

## NEWS RELEASE

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## Freehold Royalty Trust Announces 2006 Third Quarter Results

CALGARY, ALBERTA, (CCNMatthews – November 8, 2006) – Freehold Royalty Trust (Freehold or the Trust) (TSX:FRU.UN) today announced revenue and earnings for the period ended September 30, 2006.

### THIRD QUARTER HIGHLIGHTS

- Production averaged 8,335 barrels of oil equivalent (boe) per day, down 7% from the third quarter of 2005.
- Price realizations averaged \$48.95 per boe, 7% lower than a year ago.
- Operating netback averaged \$44.92 per boe, down 10% from the same period last year.
- Funds generated from operations were \$0.65 per Trust Unit, down 18% from the third quarter of 2005.
- Distributions declared in the third quarter totalled \$0.54 per Trust Unit, 17% higher than last year.

As a result of additional capital requirements and weaker commodity prices, particularly natural gas, the Board of Directors has reduced the monthly distribution rate to \$0.15 per Trust Unit from \$0.18 per Trust Unit. The new distribution rate is effective with the December 15, 2006 payment to Unitholders of record on November 30, 2006 (ex-distribution date November 28, 2006). Including the December 15 payment, 12-month trailing cash distributions total \$2.21 per Trust Unit. The regular monthly distribution will be 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. However, erosion of commodity prices has significantly affected cash available for distribution.

Results at a Glance	Three Months Ended September 30			Nine Months Ended September 30		
	2006	2005	Change	2006	2005	Change
<b>Financial</b> (\$000s, except as noted)						
Gross revenue	37,994	43,936	-14%	110,853	92,359	20%
Operating income	34,439	41,188	-16%	101,421	85,341	19%
Net income	12,728	19,373	-34%	35,636	39,599	-10%
Per Trust Unit, basic and diluted (\$)	0.26	0.40	-35%	0.73	0.97	-25%
Funds generated from operations	31,692	38,893	-19%	92,455	79,340	17%
Per Trust Unit (\$)	0.65	0.79	-18%	1.88	1.95	-4%
Distributions declared	26,521	22,527	18%	79,506	53,444	49%
Per Trust Unit (\$) <sup>(1)</sup>	0.54	0.46	17%	1.62	1.28	27%
Long-term debt	98,000	118,000	-17%	98,000	118,000	-17%
Unitholders' equity	357,963	411,420	-13%	357,963	411,420	-13%
<b>Operating</b>						
Average daily production (boe/d)	8,335	8,974	-7%	8,445	7,264	16%
Average price realizations (\$/boe)	48.95	52.61	-7%	47.61	45.92	4%
Operating netback (\$/boe)	44.92	49.89	-10%	43.99	43.03	2%

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

## Message to Unitholders

### FREEHOLD CELEBRATES 10 YEARS

In the third quarter of 2006, Freehold declared distributions of \$26.5 million, or \$0.54 per Trust Unit, representing 84% of cash flow. As we prepare to celebrate the tenth anniversary of the Trust on November 25, 2006, the tally of our distributions over the past ten years is \$479 million, or \$14.15 per Trust Unit. We have paid out distributions well in excess of our \$10 initial public offering price. Unitholders who have held our units from the beginning and reinvested all distributions have achieved a compound annual return of 12.5%.

### MINOR ACQUISITION ADDS 100 BOE PER DAY

Effective July 1, 2006, we purchased a 5.2% working interest in the Wildmere Lloydminster 'A' Pool Unit No 1. Our share of production is 100 boe per day. Since we already owned a 2.6% gross overriding royalty interest in the Unit, this was an opportunity to increase our interest in the property and participate in its development. It has a large number of undrilled spacing units and we believe there is further development potential through continued waterflood management. The \$5.4 million 'tuck-in' acquisition was funded from cash flow.

### COMMODITY MARKETS REMAIN VOLATILE

Our average price realizations were 7% lower in the third quarter and 4% higher for the year to date. These fluctuations serve to reinforce that our cash flows, and thus our distributions, are largely dependent on supply and demand factors that are beyond our control.

Commodity prices fell significantly during the third quarter of 2006. 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 (per boe) price realizations. A global surplus of heavy crude and lack of upgrading capacity in North America has contributed to volatility in light/heavy oil differentials. Earlier this year, new pipeline access expanded the market for Alberta heavy oil, and we benefited from a significant narrowing of the price spread in the second and third quarters. However, with an end to the summer paving season, differentials have begun to widen again.

Longer-term, industry fundamentals remain positive; however, the near-term outlook is uncertain. Ample inventories, a mild winter, and a slowing U.S. economy could further depress commodity prices over the coming months. We anticipate that our fourth quarter price realizations will be significantly lower than the fourth quarter of 2005, when hurricanes Katrina and Rita knocked out production and refining capacity in the Gulf of Mexico and sent energy prices soaring.

### DISTRIBUTION GUIDANCE

Additional capital requirements totalling \$10.4 million (the \$5.4 million Wildmere acquisition and the \$5.0 million increase in our development budget announced in August) and the weakening in commodity prices have prompted our Board of Directors to reduce the monthly distribution rate to \$0.15 per Trust Unit. As a result, our cash distributions for 2006 will total \$2.10 per Trust Unit, down 3% from our previous guidance of \$2.16.

Looking ahead to 2007, we anticipate that lower commodity prices will slow drilling activity. The Canadian Association of Oilwell Drilling Contractors predicts a 15% decline in drilling next year. 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. Largely due to development of the oil sands, the demand for people and oilfield services is unprecedented. The industry continues to experience higher operating, administrative, and finding and development costs, as well as a severe shortage of experienced professionals and skilled trades.

Considering all of the above factors (and based on the assumptions provided in the accompanying Management's Discussion & Analysis) our distribution guidance for 2007 is \$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 unexpectedly announced a proposal to amend the *Income Tax Act* (Canada) to apply a Distribution Tax on distributions from publicly-traded income trusts. 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. Under the proposal, existing income trusts will be subject to the new measures commencing in their 2011 taxation year, following a four-year grace period. The Minister of Finance has issued a Notice of Ways and Means Motion to Amend the *Income Tax Act*, but it is not known at this time if or when the proposal will be enacted by Parliament.

