)			(11,446)
Acquisitions	—	(5,382)			(5,382)
Changes in debt	(14,444)	7,444			(7,000)
Changes in working capital	5,614	1,618			7,232
Distributions declared	91,557	11,543			103,100

## TRUST UNITS OUTSTANDING

As at December 31, 2006 and February 28, 2007, there were 49,174,197 million Trust Units outstanding. At the end of the fourth quarter, the Trust issued 35,654 Trust Units to the Manager in payment of the quarterly management fee. In May 2005, the Trust issued 17.4 million Trust Units in association with the Petrovera acquisition.

At the Annual and Special Meeting of Unitholders held on May 10, 2006, Unitholders approved a deferred trust unit plan for non-management directors whereby fully vested deferred trust units are granted annually. Subsequently, the Board allocated 1,595 deferred trust units to each eligible director and 3,190 deferred trust units to the Chair of the Board. Under this plan, distributions to Unitholders declared by the Trust prior to redemption are assumed to be reinvested on behalf of the directors in notional units on the date of distribution. As at December 31, 2006, there were 12,559 deferred trust units outstanding, which are redeemable for an equal number of Trust Units any time after the director's retirement.

On January 1, 2007, the Board approved annual grants for 2007 totalling 14,181 deferred trust units, allocating 2,026 to each eligible director and 4,051 to the Chair of the Board. As at February 28, 2007, there were 27,303 deferred trust units outstanding.

Trust Units Outstanding	Three Months Ended			Twelve Months Ended		
	December 31			December 31		
	2006	2005	Change	2006	2005	Change
Weighted average						
Basic	49,138,931	48,966,315	—	49,085,795	42,812,470	15%
Diluted	49,151,287	48,966,315	—	49,093,609	42,812,470	15%
At period end	49,174,197	49,031,581	—	49,174,197	49,031,581	—

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

The acquisition of Petrovera Resources had a positive impact on our results from the date of closing on May 10, 2005. The Petrovera contribution is partially reflected in the second quarter of 2005 (52 days of production) and is fully reflected in the following periods. Another factor that has influenced our results over the past several quarters is higher operating expenses on our working interest properties, which currently comprise about one-fifth 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	2006				2005			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
<b>Financial</b> (\$000s, except as noted)								
Revenue, net of royalty expense	31,765	36,550	36,998	33,923	43,364	42,867	27,922	19,170
Funds generated from operations	27,394	31,692	32,565	28,198	38,694	38,893	24,344	16,103
Per Trust Unit (\$)	0.56	0.65	0.66	0.58	0.79	0.79	0.59	0.51
Distributions to Unitholders	23,594	26,521	26,502	26,483	31,366	22,527	17,981	12,936
Per Trust Unit (\$) <sup>(1)</sup>	0.48	0.54	0.54	0.54	0.64	0.46	0.41	0.41
Payout ratio (%)	86	84	81	94	81	58	74	80
Net income	9,545	12,728	14,142	8,766	18,747	19,373	10,858	9,368
Per Trust Unit, basic and diluted (\$)	0.19	0.26	0.29	0.18	0.38	0.40	0.26	0.30
Property and royalty acquisitions	—	5,382	—	—	—	—	351,705	—
Development expenditures	3,766	4,649	1,430	1,601	1,631	4,059	1,215	1,077
Long-term debt	100,000	98,000	96,000	105,000	107,000	118,000	120,000	27,000
Trust Units outstanding								
Weighted average (000s)	49,139	49,103	49,068	49,032	48,996	48,961	41,489	31,544
At quarter end (000s)	49,174	49,139	49,103	49,067	49,032	48,996	48,960	31,567
<b>Operating</b> (\$/boe, except as noted)								
Daily production (boe/d)	8,313	8,335	8,212	8,794	8,739	8,974	7,279	5,502
Average selling price	41.44	48.95	50.27	43.78	54.95	52.61	42.42	39.47
Operating netback	38.57	44.92	47.08	40.18	51.56	49.89	39.61	36.18
Operating expenses	2.95	2.75	2.43	2.68	2.38	2.03	2.54	2.53
Working Interest properties	13.86	11.88	11.51	11.26	12.06	10.35	11.00	7.59
General and administrative expenses	1.44	1.32	1.79	2.69	1.52	1.17	1.42	2.55
<b>Benchmark Prices</b>								
WTI crude oil (US\$/bbl)	60.26	70.48	70.70	63.45	60.02	63.19	53.20	49.84
Exchange rate (Cdn\$/US\$)	0.89	0.89	0.89	0.87	0.85	0.83	0.80	0.82
Edmonton Par (Cdn\$)	64.48	79.08	78.55	68.96	71.17	76.51	65.76	61.45
Light/heavy oil differential (Cdn\$/bbl)	18.80	20.14	17.43	28.57	28.14	20.79	24.17	22.48
Bow River/Hardisty (Cdn\$/bbl)	45.69	58.94	61.11	40.39	43.03	55.72	41.59	38.97
AECO natural gas (Cdn\$/Mcf)	6.36	6.03	6.27	9.27	11.68	8.17	7.38	6.69
<b>Unit Trading Performance</b>								
High (\$)	19.80	23.06	21.70	22.20	18.98	19.30	17.63	18.49
Low (\$)	12.43	18.50	18.02	18.44	15.15	15.99	14.25	15.50
Close (\$)	14.81	19.00	21.00	19.50	18.81	18.68	15.99	16.10
Volume (000s)	13,867	5,153	5,336	11,155	7,611	9,980	8,311	2,418

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

## DEVELOPMENT ACTIVITIES

Industry wide, 22,127 wells were drilled in western Canada during 2006, up 1% from 2005. Drilling on Freehold's lands was down 15% from 2005's record, although 2006 was still the second best year in our 10-year history with 851 gross (26.2 equivalent net) wells drilled on our lands. In the fourth quarter, the total number of wells drilled on our lands was up 38%; however, on an equivalent net basis, drilling was 27% lower than last year.

