

## Quarterly Report

THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2009

## Freehold Royalty Trust Announces 2009 Third Quarter Results, 17% Increase in Monthly Distributions, and Extra Distribution for 2009

RESULTS AT A GLANCE Financial (\$000s, except as noted)	Three Months Ended September 30			Nine Months Ended September 30		
	2009	2008	Change	2009	2008	Change
Gross revenue	29,016	59,780	-51%	84,798	169,655	-50%
Net income	7,853	36,772	-79%	17,020	96,582	-82%
Per Trust Unit, basic and diluted (\$)	0.16	0.74	-79%	0.34	1.96	-83%
Cash provided by operating activities	26,215	57,380	-54%	69,722	137,580	-49%
Per Trust Unit (\$)	0.53	1.16	-54%	1.41	2.79	-49%
Funds generated from operations (1)	24,189	51,977	-53%	64,641	144,342	-55%
Per Trust Unit (\$)	0.49	1.05	-53%	1.31	2.92	-55%
Capital expenditures	7,368	4,885	51%	11,056	9,222	20%
Property and royalty acquisitions (net)	-	8,475	0%	-	8,475	0%
Distributions declared	16,850	37,050	-55%	46,543	89,362	-48%
Per Trust Unit (\$) (2)	0.34	0.75	-55%	0.94	1.81	-48%
Long-term debt, period end	147,000	141,000	4%	147,000	141,000	4%
Unitholders' equity, period end	192,103	260,612	-26%	192,103	260,612	-26%
Trust Units (000s) (3)	49,543	49,389	0%	49,500	49,353	0%
<b>Operating</b> (per boe) (4)						
Average daily production (boe/d)	6,994	7,613	-8%	7,268	7,812	-7%
Average price realizations (\$)	44.01	83.47	-47%	41.57	77.75	-47%
Operating netback (\$) (1)	42.16	79.14	-47%	37.55	72.90	-48%

(1) See non-GAAP measures.

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

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

(4) See "Management's Discussion and Analysis (MD&amp;A) – Conversion of Natural Gas to Barrels of Oil Equivalent (boe)".

## DISTRIBUTION INCREASE AND EXTRA DISTRIBUTION FOR 2009

Due to the continued strength of oil prices, we are increasing monthly distributions by 17% and declaring an additional payment for 2009 as we expect to have excess cash from operating activities this year. The regular monthly distribution will be \$0.14 per Trust Unit until further notice. The Board of Directors has declared the November distribution of \$0.14 per Trust Unit and an extra distribution of \$0.06 per Trust Unit (for a total of \$0.20 per Trust Unit) to be paid concurrently on December 15, 2009 to Unitholders of record on November 30, 2009 (ex-distribution date November 26, 2009). Including the December 15 payment, our 12-month trailing cash distributions total \$1.86 per Trust Unit.

## Message to Unitholders

Our results for the third quarter and nine months ended September 30, 2009 reflect sharply lower commodity prices compared with last year. Production volumes were also lower than last year, reflecting the reduction in industry drilling activity and our decision to defer major capital projects to the second half of 2009.

### OIL AND GAS MARKETS

While WTI crude oil prices remain volatile, the improving global economic outlook has fuelled a gradual oil price improvement since the first quarter of this year – with the benefit being partly offset by the corresponding rise of the Canadian dollar. As anticipated, light/heavy oil differentials widened in the third quarter, marking the end of the summer asphalt-paving season. The differential remains at historical lows, however, due to continued strong demand for heavier crude by North American refiners. We believe this trend will continue, which is positive for Freehold given our product mix.

The short-term outlook for natural gas remains clouded. Marginal production continues to be shut-in and natural gas directed drilling curtailed. With stockpiles high and demand low, prices continued to fall in the third quarter. Leading into the winter heating season, natural gas in storage is at record levels. Over the coming months, natural gas prices will depend largely on weather-related demand. We believe that lower reinvestment will reduce natural gas supply and lead to an eventual price recovery as economic conditions improve but the timing of such a recovery remains uncertain. In this environment, we are fortunate to have an oil-weighted portfolio and oil-weighted development opportunities.

### ROYALTY LANDS AND INDUSTRY ACTIVITY

As expected, drilling on our royalty lands continues to reflect the overall decline in industry drilling, which was down 64% from last year. The Alberta Government's short-term stimulus plan to encourage conventional oil and natural gas activity in the province is expected to have a positive impact on industry activity levels in the coming months, although producers may delay initial production (particularly for natural gas wells) until prices improve. While operators may focus on opportunities on Crown lands to take advantage of the incentives, we anticipate that increased activity will be eventually reflected on our royalty lands.

As at September 30, 2009, there were 61 (Q3 2008 – 79) licensed drilling locations on our royalty lands, up from only 43 at the end of June, perhaps signalling an improvement in industry activity. That outlook is shared by the Canadian Association of Oilwell Drilling Contractors, which expects a 4% increase in activity next year. The CAODC's forecast suggests that most of the improvement in 2010 will come in the last half of the year and assumes some improvement in natural gas prices. The Canadian Association of Petroleum Producers also predicts a modest increase in capital spending in 2010 versus 2009.

Improving access to equity markets is another sign that we might be nearing the bottom of the cycle. In recent months, a number of financings for oil and gas companies have been completed. Although access to capital has moderately improved, producers' capital investment programs continue to be funded primarily from cash flows.

### WORKING INTEREST PROPERTIES

Third quarter drilling on working interest properties was significantly higher than last year on a net basis, as we drilled our first two 100% working interest wells on our Bakken oil-prone title lands in Southeast Saskatchewan. Both wells were recently fracture stimulated using multi-stage packer technology along the horizontal leg. Initial production tests are underway. In addition, we participated as to our title interest in one (0.5 net) Bakken well at Taylorton, near the Saskatchewan/North Dakota border. The economics of our participation are extremely attractive, as we own the mineral rights. The production is light oil (which we intend to take in kind) and yields very high netbacks. Since 2005, we have participated in the drilling of 25 (6.5 net) Bakken wells on our title lands.

In Alberta, we completed our 2009 infill-drilling program at Hayter with 11 (2.6 net) horizontal wells, and participated in the drilling of three (0.3 net) wells at Pembina Cardium Unit #9. The Pembina unit wells were part of a pilot program initiated in the first quarter, using horizontal drilling, staged fracture stimulation, and micro-seismic technology. Production from this successful third quarter development activity will be reflected in our volumes over the next two quarters.

Successful drilling, particularly in Southeast Saskatchewan, has led to additional oil development opportunities on our working interest properties. As a result, we have increased our 2009 capital program by \$2 million to \$14 million. Fourth quarter capital expenditures will be approximately \$3 million.

Our Board has approved a capital budget for 2010 of \$24 million. This is a substantial increase over 2009, as we plan to accelerate development of our Bakken-prone title lands in Southeast Saskatchewan. In addition, we anticipate an active program at Pembina Cardium Unit #9 as the operator continues with field redevelopment using horizontal infill drilling and multistage fracture technology. Based on this activity, and excluding any potential acquisitions, our 2010 production is forecast to average 7,000 boe per day. Our other key operating assumptions are outlined in the accompanying MD&A.

#### BOARD AND MANAGEMENT CHANGES

In the third quarter of 2009, Peter Harrison joined CN Investment Division. Because the Manager of Freehold is a wholly-owned subsidiary of the CN Pension Trust Funds, Mr. Harrison is no longer considered an independent director of Freehold. To maintain the number of Manager-appointed directors at two, Russell Hiscock of CN Investment Division has stepped down from the Board. We thank Mr. Hiscock for his valuable wisdom, advice, and support as a member of our Board. The Manager-appointed directors are now Peter Harrison and Bill Ingram.

We are pleased to announce the appointment of a new independent director, Rodger Tourigny, to Freehold's Board effective November 10, 2009. A Chartered Accountant, Mr. Tourigny is President of Tourigny Management Ltd., a private consulting company providing services to the oil and gas, financial services, and real estate sectors since 1979. Mr. Tourigny was appointed to the Audit, Compensation, and Corporate SIFT Tax Strategy Committees, and will serve as Chair of the Audit Committee.

Michael Okrusko, Vice-President, Land, has indicated his intention to retire during 2010 after serving for more than 28 years with Rife Resources, the Manager of the Trust. We appreciate Mike's significant contributions toward the success of Freehold since 1996. The Board is working with the Manager on the succession planning process to provide for a smooth transition.

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



William O. Ingram  
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 Royalty Trust, Freehold Resources Ltd. and Petrovera Resources (a general partnership) (collectively, Freehold or the Trust), for the three and nine months ended September 30, 2009 and previous periods, and the outlook for Freehold based on information available as at November 10, 2009. The financial information contained herein was based on information in the consolidated financial statements, which have been prepared in accordance with Canadian generally accepted accounting principles (GAAP). All comparative percentages are between the quarters ended September 30, 2009 and September 30, 2008, 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, 2008 and 2007, together with the accompanying notes.

