

Freehold

ROYALTY TRUST

400, 144 – 4TH AVENUE S.W.
CALGARY, ALBERTA T2P 3N4
TELEPHONE: 403 . 221 . 0802
FAX: 403 . 221 . 0888

NEWS RELEASE

TSX: FRU.UN
CUSIP: 355904103

Freehold Royalty Trust Announces 2008 Fourth Quarter and Year End Results

CALGARY, ALBERTA, (Marketwire – March 11, 2009) – Freehold Royalty Trust (Freehold or the Trust) (TSX:FRU.UN) today announced fourth quarter and full year results for the period ended December 31, 2008.

RESULTS AT A GLANCE

Financial (\$000s, except as noted)	Three Months Ended			Twelve Months Ended		
	December 31			December 31		
	2008	2007	Change	2008	2007	Change
Gross revenue	34,461	40,511	-15%	204,116	152,184	34%
Net income (loss)	13,374	19,067	-30%	109,956	(1,192)	-
Per Trust Unit, basic and diluted (\$)	0.27	0.39	-30%	2.23	(0.02)	-
Cash provided by operating activities	41,672	32,503	28%	179,252	119,641	50%
Per Trust Unit (\$)	0.84	0.66	27%	3.63	2.43	49%
Funds generated from operations (1)	26,942	32,591	-17%	171,282	121,008	42%
Per Trust Unit (\$)	0.55	0.66	-17%	3.47	2.46	41%
Capital expenditures	3,770	3,901	-3%	12,992	12,167	7%
Property and royalty acquisitions (net)	(782)	26	-	7,693	90,456	-91%
Distributions declared	54,387	28,096	94%	143,749	94,545	52%
Per Trust Unit (\$) (2)	1.10	0.57	93%	2.91	1.92	52%
Long-term debt, period end	140,000	178,000	-21%	140,000	178,000	-21%
Unitholders' equity, period end	220,005	251,106	-12%	220,005	251,106	-12%
Trust Units (000s) (3)	49,424	49,282	0%	49,371	49,228	0%
Operating (per boe) (4)						
Average daily production (boe/d)	7,779	8,591	-9%	7,804	8,484	-8%
Average price realizations (\$)	46.55	50.57	-8%	69.93	48.63	44%
Operating netback (\$) (1)	42.14	46.47	-9%	65.18	43.54	50%

(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 Conversion of Natural Gas to Barrels of Oil Equivalent (boe).

As a result of higher average commodity prices during 2008, cash provided by operating activities increased 50% and funds generated from operations increased 42% for the year. Distributions reached a record \$2.91 per Trust Unit, more than 50% higher than in 2007. From inception to December 31, 2008, the Trust has distributed \$724 million (\$19.13 per Trust Unit) to Unitholders.

With the significant decline in commodity prices in the last quarter of 2008, the Board of Directors has declared the March distribution of \$0.10 per Trust Unit, which will be paid on April 15, 2009 to Unitholders of record on March 31, 2009 (ex-distribution date March 27, 2009). Including the April 15, 2009 payment, our 12-month trailing cash distributions total \$2.76 per Trust Unit.

Results for the twelve months ended December 31, 2008 reflect higher average commodity prices for the year, while results for the fourth quarter reflect the steep decline in commodity prices in the final months of 2008. Record high oil prices earlier in the year and the low cost structure of our royalty production combined to deliver strong netbacks and record cash distributions to Unitholders. Commodity price and currency rate fluctuations serve to reinforce that our cash flows, and thus our distributions, are largely dependant on cyclical supply and demand factors that are beyond our control. Notwithstanding our exposure to this price volatility, we continue to believe our 'no hedging' policy is the right strategy for Freehold.

The following summary is aimed at helping investors better understand the impact of price volatility on our results, and therefore on our distributions.