## ROYALTY INTEREST LANDS

Drilling on our royalty lands generally mirrors industry activity. A total of 256 wells were drilled on our royalty lands in the fourth quarter, up 51% over last year. However, on an equivalent net basis, drilling was down 33% from the fourth quarter of 2005. There are currently 119 (6.1 equivalent net) licensed drilling locations on our royalty lands, up from 92 (4.6 equivalent net) locations at this time last year. The higher number of drilling licences is evidence of the ongoing development potential of our royalty lands.

Royalty Interest Lands Drilling Summary (includes unitized wells)	Three Months Ended December 31			Twelve Months Ended December 31		
	2006	2005	Change	2006	2005	Change
	Gross wells	256	169	51%	778	884
Equivalent net wells <sup>(1)</sup>	4.3	6.4	-33%	18.7	25.0	-25%
Net success rate	99.6%	99.0%	1%	99.1%	99.0%	0%

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

## WORKING INTEREST PROPERTIES

About 21% of our production comes from working interest properties on which we incur our proportionate share of development costs. Our 2006 development expenditures were \$11.4 million, of which \$3.8 million was spent in the fourth quarter. Major projects in the quarter included a battery expansion at Hayter, continued drilling in Southeast Saskatchewan and Pouce Coupe, and recompletion work at Luseland and LaGlance. Our net drilling success rate in 2006 was 100%.

Development expenditures for 2007 are estimated to be \$8.0 million. The majority of our activity will be focused on continued drilling activity at Hayter, Alberta and in Southeast Saskatchewan.

Working Interest Properties Drilling Summary	Three Months Ended December 31				Twelve Months Ended December 31			
	2006		2005		2006		2005	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Oil	8	1.5	11	1.2	36	6.3	44	6.9
Natural gas	2	0.2	11	0.6	32	0.9	69	1.8
Other	1	0.1	2	0.2	5	0.3	4	0.4
Total	11	1.8	24	2.0	73	7.5	117	9.1

## RESULTS OF OPERATIONS

### PRODUCTION

Production volumes in the fourth quarter averaged 8,313 boe per day, down 5% from last year. Royalty production declined 7% as drilling did not offset natural production declines. Working interest production increased 3% due to the success of our 2006 development program, the Wildmere acquisition, and the Hayter facility expansion. Royalty interests contributed 79% of total volumes produced during the quarter. In December, we reclassified a natural gas well in northeast British Columbia as a royalty well. The well had been previously reclassified as a working interest well in June as we believed payout had occurred. The reversal, applied in the fourth quarter, reduced working interest production by 400 boe per day and increased royalty volumes by 150 boe per day.

Annual production was 10% higher than last year, boosted by the Petrovera acquisition that occurred midway through the second quarter of 2005. On a boe basis, our production profile for 2006 was 38% natural gas, 4% natural gas liquids (NGL), 20% light and medium oil, and 38% heavy oil.

Average Daily Production	Three Months Ended December 31			Twelve Months Ended December 31		
	2006	2005	Change	2006	2005	Change
<b>Royalty lands</b>						
Oil (bbls/d)	3,394	3,699	-8%	3,456	3,185	9%
NGL (bbls/d)	301	302	0%	297	284	5%
Natural gas (Mcf/d)	17,084	18,089	-6%	16,660	14,501	15%
Oil equivalent (boe/d)	6,542	7,016	-7%	6,530	5,885	11%
<b>Working interest properties</b>						
Oil (bbls/d)	1,595	1,290	24%	1,409	1,303	8%
NGL (bbls/d)	37	66	-44%	61	61	0%
Natural gas (Mcf/d)	834	2,202	-62%	2,478	2,320	7%
Oil equivalent (boe/d)	1,771	1,723	3%	1,882	1,751	7%
<b>Total Trust</b>						
Oil (bbls/d)	4,989	4,989	0%	4,865	4,488	8%
NGL (bbls/d)	338	368	-8%	358	345	4%
Natural gas (Mcf/d)	17,918	20,291	-12%	19,138	16,821	14%
Oil equivalent (boe/d)	8,313	8,739	-5%	8,412	7,636	10%
Number of days in period (days)	92	92	—	365	365	—
Total volumes during period (Mboe)	765	804	-5%	3,070	2,787	10%
Potash production (tonnes/d)	13.8	11.1	24%	10.5	9.7	8%

## BENCHMARK PRICES

WTI crude oil prices averaged US\$60.26 per barrel in the fourth quarter, down 15% from the third quarter and flat compared with the same period in 2005. A higher Canadian dollar lowered the average Edmonton Par crude oil price by 9%. Of particular relevance for Freehold are the markets for heavy oil and prices for the benchmark Bow River/Hardisty stream, which is a close proxy for our average oil realizations. In March 2006, new pipeline access expanded the market for Alberta heavy oil, and we benefited from a significant narrowing of the price spread in 2006. Bow River/Hardisty prices were 6% higher quarter-over-quarter and 15% higher year-over-year.

Natural gas prices averaged \$6.36 per Mcf, 5% higher than the third quarter but 46% lower than the fourth quarter of 2005. Last year, prices spiked in the fourth quarter with the temporary loss of supply following hurricanes Katrina and Rita in the Gulf of Mexico. Since the beginning of 2006, however, natural gas prices have weakened from the record highs of 2005 as a warmer than normal winter enabled gas storage levels to build and remain above the five year average. Year-over-year, prices are down 18%.

Longer-term, industry fundamentals remain positive; however, ample inventories, a mild winter, and a slowing U.S. economy could further depress commodity prices in the near term.