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

### FORWARD-LOOKING STATEMENTS

This MD&A offers our assessment of Freehold's future plans and operations as at November 10, 2009, and contains forward-looking statements including our expectations for improving economic conditions, access to capital markets, industry drilling and activity on our royalty lands, capital expenditures, average production, commodity prices, demand for heavier crude, reduced natural gas supply, and acquisition opportunities referred to in the Message to Unitholders; Future Income Tax; and our expectations for improving economic conditions, access to capital markets, industry drilling and activity on our royalty lands, participation in the DRIP; long-term debt, capital expenditures, average production, commodity prices, demand for and differential pricing of heavier crude, key operating assumptions, and acquisition opportunities referred to under Business Environment. These forward-looking statements are provided to allow readers to better understand our business and prospects.

Such statements are generally identified by the use of words such as "anticipate", "continue", "estimate", "expect", "forecast", "may", "will", "project", "should", "plan", "intend", "believe", and similar expressions (including the negatives thereof). By their nature, forward-looking statements are subject to numerous risks and uncertainties, some of which are beyond our control, including the impact of general economic conditions, industry conditions, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, taxation, royalties, regulation, competition from other industry participants, the lack of availability of qualified personnel or management, stock market volatility, and our ability to access sufficient capital from internal and external sources. Risks are described in more detail in our AIF.

With respect to forward-looking statements contained in this MD&A, we have made assumptions regarding, among other things, future oil and natural gas prices, future capital expenditure levels, future production levels, future exchange rates, future participation rates in the DRIP, the cost of developing and producing our assets, our ability and the ability of our lessees to obtain equipment in a timely manner to carry out development activities, our ability to market our oil and natural gas successfully to current and new customers, our expectation for the consumption of crude oil and natural gas, our expectation for industry drilling levels, our ability to obtain financing on acceptable terms, and our ability to add production and reserves through development and acquisition activities. The key operating assumptions with respect to the forward-looking statements referred to above are detailed in our discussion of the Business Environment.

You are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. Our actual results, performance, or achievement could differ materially from those expressed in, or implied by, these forward-looking statements. We can give no assurance that any of the events anticipated will transpire or occur, or if any of them do, what benefits we will derive from them. The forward-looking information contained in the MD&A is expressly qualified by this cautionary statement. Our policy for updating forward-looking

statements is to update our key operating assumptions quarterly and, except as required by law, we do not undertake to update any other forward-looking statements.

#### CONVERSION OF NATURAL GAS TO BARRELS OF OIL EQUIVALENT (BOE)

To provide a single unit of production for analytical purposes, natural gas production and reserves volumes are converted mathematically to equivalent barrels of oil (boe). We use the industry-accepted standard conversion of six thousand cubic feet of natural gas to one barrel of oil (6 Mcf = 1 bbl). The 6:1 boe ratio is based on an energy equivalency conversion method primarily applicable at the burner tip. It does not represent a value equivalency at the wellhead and is not based on either energy content or current prices. While the boe ratio is useful for comparative measures and observing trends, it does not accurately reflect individual product values and might be misleading, particularly if used in isolation.

#### NON-GAAP MEASURES

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

Operating netback, which is calculated as average unit sales price less royalties and operating expenses, represents the cash margin for product sold, calculated on a per boe basis. See Operating Netback.

Funds generated from operations is a financial term commonly used in the oil and gas industry. It represents cash provided by operating activities before changes in non-cash working capital and is a key measure of our ability to generate cash, finance operations, and pay monthly distributions. Funds generated from operations as presented is not intended to represent operating cash flow or operating profits for the period nor should it be viewed as an alternative to cash provided by operating activities, net income or other measures of financial performance calculated in accordance with GAAP. The key difference between cash provided by operating activities and funds generated from operations is changes in non-cash working capital, which is affected by accounts receivable, accounts payable, and accrued liabilities. Accounts receivable, and therefore working capital, can fluctuate greatly between reporting periods due to timing of receipt of payments. In the event that commodity prices and/or volumes have changed significantly from the previous reporting period, a significant difference could occur between cash provided by operating activities and funds generated from operations. All references to funds generated from operations throughout this report are based on cash provided by operating activities before changes in non-cash working capital as per the Statements of Cash Flows. Funds generated from operations per Trust Unit is calculated based on the weighted average number of Trust Units outstanding consistent with the calculation of net income per Trust Unit. See Funds Generated From Operations and Net Income.

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

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

## Business Environment

While WTI crude oil prices remain volatile, the improving global economic outlook has fuelled a gradual oil price improvement since the first quarter of this year – with the benefit being partly offset by the corresponding rise of the Canadian dollar.

As approximately one-third of our total boe production is heavy oil, the markets for heavy oil are of particular relevance for us. Light/heavy oil price differentials have narrowed significantly over the past year because of improved transportation routes, strong refinery demand for this product type, and high seasonal demand. As is typical, light/heavy oil differentials widened in the third quarter, marking the end of the summer asphalt-paving season. However, the price spread remained tight compared with the previous year, averaging \$7.75 per barrel. We believe this trend will continue, which is positive for Freehold given our product mix.

The short-term outlook for natural gas remains clouded. Marginal production continues to be shut-in and natural gas directed drilling curtailed. With stockpiles high and demand low, prices continued to fall in the third quarter. Leading into the winter heating season, natural gas in storage is at record levels. Over the coming months, natural gas prices will depend largely on weather-related demand. We believe that lower reinvestment will reduce natural gas supply and lead to an eventual price recovery as economic conditions improve, but the timing of such a recovery remains uncertain. In this environment, we are fortunate to have an oil-weighted portfolio and oil-weighted development opportunities.

In recent months, a number of oil and gas financings have been marketed, with some deals being oversubscribed. Although access to capital has moderately improved, producers' capital investment programs continue to be funded primarily from cash flows.

The Alberta Government's short-term stimulus plan to encourage conventional oil and natural gas activity in the province is expected to have a positive impact on industry activity levels in the coming months, although producers may delay initial production (particularly for natural gas wells) until prices improve. While operators may focus on opportunities on Crown lands to take advantage of the incentives, we anticipate that increased activity will be eventually reflected on our royalty lands.

The Canadian Association of Oilwell Drilling Contractors expects a 4% increase in activity next year. The CAODC's forecast suggests that most of the improvement in 2010 will come in the last half of the year and assumes some improvement in natural gas prices. The Canadian Association of Petroleum Producers also predicts a modest increase in capital spending in 2010 versus 2009.

### DISTRIBUTION REINVESTMENT PLAN (DRIP)

Freehold's DRIP has been in place since 1997 to provide Unitholders who are residents of Canada with a method of reinvesting cash distributions into new Trust Units. To September 30, 2009, the DRIP participation rate has averaged less than 5,000 Trust Units per month and Freehold has elected to purchase reinvestment units through the facilities of The Toronto Stock Exchange (TSX) at prevailing market prices.

In early October, CN Pension Trust Funds, which owns approximately 11.3 million Trust Units, advised Freehold of its intention to participate in the DRIP, effective with the November 15 payment. On October 26, 2009, our Board approved the monthly issuance of Trust Units from treasury for the DRIP, effective with the November 15, 2009 cash distribution date.

With a higher participation rate in the DRIP and by issuing Trust Units from treasury instead of purchasing them in the market, we will have a new source of capital to reinvest in the development of our working interest properties, reduce long-term debt, or for acquisition opportunities.

**DISTRIBUTION POLICY**

Due to the continued strength of oil prices, we are increasing our monthly distribution by 17% to \$0.14 per Trust Unit, commencing with the December 15, 2009 payment. As well, we are declaring an additional payment of \$0.06 per Trust Unit for 2009 as we expect to have excess cash from operating activities this year. The extra \$0.06 distribution will be made concurrently with the regular monthly payment of \$0.14 (for a total of \$0.20 per Trust Unit) on December 15, 2009 to Unitholders of record on November 30, 2009. We will continue to review our distributions policy monthly and make adjustments, if necessary, to ensure that cash distributions are in line with cash flow.

The following table updates our key operating assumptions for 2009 based on actual results for the first nine months of the year and our current outlook for the fourth quarter. Production from our successful third quarter development activity will be reflected in our volumes over the next two quarters. Successful drilling, particularly in Southeast Saskatchewan, has led to additional oil development opportunities on our working interest properties. As a result, we have increased our 2009 capital program; fourth quarter capital expenditures will be approximately \$3 million.