- WTI crude prices have exhibited significant volatility in the last two years. Prices climbed steadily between January 2007 and July 2008, when they reached an all time high of over US\$147 per barrel. During this period, rising oil prices boosted our revenues and cash distributions, although the gain was somewhat muted by the rising value of the Canadian dollar relative to its U.S. counterpart.
- WTI prices declined modestly through the third quarter of 2008 and then plunged rapidly in the fourth quarter, causing revenues to decline sharply as well. This steep price decline resulted from a drop in demand for crude oil due to the rapidly deteriorating global economic picture. The Canadian dollar, which had been trading on parity with the U.S. dollar, also weakened by 20%.
- AECO natural gas prices have also exhibited significant volatility, dipping as low as Cdn\$5.02 per thousand cubic feet (Mcf) in September 2007. Natural gas markets began to strengthen in the first quarter of 2008, and we benefited from higher prices in the first nine months of 2008. However, natural gas prices also faced sharp downward pressure through the fourth quarter due to weak North American supply and demand fundamentals.
- We have adjusted our monthly distributions in response to changing commodity prices. In January 2007 (when WTI oil prices averaged US\$58.65 per barrel), our distribution was \$0.15 per Trust Unit. We raised the monthly rate to \$0.18 per Trust Unit in April 2008, and raised it again in June, to \$0.25 per Trust Unit. Our unhedged production benefited from strong commodity pricing through the first nine months of 2008 and, as a result, we had excess cash from operating activities and declared an additional distribution of \$0.35 per Trust Unit for 2008. In January 2009, with weakening demand pushing commodity prices lower, we lowered the monthly distribution to \$0.10 per Trust Unit to preserve operating stability and financial flexibility.

OPERATIONAL UPDATE

The assets we acquired with the \$264 million proceeds of our Initial Public Offering in 1996 have performed very well over the past 12 years, supported by an experienced management team who have managed those assets for more than 25 years. We have augmented our holdings over the years with complementary acquisitions, resulting in an overall asset value of \$13.92 per Trust Unit at December 31, 2008. During this period, we distributed \$19.13 per Trust Unit, almost double the IPO price of \$10.00.

We have royalty interests in 2.2 million gross acres of land throughout the Western Canada Sedimentary Basin and receive royalties from approximately 250 industry operators. This diversity lowers our risk, while we benefit from the drilling activity of others. As a royalty interest owner, we do not pay any of the capital costs to drill and equip the wells for production, nor do we incur costs to operate the wells, maintain production, and ultimately restore the land to its original state. All of the costs are paid by others and we simply receive a royalty on the gross production revenue. Drilling on our royalty lands was down slightly in 2008, although it was still a strong year, with 605 gross wells drilled. Since 1996, operators leasing our royalty lands have drilled 6,800 new wells – at no cost to Freehold. Historically, this 'free drilling' has helped to replace production and reserves. However, as the Basin matures, reserves added per well are declining and that is being reflected in our reserve replacement.

Our 2008 capital and acquisition program was successful in replacing 45% of our production for the year. We spent \$13 million on development activities, adding 0.8 million boe of net proved plus probable reserves at an average cost of \$14.92 per boe. In addition, we spent \$7.7 million on royalty acquisitions, acquiring 0.3 million boe of net proved plus probable reserves at an average cost of \$28.25 per boe. These royalty assets have a high value because they are unencumbered by capital or operating costs. Overall, these activities contributed to a three-year average recycle ratio of 2.1 times the capital invested.

We're particularly pleased with the success we've had to date on undeveloped mineral title lands acquired in Southeast Saskatchewan in 2001. Over the past three years, we have selectively chosen to participate (that is, take a working interest position) with industry partners to develop these lands, most notably along the Bakken trend. This strategy has been successful in adding value for our Unitholders. The resulting production yields high netbacks; because we hold the mineral title, our share of production is royalty free. Given our large land position spanning most of the Basin, there is potential to employ this strategy in other areas in the future.