Average Benchmark Prices	Three Months Ended December 31			Twelve Months Ended December 31		
	2006	2005	Change	2006	2005	Change
WTI crude oil (US\$/bbl)	60.26	60.02	0%	66.22	56.56	17%
US\$/Cdn\$ exchange rate	0.8878	0.8524	4%	0.8818	0.8260	7%
Edmonton Par crude oil (Cdn\$/bbl)	64.48	71.17	-9%	72.77	68.72	6%
Light/heavy oil differential (Cdn\$/bbl)	18.80	28.14	-33%	21.23	23.90	-11%
Bow River/Hardisty (Cdn\$/bbl)	45.69	43.03	6%	51.53	44.83	15%
AECO natural gas (Cdn\$/Mcf)	6.36	11.68	-46%	6.98	8.48	-18%

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. Our prices were negatively affected by the decline in natural gas prices and a stronger Canadian dollar compared with last year. On a boe basis, our average price realizations were 25% lower in the fourth quarter of 2006 and 5% lower for the year.

Average Selling Prices	Three Months Ended			Twelve Months Ended		
	December 31			December 31		
	2006	2005	Change	2006	2005	Change
Oil (\$/bbl)	44.34	45.79	-3%	50.24	46.65	8%
NGL (\$/bbl)	39.25	58.67	-33%	50.29	50.58	-1%
Oil and NGL (\$/bbl)	44.01	46.67	-6%	50.25	46.93	7%
Natural gas (\$/Mcf)	6.14	11.34	-46%	6.54	8.55	-24%
Oil equivalent (\$/boe)	41.44	54.95	-25%	46.07	48.53	-5%
Potash (\$/tonne)	228.84	205.76	11%	220.13	213.28	3%

## REVENUE

Gross revenue was 28% lower in fourth quarter but 4% higher for the year, due to the changes in realized prices and production volumes discussed above.

Revenue	Three Months Ended			Twelve Months Ended		
	December 31			December 31		
	2006	2005	Change	2006	2005	Change
Gross revenue	32,214	44,555	-28%	143,067	136,914	4%
Royalty expense <sup>(1)</sup>	(449)	(1,191)	-62%	(3,831)	(3,591)	7%
Net revenue	31,765	43,364	-27%	139,236	133,323	4%

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

The accompanying table demonstrates the net effect of price and volume variances on gross revenues. "Other" includes potash revenue, sulphur revenue, lease rentals, processing fees, and interest income. In the fourth quarter, approximately 90% of the decline in gross revenue was attributable to lower prices.

Gross Revenue Variances (\$000s)	Three Months Ended		Twelve Months Ended	
	December 31		December 31	
	2006 vs. 2005	2005 vs. 2004	2006 vs. 2005	2005 vs. 2004
<b>Oil and NGL</b>				
Production increase (decrease)	(123)	5,923	7,149	16,191
Price increase (decrease)	(1,310)	3,072	5,844	12,637
Net increase (decrease)	(1,433)	8,995	12,993	28,828
<b>Natural gas</b>				
Production increase (decrease)	(1,341)	11,175	5,531	20,345
Price increase (decrease)	(9,708)	4,326	(12,322)	8,531
Net increase (decrease)	(11,049)	15,501	(6,791)	28,876
Other	141	123	(49)	719
<b>Gross revenue increase (decrease)</b>	<b>(12,341)</b>	<b>24,619</b>	<b>6,153</b>	<b>58,423</b>

## EXPENSES

### ROYALTIES PAID

Royalty expense rates are linked to commodity prices and production volumes. Royalty expenses in the fourth quarter reflect the prior period adjustments including the category reversal discussed above (see Production), which decreased royalty expenses for the last three months of 2006 by \$500,000 (\$0.65 per boe), but related to 17 months of production. For the full year, royalty expenses per boe were down 3% on lower prices and production volumes year-over-year.

Royalty Expenses (net of Alberta Royalty Credit)	Three Months Ended			Twelve Months Ended		
	December 31			December 31		
	2006	2005	Change	2006	2005	Change
Working interest properties (\$000s)	449	1,191	-62%	3,831	3,591	7%
Per boe (\$)	2.75	7.51	-63%	5.58	5.62	-1%
Royalty interest lands <sup>(1)</sup> (\$000s)	—	—	—	—	—	—
Per boe (\$)	—	—	—	—	—	—
Total royalty expenses (\$000s)	449	1,191	-62%	3,831	3,591	7%
Total Trust (\$/boe)	0.59	1.48	-60%	1.25	1.29	-3%

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

### OPERATING EXPENSES

Overall, operating costs per boe were 24% higher quarter-over-quarter and 16% higher year-over-year. Demand for people and services, particularly in Alberta, is unprecedented and cost inflation continues to drive up operating expenses industrywide. Our large component of royalty interest production, which does not incur operating expenses, helps to shelter the Trust; however, on our working interest properties we continue to experience higher costs for services, materials, and equipment. We anticipate operating expenses will average approximately \$3.00 per boe in 2007.

Operating Expenses	Three Months Ended			Twelve Months Ended		
	December 31			December 31		
	2006	2005	Change	2006	2005	Change
Working interest properties (\$000s)	2,259	1,912	18%	8,309	6,530	27%
Per boe (\$)	13.86	12.06	15%	12.09	10.22	18%
Royalty interest lands <sup>(1)</sup> (\$000s)	—	—	—	—	—	—
Per boe (\$)	—	—	—	—	—	—
Total operating expenses (\$000s)	2,259	1,912	18%	8,309	6,530	27%
Total Trust (\$/boe)	2.95	2.38	24%	2.71	2.34	16%

(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. Depletion and depreciation on property, plant and equipment and accretion on the asset retirement obligation totalled \$72.1 million (\$23.50 per boe) in 2006, up from \$57.2 million (\$20.52 per boe) in 2005. The increase reflects the addition of petroleum and natural gas interests from the Petrovera acquisition in May 2005 at a higher cost than our historical average.