2009 KEY OPERATING ASSUMPTIONS	November 10 2009	August 12 2009	May 13 2009
Average daily production (boe/d)	7,300	7,300	7,500
Average WTI oil price (US\$/bbl)	60.00	60.00	44.00
Average AECO natural gas price (Cdn\$/Mcf)	3.70	3.70	5.00
Average exchange rate (Cdn\$/US\$)	0.88	0.87	0.80
Average operating costs (\$/boe)	4.10	4.10	4.10
Average G&A costs (1)	2.90	2.90	2.90
Capital expenditures (\$ millions)	14.0	12.0	12.0
Long-term debt at year end (\$ millions)	146.0	155.0	159.0
Weighted average Trust Units outstanding (thousands)	49,563	49,521	49,514
Estimated portion of distributions taxable as income (%)	90-100%	90-100%	90-100%

(1) Excludes unit based compensation.

**2010 PLANS**

Our capital budget for 2010 represents a substantial increase over 2009, as we plan to accelerate development of our Bakken-prone title lands in Southeast Saskatchewan. In addition, we anticipate an active program at Pembina Cardium Unit #9 as the operator continues with field redevelopment using horizontal infill drilling and multistage fracture technology.

Our key operating assumptions for 2010 are outlined below.

2010 KEY OPERATING ASSUMPTIONS	November 10 2009
Average daily production (boe/d)	7,000
Average WTI oil price (US\$/bbl)	75.00
Average AECO natural gas price (Cdn\$/Mcf)	5.00
Average exchange rate (Cdn\$/US\$)	0.90
Average operating costs (\$/boe)	4.75
Average G&A costs (1)	3.00
Capital expenditures (\$ millions)	24.0
Long-term debt at year end (\$ millions)	125.0
Weighted average Trust Units outstanding (thousands)	50,734
Estimated portion of distributions taxable as income (%)	90-100%

(1) Excludes unit based compensation.

A sensitivity analysis of the potential impact of key variables on distributions to Unitholders is provided on page 40 of our 2008 annual report. Recognizing the cyclical nature of our industry, we caution that significant changes (positive or negative) in commodity prices, foreign exchange rates, or production rates will result in adjustments to the distribution level. It is also inherently difficult to predict activity levels on our royalty lands since we do not know the future plans of the various operators. Freehold is particularly vulnerable to swings in the light/heavy oil price differential, as about one-third of our total boe production is heavy oil.

## Development Activities

The drilling industry experienced a sharp decline in activity through the first nine months of 2009, as producers pared back their capital spending in light of lower commodity prices (particularly natural gas) and reduced cash flows. Drilling activity in the third quarter fell 64% with only 1,667 new wells drilled in Canada – the lowest level since 1992.

As expected, drilling on our royalty lands reflected the overall decline in industry activity levels. As at September 30, 2009, there were 61 licensed drilling locations on our royalty lands, down from 79 locations at the same time last year.

DRILLING ON ROYALTY LANDS	Three Months Ended			Nine Months Ended		
	September 30			September 30		
	2009	2008	Change	2009	2008	Change
<b>Unitized wells</b>						
Gross	70	58	21%	289	228	27%
Equivalent net (1)	0.2	0.3	-33%	1.1	1.0	10%
<b>Non-unitized wells</b>						
Gross	31	122	-75%	97	273	-64%
Equivalent net (1)	1.4	5.1	-73%	4.1	11.4	-64%
<b>Total</b>						
Gross	101	180	-44%	386	501	-23%
Equivalent net (1)	1.6	5.4	-70%	5.2	12.4	-58%

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

Third quarter drilling on working interest properties was significantly higher than last year on a net basis, as we drilled our first two 100% wells on our Bakken oil-prone title lands in Southeast Saskatchewan. Both wells were recently fracture stimulated using multi-stage packer technology along the horizontal leg. In addition, we participated as to our title interest in one (0.5 net) Bakken well at Taylorton, near the Saskatchewan/North Dakota border. The economics of our participation are extremely attractive, as we own the mineral rights. The production is light oil (which we intend to take in kind) and yields very high netbacks. Since 2005, we have participated in the drilling of 25 (6.5 net) Bakken wells on our title lands.

In Alberta, we completed our 2009 infill-drilling program at Hayter with 11 (2.6 net) horizontal wells, and participated in the drilling of three (0.3 net) wells at Pembina Cardium Unit #9. The Pembina unit wells were part of a pilot program initiated in the first quarter, using horizontal drilling, staged fracture stimulation, and micro-seismic technology.

DRILLING ON WORKING INTEREST PROPERTIES	Three Months Ended September 30				Nine Months Ended September 30			
	2009		2008		2009		2008	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Oil	17	6.2	15	3.2	23	6.9	29	5.9
Natural gas	-	-	2	0.7	1	-	9	0.9
Other	1	0.1	(1)	(0.2)	1	0.1	1	0.1
<b>Total</b>	<b>18</b>	<b>6.3</b>	<b>16</b>	<b>3.7</b>	<b>25</b>	<b>7.0</b>	<b>39</b>	<b>6.9</b>

## Quarterly Performance and Trends

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

The following significant changes have occurred over the last eight quarters that have influenced our financial results:

- WTI crude oil prices exhibited significant volatility. After reaching record levels in mid-2008, the benchmark price fell significantly in the last half of 2008 as global economic conditions deteriorated. Low prices prevailed through the first quarter of 2009 but strengthened over the past two quarters.
- Fluctuations in U.S. to Canadian dollar exchange rates also affected our oil price realizations, resulting in both positive and negative effects on our Canadian dollar oil revenues relative to the benchmark WTI, which is referenced in U.S. dollars.
- Demand for Canadian heavy crude strengthened as new pipelines added in 2006 gave producers in western Canada better access to U.S. markets. In addition, many North American refineries were retooled to process heavier grades of crude. As a result, heavy oil differentials narrowed significantly from historical levels. Demand for heavy oil is typically highest during the summer paving season.
- AECO natural gas prices also exhibited significant volatility. Natural gas markets strengthened briefly in mid-2008; however, with supply continuing to outstrip demand, prices have faced downward pressure for the past four quarters, falling to 10-year lows during the third quarter of 2009. Natural gas is a typically seasonal, weather-dependent fuel; demand is generally higher during the winter (for heating) and summer (for cooling), and lower during the spring and fall.
- We adjusted our monthly distributions in response to changing commodity prices. In April 2008, we raised the rate by \$0.03 to \$0.18 per Trust Unit, and raised it again in June 2008, to \$0.25 per Trust Unit. We also declared an additional distribution of \$0.35 per Trust Unit for 2008. In January 2009, we lowered the rate to \$0.10 per Trust Unit. As oil prices strengthened, we increased the rate to \$0.12 per Trust Unit in August 2009; this rate was maintained through the third quarter of 2009.
- In 2007 and 2008, the oil and gas industry experienced rising costs due to strong economic growth. These inflationary pressures began to ease in late 2008 as weak commodity prices cooled industry activity levels and brought down power costs.
- Fluctuations in our Trust Unit price resulted in corresponding changes in unit based compensation, which is based in part on the closing unit price at each quarter end.