Based on the independent evaluation of our reserves as at December 31, 2008, the present value of our net proved plus probable oil and gas reserves (discounted at 10%, before tax), was \$730.7 million, up from \$711.6 million at the end of 2007. Our undeveloped land was independently valued at \$94 million. This represents a 310% increase over the prior year, mainly due to a higher value attributed to our mineral title lands in Southeast Saskatchewan. Higher land and reserves values contributed to an 18% increase in net asset value per Trust Unit.

Excluding any potential acquisitions, we are forecasting average production of 7,500 boe per day for 2009. This is about 5% lower than 2008, as royalty drilling and development activities on our working interest properties will be insufficient to fully offset natural production declines.

While supply and demand fundamentals point to higher prices over the long range, the short-term outlook remains clouded. The continuing deterioration in the economic outlook has reduced current and expected petroleum consumption. The resulting reduction in commodity prices has dampened activity levels in western Canada, as lower prices have reduced producers' cash flows and therefore capital expenditure budgets. Industry drilling will be down sharply in 2009 and we expect that will be mirrored on our royalty lands. Commodity prices may face further downward pressure in 2009, especially if demand continues to fall. However, reduced production by Canadian and world producers could allow for some price recovery later in the year.

The lending capacity of financial institutions has been diminished and risk premiums have increased. In this environment, many businesses will have restricted access to capital and increased borrowing costs. Tightening credit markets and a deepening global recession have created turmoil in financial and equity markets, causing significant reductions in market valuations throughout the world. Freehold's unit price has largely tracked the decline in oil prices, falling sharply from a high of \$24.40 in June 2008 and dipping below \$7.00 in February 2009 – a level we have not seen since 2000. While these issues may affect our ability to access financing for potential future acquisitions, we are not reliant on debt or equity markets to finance operating activities. In the near term, with the expectation that commodity prices will remain weak, our Board has established a distribution policy for the second quarter of 2009 of \$0.10 per Trust Unit per month based on the key operating assumptions outlined in our fourth quarter MD&A. We will review this policy monthly and make adjustments, if necessary, to ensure that cash distributions are in line with expected cash flow.

SIFT TAX STRATEGY UPDATE

Freehold, with its large, diversified asset base of primarily royalty interests, low risk profile, low sustaining capital requirements, and high payout ratio, is ideally suited to be an income trust. As such, we plan to retain the flow-through advantages of our current structure for as long as is prudent. However, given the federal government's plan to impose a tax on distributions from certain publicly-traded specified investment flow-through (SIFT) entities beginning in 2011, we must assess our options and examine our future strategic direction. Our Board has formed a special committee of independent directors with a mandate to determine a course of action that best maximizes Unitholder value. We anticipate the committee's recommendation by the end of 2009. This will be an involved process requiring careful due diligence. Among the most important considerations will be commodity price forecasts, the structures that our peers adopt, overall market sentiment, and future access to capital. While draft rules have been issued to facilitate conversion from a trust to a corporation, our current limited ability to generate tax pools makes this alternative a less obvious choice for Freehold than it is for many other oil and gas trusts.

BOARD AND MANAGEMENT CHANGES

Bill Siebens, Chair of the Board of Freehold Resources since 1996, plans to retire from the Board in 2009 and will not stand for re-election in May. Bill has been active in the Canadian petroleum industry since the late 1950s. His knowledge and experience, particularly with respect to the Trust's original royalty assets, have been invaluable to the Board over the past 12 years. We will miss the broad perspective he has added to the Board's strategic decision making.

After 45 years in the oil and gas business, David Sandmeyer also plans to retire in May. The Board plans to appoint Bill Ingram, currently Executive Vice-President and Chief Operating Officer of Freehold, as his successor. David Sandmeyer and Joe Holowisky, who retired in January, have been vital members of the Rife Resources management team for more than 27 years.