Depletion, Depreciation and Accretion Expenses	Year Ended	
	December 31	
	2006	2005
Depletion and depreciation (\$000s)	71,874	56,938
Accretion of asset retirement obligation (\$000s)	257	252
Total depletion, depreciation and accretion expenses (\$000s)	72,131	57,190
Per boe (\$)	23.50	20.52

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

In the fourth quarter, G&A costs totalled \$1.1 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 5% lower quarter-over-quarter but 15% higher year-over-year. An increase in the Manager's staff levels following the Petrovera acquisition, higher stock exchange listing fees due to additional Trust Units outstanding, rising costs associated with financial reporting and regulatory compliance, and higher directors' fees all contributed to higher G&A expenses in 2006.

We recorded a non-cash expense of \$247,000 (with a corresponding increase to contributed surplus) as unit based compensation relating to the grant of 12,559 deferred trust units to non-management directors during 2006. G&A for the year also included a non-cash charge of \$43,000 for the Trust's proportionate share of the Manager's LTIP for the year 2006 and \$450,000 (expensed in the first quarter) for the Trust's proportionate share of the Manager's annual bonus plan for 2006 (See New Accounting Policies).

G&A Expenses	Three Months Ended December 31			Twelve Months Ended December 31		
	2006	2005	Change	2006	2005	Change
G&A expenses (\$000s)	1,100	1,222	-10%	5,581	4,392	27%
Per boe (\$)	1.44	1.52	-5%	1.82	1.58	15%
As a percentage of revenue	3.4%	2.7%	26%	3.9%	3.2%	22%

### MANAGEMENT FEES

The issue of 17.4 million Trust Units in May 2005 resulted in a pro-rata increase in the management fee, in accordance with the management agreement. The quarterly management fee, which is paid in Trust Units, was 35,654 Trust Units for the fourth quarter of 2006, unchanged from last year. The ascribed value was 21% lower due to a lower Trust Unit price at the end of the fourth quarter this year.

Management Fees (paid in Trust Units) (\$000s, except as noted)	Three Months Ended December 31			Twelve Months Ended December 31		
	2006	2005	Change	2006	2005	Change
Ascribed value of management fees <sup>(1)</sup>	528	670	-21%	2,649	2,178	22%
Per boe (\$)	0.69	0.83	-17%	0.86	0.78	10%

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

### INTEREST EXPENSES

Additional debt assumed in May 2005 to finance the Petrovera acquisition resulted in higher interest expense during 2006. In the fourth quarter, interest expense totalled \$1.4 million, up 19% due to higher effective interest rates.

Interest Expenses (\$000s, except as noted)	Three Months Ended December 31			Twelve Months Ended December 31		
	2006	2005	Change	2006	2005	Change
Net interest expense	1,358	1,141	19%	5,194	3,158	64%
Per boe (\$)	1.78	1.42	25%	1.69	1.13	50%

## OPERATING NETBACK

Our operating netback in the fourth quarter was \$38.57 per boe, down 25% mainly due to lower commodity prices. Fourth quarter netbacks were also affected by the prior period adjustment to production discussed above. For the full year, the operating netback averaged \$42.64 per boe, down 6%. We did not hedge any of our production in 2006, and we have no plans to enter into any foreign currency or commodity price hedges at this time. This policy is subject to quarterly review by our Board.

Operating Netback (\$/boe)	Three Months Ended			Twelve Months Ended		
	December 31			December 31		
	2006	2005	Change	2006	2005	Change
Gross revenue <sup>(1)</sup>	42.11	55.42	-24%	46.60	49.12	-5%
Royalty expenses <sup>(2)</sup>	0.59	1.48	-60%	1.25	1.29	-3%
Operating expenses	2.95	2.38	24%	2.71	2.34	16%
Operating netback	38.57	51.56	-25%	42.64	45.49	-6%

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

(2) Net of Alberta Royalty Credit.

## FUNDS GENERATED FROM OPERATIONS AND NET INCOME

Lower production volumes and lower average selling prices led to a reduction in funds generated from operations in the fourth quarter of 2006. Non-cash expenses, primarily higher depletion and depreciation, reduced net income to \$9.5 million for the quarter.

Funds Generated From Operations and Net Income	Three Months Ended			Twelve Months Ended		
	December 31			December 31		
	2006	2005	Change	2006	2005	Change
Funds generated from operations (\$000s)	27,394	38,694	-29%	119,849	118,034	2%
Per Trust Unit (\$)	0.56	0.79	-29%	2.44	2.76	-12%
Net income (\$000s)	9,545	18,747	-49%	45,181	58,346	-23%
Per Trust Unit, basic and diluted (\$)	0.19	0.38	-50%	0.92	1.36	-32%

## DISTRIBUTIONS AND UNITHOLDER TAXATION

Distributions to Unitholders totalled \$0.48 per Trust Unit for the fourth quarter and a record \$2.10 per Trust Unit for the year. Royalty income contributed 89% of distributions for the year. Since inception, the Trust has distributed \$486.1 million (\$14.30 per Trust Unit) to Unitholders.