QUARTERLY REVIEW	2009			2008				2007
	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
<b>Financial</b> (\$000s, except as noted)								
Revenue, net of royalty expense	29,435	28,516	25,315	33,174	58,210	59,563	46,553	39,218
Distributions declared	16,850	14,852	14,841	54,387	37,050	30,114	22,198	28,096
Per Trust Unit (\$) (1) (2)	0.34	0.30	0.30	1.10	0.75	0.61	0.45	0.57
Net income (loss)	7,853	6,776	2,391	13,374	36,772	36,163	23,647	19,067
Per Trust Unit, basic and diluted (\$)	0.16	0.14	0.05	0.27	0.74	0.73	0.48	0.39
Cash provided by operating activities	26,215	21,938	21,569	41,672	57,380	46,379	33,821	32,503
Per Trust Unit (\$)	0.53	0.44	0.44	0.84	1.16	0.94	0.69	0.66
Funds generated from operations (3)	24,189	21,833	18,619	26,942	51,977	53,183	39,182	32,591
Per Trust Unit (\$)	0.49	0.44	0.38	0.55	1.05	1.08	0.79	0.66
Property and royalty acquisitions	-	-	-	(782)	8,475	-	-	26
Capital expenditures	7,368	1,661	2,027	3,770	4,885	2,135	2,202	3,901
Long-term debt	147,000	156,000	160,000	140,000	141,000	151,000	169,000	178,000
Trust Units outstanding								
Weighted average (000s)	49,543	49,495	49,460	49,424	49,389	49,353	49,317	49,282
At quarter end (000s)	49,582	49,531	49,495	49,459	49,424	49,388	49,352	49,317
<b>Operating</b> (\$/boe, except as noted)								
Daily production (boe/d)	6,994	7,295	7,522	7,779	7,613	7,674	8,152	8,591
Royalty interest production (%)	71	71	70	71	71	72	71	70
Average selling price	44.01	42.99	37.85	46.55	83.47	86.43	64.16	50.57
Operating netback (3)	42.16	37.56	33.13	42.14	79.14	81.21	59.18	46.47
Operating expenses	3.59	5.39	4.27	4.21	3.97	4.08	3.58	3.14
Working interest properties	12.59	18.78	14.27	14.31	13.51	14.37	12.54	10.56
General and administrative expenses	2.35	2.12	3.98	2.20	1.95	2.15	3.16	1.80
<b>Benchmark Prices</b>								
WTI crude oil (US\$/bbl)	68.30	59.62	43.08	58.69	117.98	123.98	97.86	90.68
Exchange rate (Cdn\$/US\$)	0.91	0.86	0.80	0.83	0.96	0.99	1.00	1.02
Edmonton Par crude oil (Cdn\$)	71.50	65.90	49.66	63.21	121.85	126.07	97.50	86.42
Light/heavy oil differential (Cdn\$/bbl) (4)	7.75	5.19	7.12	15.49	17.98	22.75	20.80	30.75
Western Canada Select/Hardisty (Cdn\$/bbl)	63.75	60.71	42.54	47.72	103.87	103.32	76.70	55.67
AECO natural gas (Cdn\$/Mcf)	3.02	3.66	5.62	6.78	9.24	9.35	7.13	6.00
<b>Unit Trading Performance</b>								
High (\$)	17.00	15.18	11.76	18.43	24.35	24.40	19.29	15.85
Low (\$)	12.75	8.70	6.87	9.15	16.01	17.51	14.55	14.46
Close (\$)	16.24	13.85	8.90	10.49	17.10	23.99	18.04	15.60
Volume (000s)	5,131	8,756	9,310	10,474	10,263	8,993	6,740	7,036

- (1) Based on the number of Trust Units issued and outstanding at each record date.
- (2) The fourth quarters include additional distributions relating to excess income earned during the full year (\$0.35 per Trust Unit in 2008 and \$0.12 per Trust Unit in 2007).
- (3) See Non-GAAP Measures.
- (4) The difference between Edmonton Par and Western Canada Select/Hardisty crude oil streams.

## Results of Operations

Overall, our results for the third quarter and nine months ended September 30, 2009 reflect lower production and lower selling prices due to the steep decline in commodity prices compared with last year. Cash provided by operating activities and net income declined significantly due to lower revenues.

FUNDS GENERATED FROM OPERATIONS AND NET INCOME (\$000s, except as noted)	Three Months Ended September 30			Nine Months Ended September 30		
	2009	2008	Change	2009	2008	Change
	Cash provided by operating activities	26,215	57,380	-54%	69,722	137,580
Changes in non-cash working capital	(2,026)	(5,403)	-63%	(5,081)	6,762	-155%
Funds generated from operations	24,189	51,977	-53%	64,641	144,342	-52%
Per Trust Unit (\$)	0.49	1.05	-53%	1.31	2.92	-52%
Net income	7,853	36,772	-79%	17,020	96,582	-90%
Per Trust Unit, basic and diluted (\$)	0.16	0.74	-79%	0.34	1.96	-90%

### PRODUCTION

On a boe basis, our production was down 8% in the third quarter and 7% for the year to date, as drilling activity was insufficient to offset natural production declines on our royalty lands. The deferral of our major capital projects to the second half of the year also contributed to the decline in working interest production.

Royalty interests contributed 71% (2008 Q3 – 71%) of total volumes produced in the quarter. Our production mix for the first nine months of 2009 was approximately 36% natural gas and 64% liquids (32% heavy oil, 27% light and medium oil, and 5% NGL), consistent with last year.

AVERAGE DAILY PRODUCTION	Three Months Ended September 30			Nine Months Ended September 30		
	2009	2008	Change	2009	2008	Change
<b>Royalty lands</b>						
Oil (bbls/d)	2,714	2,767	-2%	2,790	2,931	-5%
NGL (bbls/d)	257	275	-7%	266	246	8%
Natural gas (Mcf/d)	12,161	14,026	-13%	12,599	14,328	-12%
Oil equivalent (boe/d)	4,998	5,379	-7%	5,156	5,565	-7%
<b>Working interest properties</b>						
Oil (bbls/d)	1,391	1,643	-15%	1,493	1,637	-9%
NGL (bbls/d)	79	77	3%	72	73	-1%
Natural gas (Mcf/d)	3,154	3,081	2%	3,281	3,219	2%
Oil equivalent (boe/d)	1,996	2,234	-11%	2,112	2,247	-6%
<b>Total Trust</b>						
Oil (bbls/d)	4,105	4,410	-7%	4,283	4,568	-6%
NGL (bbls/d)	336	352	-5%	338	319	6%
Natural gas (Mcf/d)	15,315	17,107	-10%	15,880	17,547	-10%
Oil equivalent (boe/d)	6,994	7,613	-8%	7,268	7,812	-7%
Number of days in period (days)	92	92	-1%	273	274	0%
Total volumes during period (Mboe)	643	700	-8%	1,984	2,141	-7%

## MARKETING AND HEDGING

As at September 30, 2009, approximately 47% of our royalty oil production was being marketed by Freehold using 30-day contracts. We market most of our working interest oil production using 30-day contracts to ensure the highest competitive pricing. Approximately 21% of our working interest natural gas production is sold under marketing arrangements tied to the Alberta monthly or daily spot price (AECO) or other indexed referenced prices. The balance of our working interest natural gas production (79%) is marketed with the operators' production.

Our production remained unhedged in the third quarter. This policy is subject to quarterly review by our Board.

## COMMODITY PRICES

The following table is a summary of average benchmark prices, which were significantly lower than last year. We now include Western Canada Select/Hardisty (WCS) as a new benchmark crude. WCS is made up of existing Canadian heavy conventional and bitumen crude oils blended with sweet synthetic and condensate diluents. With an average API gravity of 20.5 degrees, the benchmark WCS heavy oil stream is considered a rough proxy for our average oil price realizations.

AVERAGE BENCHMARK PRICES (1)	Three Months Ended September 30			Nine Months Ended September 30		
	2009	2008	Change	2009	2008	Change
WTI crude oil (US\$/bbl)	68.30	117.98	-42%	57.01	113.29	-50%
US\$/Cdn\$ exchange rate	0.9115	0.9600	-5%	0.8575	0.9821	-13%
Edmonton Par crude oil (Cdn\$/bbl)	71.50	121.85	-41%	62.35	115.14	-46%
Light/Heavy oil differential (Cdn\$/bbl)	7.75	17.98	-57%	6.68	20.51	-67%
Western Canada Select/Hardisty (Cdn\$/bbl)	63.75	103.87	-39%	55.67	94.63	-41%
AECO natural gas (Cdn\$/Mcf)	3.02	9.24	-67%	4.10	8.57	-52%

(1) Source for commodity prices: Canadian Association of Petroleum Producers.

Our average selling prices reflect product quality and transportation differences from benchmark prices. Despite significantly lower commodity prices, our Canadian dollar crude oil realizations benefitted from slightly lower U.S./Canadian dollar exchange rates through the first nine months of this year. Due to extremely low natural gas prices in 2009, processing fees, which are netted from the royalty payments, made up a larger proportion of price, reducing our natural gas price realizations.

AVERAGE SELLING PRICES	Three Months Ended September 30			Nine Months Ended September 30		
	2009	2008	Change	2009	2008	Change
Oil (\$/bbl)	61.27	105.40	-42%	53.69	94.73	-43%
NGL (\$/bbl)	40.50	77.31	-48%	39.57	75.47	-48%
Oil and NGL (\$/bbl)	59.70	103.33	-42%	52.66	93.47	-44%
Natural gas (\$/Mcf)	2.78	8.38	-67%	3.70	8.58	-57%
Oil equivalent (\$/boe)	44.01	83.47	-47%	41.57	77.75	-47%

## Revenue

Gross revenue declined 51% in the third quarter of 2009, due to significantly lower realized prices and, to a lesser extent, lower production volumes. The accompanying table demonstrates the net effect of price and volume variances on gross revenues.