SUMMARY OF RESERVES

Our oil and natural gas reserves were independently evaluated by Trimble Engineering Associates Ltd. (Trimble) as at December 31, 2008. The evaluation was conducted in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in National Instrument 51-101 (NI 51-101).

Our Reserves Committee met with Trimble to review the findings and procedures, and the reserves report has been accepted by our Board. A summary of net reserves, on a before-tax basis, is provided below. Complete NI 51-101 reserves disclosure, including after-tax reserve values, reserves by major property, and abandonment costs, are included in our annual information form (AIF), which will be filed on SEDAR later this month.

Our reserves are calculated on a net basis (our share of working interest properties minus royalties payable to others, plus royalties receivable on our royalty lands). Freehold is unique in that the majority of our assets are royalty interests. However, under NI 51-101, royalty interests cannot be included under gross reserves. This causes our gross reserves to be lower than our net reserves and makes it difficult for investors to compare our reserves to others in our industry. We believe the most appropriate measure of reserves for Freehold is net reserves.

As at December 31, 2008, reserves were assigned to 23,916 wells. On a boe basis, our reserves profile is 38% natural gas, 34% heavy oil, 23% light and medium oil, and 5% natural gas liquids (NGL). Approximately 65% of our reserves are in the proved category, and 99% of our proved reserves are producing, which is high by industry standards

OIL AND GAS RESERVES AS AT DECEMBER 31, 2008 ⁽¹⁾	Light and Medium Crude Oil		Heavy Crude Oil		Total Crude Oil	
	Gross ⁽²⁾	Net ⁽³⁾	Gross ⁽²⁾	Net ⁽³⁾	Gross ⁽²⁾	Net ⁽³⁾
	(Mbbbl)	(Mbbbl)	(Mbbbl)	(Mbbbl)	(Mbbbl)	(Mbbbl)
Reserves Category						
Proved developed producing	1,706	3,839	1,151	5,311	2,858	9,150
Proved developed non-producing	60	52	20	113	79	165
Proved undeveloped	-	-	-	-	-	-
Total proved	1,766	3,891	1,171	5,424	2,937	9,315
Probable	804	1,971	578	3,160	1,382	5,131
Total proved plus probable	2,570	5,862	1,749	8,584	4,319	14,446

Reserves Category	Natural Gas		Natural Gas Liquids		Oil Equivalent ⁽⁴⁾	
	Gross ⁽²⁾	Net ⁽³⁾	Gross ⁽²⁾	Net ⁽³⁾	Gross ⁽²⁾	Net ⁽³⁾
	(Mbbbl)	(Mbbbl)	(MMcf)	(MMcf)	(Mboe)	(Mboe)
Proved developed producing	5,316	38,132	198	815	3,941	16,321
Proved developed non-producing	19	121	1	-	83	185
Proved undeveloped	-	-	-	-	-	-
Total proved	5,335	38,253	198	816	4,024	16,506
Probable	2,775	20,095	90	387	1,935	8,867
Total proved plus probable	8,110	58,348	289	1,203	5,959	25,374

(1) Numbers may not add due to rounding.

(2) Gross reserves are our share of working interest properties before deduction of royalties payable to others. Gross reserves exclude royalty interests.

(3) Net reserves are our share of working interest properties minus royalties payable to others, plus royalties receivable on our royalty lands.

(4) See Conversion of Natural Gas to Barrels of Oil Equivalent (boe).