Distributions to Unitholders (\$000s, except as noted)	Three Months Ended			Twelve Months Ended		
	December 31			December 31		
	2006	2005		2006	2005	
Cash provided by operating activities	26,401	39,261		130,934	97,067	
Net reclamation fund contribution	(15)	(72)		(153)	(318)	
Development expenditures	(3,766)	(1,631)		(11,446)	(7,982)	
Debt additions (repayment)	2,000	(11,000)		(7,000)	80,000	
Proceeds from Trust Unit issuance	—	—		—	258,935	
Property and Royalty acquisitions	—	—		(5,382)	(351,705)	
<b>Cash available for distribution</b>	<b>24,620</b>	<b>26,558</b>		<b>106,953</b>	<b>75,997</b>	
<b>Distributions to Unitholders</b>	<b>23,594</b>	<b>31,366</b>		<b>103,100</b>	<b>84,810</b>	
Accumulated, beginning of period	462,530	351,658		383,024	298,214	
Accumulated, end of period	486,124	383,024		486,124	383,024	
<b>Distributions per Trust Unit (\$) <sup>(1)</sup></b>	<b>0.48</b>	<b>0.64</b>		<b>2.10</b>	<b>1.92</b>	
Accumulated, beginning of period	13.82	11.56		12.20	10.28	
Accumulated, end of period	14.30	12.20		14.30	12.20	

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

Cash available for distribution is typically less than cash provided by operating activities as we retain funds to finance reclamation fund contributions, development expenditures, minor acquisitions, and debt repayment. Differences between cash available for distribution and actual distributions result from changes in working capital.

Payout Ratio <sup>(1)</sup> (\$ per Trust Unit, except as noted)	Three Months Ended			Twelve Months Ended		
	December 31			December 31		
	2006	2005	Change	2006	2005	Change
Funds generated from operations <sup>(2)</sup>	0.56	0.79	-29%	2.44	2.76	-12%
Distributions to Unitholders <sup>(3)</sup>	0.48	0.64	-25%	2.10	1.92	9%
Payout ratio <sup>(1)</sup>	86%	81%	6%	86%	72%	19%

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

(2) Based on the weighted average number of Trust Units outstanding during the period.

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

Fourth quarter distributions represented 86% of funds generated from operations, versus 81% in the fourth quarter of 2005. The lower payout ratio in 2005 indirectly reflects the step change in our production volumes with the Petrovera acquisition last year. The increase in royalty interest production and high product prices required a corresponding increase in our accounts receivables caused by the normal lag in receiving royalty revenue. The increase in accounts receivables was included in changes in working capital. Since inception, our payout ratio has averaged 82%.

For Canadian tax purposes, 90% of distributions paid or payable in 2006 were taxable as income, unless held in a registered plan, such as a Registered Retirement Savings Plan, a Registered Retirement Income Fund, a Deferred Profit Sharing Plan or a Registered Education Savings Plan. Further information on Unitholder taxation is available on our website.

On October 31, 2006, the Federal Minister of Finance announced a proposal to apply a tax at the trust level on distributions of certain income from publicly traded mutual fund trusts at rates of tax comparable to the combined federal and provincial corporate tax and to treat such distributions as dividends to the Unitholders. On December 21, 2006, draft legislation was released to implement the proposed tax changes pursuant to which, commencing January 1, 2011 (provided Freehold only experiences “normal growth” and no “undue expansion” before then) certain distributions from Freehold which would have otherwise been taxed as ordinary income generally will be characterized as dividends in addition to being subject to tax at corporate rates at Freehold’s level.

The long-term effect of the proposed tax changes on Freehold is yet to be determined. However, assuming the changes are ultimately enacted in the form currently proposed, the implementation of such legislation would be expected to result in adverse tax consequences to Freehold and certain Unitholders (including most particularly Unitholders that are tax deferred or non-residents of Canada) and may impact cash distributions from Freehold starting in 2011. It is not known at this time when the proposed tax changes will be enacted by Parliament, if at all, or whether they will be enacted in the form currently proposed.

### LIQUIDITY AND CAPITAL RESOURCES

In conjunction with the Petrovera acquisition in 2005, we expanded our credit facilities from \$65 million to \$165 million. These credit facilities were used to fund \$93 million of the purchase price for the acquisition, inclusive of transaction costs. During the last 12 months, we have repaid \$7 million of long-term debt with funds generated from operations. At December 31, 2006, we had no short-term debt outstanding and long-term debt was \$100 million. We had working capital of \$9.1 million, resulting in net debt of \$91 million. In addition, we had accrued \$129,000 as a long term liability relating to incentive compensation pursuant to the Manager’s LTIP (see General and Administrative Expenses). We currently have \$65 million of available capacity under our credit facilities.

Debt Analysis (\$000s)	As at December 31		
	2006	2005	Change
Long-term debt	100,000	107,000	-7%
Short-term debt	—	—	—
Total debt	100,000	107,000	-7%
Less: working capital	9,050	16,281	-44%
Net debt obligations	90,950	90,719	0%

At December 31, 2006, the Trust’s ratio of net debt (total debt less positive working capital) to trailing funds generated from operations was 0.8 to 1, unchanged from the end of 2005.

Financial Leverage and Coverage Ratios <sup>(1)</sup>	As at December 31		
	2006	2005	Change
Net debt to funds generated from operations (times)	0.8	0.8	—
Net debt to distributions (times)	0.9	1.1	-18%
Distributions to interest expense (times)	19.9	26.9	-26%
Net debt to net debt plus equity (%)	21%	19%	11%

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

The increased royalty interest production from the Petrovera acquisition in 2005 required a corresponding increase in our accounts receivables, caused by the normal time lag in receiving royalty revenue. The dollar amount of receivables also increased due to higher commodity prices. Accounts payable at December 31, 2006 were higher as a result of the significant amount of capital spent in 2006 and the timing of invoices. In addition, distributions payable to Unitholders at December 31, 2005 included a special distribution of \$0.08 per Trust Unit as a result of excess taxable income earned in 2005.