GROSS REVENUE VARIANCES (\$000s)	Three Months Ended September 30		Nine Months Ended September 30	
	2009 vs. 2008	2008 vs. 2007	2009 vs. 2008	2008 vs. 2007
<b>Oil and NGL</b>				
Production decrease	(1,764)	(5,491)	(4,090)	(10,664)
Price increase (decrease)	(19,113)	22,522	(54,660)	59,034
Net increase (decrease)	(20,877)	17,031	(58,750)	48,370
<b>Natural gas</b>				
Production decrease	(459)	(128)	(1,747)	(2,659)
Price increase (decrease)	(8,813)	5,056	(23,448)	10,094
Net increase (decrease)	(9,272)	4,928	(25,195)	7,435
<b>Other (1)</b>	(615)	890	(912)	1,899
Gross revenue increase (decrease)	(30,764)	22,849	(84,857)	57,704

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

## Expenses

### ROYALTY EXPENSE AND MINERAL TAX

Royalty expense and mineral tax includes all Crown charges and royalty payments to third parties. Mineral tax is payable annually to the Crown, in the first quarter of the year. Crown royalty rates, which are tied to commodity prices and production volumes, were significantly lower in 2009, due to lower commodity prices and, to a lesser extent, lower production compared with last year. In the third quarter, we recovered \$1.3 million of freehold mineral tax from certain lessees.

ROYALTY EXPENSE AND MINERAL TAX (1) (\$000s, except as noted)	Three Months Ended September 30			Nine Months Ended September 30		
	2009	2008	Change	2009	2008	Change
<b>Working interest properties</b>						
Crown royalties	514	1,052	-51%	1,335	3,543	-62%
Third party royalties	186	347	-46%	529	910	-42%
Mineral tax	114	123	-7%	370	338	9%
Working interest properties	814	1,522	-47%	2,234	4,791	-53%
Per boe (\$)	4.43	7.40	-40%	3.87	7.78	-50%
<b>Royalty lands</b>						
Crown royalties	-	-	-	-	-	-
Third party royalties	-	-	-	-	-	-
Mineral tax	(1,233)	48	-2669%	(702)	538	-230%
Royalty lands	(1,233)	48	-2669%	(702)	538	-230%
Per boe (\$)	(2.67)	0.10	-2780%	(0.50)	0.35	-243%
<b>Total Trust</b>	(419)	1,570	-127%	1,532	5,329	-71%
Per boe (\$)	(0.65)	2.24	-129%	0.77	2.49	-69%

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

**OPERATING EXPENSES**

Operating expenses in the third quarter were 10% lower than last year, mainly due to lower power costs. Included in operating expenses for the nine months ended September 30, 2009 was a one-time adjustment of approximately \$800,000 for expenses incurred from 2005 to 2008.

OPERATING EXPENSES	Three Months Ended			Nine Months Ended		
	September 30			September 30		
	2009	2008	Change	2009	2008	Change
Working interest properties (\$000s)	2,311	2,778	-17%	8,779	8,284	6%
Per boe (\$)	12.59	13.51	-7%	15.23	13.45	13%
Royalty lands (\$000s) (1)	-	-	-	-	-	-
Per boe (\$)	-	-	-	-	-	-
Total operating expenses (\$000s)	2,311	2,778	-17%	8,779	8,284	6%
Total Trust (\$/boe)	3.59	3.97	-10%	4.42	3.87	14%

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

**OPERATING NETBACK**

We manage one of the largest portfolios of oil and gas royalties in Canada. Our royalty lands are comprised of a large and widely diversified portfolio of properties extending from northeastern British Columbia to southern Ontario. As a royalty owner, we share in production revenue without incurring the operational costs, risks, and responsibilities typically associated with oil and gas operations. The following table demonstrates the advantage of our royalty lands which yield higher operating netbacks than our working interest properties.

NETBACK ANALYSIS (\$000s)	Nine months ended September 30, 2009		
	Royalty Interest	Working Interest	Total Trust
	Lands	Properties	
Gross revenue (1)	58,148	26,650	84,798
Royalty expense and mineral tax (2)	702	(2,234)	(1,532)
Net revenue	58,850	24,416	83,266
Operating expense	-	(8,779)	(8,779)
Operating netback	58,850	15,637	74,487

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

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

Our operating netback per boe for the first nine months of 2009 declined significantly due to lower commodity prices.

OPERATING NETBACK (\$/boe)	Three Months Ended			Nine Months Ended		
	September 30			September 30		
	2009	2008	Change	2009	2008	Change
Gross revenue (1)	45.10	85.35	-47%	42.74	79.26	-46%
Royalty expense and mineral tax (2)	0.65	(2.24)	-129%	(0.77)	(2.49)	-69%
Operating expenses	(3.59)	(3.97)	-10%	(4.42)	(3.87)	14%
Operating netback	42.16	79.14	-47%	37.55	72.90	-48%

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

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

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

G&A expenses include direct costs incurred by the Trust and reimbursement of G&A expenses incurred by the Manager on behalf of the Trust. G&A expenses in the third quarter included \$1.3 million (2008 – \$1.2 million) charged by the Manager for time and direct costs incurred on behalf of the Trust. The total for the nine months ended September 30, 2009 was \$4.6 million (2008 – \$4.2 million).

G&A EXPENSES	Three Months Ended September 30			Nine Months Ended September 30		
	2009	2008	Change	2009	2008	Change
G&A expenses (\$000s)	1,514	1,369	11%	5,612	5,216	8%
Per boe (\$)	2.35	1.95	21%	2.83	2.44	16%
As a percentage of revenue	5%	2%	117%	7%	3%	126%

**UNIT BASED COMPENSATION**

**Manager’s Long-Term Incentive Plan (LTIP)**

Employees of the Manager receive cash compensation in relation to the value of a specified number of notional units after a three-year vesting period. Distributions to Unitholders declared by the Trust during the vesting period are assumed to be reinvested in notional units on the date of distribution. The LTIP liability is estimated at the end of each quarter based on the quarter-end Trust Unit price and performance factors; the related compensation charges are recognized over the vesting period. The 2006 LTIP grants vested in January 2009 and \$81,000 of unit based compensation was paid out in the first quarter.

**Deferred Trust Unit Plan**

Fully-vested deferred trust units are granted annually to non-management directors and are redeemable for an equal number of Trust Units (less tax withholdings) any time after the director’s retirement. Distributions to Unitholders declared by the Trust prior to redemption are assumed to be reinvested in notional units on the date of distribution.

In the third quarter, 1,272 deferred trust units were granted to Nolan Blades, who became Chair of the Board in May, and 954 deferred trust units were granted to David Sandmeyer, who became an eligible director in July. Following his retirement from the Board, William Siebens redeemed 22,038 deferred trust units and was issued 15,427 Trust Units from treasury.

UNIT BASED COMPENSATION	Three Months Ended September 30			Nine Months Ended September 30		
	2009	2008	Change	2009	2008	Change
Manager’s long-term incentive plan	1,634	(986)	-266%	2,518	689	265%
Deferred trust unit plan	54	31	74%	324	269	20%
Unit based compensation	1,688	(955)	-277%	2,842	958	197%
Per boe (\$)	2.62	(1.36)	-293%	1.43	0.45	218%
As a percentage of revenue	6%	-2%	-400%	3%	1%	200%

### INTEREST AND FINANCING

Interest and financing expense declined 26% in the third quarter of 2009 due to a reduction in lending rates, despite slightly higher debt levels compared with the third quarter last year. Interest and financing expense for the nine months ended September 30, 2009 included rollover fees related to the annual renewal of our credit facilities in May.

INTEREST AND FINANCING	Three Months Ended			Nine Months Ended		
	September 30			September 30		
	2009	2008	Change	2009	2008	Change
Interest and financing expense (000s)	1,213	1,648	-26%	3,629	5,648	-36%
Per boe (\$)	1.89	2.35	-20%	1.83	2.64	-31%

### DEPLETION AND DEPRECIATION AND ACCRETION OF ASSET RETIREMENT OBLIGATION

Depletion of oil and natural gas properties (including the capitalized portion of the asset retirement obligation) and depreciation of equipment are provided for on a unit-of-production basis using estimated proved reserves.

DEPLETION, DEPRECIATION AND ACCRETION EXPENSES (\$000s, except as noted)	Three Months Ended			Nine Months Ended		
	September 30			September 30		
	2009	2008	Change	2009	2008	Change
Depletion and depreciation	15,640	17,293	-10%	47,280	51,872	-9%
Accretion of asset retirement obligation	83	97	-14%	246	288	-15%
Total depletion, depreciation and accretion expenses	15,723	17,390	-10%	47,526	52,160	-9%
Per boe (\$)	24.44	24.83	-2%	23.95	24.37	-2%

### MANAGEMENT FEES

The management fee, which is paid in Trust Units, was 35,654 Trust Units per quarter in 2009, unchanged from 2008. The ascribed value was lower in 2009 because of lower closing Trust Unit prices at the end of each quarter.