RECONCILIATION OF NET OIL AND GAS RESERVES BY PRINCIPAL PRODUCT TYPE ^{(1) (2)}	Light and	Heavy	Total	Natural	Associated and Non- Associated	Oil
	Medium Crude Oil (Mbbbls)	Crude Oil (Mbbbls)	Crude Oil (Mbbbls)	Gas Liquids (Mbbbls)	Gas (MMcf)	Equivalent ⁽⁴⁾ (Mboe)
Proved Producing						
December 31, 2007	4,230	6,238	10,468	937	40,438	18,144
Extensions	146	155	301	12	581	409
Improved recovery	-	-	-	-	-	-
Technical revisions	146	(104)	42	5	2,780	511
Discoveries	-	-	-	-	-	-
Acquisitions	57	32	89	-	618	192
Dispositions	-	-	-	-	-	-
Economic factors	(125)	(7)	(132)	8	400	(58)
Production ⁽³⁾	(614)	(1,003)	(1,617)	(147)	(6,684)	(2,877)
December 31, 2008	3,839	5,311	9,150	815	38,132	16,321
Total Proved						
December 31, 2007	4,230	6,373	10,602	939	40,662	18,318
Extensions	146	155	301	12	581	409
Improved recovery	-	-	-	-	-	-
Technical revisions	197	(128)	69	4	2,674	519
Discoveries	-	-	-	-	-	-
Acquisitions	57	32	89	-	618	192
Dispositions	-	-	-	-	-	-
Economic factors	(125)	(5)	(130)	8	402	(55)
Production ⁽³⁾	(614)	(1,003)	(1,617)	(147)	(6,684)	(2,877)
December 31, 2008	3,891	5,424	9,315	816	38,253	16,506
Proved Plus Probable						
December 31, 2007	6,128	10,210	16,338	1,394	61,381	27,963
Extensions	235	330	565	18	1,503	833
Improved recovery	-	-	-	-	-	-
Technical revisions	221	(985)	(764)	(73)	786	(706)
Discoveries	-	-	-	-	-	-
Acquisitions	82	44	126	-	876	272
Dispositions	-	-	-	-	-	-
Economic factors	(191)	(13)	(204)	11	485	(112)
Production ⁽³⁾	(614)	(1,003)	(1,617)	(147)	(6,684)	(2,877)
December 31, 2008	5,862	8,584	14,446	1,203	58,348	25,374

(1) Numbers may not add due to rounding.

(2) Net reserves are our share of working interest properties minus royalties payable to others, plus royalties receivable on our royalty lands.

(3) Production estimated by Trimble.

(4) See Conversion of Natural Gas to Barrels of Oil Equivalent (boe).

RESERVE LIFE INDEX ⁽¹⁾	Proved Producing	Total Proved	Proved Plus Probable
Net reserves (Mboe)	16,321	16,506	25,374
Net production (Mboe)	2,355	2,371	2,601
Reserve life index (years)	6.9	7.0	9.8

(1) Calculated by dividing the Trimble forecast of 2009 net production into the remaining net reserves.

**TOTAL FUTURE NET REVENUE (UNDISCOUNTED)
AS AT DECEMBER 31, 2008 - FORECAST PRICES AND COSTS ^{(1) (2)}**

(\$000s)	Proved	Proved Plus Probable
Royalty Income	879,039	1,525,343
Revenue from Working Interest Properties	349,781	563,005
Royalty expense on Working Interest Properties	(44,365)	(76,961)
Operating costs	(128,094)	(199,838)
Development costs	(1,172)	(3,706)
Well abandonment and reclamation costs	(7,874)	(9,152)
Future net revenue before income taxes	1,047,314	1,798,692
Future income taxes	(175,762)	(360,218)
Future net revenue after income taxes	871,552	1,438,474

(1) Future net revenue values do not represent fair market value.

(2) Future net revenue calculation includes future capital expenditures required to bring booked non-producing and undeveloped reserves on production.

FUTURE DEVELOPMENT COSTS ⁽¹⁾

(\$000s)	Proved Reserves	Proved Plus Probable Reserves
2009	70	1,074
2010	78	1,082
2011	73	1,099
2012	74	74
2013	30	30
Remainder	848	347
Total	1,173	3,706

(1) Based on forecast prices and costs. The source of funding for future development costs includes internally generated cash flow, debt or a combination of both. Disclosed reserves and future net revenue will not be materially affected by the costs of funding the future development expenditures.