<b>Components of Working Capital</b> (\$000s)	<b>Dec. 31</b> <b>2006</b>	Sept. 30 2006	June 30 2006	Mar. 31 2006	Dec. 31 2005
Cash	421	585	245	38	192
Accounts receivable	29,850	28,311	28,051	32,125	35,728
Current assets	30,271	28,896	28,296	32,163	35,920
Distributions payable to Unitholders	(7,376)	(8,845)	(8,839)	(8,832)	(12,748)
Accounts payable and accrued liabilities	(13,845)	(12,498)	(9,107)	(9,042)	(6,891)
Current liabilities	(21,221)	(21,343)	(17,946)	(17,874)	(19,639)
Working capital <sup>(1)</sup>	9,050	7,553	10,350	14,289	16,281

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

The following table outlines our sources and uses of funds during the reporting periods.

<b>Sources and Uses of Funds</b> (\$000s)	Three Months Ended December 31			Twelve Months Ended December 31		
	2006	2005	Change	2006	2005	Change
<b>Sources of funds</b>						
Funds generated from operations	27,394	38,694	-29%	119,849	118,034	2%
Equity issued, net of costs	—	—	—	—	258,935	—
Change in non-cash working capital	(716)	(339)	111%	12,832	(20,990)	-161%
	26,678	38,355	-30%	132,681	355,979	-63%
<b>Uses of funds</b>						
Debt reduction (addition)	(2,000)	11,000	-118%	7,000	(80,000)	-109%
Net reclamation fund contributions	15	72	-79%	153	318	-52%
Development expenditures	3,766	1,631	131%	11,446	7,982	43%
Property acquisitions, net of costs	—	—	—	5,382	351,705	-98%
Distributions declared	25,061	25,477	-2%	108,471	75,848	43%
Change in cash	(164)	175	-194%	229	126	82%
	26,678	38,355	-30%	132,681	355,979	-63%

The proposed taxation of income trusts may reduce the value of our Trust Units, which would be expected to increase our cost of raising capital in the public capital markets. In addition, the proposed tax changes are expected to substantially eliminate the competitive advantage that Freehold and other Canadian energy trusts enjoy relative to their corporate peers in raising capital in a tax-efficient manner and place Freehold and other Canadian energy trusts at a competitive disadvantage relative to industry competitors, including U.S. master limited partnerships, which will continue to not be subject to entity level taxation.

The proposed tax changes are also expected to make our Trust Units less attractive as an acquisition currency. As a result, it may become more difficult for Freehold to compete effectively for acquisition opportunities. There can be no assurance that we will be able to reorganize Freehold's legal and tax structure to substantially mitigate the expected impact of the proposed tax changes.

Further, the proposed tax changes provide that, while there is no intention to prevent "normal growth" during the transitional period, any "undue expansion" could result in the transition period being "revisited", presumably with the loss of the benefit to us of that transitional period. As a result, the adverse tax consequences resulting from the proposed tax changes could be realized sooner than January 1, 2011. On December 15, 2006, the Department of Finance issued guidelines with respect to what is meant by "normal growth" in this context. "Normal growth" would include equity growth within certain "safe harbour" limits, measured by reference to market capitalization as of the end of trading on October 31, 2006. Those safe harbour limits are 40% for the period from November 1, 2006 to December 31, 2007, and 20% in each of the following three years. Moreover, these limits are cumulative, so that any unused limit for a period carries over into the subsequent period.

Our market capitalization as of the close of trading on October 31, 2006 was approximately \$928.7 million, which means our “safe harbour” equity growth amount for the period ending December 31, 2007 is approximately \$371.5 million, and for each of calendar 2008, 2009 and 2010 is an additional \$185.7 million.

While these guidelines are such that it is unlikely they would affect our ability to raise the capital required to maintain and grow our existing operations in the ordinary course during the transition period, they could adversely affect the cost of raising capital and our ability to undertake more significant acquisitions.

## DISTRIBUTION OUTLOOK

Based on the assumptions provided in the accompanying table, our distribution guidance for 2007 remains unchanged at \$1.80 per Trust Unit, based on monthly distributions of \$0.15 per Trust Unit. 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. Supply and demand imbalances could keep heavy oil price differentials well above historical averages. We will continue to monitor prices and activity levels closely, and our guidance will be reviewed and updated quarterly.

<b>Distribution Outlook and Key Assumptions (as of February 28, 2007)</b>		<b>2007</b>
<b>Estimated cash distributions</b> (\$ per Trust Unit)		<b>1.80</b>
<b>Key assumptions</b>		
Average daily production, excluding acquisitions (boe/d)		7,950
Average WTI oil price (US\$/bbl)		62.50
Average AECO natural gas price (Cdn\$/Mcf)		7.25
Average light/heavy oil price differential (Cdn\$/bbl)		25.00
Average exchange rate (Cdn\$/US\$)		0.90
Average operating costs (\$/boe)		3.00
Average general and administrative costs (\$/boe)		2.10
Development expenditures (\$ millions)		8.0
Long-term debt at year end (\$ millions)		97
Weighted average Trust Units outstanding (thousands)		49,228
Payout ratio (%)		89
Estimated portion of distributions taxable as income (%)		100

The following table provides an analysis of the potential impact of changes in certain key factors on distributions to Unitholders, based on our current distribution outlook.