In simplified terms, under the proposed tax plan, income distributions will first be taxed at the trust level at a special rate estimated to be 31.5%. Income distributions to individual unitholders will then be treated as dividends from a Canadian corporation and eligible for the dividend tax credit. Income distributions to corporations resident in Canada will be eligible for full deduction as tax-free intercorporate dividends. Tax-deferred accounts (RRSPs, RRIFs and RPPs) will continue to pay no tax on distributions. Non-resident unitholders will be taxed on distributions at the non-resident withholding tax rate for dividends. The net impact on Canadian taxable investors is expected to be minimal because they can take advantage of the dividend tax credit. However, as a result of the 31.5% Distribution Tax at the trust level, distributions to tax-deferred accounts will be reduced by approximately 31.5%, and distributions to non-residents will be reduced by approximately 26.5%.

Following the Minister's announcement, the market's reaction was immediate and significant, with a widespread sell-off across the entire trust sector that eliminated billions of dollars in unitholder value. 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 encourage our Unitholders to read the full transcript of the government's plan at: [www.fin.gc.ca/news06/06-061e.html](http://www.fin.gc.ca/news06/06-061e.html) and consult with their personal financial and tax advisors regarding potential tax consequences based on their individual circumstances. Unitholders may also express their views directly to the Minister of Finance, whose contact information is available at [www.fin.gc.ca/admin/contact-e.html](http://www.fin.gc.ca/admin/contact-e.html).

Given the four-year grace period before existing trusts will be taxed, we have an opportunity to examine our strategy and, if warranted, modify it to provide the best possible returns for our Unitholders. At the same time, our investors have an opportunity to arrange their investments before 2011 to minimize the impact of the proposed tax changes on their portfolios. The long-term effect of the proposed tax changes on Freehold is yet to be determined.

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



David J. Sandmeyer  
President and Chief Executive Officer

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

The following discussion is management's opinion about the operating and financial results of Freehold Resources Ltd., Petrovera Resources (a general partnership), and Freehold Royalty Trust (collectively, Freehold or the Trust), for the three and nine months ended September 30, 2006 and previous periods, and the outlook for Freehold based on information available as at November 8, 2006. The financial information contained herein has been prepared in accordance with Canadian generally accepted accounting principles (GAAP). All comparative percentages are between the quarters ended September 30, 2006 and September 30, 2005, and all dollar amounts are expressed in Canadian currency, unless otherwise noted. This discussion should be read in conjunction with the Trust's annual MD&A and audited financial statements for the years ended December 31, 2005 and 2004, together with the accompanying notes. These are on pages 23 through 59 of the Trust's 2005 annual report to Unitholders.

### FORWARD-LOOKING STATEMENTS

This MD&A offers our assessment of Freehold's future plans and operations as at November 8, 2006, and contains forward-looking statements. By their nature, forward-looking statements are subject to numerous risks and uncertainties, some of which are beyond our control, including the impact of general economic conditions, industry conditions, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other industry participants, the lack of availability of qualified personnel or management, stock market volatility and ability to access sufficient capital from internal and external sources. Risks are described in more detail in our Annual Information Form, which is available on our website. You are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. Our actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements. We can give no assurance that any of the events anticipated will transpire or occur, or if any of them do, what benefits we will derive from them. Except as required by law, we do not undertake to update these forward-looking statements.

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

**CRITICAL ACCOUNTING ESTIMATES**

The assets, liabilities, revenues and expenses reported in our financial statements depend to varying degrees on estimates made by management. These estimates are based on historical experience and reflect certain assumptions about the future that are believed to be both reasonable and conservative. The more significant reporting areas are crude oil and natural gas reserve estimation, depletion, impairment of assets, and oil and gas revenue accruals. Management's judgments and estimates in these areas are based on information available from both internal and external sources, including engineers, geologists, and historical experience in similar matters. Except as discussed in this MD&A, we are not aware of trends, commitments, events, or uncertainties that are expected to materially affect the methodology or assumptions associated with the critical accounting estimates.

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

**CONVERSION OF NATURAL GAS TO OIL EQUIVALENT**

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

**SUPPLEMENTAL DISCLOSURE**

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

**THE ROYALTY ADVANTAGE**

The following table demonstrates the advantage of our royalty lands on which we do not incur royalty expenses, operating expenses, site restoration expenses, or development expenditures. For the nine months ended September 30, 2006, royalty interest properties accounted for 76% of gross revenue, 84% of funds generated from operations, and 95% of distributions to Unitholders.

<b>Components of Distributions to Unitholders</b> <b>Nine months ended September 30, 2006</b> (\$000s)	Royalty Interest		Working Interest	<b>Total Trust</b>
	Properties	Properties	Properties	
Gross revenue	84,235	26,618		<b>110,853</b>
Royalty expense	—	(3,382)		<b>(3,382)</b>
Net revenue	84,235	23,236		<b>107,471</b>
Operating expense	—	(6,050)		<b>(6,050)</b>
Net operating income	84,235	17,186		<b>101,421</b>
General and administrative expense	(3,462)	(1,019)		<b>(4,481)</b>
Interest expense	(3,433)	(403)		<b>(3,836)</b>
Income and capital taxes	—	(862)		<b>(862)</b>
Unit based compensation	320	94		<b>414</b>
Expenditures on reclamation	—	(201)		<b>(201)</b>
Funds generated from operations	77,660	14,795		<b>92,455</b>
Reclamation fund contributions	—	(138)		<b>(138)</b>
Development expenditures	—	(7,680)		<b>(7,680)</b>
Acquisitions	—	(5,382)		<b>(5,382)</b>
Changes in debt	(9,000)	—		<b>(9,000)</b>
Changes in working capital	7,148	2,103		<b>9,251</b>
Distributions declared	75,808	3,698		<b>79,506</b>

**TRUST UNITS OUTSTANDING**

As at September 30, 2006 and November 8, 2006, there were 49.1 million Trust Units outstanding. At the end of the third quarter, the Trust issued 35,654 Trust Units to the Manager in payment of the 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. 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. Subsequently, the Board allocated 1,595 deferred trust units to each eligible director and 3,190 deferred trust units to the Chair of the Board. As at September 30, 2006, there were 12,153 deferred trust units outstanding, which are redeemable for an equal number of Trust Units any time after the director's retirement.

