Freehold Royalties Ltd. Announces 2013 Fourth Quarter Results and Year-end Reserves

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CALGARY, ALBERTA--(Marketwired - Mar 6, 2014) - Freehold Royalties Ltd. (Freehold) (TSX:FRU) today announced 2013 fourth quarter results and reserves as at December 31, 2013.

Results at a Glance

FINANCIAL HIGHLIGHTS	Three Months Ended December 31			Twelve Months Ended December 31		
($000s, except as noted)	2013	2012	Change	2013	2012	Change
Gross revenue	45,287	45,794	-1 %	181,578	168,134	8 %
Net income	14,106	13,431	5 %	57,852	46,328	25 %
Per share, basic and diluted ($)	0.21	0.20	5 %	0.86	0.71	21 %
Funds from operations (1)	29,092	31,475	-8 %	119,431	103,882	15 %
Per share ($) (1)	0.43	0.48	-10 %	1.79	1.60	12 %
Capital expenditures	5,335	7,743	-31 %	29,287	36,746	-20 %
Property and royalty acquisitions (net)	6,891	243	-	10,091	60,852	-83 %
Dividends paid in cash (3) (4)	20,697	21,060	-2 %	84,340	81,436	4 %
Dividends paid in shares (DRIP) (2)	7,617	6,672	14 %	27,948	27,414	2 %
Average DRIP participation rate (%)	27	24	13 %	25	25	0 %
Dividends declared (3) (4)	28,373	27,787	2 %	112,495	109,568	3 %
Per share ($) (4)	0.42	0.42	0 %	1.68	1.68	0 %
Long-term debt, period end	49,000	18,000	172 %	49,000	18,000	172 %
Shares outstanding, period end (000s)	67,746	66,270	2 %	67,746	66,270	2 %
Average shares outstanding (000s) (5)	67,483	66,091	2 %	66,900	64,880	3 %
OPERATING HIGHLIGHTS						
Average daily production (boe/d) (6) (7)	9,173	9,510	-4 %	8,913	8,850	1 %
Average realized price ($/boe) (6)	52.99	51.55	3 %	55.06	51.00	8 %
Operating netback ($/boe) (1) (6)	44.97	44.59	1 %	47.91	45.09	6 %

(1) See Additional GAAP Measures and Non-GAAP Financial Measures.
(2) Excludes dividend declared in December and paid in January.
(3) Includes dividend declared in December and paid in January.
(4) Based on the number of shares issued and outstanding at each record date.
(5) Weighted average number of shares outstanding during the period, basic.
(6) See Conversion of Natural Gas to Barrels of Oil Equivalent (boe).
(7) Our production mix in 2013 was approximately 36% natural gas and 64% liquids (34% light and medium oil, 25% heavy oil, and 5% NGL).

March Dividend Announcement

The Board of Directors has declared the March dividend of $0.14 per share, which will be paid on April 15, 2014 to shareholders of record on March 31, 2014. Including the April 15 payment, our 12-month trailing cash dividends total $1.68 per share. This dividend is designated as an eligible dividend for Canadian income tax purposes. Over the past 17 years, we have paid out over $1.2 billion to our shareholders.

2013 Fourth Quarter Highlights

Freehold delivered strong operational results in the fourth quarter of 2013. Highlights included:

- Production for the quarter averaged 9,173 boe per day representing a 4% decrease versus Q4/12. The key driver behind the reduction in volumes was lower prior period adjustments for the quarter (325 boe per day) as Freehold realized an above average total (650 boe per day) in Q4/12. Netting this out, production volumes were similar to the same period last year.
- Gross revenue for the quarter totalled $45.3 million, compared to $45.8 million in Q4/12.
- Funds from operations totalled $29.1 million, compared to $31.5 million in Q4/12, with the decrease year-over-year associated with production declines, higher operating costs and higher current income taxes, offset by higher pricing.
- Dividends for the fourth quarter of 2013 totalled $0.42 per share, unchanged from last year.
- Net income of $14.1 million was 5% higher than last year. Variance in earnings versus Q4/12 was primarily driven by the above mentioned factors, lower depletion and depreciation, lower share based and other compensation and a larger deferred income tax recovery.
- Acquired royalty interests in 4,480 acres in east central Alberta, producing approximately 40 boe per day for $5.1 million (net of adjustments). In addition, acquired a gross overriding royalty in two units and contractual gross overriding royalties in Alberta, producing approximately 22 boe per day for $0.9 million. We expect production from these acquired areas to grow in 2014.
- Net capital expenditures on our working interest properties totalled $5.3 million in the fourth quarter (Q4 2012 - $7.7 million) with the majority of spending allocated to southeast Saskatchewan.
- Freehold continues to maintain a strong balance sheet with long-term debt of $49 million as at December 31, 2013, flat when compared to Q3/13 and up from $18 million at December 31, 2012. Debt levels increased when compared to 2012 primarily as a result of paying taxes in 2013 for both the 2012 and 2013 tax years.
- Average DRIP participation was 27% in the fourth quarter of 2013 (Q4 2012 - 24%), allowing us to retain $7.6 million (Q4 2012 - $6.7 million) in cash dividend payments by issuing shares from treasury.

2013 Year-end Reserves and Land Highlights

Freehold's reserves data is presented 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 National Instrument 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. Reserve values do not include potential reserve additions that may occur as a result of future drilling on most of our royalty lands.

- Net proved plus probable reserves at December 31, 2013 totalled 23.1 MMboe, with reserves assigned to 22,885 wells. Net proved plus probable royalty interest reserves declined 8% year-over-year, and net proved plus probable working interest reserves were up 4%. Approximately 63% of our net reserves are in the proved category, and 94% of our net proved reserves are producing. On a boe basis, net reserves are 61% liquids (30% heavy oil, 25% light and medium oil, 6% natural gas liquids) and 39% natural gas.
- Net proved plus probable reserve additions totalled 1.9 MMboe (76% liquids). Drilling on our royalty lands added 0.5 MMboe (26%) of net proved plus probable reserves, development activities added 1.1 MMboe (58%), and acquisitions added 0.3 MMboe (16%). Based on this, we replaced approximately 64% of 2013 production.
- Freehold's finding costs are calculated based on net reserves. In 2013, finding and development costs for net proved plus probable reserves were $19.85 per boe, while acquisition costs were $34.38 per boe and the all-in finding, development and acquisition (FD&A) cost was $22.04 per boe (including changes in future development capital). Based on an operating netback of $47.91 per boe in 2013, these activities resulted in a recycle ratio of 2.2 times the capital invested, and a three-year average recycle ratio of 2.3.
- Our land holdings as at December 31, 2013 encompassed 3.1 million gross acres, up 2% from last year mainly as a result of some small acquisitions. Royalty interests comprised 93% of our acreage. Our undeveloped land was independently valued by Seaton-Jordan & Associates Ltd., at $89.1 million.

Royalty Interest Activity

On an equivalent net basis, 76% of the royalty wells drilled on our lands during 2013 were oil wells (2012 - 85%) due to the oil-prone nature of our lands. As well, over 70% of the equivalent net wells drilled on our royalty lands in 2013 were horizontal wells, up from 66% last year.

Our royalty lands give us exposure to several of the attractive resource plays employing horizontal drilling, including Bakken and Mississippian light oil in southeast Saskatchewan, heavy oil in the Lloydminster area, and Cardium light oil in west-central Alberta.

As at December 31, 2013, there were 51 (3.6 equivalent net) licensed drilling locations on our royalty lands.

ROYALTY INTEREST WELLS DRILLED	Three Months Ended December 31				Twelve Months Ended December 31			
	2013		2012		2013		2012	
	Gross	Equiv. Net (1)	Gross	Equiv. Net (1)	Gross	Equiv. Net (1)	Gross	Equiv. Net (1)
Non-unitized	68	4.3	57	2.6	197	11.3	231	11.6
Unitized (2)	38	0.2	30	0.1	141	0.6	200	1.2
Total	106	4.5	87	2.7	338	11.9	431	12.8

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

(2) Unitized wells are in production units wherein we generally have small royalty interests in hundreds of wells.