**NET PRESENT VALUES
OF FUTURE NET REVENUE ^{(1) (2) (3)}**

(\$000s)	Before tax, discounted at			
	0% per year	5% per year	10% per year	15% per year
Proved developed producing	1,037,477	698,659	531,442	432,955
Proved developed non-producing	9,837	7,395	5,895	4,894
Proved undeveloped	-	-	-	-
Total proved	1,047,314	706,054	537,337	437,849
Total probable	751,378	328,262	193,322	133,697
Proved plus probable	1,798,692	1,034,316	730,659	571,546

(1) Columns may not add due to rounding.

(2) Forecast prices and costs, before tax. Based on the December 31, 2008 escalated oil and gas price forecasts by an independent qualified reserves evaluator.

(3) Future net revenue values do not represent fair market value.

ANALYSIS OF DEVELOPMENT AND ACQUISITIONS COSTS ^{(1) (2) (3) (4)}	2008	2007	2006	Three-Year Results
Net Proved Reserves:				
Development expenditures (\$000s)	12,992	12,167	11,446	36,605
Change in future development capital estimates (\$000s)	597	(2,376)	260	(1,519)
Net reserve additions by development (Mboe)	409	329	651	1,389
Development costs (\$/boe)	33.22	29.79	17.98	25.26
Acquisition expenditures (\$000s)	7,693	90,456	5,382	103,531
Net reserve additions by acquisition (Mboe)	192	1,696	256	2,144
Acquisition costs (\$/boe)	40.07	53.33	21.00	48.29
Total expenditures (\$000s)	20,685	102,623	16,828	140,136
Change in future development capital estimates (\$000s)	597	(2,376)	260	(1,519)
Net reserve additions (Mboe)	601	2,025	907	3,533
Development and acquisition costs (\$/boe)	35.41	49.50	18.84	39.23
Net Proved Plus Probable Reserves:				
Development expenditures (\$000s)	12,992	12,167	11,446	36,605
Change in future development capital estimates (\$000s)	(564)	(3,305)	(2,549)	(6,418)
Net reserve additions by development (Mboe)	833	616	1,146	2,595
Development costs (\$/boe)	14.92	14.38	7.76	11.63
Acquisition expenditures (\$000s)	7,693	90,456	5,382	103,531
Net reserve additions by acquisition (Mboe)	272	2,473	376	3,121
Acquisition costs (\$/boe)	28.25	36.57	14.33	33.17
Total expenditures (\$000s)	20,685	102,623	16,828	140,136
Change in future development capital estimates (\$000s)	(564)	(3,305)	(2,549)	(6,418)
Net reserve additions (Mboe)	1,105	3,090	1,522	5,717
Development and acquisition costs (\$/boe)	18.20	32.15	9.38	23.39

(1) The Trust did not incur any exploration costs in any of the applicable years.

(2) In calculating finding and development costs, NI 51-101 requires that the exploration and development costs incurred in the year and the change in estimated future development costs be aggregated and then divided by the applicable reserve additions. The calculation specifically excludes the effects of acquisitions on both reserves and costs. We believe that by excluding the effects of acquisitions the provisions of NI 51-101 do not fully reflect the Trust's ongoing reserve replacement costs. Because acquisitions can have a significant impact on the Trust's annual reserve replacement costs, excluding these amounts could result in an inaccurate portrayal of the Trust's cost structure. Accordingly, we also provide costs that incorporate all acquisitions during the year.

(3) The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year.

(4) See Conversion of Natural Gas to Barrels of Oil Equivalent (boe).

RECYCLE STATISTICS

NET PROVED PLUS PROBABLE RESERVES (\$ per boe, except as noted) ⁽¹⁾	2008	2007	2006	Three-Year Results
Operating netback ^{(2) (5)}	65.18	43.54	42.64	50.09
Development and acquisition costs ^{(3) (5)}	18.20	32.15	9.38	23.39
Recycle ratio (times) ⁽⁴⁾	3.6	1.4	4.5	2.1

(1) See Conversion of Natural Gas to Barrels of Oil Equivalent (boe).