<b>Trust Units Outstanding</b>	Three Months Ended			Nine Months Ended		
	September 30			September 30		
	2006	2005	Change	2006	2005	Change
Weighted average						
Basic	<b>49,103,277</b>	48,960,661	—	<b>49,067,888</b>	40,728,537	20%
Diluted	<b>49,115,279</b>	48,960,661	—	<b>49,074,173</b>	40,728,537	20%
At period end	<b>49,138,543</b>	48,995,927	—	<b>49,138,543</b>	48,995,927	—

**HISTORICAL PERFORMANCE SUMMARY**

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.

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. Oil and natural gas prices have shown significant volatility in recent years. The accompanying Quarterly Review table illustrates the fluctuations in pricing experienced over the past eight quarters and the resulting effect on our financial results.

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 23% of our total production volumes. Rising costs have been experienced throughout the oil and gas industry. However, the effect of higher costs on our overall results is mitigated by our large proportion of royalty interest production, which is unencumbered by operating expenses.

Quarterly Review	2006			2005			2004	
	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
<b>Financial</b> (\$000s, except as noted)								
Revenue, net of royalty expense	36,550	36,998	33,923	43,364	42,867	27,922	19,170	19,204
Funds generated from operations	31,692	32,565	28,198	38,694	38,893	24,344	16,103	16,139
Per Trust Unit (\$)	0.65	0.66	0.58	0.79	0.79	0.59	0.51	0.51
Distributions to Unitholders	26,521	26,502	26,483	31,366	22,527	17,981	12,936	15,449
Per Trust Unit (\$) <sup>(1)</sup>	0.54	0.54	0.54	0.64	0.46	0.41	0.41	0.49
Payout ratio (%)	84	81	94	81	58	74	80	96
Net income	12,728	14,142	8,766	18,747	19,373	10,858	9,368	9,397
Per Trust Unit, basic and diluted (\$)	0.26	0.29	0.18	0.38	0.40	0.26	0.30	0.30
Development expenditures	4,649	1,430	1,601	1,631	4,059	1,215	1,077	1,895
Property and royalty acquisitions	5,382	—	—	—	—	351,705	—	9,799
Long-term debt	98,000	96,000	105,000	107,000	118,000	120,000	27,000	27,000
Trust Units outstanding (000s) <sup>(2)</sup>	49,103	49,068	49,032	48,996	48,961	41,489	31,544	31,522
<b>Operating</b> (\$/boe, except as noted)								
Daily production (boe/d)	8,335	8,212	8,794	8,739	8,974	7,279	5,502	5,575
Average selling price	48.95	50.27	43.78	54.95	52.61	42.42	39.47	38.37
Operating netback	44.92	47.08	40.18	51.56	49.89	39.61	36.18	34.67
Operating expenses	2.75	2.43	2.68	2.38	2.03	2.54	2.53	2.77
Working Interest properties	11.88	11.51	11.26	12.06	10.35	11.00	7.59	8.16
General and administrative expenses	1.32	1.79	2.69	1.52	1.17	1.42	2.55	1.68
<b>Benchmark Prices</b>								
WTI crude oil (US\$/bbl)	70.48	70.70	63.45	60.02	63.19	53.20	49.84	48.28
Exchange rate (Cdn\$/US\$)	0.89	0.89	0.87	0.85	0.83	0.80	0.82	0.82
Edmonton Par (Cdn\$)	79.08	78.55	68.96	71.17	76.51	65.76	61.45	57.70
Light/heavy oil differential (Cdn\$/bbl)	20.14	17.43	28.57	28.14	20.79	24.17	22.48	21.60
Bow River/Hardisty (Cdn\$/bbl)	58.94	61.11	40.39	43.03	55.72	41.59	38.97	36.10
AECO natural gas (Cdn\$/Mcf)	6.03	6.27	9.27	11.68	8.17	7.38	6.69	7.08
<b>Unit Trading Performance</b>								
High (\$)	23.06	21.70	22.20	18.98	19.30	17.63	18.49	18.42
Low (\$)	18.50	18.02	18.44	15.15	15.99	14.25	15.50	15.75
Close (\$)	19.00	21.00	19.50	18.81	18.68	15.99	16.10	17.45
Volume (000s)	5,153	5,336	11,155	7,611	9,980	8,311	2,418	4,252

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

(2) Weighted average during the quarter.

**DEVELOPMENT ACTIVITIES**

Lower natural gas prices have resulted in lower activity levels. Drilling on all of Freehold's lands was down 40% for the quarter, led by a 50% reduction in drilling for natural gas. Year to date, drilling is down 28%, with a 36% reduction in natural gas drilling. The Canadian Association of Oilwell Drilling Contractors predicts that 22,298 wells will be drilled this year; this would make 2006 another record year for drilling but not as high as it had previously predicted.

**ROYALTY INTEREST LANDS**

Drilling on our royalty lands generally mirrors industry activity. A total of 168 wells were drilled on our royalty lands in the third quarter, including 74 unitized wells. On an equivalent net basis, this is 6.5 wells, down 22% from the third quarter of 2005. Natural gas drilling was down about 40% as expected, while oil drilling remained strong. There are currently 88 (6.7 equivalent net) licensed drilling locations on our royalty lands, compared with 95 (3.9 equivalent net) locations at this time last year. The higher number of net locations is evidence of the ongoing development potential of our royalty lands.

Royalty Interest Lands Drilling Summary <sup>(1)</sup> (includes unitized wells)	Three Months Ended September 30			Nine Months Ended September 30		
	2006	2005	Change	2006	2005	Change
	Gross wells	168	250	-33%	522	715
Equivalent net wells <sup>(2)</sup>	6.5	8.3	-22%	14.4	18.5	-22%
Net success rate	97.7%	99.4%	-2%	98.8%	99.6%	-1%

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

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

**WORKING INTEREST PROPERTIES**

Effective July 1, 2006, we purchased a 5.2% working interest in the Wildmere Lloydminster 'A' Pool Unit No 1, in which we also have a 2.6% gross overriding royalty interest. The \$5.4 million acquisition was funded from funds generated from operations and is expected to produce 90 boe per day during the fourth quarter. The property has an 11-year reserve life with estimated reserves of 395,000 barrels. There are currently a large number of undrilled spacing units in the Unit and we believe there is further development potential in the pool through continued waterflood management.