MANAGEMENT FEES (Paid in Trust Units)	Three Months Ended			Nine Months Ended		
	September 30			September 30		
	2009	2008	Change	2009	2008	Change
Trust Units issued in payment of management fees	35,654	35,654	0%	106,962	106,962	0%
Ascribed value (\$000s) (1)	579	610	-5%	1,390	2,108	-34%
Per boe (\$)	0.90	0.87	3%	0.70	0.98	-29%

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

### FUTURE INCOME TAX

As a result of changes to the SIFT tax rules in the first quarter of 2009, the provincial component of the SIFT tax applicable to Freehold was reduced from 13% to 10%. This will result in a combined SIFT tax rate in 2011 of 26.5%, and 25.0% thereafter. In the third quarter of 2009, we recorded a \$1.5 million recovery in future income tax, bringing the total recovery for the nine months ended September 30, 2009 to \$3.8 million.

## Liquidity and Capital Resources

### CAPITAL EXPENDITURES

We have no capital requirements with respect to our royalty properties. Our capital expenditure obligations (with respect to our working interest properties) are deducted from funds generated from operations prior to determining distributions to Unitholders. More than half of our capital spending for the year occurred in the third quarter and included \$5.8 million on drilling and completions and \$1.6 million on associated production facilities.

ACQUISITIONS AND CAPITAL EXPENDITURES (\$000s, except as noted)	Three Months Ended			Nine Months Ended		
	September 30			September 30		
	2009	2008	Change	2009	2008	Change
Property and royalty acquisitions (net)	-	8,475	-100%	-	8,475	-100%
Capital expenditures	7,368	4,885	51%	11,056	9,222	20%
Change in reclamation fund	138	(113)	-222%	330	(32)	-1131%
	<b>7,506</b>	<b>13,247</b>	<b>-43%</b>	<b>11,386</b>	<b>17,665</b>	<b>-36%</b>

### WORKING CAPITAL

The following table shows the changes in working capital over the past four quarters. In the oil and gas industry, accounts receivable from industry partners are typically settled in the following month. However, due to administrative complexity, payments to royalty owners are often delayed longer. Working capital at each period end can vary due to volume and prices changes during the period. Lower accounts receivable at the end of the third quarter was attributable to lower commodity prices, while higher accounts payable and accrued liabilities reflect the large amount of capital expended during the quarter.

COMPONENTS OF WORKING CAPITAL (\$000s)	Sept. 30 2009	June 30 2009	Mar. 31 2009	Dec. 31 2008	Sept. 30 2008
Cash	311	369	546	537	212
Current portion of deferred compensation	-	-	34	-	38
Accounts receivable	19,622	21,315	21,870	23,261	38,507
Current assets	19,933	21,684	22,450	23,798	38,757
Distributions payable to Unitholders	(5,950)	(4,953)	(4,950)	(29,676)	(12,356)
Current portion of unit based compensation	(1,559)	(743)	(131)	(83)	(452)
Accounts payable and accrued liabilities	(20,243)	(13,824)	(15,780)	(14,094)	(14,830)
Current liabilities	(27,752)	(19,520)	(20,861)	(43,853)	(27,638)
Working capital (1)	(7,819)	2,164	1,589	(20,055)	11,119

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

### DEBT ANALYSIS

During the third quarter, we reduced long-term debt by \$9 million. At the end of the third quarter, we had \$63 million of available capacity under our credit facilities. Our borrowing base is dependent on our lenders' annual review and interpretation of our reserves and future commodity prices. The latest review process was completed in May 2009 with no changes to our \$210 million borrowing base.

We have a \$195 million extendible revolving term credit facility with a syndicate of three Canadian chartered banks and 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 and standby fees. The facilities are secured with \$300 million demand debentures over Freehold's petroleum and natural gas assets but do not contain any financial covenants. The lenders at any time can request a redetermination of the borrowing base, which may require a repayment to the lenders within 90 days of receiving notice.

DEBT ANALYSIS (\$000s)	As at September 30	As at December 31	Change
	2009	2008	
Long-term debt	147,000	140,000	5%
Short-term debt	-	-	-
Total debt	147,000	140,000	5%
Less: working capital	(7,819)	(20,055)	-61%
Net debt obligations	154,819	160,055	-3%

Under our credit facilities, we are restricted from making distributions if we are or would be in default under the facilities or if our borrowings thereunder exceed our borrowing base. As at September 30, 2009, the Trust was in compliance with all such covenants.

FINANCIAL LEVERAGE AND COVERAGE RATIOS (1)	As at September 30	As at December 31	Change
	2009	2008	
Net debt to funds generated from operations (times)	1.7	0.9	89%
Net debt to distributions (times)	1.5	1.1	36%
Distributions to interest expense (times)	20.1	20.4	-1%
Net debt to net debt plus equity (%)	45%	42%	7%

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

#### DISTRIBUTIONS

Distributions in the third quarter totalled \$16.9 million (\$0.34 per Trust Unit). Cumulative distributions (from 1996 to September 30, 2009) totalled \$771 million (\$20.07 per Trust Unit).

ACCUMULATED DISTRIBUTIONS	Three Months Ended		Nine Months Ended	
	September 30		September 30	
	2009	2008	2009	2008
Distributions declared (\$000s)	16,850	37,050	46,543	89,362
Accumulated, beginning of period	754,111	632,981	724,418	580,669
Accumulated, end of period	770,961	670,031	770,961	670,031
Distributions per Trust Unit (\$) (1)	0.34	0.75	0.94	1.81
Accumulated, beginning of period	19.73	17.28	19.13	16.22
Accumulated, end of period	20.07	18.03	20.07	18.03

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

The following table illustrates the relationship between cash provided from operating activities and historical distributions, as well as net income and historical distributions. On an annual basis, the Trust has historically distributed less cash than cash provided by operating activities. This excess cash has been used to fund capital expenditures and repay bank debt. Net income includes significant non-cash charges that do not affect cash flow. These charges amounted to \$16.3 million for the third quarter of 2009 (2008 – \$15.5 million) and \$47.7 million for the first nine months of 2009 (2008 – \$48.3 million). Net earnings also include fluctuations in future income taxes due to changes in tax rates and tax rules. In addition, other non-cash charges, such as depletion and depreciation on property, plant and equipment and accretion on the asset retirement obligation, do not represent the actual cost of maintaining our productive capacity given the natural declines associated with oil and gas assets. In these instances, where distributions exceed net earnings, a portion of the cash distribution paid to Unitholders may represent an economic return of the Unitholders' capital.

DISTRIBUTION ANALYSIS (\$000s)	Three Months Ended September 30			Nine Months Ended September 30		
	2009	2008		2009	2008	
	Cash provided by operating activities	26,215	57,380		69,722	137,580
Net income	7,853	36,772		17,020	96,582	
Distributions declared	16,850	37,050		46,543	89,362	
Excess of cash provided by operating activities over distributions declared	56%	55%		50%	54%	
Excess (shortfall) of net income over distributions declared	(53%)	(1%)		(63%)	8%	

#### UNITHOLDERS' CAPITAL

During the third quarter, 51,081 Trust Units were issued from treasury (see Management Fees and Unit Based Compensation). As at September 30, 2009 and November 10, 2009, there were 49,581,818 Trust Units outstanding.

During the third quarter, 22,038 deferred trust units were redeemed and 2,226 deferred trust units were granted (see Unit Based Compensation). As at September 30, 2009, there were 51,243 deferred trust units outstanding and at November 10, 2009, there were 51,636 deferred trust units outstanding.

TRUST UNITS OUTSTANDING	Three Months Ended September 30			Nine Months Ended September 30		
	2009	2008	Change	2009	2008	Change
	Weighted average					
Basic	49,542,862	49,388,509	0%	49,499,692	49,352,987	0%
Diluted	49,586,105	49,429,481	0%	49,559,349	49,394,439	0%
At period end	49,581,818	49,423,775	0%	49,581,818	49,423,775	0%

## 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.

## New Accounting Standards

#### INTERNATIONAL FINANCIAL REPORTING STANDARDS (IFRS)

As discussed in our 2008 annual MD&A, we are continuing to prepare for the adoption of IFRS effective January 1, 2011. We have assigned internal staff to lead the conversion project. We have also retained an external advisor to assist us, and are involving our auditors in the process. Our transition plan addresses resources required, employee training, continued analysis of key accounting standard differences, evaluation of information system requirements, and an impact assessment on operations, internal controls over financial reporting, and disclosures.

We are currently analyzing the accounting policy choices available under IFRS and assessing the impact of certain accounting standards relating to crude oil and natural gas operations. Through a business impact study, we have identified and are focusing our efforts on high and medium impact areas. These areas include determining appropriate cash generating units for petroleum and natural gas interests and evaluating options for transitioning from full cost accounting for petroleum and natural gas operations, including the first-time adoption elections.