Working Interest Activity

Our development plans are primarily oil related, and are focused almost entirely on our own mineral title lands, where we have chosen to invest our own capital on attractive, low-risk opportunities.

In the fourth quarter of 2013, capital expenditures amounted to $5.3 million, the majority of which was spent to complete, equip, and tie-in wells drilled in southeast Saskatchewan. We participated in the drilling of six (1.2 net) wells with a 100% success rate.

- In southeast Saskatchewan, we participated in the drilling of one (0.1 net) horizontal Tilston oil well, two (0.8 net) horizontal Frobisher oil wells and one (0.1 net) horizontal Bakken oil well.
- In Alberta, we participated in the drilling of one (0.2 net) horizontal Cardium oil well at Ferrier and one small interest horizontal Glauconite oil well in the Thorsby Unit.

WORKING INTEREST WELLS DRILLED (1)	Three Months Ended December 31				Twelve Months Ended December 31			
	2013		2012		2013		2012	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Oil	6	1.2	7	1.3	41	12.9	36	13.5
Natural gas	-	-	-	-	-	-	-	-
Other	-	-	-	-	7	0.7	1	0.6
Total	6	1.2	7	1.3	48	13.6	37	14.1

(1) Excludes royalty interest portion on properties where Freehold has both a working interest and a royalty interest. The royalty interest portion is included in equivalent net wells in the Royalty Interest Wells Drilled table above.

Operating Expense

Total operating expense of $5.5 million ($6.50 per boe) was 14% higher than the fourth quarter last year (18% higher on a per boe basis). The increase in costs was associated with a combination of higher than forecast electricity charges, well servicing and maintenance costs on our heavy oil properties.

GROSS REVENUE BY PRODUCT	Three Months Ended December 31			Twelve Months Ended December 31		
($000s)	2013	2012	Change	2013	2012	Change
Royalty Interest						
Oil	22,147	20,503	8 %	89,511	87,721	2 %
NGL	1,849	1,512	22 %	7,273	6,887	6 %
Natural gas	3,775	3,831	-1 %	14,343	10,501	37 %
Other (1)	470	556	-15 %	2,193	2,525	-13 %
Total royalty interest revenue	28,241	26,402	7 %	113,320	107,634	5 %
Working Interest						
Oil	15,300	17,801	-14 %	62,451	55,577	12 %
NGL	574	476	21 %	2,088	1,870	12 %
Natural gas	1,069	978	9 %	3,454	2,640	31 %
Other (1)	103	137	-25 %	265	413	-36 %
Total working interest revenue	17,046	19,392	-12 %	68,258	60,500	13 %

Total						
Oil	37,447	38,304	-2 %	151,962	143,298	6 %
NGL	2,423	1,988	22 %	9,361	8,757	7 %
Natural gas	4,844	4,809	1 %	17,797	13,141	35 %
Other (1)	573	693	-17 %	2,458	2,938	-16 %
Total gross revenue	45,287	45,794	-1 %	181,578	168,134	8 %

(1) Other includes potash, sulphur, lease rentals, and other revenue for royalty interest, and processing fees, interest, and other revenue for working interest.

Fourth Quarter Production

Production volumes through the fourth quarter were down slightly when compared with levels averaged one-year ago, but up versus Q3/13.

- Royalty production averaged 6,271 boe per day through the fourth quarter, representing a 1% decrease when compared to Q4/12. Oil and natural gas liquids production was up 5% due to drilling activity and prior period adjustments. On the natural gas side, volumes were down 7% from Q4/12, largely as the result of a higher number of prior period adjustments in Q4/12.
- Working interest production volumes averaged 2,902 boe per day in Q4/13. This represented a 300 boe per day decrease versus Q4/12 with reduced volumes primarily associated with greater flush production one-year ago.