About 23% of our production comes from working interest properties on which we incur our proportionate share of development costs. Our 2006 capital budget is \$11 million, of which \$7.7 million has been spent to date. In the third quarter, capital expenditures were \$4.6 million.

In Southeast Saskatchewan, 3 (1.1 net) wells were drilled; 5 (0.1 net) wells were drilled at Provost; 9 (2.1 net) wells at Hayter; and 5 (0.3 net) wells in other areas. Our net drilling success rate for the year to date is 100%. Production additions during the fourth quarter from development activities are expected to be 650 boe per day.

Working Interest Properties Drilling Summary	Three Months Ended September 30				Nine Months Ended September 30			
	2006		2005		2006		2005	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Oil	14	3.6	23	4.9	33	5.7	33	5.7
Natural gas	7	0.0	37	1.0	58	1.2	58	1.2
Other	1	0.0	2	0.2	2	0.2	2	0.2
Total	22	3.6	62	6.1	93	7.1	93	7.1

Fourth quarter expenditures are estimated to be \$3.3 million. Major projects include a battery expansion at Hayter and continued drilling opportunities in Southeast Saskatchewan, Pouce Coupe and Luseland.

**RESULTS OF OPERATIONS****PRODUCTION**

Production volumes in the third quarter averaged 8,335 boe per day, down 7% from last year. Royalty production declined 11% as drilling did not offset natural production declines. In addition, certain royalty interests were converted to working interests upon payout. Working interest production climbed 10% due to the royalty conversions, the Wildmere acquisition, and ongoing development activities. Royalty interests contributed 77% of total volumes produced during quarter.

For the year to date, production was 16% 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 the first nine months of 2006 was 39% natural gas, 4% natural gas liquids (NGL), 20% light and medium oil, and 37% heavy oil.

Considering results for the first nine months of the year and planned activity levels in the fourth quarter, we expect that production for the full year 2006 will average 8,450 boe per day.

Average Daily Production	Three Months Ended			Nine Months Ended		
	September 30		Change	September 30		Change
	2006	2005		2006	2005	
<b>Royalty lands</b>						
Oil (bbls/d)	3,346	3,756	-11%	3,477	3,011	15%
NGL (bbls/d)	301	310	-3%	296	277	7%
Natural gas (Mcf/d)	16,542	18,860	-12%	16,518	13,292	24%
Oil equivalent (boe/d)	6,404	7,211	-11%	6,526	5,504	19%
<b>Working interest properties</b>						
Oil (bbls/d)	1,394	1,260	11%	1,346	1,308	3%
NGL (bbls/d)	72	61	18%	69	59	17%
Natural gas (Mcf/d)	2,793	2,653	5%	3,032	2,360	28%
Oil equivalent (boe/d)	1,932	1,763	10%	1,920	1,760	9%
<b>Total Trust</b>						
Oil (bbls/d)	4,740	5,016	-6%	4,823	4,319	12%
NGL (bbls/d)	373	371	1%	364	336	8%
Natural gas (Mcf/d)	19,335	21,513	-10%	19,550	15,652	25%
Oil equivalent (boe/d)	8,335	8,974	-7%	8,446	7,264	16%
Number of days in period (days)	92	92	—	273	273	—
Total volumes during period (Mboe)	767	826	-7%	2,306	1,983	16%
Potash production (tonnes/d)	9.3	8.6	8%	9.4	9.3	1%

**BENCHMARK PRICES**

Since mid-July, the average price for WTI crude oil has declined on lower demand, a calmer-than-expected hurricane season, and an easing of concerns that global tensions would disrupt supply. With spot crude oil prices dipping below US\$60 in October, the Organization of Petroleum Exporting Countries (OPEC) recently announced its members would cut oil production to stem the falling prices. Natural gas markets within North America continue to be influenced by weather and storage levels. Quarter over quarter, prices weakened 26%. Ample inventories, a mild winter, and a slowing U.S. economy could further depress commodity prices over the coming months.

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 (per boe) price realizations. Earlier this year, new pipeline access expanded the market for Alberta heavy oil, and we benefited from a significant narrowing of the light/heavy oil price spread in the second and third quarters. However, with an end to the summer paving season, differentials have begun to widen again.

Average Benchmark Prices	Three Months Ended			Nine Months Ended		
	September 30			September 30		
	2006	2005	Change	2006	2005	Change
WTI crude oil (US\$/bbl)	<b>70.48</b>	63.19	12%	<b>68.21</b>	55.40	23%
US\$/Cdn\$ exchange rate	<b>0.8919</b>	0.8325	7%	<b>0.8831</b>	0.8172	8%
Edmonton Par crude oil (Cdn\$/bbl)	<b>79.08</b>	76.51	3%	<b>75.53</b>	67.91	11%
Light/heavy oil differential (Cdn\$/bbl)	<b>20.14</b>	20.79	-3%	<b>22.04</b>	22.48	-2%
Bow River/Hardisty (Cdn\$/bbl)	<b>58.94</b>	55.72	6%	<b>53.48</b>	45.42	18%
AECO natural gas (Cdn\$/Mcf)	<b>6.03</b>	8.17	-26%	<b>7.19</b>	7.41	-3%

Source for commodity prices: Canadian Association of Petroleum Producers.

### FREEHOLD'S REALIZED PRICES

Freehold's realized prices reflect product quality and transportation differences from benchmark prices. On a boe basis, our average price realizations were 7% lower in the third quarter of 2006 but 4% higher for the year to date. Our realized selling prices were also negatively affected by a stronger Canadian dollar compared with last year. We anticipate that our fourth quarter price realizations will be significantly lower than last year.

Average Selling Prices	Three Months Ended			Nine Months Ended		
	September 30			September 30		
	2006	2005	Change	2006	2005	Change
Oil (\$/bbl)	<b>58.62</b>	56.46	4%	<b>52.30</b>	46.99	11%
NGL (\$/bbl)	<b>53.80</b>	54.21	-1%	<b>53.74</b>	47.60	13%
Oil and NGL (\$/bbl)	<b>58.27</b>	56.31	3%	<b>52.40</b>	47.03	11%
Natural gas (\$/Mcf)	<b>5.70</b>	7.84	-27%	<b>6.66</b>	7.32	-9%
Oil equivalent (\$/boe)	<b>48.95</b>	52.61	-7%	<b>47.61</b>	45.92	4%
Potash (\$/tonne)	<b>215.57</b>	234.72	-8%	<b>215.83</b>	216.31	—

### REVENUE

Gross revenue was 14% lower in third quarter but 20% higher for the year to date, due to the changes in realized prices and production volumes discussed above. We receive revenue from about 200 industry operators.