In July 2009, an amendment to IFRS 1, “*First Time Adoption of International Reporting Standards*”, was issued that applies to oil and gas assets. The amendment would allow us to elect, upon adoption, to measure exploration and evaluation assets at the amount determined under Canadian GAAP and to measure oil and gas assets in the development or production phases by allocating the amount determined under Canadian GAAP for those assets to the underlying assets pro rata using reserve volumes or reserve values as of that date.

#### FINANCIAL INSTRUMENTS – DISCLOSURES

In May 2009, the Canadian Institute of Chartered Accountants amended Section 3862, “*Financial Instruments – Disclosures*”, to include additional disclosure requirements about fair value measurement for financial instruments and liquidity risk disclosures. These amendments require a three level hierarchy that reflects the significance of the inputs used in making the fair value measurements. Fair values of assets and liabilities included in Level 1 are determined by reference to quoted prices in active markets for identical assets and liabilities. Assets and liabilities in Level 2 include valuations using inputs other than quoted prices for which all significant outputs are observable, either directly or indirectly. Level 3 valuations are based on inputs that are unobservable and significant to the overall fair value measurement. These amendments are effective for the Trust on December 31, 2009.

## Related Party Transactions

The Trust does not have any employees. The Manager of the Trust is a wholly owned subsidiary of Rife Resources Ltd., which is 100% owned by the CN Pension Trust Funds (the pension funds for the employees of Canadian National Railway Company). The Manager recovers its costs (see General and Administrative Expenses and Unit Based Compensation) and receives a quarterly management fee paid in Trust Units (see Management Fees).

## Contingency

In the second quarter of 2009, a statement of claim was filed against the Trust for \$9 million. The claim involves disputed land interests and royalty obligations. After receiving outside legal advice, the Trust has assessed the claim, believes it has no merit, and intends to aggressively defend itself in the claim. The outcome is not determinable; therefore, no amounts have been recorded in the financial statements.

## Internal Controls

Freehold is required to comply with National Instrument 52-109, *Certification of Disclosure in Issuers’ Annual and Interim Filings*. The certification of interim filings requires us to disclose in the MD&A any changes in the Trust’s internal controls over financial reporting that have materially affected, or are reasonably likely to materially affect the Trust’s internal control over financial reporting. We confirm that no such changes were made to the internal controls over financial reporting during the nine months ended September 30, 2009. The Chief Executive Officer and Chief Financial Officer have signed form 52-109F2, *Certification of Interim Filings*, which can be found on SEDAR at [www.sedar.com](http://www.sedar.com).

## Consolidated Balance Sheets

(\$000s) (unaudited)	September 30 2009	December 31 2008
<b>Assets</b>		
Current assets:		
Cash	\$ 311	\$ 537
Accounts receivable	19,622	23,261
	<b>19,933</b>	<b>23,798</b>
Reclamation fund	2,157	1,827
Deferred long-term compensation (note 5)	2,435	120
Petroleum and natural gas interests, net of accumulated depletion and depreciation of \$497,359 (2008 - \$450,079)	390,608	426,530
	<b>\$ 415,133</b>	<b>\$ 452,275</b>
<b>Liabilities and Unitholders' Equity</b>		
Current liabilities:		
Distributions payable to Unitholders	\$ 5,950	\$ 29,676
Accounts payable and accrued liabilities	20,243	14,094
Current portion of unit based compensation (note 5)	1,559	83
	<b>27,752</b>	<b>43,853</b>
Asset retirement obligation	6,083	5,663
Unit based compensation payable (note 5)	3,518	243
Long-term debt (note 2)	147,000	140,000
Future income tax liability	38,677	42,511
Unitholders' equity:		
Unitholders' capital (note 3)	568,922	567,310
Contributed Surplus (note 5)	731	722
Deficit	(377,550)	(348,027)
	<b>192,103</b>	<b>220,005</b>
	<b>\$ 415,133</b>	<b>\$ 452,275</b>

See accompanying notes to interim consolidated financial statements.

## Consolidated Statements of Income, Comprehensive Income and Deficit

(unaudited) (\$000s, except per unit and weighted average data)	Three Months Ended September 30		Nine Months Ended September 30	
	2009	2008	2009	2008
Revenue:				
Royalty income and working interest sales	\$ 29,016	\$ 59,780	\$ 84,798	\$ 169,655
Royalty expense and mineral tax	419	(1,570)	(1,532)	(5,329)
	29,435	58,210	83,266	164,326
Expenses:				
Operating	2,311	2,778	8,779	8,284
General and administrative	1,514	1,369	5,612	5,216
Unit based compensation (note 5)	1,688	(955)	2,842	958
Interest and financing	1,213	1,648	3,629	5,648
Depletion and depreciation	15,640	17,293	47,280	51,872
Accretion of asset retirement obligation	83	97	246	288
Management fee (note 4)	579	610	1,390	2,108
	23,028	22,840	69,778	74,374
Income before taxes	6,407	35,370	13,488	89,952
Income and capital taxes	101	73	302	233
Future income tax reduction	(1,547)	(1,475)	(3,834)	(6,863)
	(1,446)	(1,402)	(3,532)	(6,630)
Net income and comprehensive income	7,853	36,772	17,020	96,582
Deficit, beginning of period	(368,553)	(306,736)	(348,027)	(314,234)
Distributions declared	(16,850)	(37,050)	(46,543)	(89,362)
Deficit, end of period	\$ (377,550)	\$ (307,014)	\$ (377,550)	\$ (307,014)
Net income per Trust Unit, basic and diluted	\$ 0.16	\$ 0.74	\$ 0.34	\$ 1.96
Weighted average number of Trust Units:				
Basic	49,542,862	49,388,509	49,499,692	49,352,987
Diluted	49,586,105	49,429,481	49,559,349	49,394,439

See accompanying notes to interim consolidated financial statements.

## Consolidated Statements of Cash Flows

(\$000s) (unaudited)	Three Months Ended September 30		Nine Months Ended September 30	
	2009	2008	2009	2008
Cash provided by (used in):				
Operating:				
Net income	\$ 7,853	\$ 36,772	\$ 17,020	\$ 96,582
Items not involving cash:				
Depletion and depreciation	15,640	17,293	47,280	51,872
Unit based compensation (note 5)	1,594	(1,045)	2,667	868
Future income tax reduction	(1,547)	(1,475)	(3,834)	(6,863)
Accretion of asset retirement obligation	83	97	246	288
Trust Units issued in lieu of management fee	579	610	1,390	2,108
Expenditures on reclamation	(13)	(275)	(128)	(513)
	24,189	51,977	64,641	144,342
Changes in non-cash working capital	2,026	5,403	5,081	(6,762)
	26,215	57,380	69,722	137,580
Financing:				
Long-term debt	(9,000)	(10,000)	7,000	(37,000)
Distributions paid	(15,853)	(37,041)	(70,269)	(84,403)
	(24,853)	(47,041)	(63,269)	(121,403)
Investing:				
Property and royalty acquisitions	-	(8,475)	-	(8,475)
Capital expenditures	(7,368)	(4,885)	(11,056)	(9,222)
Deposit on acquisition	-	850	-	-
Change in reclamation fund	(138)	113	(330)	32
Changes in non-cash working capital	6,086	1,749	4,707	1,307
	(1,420)	(10,648)	(6,679)	(16,358)
Decrease in cash	(58)	(309)	(226)	(181)
Cash, beginning of period	369	521	537	393
Cash, end of period	\$ 311	\$ 212	\$ 311	\$ 212

See accompanying notes to interim consolidated financial statements.

# Notes to Interim Consolidated Financial Statements

For the three and nine months ended September 30, 2009 and 2008.

## 1. Significant Accounting Policies

The interim consolidated financial statements of Freehold Royalty Trust (Freehold or the Trust) have been prepared by management in accordance with Canadian generally accepted accounting principles. The interim consolidated financial statements have been prepared following the same accounting policies and methods of computation as the consolidated financial statements for the fiscal year ended December 31, 2008 and should be read in conjunction with the audited consolidated financial statements and notes for the year ended December 31, 2008. In the opinion of management, these interim consolidated financial statements contain all adjustments of a normal recurring nature necessary to present fairly the Trust's financial position as at September 30, 2009 and the results of its operations and cash flows for the three and nine months then ended.