AVERAGE DAILY PRODUCTION	Royalty Interest		Working Interest		Total	
Three months ended December 31	2013	2012	2013	2012	2013	2012
Oil (bbls/d)	3,336	3,190	2,225	2,561	5,561	5,751
NGL (bbls/d)	293	267	91	88	384	355
Total oil and NGL (bbls/d)	3,629	3,457	2,316	2,649	5,945	6,106
Natural gas (Mcf/d)	15,853	17,105	3,515	3,315	19,368	20,420
Oil equivalent (boe/d)	6,271	6,308	2,902	3,202	9,173	9,510

Commodity Prices

In the fourth quarter, the benchmark West Texas Intermediate (WTI) crude oil price averaged US$97.46 per barrel, 11% higher than the previous year. While prices were up compared to 2012 levels, the short-term outlook was somewhat bearish with prices retreating versus Q3/13. We saw weakness into year-end driven by a combination of increased supply associated with U.S. shale and Canadian oil sands growth, indications that the U.S. federal reserve would look to implement tapering initiatives early in 2014 and weakening economic fundamentals out of China.

In the near-term, crude oil supply out of North America is expected to grow at not seen before levels, driven primarily by tight oil plays in North Dakota, Montana, and Texas, along with smaller gains from unconventional resource plays and oil sands within Canada. While growth in supply remains strong, getting volumes through pipeline bottlenecks to premium pricing points in the U.S. Gulf Coast remains a near-term concern for Canadian producers, reflecting some of the discount realized within Edmonton Par and Western Canadian Select pricing in the fourth quarter. Looking forward, while the macro environment is expected to improve marginally for heavy oil producers, we expect Canadian light oil prices to remain discounted through the remainder of 2014.

While remaining depressed for much of the trailing five years, natural gas prices within North America appear to be building momentum, exhibited by strong recent price appreciation. In the fourth quarter, the average benchmark AECO natural gas price was C$3.15 per mcf, representing a 3% improvement versus prices realized in 2012. A key driver behind price appreciation included below average temperatures within consuming regions of the eastern U.S. which has spurred incremental U.S. residential and commercial consumption.

At year-end, North American natural gas inventories stood at approximately 16% below levels seen one year ago and 9% below the five year average. In the near-term, we expect weather within key demand centres, along with the supply response from growing U.S. shale plays to be the primary drivers behind further movement in price levels. In the longer-term, LNG initiatives both within the U.S. and Canada will present some optionality within the North American price environment.

Our average selling prices reflect product quality and transportation differences from benchmark prices. In the fourth quarter of 2013, our average realized oil price was $73.20 (Q4 2012 - $72.40) per barrel and our average realized natural gas price was $2.72 (Q4 2012 - $2.56) per Mcf.

2013 Performance Compared to Guidance

The following table compares our key operating assumptions during 2013 to our actual results for the year.

Compared to our November guidance:

- Average production for the year was 113 boe per day higher than November production guidance, mainly due to prior period adjustments.
- Average oil prices, both for WTI and WCS were in-line with our forecasts.
- General and administrative costs per boe were lower than November guidance, as a result of a higher production base.
- Operating costs per boe were higher than forecast as electricity prices and maintenance charges increased costs.
- Capital expenditures were $3 million lower than forecast, primarily associated with timing delays in getting a scheduled well drilled before year-end. This location will be part of the Company's 2014 drilling program.

2013 Key Operating Assumptions

			Previous Guidance			
Annual Average		2013 Actual Results	Nov. 14, 2013	Aug. 8, 2013	May 15, 2013	Mar. 7, 2013
Daily production	boe/d	8,913	8,800	8,800	8,700	8,500
WTI oil price	US$/bbl	97.97	98.00	96.00	93.00	95.00
Western Canada Select (WCS)	Cdn$/bbl	74.99	75.00	75.00	69.00	71.00
AECO natural gas price	Cdn$/Mcf	3.16	3.25	3.00	3.50	3.10
Exchange rate	Cdn$/US$	0.97	0.97	0.98	0.98	1.00
Operating costs	$/boe	5.95	5.60	5.30	5.00	5.00
General and administrative costs (1)	$/boe	2.35	2.60	2.60	2.60	2.60
Capital expenditures	$ millions	29	32	32	30	30
Dividends paid in shares (DRIP)	$ millions	28	28	28	28	28
Long-term debt at year end	$ millions	49	53	44	44	48
Cash taxes paid in 2013 for 2012 tax year	$ millions	22	22	22	23	23
Cash taxes paid for 2013 tax year	$ millions	24	24	24	25	25
Weighted average shares outstanding	millions	67	67	67	67	67

(1) Excludes share based and other compensation.