Revenue	Three Months Ended			Nine Months Ended		
	September 30			September 30		
	2006	2005	Change	2006	2005	Change
Gross revenue	<b>37,994</b>	43,936	-14%	<b>110,853</b>	92,359	20%
Royalty expense <sup>(1)</sup>	<b>(1,444)</b>	(1,069)	35%	<b>(3,382)</b>	(2,400)	41%
Net revenue	<b>36,550</b>	42,867	-15%	<b>107,471</b>	89,959	19%

(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.

Gross Revenue Variances (\$000s)	Three Months Ended			Nine Months Ended		
	September 30			September 30		
	2006 vs. 2005	2005 vs. 2004		2006 vs. 2005	2005 vs. 2004	
<b>Oil and NGL</b>						
Production increase (decrease)	(1,476)	8,494		7,603	10,257	
Price increase (decrease)	971	4,601		6,824	9,576	
Net increase (decrease)	(505)	13,095		14,427	19,833	
<b>Natural gas</b>						
Production increase (decrease)	(1,142)	8,168		7,088	10,221	
Price increase (decrease)	(4,244)	1,642		(2,830)	3,154	
Net increase (decrease)	(5,386)	9,810		4,258	13,375	
Other	(52)	305		(191)	596	
<b>Gross revenue increase (decrease)</b>	<b>(5,943)</b>	<b>23,210</b>		<b>18,494</b>	<b>33,804</b>	

## EXPENSES

### ROYALTIES PAID

Royalty expense rates are linked to commodity prices and production volumes. Royalty expenses rose 35% in the third quarter on higher working interest production volumes and higher oil prices, as well as prior period adjustments that added \$175,000 to royalty expenses for the current quarter. For the year to date, royalty expenses have increased 41% (21% per boe).

Royalty Expenses (net of Alberta Royalty Credit)	Three Months Ended			Nine Months Ended		
	September 30			September 30		
	2006	2005	Change	2006	2005	Change
Working interest properties (\$000s)	1,444	1,069	35%	3,382	2,400	41%
Per boe (\$)	8.13	6.59	23%	6.45	5.00	29%
Royalty interest lands <sup>(1)</sup> (\$000s)	—	—	—	—	—	—
Per boe (\$)	—	—	—	—	—	—
Total royalty expenses (\$000s)	1,444	1,069	35%	3,382	2,400	41%
Total Trust (\$/boe)	1.88	1.30	45%	1.47	1.21	21%

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

### OPERATING EXPENSES

Demand for people and services is unprecedented and cost inflation continues to drive up operating expenses industry-wide. 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 have experienced higher costs for services, materials, and equipment. Overall, operating costs were \$2.75 per boe for the quarter and \$2.62 per boe for the year to date. We anticipate operating expenses will average \$2.60 per boe for the full year.

Operating Expenses	Three Months Ended			Nine Months Ended		
	September 30			September 30		
	2006	2005	Change	2006	2005	Change
Working interest properties (\$000s)	2,111	1,679	26%	6,050	4,618	31%
Per boe (\$)	11.88	10.35	15%	11.54	9.61	20%
Royalty interest lands <sup>(1)</sup> (\$000s)	—	—	—	—	—	—
Per boe (\$)	—	—	—	—	—	—
Total operating expenses (\$000s)	2,111	1,679	26%	6,050	4,618	31%
Total Trust (\$/boe)	2.75	2.03	35%	2.62	2.33	12%

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

**DEPLETION, DEPRECIATION AND ACCRETION OF ASSET RETIREMENT OBLIGATION**

Depletion of oil and natural gas properties (including the capitalized portion of the asset retirement obligation) and depreciation of equipment is provided for on a unit-of-production basis using estimated proved reserves. Depletion on property, plant and equipment, and accretion on the asset retirement obligation, totalled \$54.7 million (\$23.72 per boe), compared with \$38.3 million (\$19.32 per boe) in the first nine months of last year. The increase reflects higher volumes produced and the addition of petroleum and natural gas interests from the Petrovera acquisition at a higher cost than our historical average.

Depletion, Depreciation and Accretion Expenses	Nine Months Ended		Year Ended
	Sept 30 2006	Sept 30 2005	December 31 2005
Depletion and depreciation (\$000s)	54,497	38,118	56,938
Accretion of asset retirement obligation (\$000s)	192	185	252
Total depletion, depreciation and accretion expenses (\$000s)	54,689	38,303	57,190
Per boe (\$)	23.72	19.32	20.52

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

In the third quarter, G&A costs 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 13% higher in the third quarter and 21% higher in the first nine months of this year. Contributing factors included: 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. We also recorded a non-cash expense of \$241,000 for the nine months ended September 30, 2006 (with a corresponding increase to contributed surplus) as unit based compensation relating to the grant of 12,153 deferred trust units to non-management directors. G&A for the year to date also includes a non-cash charge of \$174,000 for the Trust's proportionate share of the Manager's LTIP for the first nine months of 2006 and \$450,000 (expensed in the first quarter) for the Trust's proportionate share of the Manager's short term incentive plan for 2006.

G&A Expenses	Three Months Ended			Nine Months Ended		
	September 30			September 30		
	2006	2005	Change	2006	2005	Change
G&A expenses (\$000s)	1,012	964	5%	4,481	3,170	41%
Per boe (\$)	1.32	1.17	13%	1.94	1.60	21%
As a percentage of revenue	2.7%	2.2%	23%	4.0%	3.4%	18%

**MANAGEMENT FEES**

The management fee is paid in Trust Units. The issue of 17.4 million Trust Units in May 2005 resulted in a pro-rata increase in the management fee, in accordance with the management agreement. The management fee for the third quarter of 2006 was 35,654 Trust Units, unchanged from the third quarter of last year.

Management Fees (paid in Trust Units) (\$000s, except as noted)	Three Months Ended			Nine Months Ended		
	September 30			September 30		
	2006	2005	Change	2006	2005	Change
Ascribed value of management fees <sup>(1)</sup>	677	666	2%	2,121	1,508	41%
Per boe (\$)	0.88	0.81	9%	0.92	0.76	21%

(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. In the third quarter, interest expense totalled \$1.3 million, or \$1.75 per boe.