### Financial Instruments – Disclosures

In May 2009, the Canadian Institute of Chartered Accountants amended Section 3862, “*Financial Instruments – Disclosures*”, to include additional disclosure requirements about fair value measurement for financial instruments and liquidity risk disclosures. These amendments require a three level hierarchy that reflects the significance of the inputs used in making the fair value measurements. Fair values of assets and liabilities included in Level 1 are determined by reference to quoted prices in active markets for identical assets and liabilities. Assets and liabilities in Level 2 include valuations using inputs other than quoted prices for which all significant outputs are observable, either directly or indirectly. Level 3 valuations are based on inputs that are unobservable and significant to the overall fair value measurement. These amendments are effective for the Trust on December 31, 2009.

## 2. Long-Term Debt

Freehold has a \$195 million extendible revolving term credit facility with a syndicate of three Canadian chartered banks, on which \$147 million was drawn at September 30, 2009. In addition, Freehold has available a \$15 million extendible revolving operating facility. The facilities are secured with \$300 million demand debentures over Freehold's petroleum and natural gas assets but do not contain any financial covenants. The lenders at any time can request a redetermination of the borrowing base, which may require a repayment to the lenders within 90 days of receiving notice. The facilities are extendible annually with the latest review completed in May 2009. In the event that the lenders do not consent to an extension, the revolving credit facility would 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 2010.

## 3. Unitholders' Capital

	September 30, 2009		December 31, 2008	
	Units	Amount (\$000s)	Units	Amount (\$000s)
Balance, beginning of period	49,459,429	567,310	49,316,813	564,828
Issued in lieu of management fee (note 4)	106,962	1,390	142,616	2,482
Issued for director's retirement (note 5)	15,427	222	-	-
Balance, end of period	49,581,818	568,922	49,459,429	567,310

## 4. Related Party Transactions

The Trust does not have any employees. The Manager of the Trust is a wholly owned subsidiary of Rife Resources Ltd., which is 100% owned by the CN Pension Trust Funds (the pension funds for the employees of Canadian National Railway Company). The Manager recovers its general and administrative and long-term incentive plan costs and receives a quarterly management fee paid in Trust Units.

For the three months ended September 30, 2009, Freehold issued 35,654 Trust Units (2008 – 35,654 Trust Units) as a management fee to the Manager pursuant to a management agreement. The ascribed value of \$0.6 million (2008 – \$0.6 million) is based on the closing price of the Trust Units on the last trading day of the quarter. The total issued for the nine months ended September 30, 2009 was 106,962 Trust Units (2008 – 106,962) with an ascribed value of \$1.4 million (2008 – \$2.1 million).

For the three months ended September 30, 2009, the Manager charged the Trust \$1.3 million in general and administrative costs (2008 – \$1.2 million). The total for the nine months ended September 30, 2009 was \$4.6 million (2008 – \$4.2 million). At September 30, 2009, there was \$0.4 million (2008 – \$0.4 million) in accounts payable and accrued liabilities relating to these costs. The transactions were in the normal course of operations and were measured at the exchange amount, which was the amount of consideration established and agreed to by the Trust and the Manager.

## 5. Unit Based Compensation

### (a) Manager's Long-Term Incentive Plan

Employees of the Manager receive cash compensation in relation to the value of a specified number of notional units after a three-year vesting period. Distributions to Unitholders declared by the Trust during the vesting period are assumed to be reinvested in notional units on the date of distribution. For the three months ended September 30, 2009, Freehold expensed \$1,634,000 (2008 – \$986,000 recovered) as unit based compensation. The total for the nine months ended September 30, 2009 was \$2,518,000 (2008 – \$689,000). At September 30, 2009, Freehold recorded \$2,435,000 (2008 – \$689,000) as a deferred long-term compensation asset, representing the portion of the liability not yet charged to earnings. In addition, Freehold accrued \$3,518,000 (2008 – \$1,374,000) as a long-term liability and \$1,559,000 (2008 – \$452,000) as a current liability.

### (b) Deferred Trust Unit Plan

Fully-vested deferred trust units are granted annually to non-management directors. Distributions to Unitholders declared by the Trust prior to redemption are assumed to be reinvested in notional units on the date of distribution. As at September 30, 2009, there were 51,243 deferred trust units outstanding, which are redeemable for an equal number of Trust Units any time after the director's retirement. During the quarter, 22,038 deferred trust units were redeemed upon a director's retirement, resulting in the issuance of 15,427 Trust Units from treasury. In payment of withholding tax, 6,611 deferred trust units were cancelled and the cash value remitted to Canada Revenue Agency.

For the three months ended September 30, 2009, Freehold expensed \$54,000 (2008 – \$31,000) of unit based compensation with a corresponding increase to contributed surplus. The total for the nine months ended September 30, 2009 was \$324,000 (2008 – \$269,000).

CONTRIBUTED SURPLUS (\$000s)	September 30 2009	December 31 2008
Balance, beginning of period	722	512
Trust Unit incentive compensation expense	324	210
Grants redeemed on director's retirement	(315)	-
Balance, end of period	731	722

## 6. Supplemental Cash Flow Disclosure

CASH EXPENSES PAID (\$000s)	Three Months Ended September 30		Nine Months Ended September 30	
	2009	2008	2009	2008
Interest	1,145	1,909	3,572	5,635
Taxes	101	52	393	255

## 7. Contingency

In the second quarter of 2009, a statement of claim was filed against the Trust for \$9 million. The claim involves disputed land interests and royalty obligations. After receiving outside legal advice, the Trust has assessed the claim, believes it has no merit, and intends to aggressively defend itself in the claim. The outcome is not determinable; therefore, no amounts have been recorded in the financial statements.

## 8. Subsequent Event

On October 26, 2009, the Board of Directors approved the monthly issuance of Trust Units from treasury for the Distribution Reinvestment Plan (DRIP), effective for the distribution payable on November 15, 2009 to Unitholders of record on October 31, 2009. Previously, Trust Units issued in relation to the DRIP were purchased through the facilities of The Toronto Stock Exchange at prevailing market prices.

## Corporate Information

### BOARD OF DIRECTORS

**D. Nolan Blades** <sup>(1)(2)(3)</sup>

President  
Sunny Gables Holdings Ltd.

**Harry S. Campbell, Q.C.** <sup>(3)(4)(5)</sup>

Vice-Chair  
Burnet, Duckworth & Palmer, LLP

**Tullio Cedraschi** <sup>(3)(4)</sup>

Corporate Director

**Peter T. Harrison** <sup>(5)</sup>

Manager, Common Stocks (North America)  
CN Investment Division

**William O. Ingram**

President and Chief Executive Officer  
Rife Resources Ltd.

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

Professor, Haskayne School of Business  
University of Calgary

**David J. Sandmeyer** <sup>(3)(5)</sup>

Corporate Director

**Rodger A. Tourigny** <sup>(1)(2)(5)</sup>

President  
Tourigny Management Ltd.

### STOCK EXCHANGE

Toronto Stock Exchange  
Trading Symbol: FRU.UN

### TRUSTEE AND TRANSFER AGENT

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

(1) Audit Committee

(2) Compensation Committee

(3) Corporate SIFT Tax Strategy Committee

(4) Governance Committee

(5) Reserves Committee

### OFFICERS

**D. Nolan Blades**

Chair of the Board

**William O. Ingram**

President and Chief Executive Officer

**Garry W. Bieber**

Vice-President, Production

**J. Frank George**

Vice-President, Exploitation

**Darren G. Gunderson**

Vice-President, Finance and Chief  
Financial Officer

**Michael J. Okrusko**

Vice-President, Land

**Michael J. Mogan**

Controller

**Karen C. Taylor**

Manager, Investor Relations and  
Corporate Secretary

### LEGAL COUNSEL

Burnet Duckworth & Palmer, LLP  
Calgary, Alberta

### AUDITORS

KPMG, LLP  
Calgary, Alberta

### BANKERS

Canadian Imperial Bank of  
Commerce  
Calgary, Alberta

Royal Bank of Canada  
Calgary, Alberta

The Toronto-Dominion Bank  
Calgary, Alberta

### RESERVE EVALUATORS

Trimble Engineering Associates Ltd.  
Calgary, Alberta

### HEAD OFFICE

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Freehold Royalty Trust  
400, 144 – 4th Avenue S.W.  
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### INVESTOR RELATIONS

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

### WEBSITE

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

### 2009 THIRD QUARTER TRADING SUMMARY

High – \$17.00

Low – \$12.75

Close – \$16.24

Volume Traded – 5.1 million

Trust Units Outstanding – 49.6 million

### 2009 THIRD QUARTER DISTRIBUTIONS DECLARED

<u>Record Date</u>	<u>Payment Date</u>	<u>Per Trust Unit</u>
July 31, 2009	Aug. 15, 2009	\$0.10
Aug. 31, 2009	Sept. 15, 2009	\$0.12
Sept. 30, 2009	Oct. 15, 2009	<u>\$0.12</u>
		<u>\$0.34</u>

Tax information and historical  
distributions are available on our  
website.