(2) Total revenue, less operating costs and royalty expenses (net of Alberta Royalty Credit in 2006).

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

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

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

SUMMARY OF LAND HOLDINGS

At December 31, 2008, our land holdings encompassed approximately 2.4 million gross acres, unchanged from 2007. Approximately 91% of our total land holdings are royalty interests.

SUMMARY OF LAND HOLDINGS (gross acres) ⁽¹⁾	Total Land Holdings		Undeveloped Land	
	2008	2007	2008	2007
Mineral title lands ⁽²⁾	549,925	549,758	162,972	160,034
Gross overriding royalty (GORR) lands ⁽³⁾	1,518,423	1,526,878	423,188	360,832
Royalty assumption lands ⁽⁴⁾	95,592	96,072	19,962	19,648
Total royalty lands	2,163,940	2,172,708	606,122	540,514
Working interest properties	210,606	207,428	44,998	48,585
Total land holdings	2,374,546	2,380,136	651,120	589,099

(1) Gross acres represents the total number of acres in which we have an interest.

(2) The royalties received from the sale of oil, natural gas and potash produced from the leased mineral title lands are determined by the individual lease agreements. Mineral title lands are held in perpetuity.

(3) Gross overriding royalty lands consist of properties owned by a number of third party oil and gas companies in respect of which varying royalties or net profits interests have been reserved to Freehold.

(4) Mineral title properties owned by a number of third party oil and gas companies in respect of which gross overriding royalties varying from 4.7% to 6.5% have been reserved to Freehold.

Approximately 63% of our land is in Alberta, 21% is in Saskatchewan, 12% is in Ontario, and 3% is in British Columbia.

LAND HOLDINGS BY PROVINCE (gross acres) ⁽¹⁾	As at December 31		
	2008	2007	2006
Alberta	1,485,388	1,488,098	1,218,097
Saskatchewan	503,634	505,223	464,977
Ontario	295,769	296,109	296,109
British Columbia	81,472	82,423	81,904
Manitoba	8,283	8,283	8,283
Total	2,374,546	2,380,136	2,069,370

(1) Gross acres represents the total number of acres in which we have an interest.

NET ASSET VALUE ⁽¹⁾

Our net asset value at December 31, 2008 was \$13.92 per Trust Unit, up 17% from year-end 2007. The present value of our net proved plus probable oil and gas reserves, discounted at 10%, before tax, increased slightly to \$730.7 million because of higher forecast prices used by our independent engineers in the 2008 evaluation. Similarly, higher forecast prices account for the majority of the increase in the value of our potash reserves. The value of our undeveloped land rose significantly in 2008; the largest increase was in Southeast Saskatchewan. The independent land evaluation took into account land sale activity during 2008. Crown land sales were robust for most of the year, particularly in the Bakken trend in Southeast Saskatchewan where we hold 10,000 gross acres of mineral title lands.

NET ASSET VALUE AS AT DECEMBER 31, 2008 (1) (2) (7)

(\$000s, except unit data)	2008	2007	2006
Present value of oil and gas reserves (3) (8)	730,659	711,624	636,267
Present value of potash reserves (4) (8)	27,807	14,317	10,530
Undeveloped land (5)	93,975	30,252	19,412
Reclamation fund (6)	1,827	1,788	2,117
Working capital (6)	(20,055)	11,219	9,050
Bank debt (6)	(140,000)	(178,000)	(100,000)
Asset retirement obligations (6)	(5,663)	(6,608)	(4,598)
Net asset value	688,550	584,592	572,778
Trust Units outstanding (000s)	49,459	49,317	49,174
Net asset value per Trust Unit (\$)	13.92	11.85	11.65