Interest Expenses (\$000s, except as noted)	Three Months Ended			Nine Months Ended		
	September 30			September 30		
	2006	2005	Change	2006	2005	Change
Net interest expense	<b>1,346</b>	1,082	24%	<b>3,836</b>	2,017	90%
Per boe (\$)	<b>1.75</b>	1.31	34%	<b>1.66</b>	1.02	63%

**OPERATING NETBACK**

Our operating netback in the third quarter was \$44.92 per boe, down 10% compared with the third quarter last year due to lower commodity prices and production volumes. For the first nine months of this year, our operating netback has averaged \$43.99 per boe, slightly higher than last year. We do not have any commodity price or foreign currency hedges in place, and we have no plans to enter into any foreign currency or commodity price hedges at this time. This policy is subject to quarterly review by our Board.

Operating Netback (\$/boe)	Three Months Ended			Nine Months Ended		
	September 30			September 30		
	2006	2005	Change	2006	2005	Change
Gross revenue <sup>(1)</sup>	<b>49.55</b>	53.22	-7%	<b>48.08</b>	46.57	3%
Royalty expenses <sup>(2)</sup>	<b>1.88</b>	1.30	45%	<b>1.47</b>	1.21	21%
Operating expenses	<b>2.75</b>	2.03	35%	<b>2.62</b>	2.33	12%
Operating netback	<b>44.92</b>	49.89	-10%	<b>43.99</b>	43.03	2%

(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 third quarter of 2006. Non-cash expenses, primarily higher depletion and depreciation, reduced net income to \$12.7 million.

Funds Generated From Operations and Net Income	Three Months Ended			Nine Months Ended		
	September 30			September 30		
	2006	2005	Change	2006	2005	Change
Funds generated from operations (\$000s)	<b>31,692</b>	38,893	-19%	<b>92,455</b>	79,340	17%
Per Trust Unit (\$)	<b>0.65</b>	0.79	-18%	<b>1.88</b>	1.95	-4%
Net income (\$000s)	<b>12,728</b>	19,373	-34%	<b>35,636</b>	39,599	-10%
Per Trust Unit, basic and diluted (\$)	<b>0.26</b>	0.40	-35%	<b>0.73</b>	0.97	-25%

**DISTRIBUTIONS AND UNITHOLDER TAXATION**

Distributions to Unitholders totalled \$0.54 per Trust Unit for the third quarter and \$1.62 per Trust Unit for first nine months of 2006. Royalty income contributed approximately 95% of distributions for the year to date. Since inception, the Trust has distributed \$462.5 million (\$13.82 per Trust Unit) to Unitholders.

Distributions to Unitholders (\$000s, except as noted)	Three Months Ended		Nine Months Ended	
	September 30		September 30	
	2006	2005	2006	2005
Funds generated from operations	31,692	38,893	92,455	79,340
Net reclamation fund contribution	70	(105)	(138)	(246)
Development expenditures	(4,649)	(4,059)	(7,680)	(6,351)
Debt additions (repayment)	2,000	(2,000)	(9,000)	91,000
Proceeds from Trust Unit issuance	—	—	—	258,935
Property and Royalty acquisitions	(5,382)	—	(5,382)	(351,705)
Changes in working capital	2,790	(10,202)	9,251	(17,529)
<b>Distributions to Unitholders</b>	<b>26,521</b>	<b>22,527</b>	<b>79,506</b>	<b>53,444</b>
Accumulated, beginning of period	436,009	329,131	383,024	298,214
Accumulated, end of period	462,530	351,658	462,530	351,658
<b>Distributions per Trust Unit (\$) <sup>(1)</sup></b>	<b>0.54</b>	<b>0.46</b>	<b>1.62</b>	<b>1.28</b>
Accumulated, beginning of period	13.28	11.10	12.20	10.28
Accumulated, end of period	13.82	11.56	13.82	11.56

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

Cash distributions are typically less than funds generated from operations as we retain a portion of funds generated to finance reclamation fund contributions, development expenditures, minor acquisitions, and debt repayments. Since inception, our payout ratio has averaged 82%. Third quarter distributions represented 84% of funds generated from operations in 2006, versus 58% in 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.

Payout Ratio <sup>(1)</sup> (\$ per Trust Unit, except as noted)	Three Months Ended			Nine Months Ended		
	September 30			September 30		
	2006	2005	Change	2006	2005	Change
Funds generated from operations	0.65	0.79	-18%	1.88	1.95	-4%
Distributions to Unitholders	0.54	0.46	17%	1.62	1.28	27%
Payout ratio	84%	58%	45%	86%	67%	28%

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

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

On October 31, 2006, the Minister of Finance unexpectedly announced a proposal to amend the *Income Tax Act* (Canada) to apply a Distribution Tax on distributions from publicly-traded income trusts. Under the proposal, existing income trusts will be subject to the new measures commencing in their 2011 taxation year, following a four-year grace period. The Minister of Finance has issued a Notice of Ways and Means Motion to Amend the *Income Tax Act*, but it is not known at this time if or when the proposal will be enacted by Parliament.

In simplified terms, under the proposed tax plan, income distributions will first be taxed at the trust level at a special rate estimated to be 31.5%. Income distributions to individual unitholders will then be treated as dividends from a Canadian corporation and eligible for the dividend tax credit. Income distributions to corporations resident in Canada will be eligible for full deduction as tax-free intercorporate dividends. Tax-deferred accounts (RRSPs, RRIFs and RPPs) will continue to pay no tax on distributions. Non-resident unitholders will be taxed on distributions at the non-resident withholding tax rate for dividends. The net impact on Canadian taxable investors is expected to be minimal because they can take advantage of the dividend tax credit. However, as a result of the 31.5% Distribution Tax at the trust level, distributions to tax-deferred accounts will be reduced by approximately 31.5%, and distributions to non-residents will be reduced by approximately 26.5%.

The long-term effect of the proposed tax changes on Freehold is yet to be determined. However, given the four-year grace period before existing trusts will be taxed, we have an opportunity to examine our strategy, and if warranted, modify it to provide the best possible return for our Unitholders.