<b>2007 Sensitivity Analysis</b>	Change (+/-)	Estimated Change in Distributions to Unitholders	
		(\$000s)	(\$/Trust Unit)
WTI crude oil price	US\$1.00/bbl	1,989	0.04
Light/heavy oil price differential	Cdn\$1.00/bbl	1,796	0.04
Natural gas price	Cdn\$0.25/Mcf	1,657	0.03
Exchange rate (US\$/Cdn\$)	0.01	1,392	0.03
Interest rates	1%	988	0.02
Oil and NGL production	100 bbls/d	1,584	0.03
Natural gas production	1,000 Mcf/d	2,557	0.05

## **NEW ACCOUNTING POLICIES**

### **Unit Based Compensation**

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

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

## **CRITICAL ACCOUNTING ESTIMATES**

The assets, liabilities, revenues, and expenses reported in our financial statements depend to varying degrees on estimates made by management. These estimates are based on historical experience and reflect certain assumptions about the future that are believed to be both reasonable and conservative. The more significant reporting areas are crude oil and natural gas reserve estimation, depletion, impairment of assets, and oil and gas revenue accruals. Management's judgments and estimates in these areas are based on information available from both internal and external sources, including engineers, geologists, and historical experience in similar matters. Except as discussed in this MD&A, we are not aware of 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. The substantial increase in royalty interest production with the Petrovera acquisition in May 2005 required a corresponding increase in our revenue accruals. The increase is reflected in higher accounts receivables.

## Consolidated Balance Sheets

(\$000s) (unaudited)	December 31, 2006	December 31, 2005
<b>Assets</b>		
Current assets:		
Cash	\$ 421	\$ 192
Accounts receivable	29,850	35,728
	30,271	35,920
Reclamation fund	2,117	1,964
Deferred long-term compensation (note 4)	86	—
Petroleum and natural gas interests, net of accumulated depletion and depreciation of \$309,731 (2005 - \$237,857)	441,754	496,194
	\$ 474,228	\$ 534,078
<b>Liabilities and Unitholders' Equity</b>		
Current liabilities:		
Distributions payable to Unitholders	\$ 7,376	\$ 12,748
Accounts payable and accrued liabilities	13,845	6,891
	21,221	19,639
Asset retirement obligations (note 5)	4,598	4,036
Unit based compensation payable (note 4)	129	—
Long-term debt (note 2)	100,000	107,000
Future income tax liability	3,832	3,932
Unitholders' equity:		
Unitholders' capital (note 3)	562,698	560,049
Contributed surplus	247	—
Deficit	(218,497)	(160,578)
	344,448	399,471
	\$ 474,228	\$ 534,078

See accompanying notes to interim consolidated financial statements.

## Consolidated Statements of Income and Deficit

(Unaudited) (\$000s, except per unit and weighted average data)	Three Months Ended December 31		Year Ended December 31	
	2006	2005	2006	2005
<b>Revenue:</b>				
Royalty income and working interest sales	\$ 32,214	\$ 44,555	\$ 143,067	\$ 136,914
Royalty expense (net of Alberta Royalty Tax Credit)	(449)	(1,191)	(3,831)	(3,591)
	<b>31,765</b>	<b>43,364</b>	<b>139,236</b>	<b>133,323</b>
<b>Expenses:</b>				
Operating	2,259	1,912	8,309	6,530
General and administrative	1,100	1,222	5,581	4,392
Interest on long-term debt	1,358	1,141	5,194	3,158
Depletion and depreciation	17,377	18,820	71,874	56,938
Accretion of asset retirement obligation	65	67	257	252
Management fee	528	670	2,649	2,178
	<b>22,687</b>	<b>23,832</b>	<b>93,864</b>	<b>73,448</b>
Net income before taxes	9,078	19,532	45,372	59,875
Income and capital taxes	(571)	361	291	1,105
Future income tax provision	(104)	424	(100)	424
	<b>(467)</b>	<b>785</b>	<b>191</b>	<b>1,529</b>
Net income	\$ 9,545	\$ 18,747	\$ 45,181	\$ 58,346
Deficit, beginning of period	(204,448)	(147,959)	(160,578)	(134,114)
Distributions declared	(23,594)	(31,366)	(103,100)	(84,810)
Deficit, end of period	\$ (218,497)	\$ (160,578)	\$ (218,497)	\$ (160,578)
Net income per Trust Unit, basic and diluted	\$ 0.19	\$ 0.38	\$ 0.92	\$ 1.36
<b>Weighted average number of Trust Units:</b>				
Basic	49,138,931	48,966,315	49,085,795	42,812,470
Diluted	49,151,287	48,966,315	49,093,609	42,812,470

See accompanying notes to interim consolidated financial statements.

## Consolidated Statements of Cash Flows

(Unaudited) (\$000s)	Three Months Ended December 31		Year Ended December 31	
	2006	2005	2006	2005
Cash provided by (used in):				
Operating:				
Net income	\$ 9,545	\$ 18,747	\$ 45,181	\$ 58,346
Items not involving cash:				
Depletion and depreciation	17,377	18,820	71,874	56,938
Trust Unit incentive compensation (note 4)	(124)	—	290	—
Future income tax provision	104	424	(100)	424
Accretion of asset retirement obligation	65	67	257	252
Trust Units issued in lieu of management fee	528	670	2,649	2,178
Expenditures on reclamation	(101)	(34)	(302)	(104)
	27,394	38,694	119,849	118,034
Changes in non-cash working capital	(993)	567	11,085	(20,967)
	26,401	39,261	130,934	97,067
Financing:				
Issue of Trust Units, net of issue costs	—	—	—	258,935
Long-term debt	2,000	(11,000)	(7,000)	80,000
Distributions paid	(25,061)	(25,477)	(108,471)	(75,848)
Changes in non-cash working capital	36	22	(99)	(142)
	(23,025)	(36,455)	(115,570)	262,945
Investing:				
Property and royalty acquisitions	—	—	(5,382)	(351,705)
Development expenditures	(3,766)	(1,631)	(11,446)	(7,982)
Increase in reclamation fund	(15)	(72)	(153)	(318)
Changes in non-cash working capital	241	(928)	1,846	119
	(3,540)	(2,631)	(15,135)	(359,886)
Increase (decrease) in cash	(164)	175	229	126
Cash, beginning of period	585	17	192	66
Cash, end of period	\$ 421	\$ 192	\$ 421	\$ 192

See accompanying notes to interim consolidated financial statements.