(1) *Non-GAAP measure. Net asset value (NAV) is a measure used widely within the investment community and in the oil and natural gas industry. It shows what is normally referred to as a 'produce-out' NAV calculation under which the Trust's reserves would be produced at forecast future prices and costs. The value is a snapshot in time and is based on various assumptions including commodity prices and foreign exchange rates that vary over time. It does not represent a 'going concern' value and it should not be assumed that the present value of oil and gas reserves represent the fair market value of the reserves. Net asset value does not have any standardized meaning prescribed by GAAP and therefore may not be comparable with the calculations of similar measures for other entities.*

(2) *Columns may not add due to rounding.*

(3) *Based on net proved plus probable reserves evaluated by Trimble, before tax, discounted at 10%.*

(4) *Based on net proved plus probable reserves evaluated by Rife Resources Ltd., before tax, discounted at 10%. Potash reserves are not subject to NI 51-101.*

(5) *Evaluated by Seaton-Jordan & Associates Ltd., effective December 31, 2008.*

(6) *Financial information per Freehold's 2008 consolidated financial statements.*

(7) *Prior periods restated to conform to current presentation.*

(8) *Future net revenue values do not represent fair market value.*

AVAILABILITY ON SEDAR

Freehold's fourth quarter report, including unaudited financial statements and Management's Discussion and Analysis, is being filed today with Canadian securities regulators and will be available on SEDAR at www.sedar.com or on our website.

FORWARD-LOOKING STATEMENTS

This news release offers our assessment of Freehold's future plans and operations as at March 11, 2009, and contains forward-looking statements including our expectations for production, capital, future income tax, and distributions. 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 Annual Information Form.

With respect to forward-looking statements contained in this news release, we have made assumptions regarding, among other things, reserves, future oil and natural gas prices; future capital expenditure levels; future production levels; future exchange rates; the cost of developing and expanding our assets; our ability and the ability of our lessees to obtain equipment in a timely manner to carry out development activities; our ability to market our oil and natural gas successfully to current and new customers; the impact of increasing competition; our expectation for consumption of crude oil and natural gas; our expectation for industry drilling levels; our ability to obtain financing on acceptable terms; our expectations with respect to maintaining our current structure and timing of a recommendation of the SIFT Committee; and our ability to add production and reserves through our development and acquisition activities. The Outlook section in our fourth quarter report sets forth our key operating assumptions with respect to the forward-looking statements referred to above.

You are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. Our actual results, performance, or achievement could differ materially from those expressed in, or implied by, these forward-looking statements. We can give no assurance that any of the events anticipated will transpire or occur, or if any of them do, what benefits we will derive from them. The forward-looking information contained in this news release 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 news release, references are made to terms commonly used as key performance indicators in the oil and gas industry. We believe that operating netback and funds generated from operations are useful supplemental measures for management and investors to analyze operating performance 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. Funds generated from operations is a financial term commonly used in the oil and gas industry. It represents cash provided by operating activities before changes in non-cash working capital and is a key measure of our ability to generate cash, finance operations, and pay monthly distributions. Funds generated from operations as presented is not intended to represent operating cash flow or operating profits for the period nor should it be viewed as an alternative to cash provided by operating activities, net income or other measures of financial performance calculated in accordance with Canadian GAAP. The key difference between cash provided by operating activities and funds generated from operations is changes in non-cash working capital, which is affected by accounts receivable, accounts 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.

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.

FOR FURTHER INFORMATION, PLEASE CONTACT:

David Sandmeyer, President and CEO (403) 221-0848

Bill Ingram, Executive Vice-President and COO (403) 221-0822

Karen Taylor, Manager, Investor Relations & Corporate Secretary (403) 221-0891

Freehold Royalty Trust

Phone: (403) 221-0802

Fax: (403) 221-0888

(Toll free in Canada/U.S. 1-888-257-1873)

E-mail: ir@freeholdtrust.com

Website: www.freeholdtrust.com