### 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 \$20 million of long-term debt with funds generated from operations. At September 30, 2006, we had no short-term debt outstanding and long-term debt was \$98 million. We had working capital of \$7.6 million, resulting in net debt of \$90.5 million. In addition, we had accrued \$694,000 as a long term liability relating to incentive compensation pursuant to the Manager's LTIP (see "General and Administrative Expenses"). We currently have \$67 million of available capacity under our credit facilities.

Debt Analysis (\$000s)	As at September 30		
	2006	2005	Change
Long-term debt	98,000	118,000	-17%
Short-term debt	—	—	—
Total debt	98,000	118,000	-17%
Less: working capital	(7,553)	(21,656)	-65%
Net debt obligations	90,447	96,344	-6%

With the addition of \$2 million in long-term debt during the third quarter, the Trust's ratio of net debt (long-term debt less positive working capital) to trailing funds generated from operations was 0.7 to 1 at September 30, 2006.

Financial Leverage and Coverage Ratios <sup>(1)</sup>	As at September 30		
	2006	2005	Change
Net debt to funds generated from operations (times)	0.7	1.0	-30%
Net debt to distributions (times)	0.8	1.4	-43%
Distributions to interest expense (times)	22.3	31.5	-29%
Net debt to net debt plus equity (%)	20%	19%	5%

(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 September 30, 2006 were higher as a result of the significant amount of capital spent in the third quarter and the timing of invoices.

<b>Components of Working Capital</b> (\$000s)	<b>Sept. 30</b> <b>2006</b>	June 30 2006	Mar. 31 2006	Dec. 31 2005	Sept. 30 2005
Cash	<b>585</b>	245	38	192	17
Accounts receivable	<b>28,311</b>	28,051	32,125	35,728	35,211
Current assets	<b>28,896</b>	28,296	32,163	35,920	35,228
Distributions payable to Unitholders	<b>(8,845)</b>	(8,839)	(8,832)	(12,748)	(6,859)
Accounts payable and accrued liabilities	<b>(12,498)</b>	(9,107)	(9,042)	(6,891)	(6,713)
Current liabilities	<b>(21,343)</b>	(17,946)	(17,874)	(19,639)	(13,572)
Working capital <sup>(1)</sup>	<b>7,553</b>	10,350	14,289	16,281	21,656

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

## **DISTRIBUTION OUTLOOK**

Additional capital requirements totalling \$10.4 million (\$5.4 million for the Wildmere acquisition and \$5.0 million to fund additional development opportunities on our working interest properties) and the weakening in commodity prices have prompted our Board of Directors to reduce the monthly distribution rate to \$0.15 per Trust Unit effective with the December 15 payment. As a result, our cash distributions for 2006 will total \$2.10 per Trust Unit, down 3% from our previous guidance of \$2.16.

Looking ahead to 2007, we anticipate that lower commodity prices will slow drilling activity. The Canadian Association of Oilwell Drilling Contractors predicts a 15% decline in drilling next year. 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. Largely due to development of the oil sands, the demand for people and oilfield services is unprecedented. The industry continues to experience higher operating, administrative, and finding and development costs, as well as a severe shortage of experienced professionals and skilled trades.

Considering all of the above factors (and based on the assumptions provided in the accompanying table) our distribution guidance for 2007 is \$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 37% 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 November 8, 2006)</b>		
	<b>2007</b>	<b>2006</b>
<b>Estimated cash distributions (\$ per Trust Unit)</b>	<b>1.80</b>	<b>2.10</b>
<b>Key assumptions</b>		
Average daily production, excluding acquisitions (boe/d)	7,950	8,450
Average WTI oil price (US\$/bbl)	62.50	66.09
Average AECO natural gas price (Cdn\$/Mcf)	7.25	7.25
Average light/heavy oil price differential (Cdn\$/bbl)	25.00	22.80
Average exchange rate (Cdn\$/US\$)	0.90	0.88
Average operating costs (\$/boe)	3.00	2.60
Average general and administrative costs (\$/boe)	2.10	1.75
Development expenditures (\$ millions)	8.0	11.0
Long-term debt at year end (\$ millions)	98	100
Weighted average Trust Units outstanding (thousands)	49,100	49,100
Payout ratio (%)	89	88
Estimated portion of distributions taxable as income (%)	100	100

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

Additional information about Freehold, including our annual information form, is available on SEDAR at [www.sedar.com](http://www.sedar.com).

**FOR FURTHER INFORMATION, PLEASE CONTACT:**

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## Consolidated Balance Sheets

(\$000s) (unaudited)	September 30, 2006	December 31, 2005
<b>Assets</b>		
Current assets:		
Cash	\$ 585	\$ 192
Accounts receivable	28,311	35,728
	<b>28,896</b>	<b>35,920</b>
Reclamation fund	2,102	1,964
Petroleum and natural gas interests, net of accumulated depletion and depreciation of \$292,354 (2005 - \$237,857)	454,906	496,194
	<b>\$ 485,904</b>	<b>\$ 534,078</b>
<b>Liabilities and Unitholders' Equity</b>		
Current liabilities:		
Distributions payable to Unitholders	\$ 8,845	\$ 12,748
Accounts payable and accrued liabilities	12,498	6,891
	<b>21,343</b>	<b>19,639</b>
Asset retirement obligations (note 5)	4,176	4,036
Unit based compensation payable (note 4)	694	—
Long-term debt (note 2)	98,000	107,000
Future income tax liability	3,728	3,932
Unitholders' equity:		
Unitholders' capital (note 3)	562,170	560,049
Contributed surplus	241	—
Deficit	(204,448)	(160,578)
	<b>357,963</b>	<b>399,471</b>
	<b>\$ 485,904</b>	<b>\$ 534,078</b>