## Notes to Interim Consolidated Financial Statements

For the period ended December 31, 2006.

These interim consolidated financial statements and notes have not been reviewed or audited by external auditors.

### 1. SIGNIFICANT ACCOUNTING POLICIES

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

#### UNIT BASED COMPENSATION

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

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

### 2. LONG-TERM DEBT

Freehold has a \$150 million extendible revolving term credit facility, extendible annually, on which \$100 million was drawn at December 31, 2006. In the event that the lender does not consent to an extension, the revolving credit facility will revert to a two-year, non-revolving term facility with equal quarterly principal repayments. The first quarterly payment would commence on January 1 of the year following the end of the revolving period, which is May 2007. In addition, Freehold has available a \$15 million extendible revolving operating facility. Borrowings under the facilities bear interest at the Bank's prime lending rate, bankers' acceptance or LIBOR rates plus applicable margins, ranging from 85 to 140 basis points and standby fees. The facilities are secured with \$300 million demand debentures over Freehold's petroleum and natural gas assets.

### 3. UNITHOLDERS' CAPITAL

	December 31, 2006		December 31, 2005	
	Units	Amount (\$000s)	Units	Amount (\$000s)
Balance, beginning of period	49,031,581	560,049	31,544,236	298,936
Issued for cash	—	—	17,363,520	270,003
Less: Issue expenses	—	—	—	(11,068)
Issued in lieu of management fee	142,616	2,649	123,825	2,178
Balance, end of period	49,174,197	562,698	49,031,581	560,049

### 4. UNIT BASED COMPENSATION

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

For the year ended December 31, 2006, the Trust expensed \$247,000 as unit based compensation, with a corresponding increase to contributed surplus.

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

At December 31, 2006, the Trust had accrued \$129,000 as a long term liability relating to incentive compensation pursuant to the Manager's LTIP and expensed \$43,000 for the year then ended.

### 5. ASSET RETIREMENT OBLIGATIONS

Freehold has no asset retirement obligations on its royalty income properties. Freehold's asset retirement obligation results from its responsibility to abandon and reclaim its net share of all working interest properties. The net present value of Freehold's total asset retirement obligation is estimated to be \$4.6 million (discounted at a weighted average, credit adjusted, risk free rate of 6.1%), with the undiscounted value being \$12.2 million. Payments to settle the obligations are expected to occur continuously over the next 50 years, with the majority of obligations being over 15 years away.

(\$000s)	December 31, 2006	December 31, 2005
Balance, beginning of period	4,036	3,937
Liabilities incurred	364	210
Liabilities added upon acquisition	—	19
Liabilities settled	(302)	(104)
Liabilities disposed	—	(352)
Revisions in estimates	243	74
Accretion expense	257	252
Balance, end of period	4,598	4,036

## 6. RELATED PARTY TRANSACTIONS

For the three month period ended December 31, 2006, Freehold issued 35,654 Trust Units as management fee to the Manager. The total for the year ended December 31, 2006 was 142,616 Trust Units.

For the three month period ended December 31, 2006, the Manager charged the Trust \$0.8 million in general and administrative costs, totalling \$3.7 million for the year ended December 31, 2006. At December 31, 2006, there was \$0.8 million in accounts payable relating to these costs.

## 7. SUPPLEMENTAL CASH FLOW DISCLOSURE

<b>Cash Expenses Paid</b> (\$000s)	Three Months Ended December 31		Year Ended December 31	
	<b>2006</b>	2005	<b>2006</b>	2005
Interest	<b>1,323</b>	1,118	<b>5,294</b>	3,301
Taxes	<b>276</b>	247	<b>1,251</b>	1,465

## Corporate Information

### BOARD OF DIRECTORS

**William W. Siebens** <sup>(2)</sup>  
 President and Chief Executive Officer  
 Candor Investments Ltd.

**D. Nolan Blades** <sup>(1)(2)(3)(4)</sup>  
 President  
 Sunny Gables Holdings Ltd.

**Harry S. Campbell, Q.C.** <sup>(3)(4)</sup>  
 Managing Partner  
 Burnet, Duckworth & Palmer, LLP

**Tullio Cedraschi**  
 President and Chief Executive Officer  
 CN Investment Division

**Peter T. Harrison** <sup>(1)(3)(4)</sup>  
 Senior Vice-President  
 Monrusco Bolton Investments Inc.

**Dr. P. Michael Maher** <sup>(1)(2)(4)</sup>  
 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

### 2006 FOURTH QUARTER DISTRIBUTIONS DECLARED

Record Date	Payment Date	Per Trust Unit
October 31, 2006	November 15, 2006	\$0.18
November 30, 2006	December 15, 2006	\$0.15
December 31, 2006	January 15, 2007	<u>\$0.15</u>
		<u>\$0.48</u>

### TAX INFORMATION AND HISTORICAL DISTRIBUTIONS

Tax information and historical distributions are available on our website at [www.freeholdtrust.com](http://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. Holowsky**  
 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](mailto:ir@freeholdtrust.com)

### WEBSITE

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

### STOCK EXCHANGE LISTING

**Toronto Stock Exchange**  
 Trading Symbol: FRU.UN

### 2006 FOURTH QUARTER

#### TRADING SUMMARY

High – \$19.80  
 Low – \$12.43  
 Close – \$14.81  
 Volume – 13,866,905  
 Trust Units Outstanding – 49.2 million  
 Dec. 31 Market Capitalization – \$728 million

### 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)

### 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

### EVALUATION ENGINEERS

Trimble Engineering Associates Ltd.  
 Calgary, Alberta