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 September 30		Nine Months Ended September 30	
	2006	2005	2006	2005
Revenue:				
Royalty income and working interest sales	\$ 37,994	\$ 43,936	\$ 110,853	\$ 92,359
Royalty expense (net of Alberta Royalty Tax Credit)	(1,444)	(1,069)	(3,382)	(2,400)
	36,550	42,867	107,471	89,959
Expenses:				
Operating	2,111	1,679	6,050	4,618
General and administrative	1,012	964	4,481	3,170
Interest on long-term debt	1,346	1,082	3,836	2,017
Depletion and depreciation	18,389	18,792	54,497	38,118
Accretion of asset retirement obligation	66	63	192	185
Management fee	677	666	2,121	1,508
	23,601	23,246	71,177	49,616
Net income before taxes	12,949	19,621	36,294	40,343
Income and capital taxes	277	248	862	744
Future income tax provision	(56)	—	(204)	—
	221	248	658	744
Net income	\$ 12,728	\$ 19,373	\$ 35,636	\$ 39,599
Deficit, beginning of period	(190,655)	(144,805)	(160,578)	(134,114)
Distributions declared	(26,521)	(22,527)	(79,506)	(53,444)
Deficit, end of period	\$ (204,448)	\$ (147,959)	\$ (204,448)	\$ (147,959)
Net income per Trust Unit, basic and diluted	\$ 0.26	\$ 0.40	\$ 0.73	\$ 0.97
Weighted average number of Trust Units:				
Basic	49,103,277	48,960,661	49,067,888	40,728,537
Diluted	49,115,279	48,960,661	49,074,173	40,728,537

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	
	2006	2005	2006	2005
Cash provided by (used in):				
Operating:				
Net income	\$ 12,728	\$ 19,373	\$ 35,636	\$ 39,599
Items not involving cash:				
Depletion and depreciation	18,389	18,792	54,497	38,118
Trust Unit incentive compensation (note 4)	74	—	414	—
Future income tax provision	(56)	—	(204)	—
Accretion of asset retirement obligation	66	63	192	185
Trust Units issued in lieu of management fee	677	666	2,121	1,508
Expenditures on reclamation	(186)	(1)	(201)	(70)
Funds generated from operations	31,692	38,893	92,455	79,340
Changes in non-cash working capital	770	(12,508)	12,078	(21,532)
	<b>32,462</b>	<b>26,385</b>	<b>104,533</b>	<b>57,808</b>
Financing:				
Issue of Trust Units, net of issue costs	—	—	—	258,935
Long-term debt	2,000	(2,000)	(9,000)	91,000
Distributions paid	(26,514)	(21,543)	(83,410)	(50,371)
Changes in non-cash working capital	44	8	(135)	(166)
	<b>(24,470)</b>	<b>(23,535)</b>	<b>(92,545)</b>	<b>299,398</b>
Investing:				
Property and royalty acquisitions	(5,382)	—	(5,382)	(351,705)
Development expenditures	(4,649)	(4,059)	(7,680)	(6,351)
Increase in reclamation fund	70	(105)	(138)	(246)
Changes in non-cash working capital	2,309	1,116	1,605	1,047
	<b>(7,652)</b>	<b>(3,048)</b>	<b>(11,595)</b>	<b>(357,255)</b>
Increase (decrease) in cash	340	(198)	393	(49)
Cash, beginning of period	245	215	192	66
Cash, end of period	\$ 585	\$ 17	\$ 585	\$ 17

See accompanying notes to interim consolidated financial statements.

## Notes to Interim Consolidated Financial Statements

For the three and nine month periods ended September 30, 2006 and 2005.

### 1. SIGNIFICANT ACCOUNTING POLICIES

The interim consolidated financial statements of Freehold Royalty Trust (Freehold or the Trust) have been prepared by management in accordance with Canadian generally accepted accounting principles. The interim consolidated financial statements have been prepared following the same accounting policies and methods of computation as the consolidated financial statements for the fiscal year ended December 31, 2005, except for the implementation of unit based compensation. The following disclosure is incremental to the disclosure contained in the 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 \$98 million was drawn at September 30, 2006. In the event that the lender does not consent to an extension, the revolving credit facility will revert to a two-year, non-revolving term facility with equal quarterly principal repayments. The first quarterly payment would commence on January 1 of the year following the end of the revolving period, which is May 2007. In addition, Freehold has available a \$15 million extendible revolving operating facility. Borrowings under the facilities bear interest at the Bank's prime lending rate, bankers' acceptance or LIBOR rates plus applicable margins, ranging from 85 to 140 basis points and standby fees. The facilities are secured with \$300 million demand debentures over Freehold's petroleum and natural gas assets.

**3. UNITHOLDERS' CAPITAL**

	September 30, 2006		December 31, 2005	
	Units	Amount (\$000s)	Units	Amount (\$000s)
Balance, beginning of period	49,031,581	560,049	31,544,236	298,936
Issued for cash	—	—	17,363,520	270,003
Less: Issue expenses	—	—	—	(11,068)
Issued in lieu of management fee	106,962	2,121	123,825	2,178
Balance, end of period	49,138,543	562,170	49,031,581	560,049

**4. UNIT BASED COMPENSATION**

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

For the nine months ended September 30, 2006, the Trust expensed \$241,000 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 September 30, 2006, the Trust had accrued \$694,000 as a long term liability relating to incentive compensation pursuant to the Manager's LTIP and expensed \$174,000 for the nine-month period then ended.

**5. ASSET RETIREMENT OBLIGATIONS**

Freehold has no asset retirement obligations (ARO) on its royalty income properties. Freehold's ARO results from its responsibility to abandon and reclaim its net share of all working interest properties. The net present value of Freehold's total ARO is estimated to be \$4.2 million (discounted at a weighted average credit adjusted risk free rate of 6.2%), with the undiscounted value being \$10.4 million. Payments to settle the obligations are expected to occur continuously over the next 50 years, with the majority of obligations being over 15 years away.

(\$000s)	September 30, 2006	December 31, 2005
Balance, beginning of period	4,036	3,937
Liabilities incurred	149	210
Liabilities added upon acquisition	—	19
Liabilities settled	(201)	(104)
Liabilities disposed	—	(352)
Revisions in estimates	—	74
Accretion expense	192	252
Balance, end of period	4,176	4,036

**6. RELATED PARTY TRANSACTIONS**

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

For the three month period ended September 30, 2006, the Manager charged the Trust \$0.8 million in general and administrative costs, totalling \$3.0 million for the nine month period ended September 30, 2006. At September 30, 2006, there was \$0.2 million in accounts payable relating to these costs.

**7. SUPPLEMENTAL CASH FLOW DISCLOSURE**

<b>Cash Expenses Paid</b> (\$000s)	Three Months Ended September 30		Nine Months Ended September 30	
	<b>2006</b>	2005	<b>2006</b>	2005
Interest	<b>1,302</b>	1,074	<b>3,990</b>	2,183
Taxes	<b>277</b>	248	<b>975</b>	1,216