2014 Outlook

Through 2014, we are forecasting a capital spending program of $35 million. Our focus will continue to centre on oil development within our mineral title lands and includes approximately 58 gross (14 net risked) wells. Our spending will be comprised of approximately 40% in southeast Saskatchewan (light oil), with the remaining balance allocated to our opportunity base in both the Lloydminster area (heavy oil), and Western Alberta (Cardium oil) plays. The increase in costs per well are related to the shift from vertical to horizontal drilling within our program, along with two well completions that were scheduled for 2013 and were delayed into 2014. We maintain that capital may be adjusted as the year progresses, depending on the operating environment and individual well results. Approximately forty percent of our total capital for the year will be spent in the first quarter of 2014, with area allocations similar to our annual budget.

Based on this level of capital investment, anticipated drilling activity by lessees on our royalty lands, and normal production declines (and excluding any potential acquisitions), we expect 2014 production to average approximately 8,700 boe/d. Volumes will be comprised of approximately 62% oil and NGL's and 38% natural gas. We continue to maintain our royalty focus with royalty production expected to account for approximately 68% of forecasted 2014 production.

After paying a large lump sum ($46 million) associated with two years tax burden in 2013, we expect our tax liability to normalize through 2014, at approximately 20% of pre-tax cash flow.

2014 Key Operating Assumptions

Annual Average		Guidance Updated March 6, 2014	Guidance Updated November 14, 2013
Daily production	boe/d	8,700	8,600
WTI oil price	US$/bbl	97.00	95.00
Western Canada Select (WCS)	Cdn$/bbl	83.00	75.00
AECO natural gas price	Cdn$/Mcf	4.50	3.50
Exchange rate	Cdn$/US$	0.90	0.95
Operating costs	$/boe	6.00	5.60
General and administrative costs (1)	$/boe	2.60	2.60
Capital expenditures	$ millions	35	30
Dividends paid in shares (DRIP) (2)	$ millions	29	29
Long-term debt at year end	$ millions	38	57
Current income tax expense (3) (4)	$ millions	32	28
Weighted average shares outstanding	millions	68	68

(1) Excludes share based and other compensation.
(2) Assumes average 25% participation rate in Freehold's dividend reinvestment plan, which is subject to change at the participants' discretion.
(3) Corporate tax estimates will vary depending on all other assumptions.
(4) November 14, 2013 Guidance was adjusted to be comparable to the current presentation.

Recognizing the cyclical nature of the oil and gas industry, we continue to closely monitor commodity prices and industry trends for signs of deteriorating market conditions. We caution that it is inherently difficult to predict activity levels on our royalty lands since we have no operational control. As well, significant changes (positive or negative) in commodity prices (including Canadian oil price differentials), foreign exchange rates, or production rates may result in adjustments to the dividend rate. In particular, our 2014 forecast for Western Canada Select pricing assumes an improvement in the second half of the year, but it is possible that the North American infrastructure constraints will become a longer-term issue for western Canadian production.

Based on our current guidance and commodity price assumptions, and assuming there are no significant changes in the current business environment, we expect to maintain the current monthly dividend rate through 2014, subject to the Board's quarterly review and approval.

Executive Retirement and Appointments

On December 31, 2013, Mr. Frank George, Vice-President, Special Projects (previously Vice-President, Exploration) retired from Rife Resources Ltd. (the Manager of Freehold) after 30 years with Rife. Mr. Garry Bieber, appointed Vice-President, Special Projects effective January 1, 2014 (previously Vice-President, Production) will be retiring effective April 1, 2014 after 28 years with Rife. The directors of Freehold thank Mr. George and Mr. Bieber for their many years of service, and wish them well in their retirement.

We are pleased to announce that Mr. Daniel Moore was appointed Vice-President, Production on January 1, 2014. Mr. Moore is a Professional Engineer with 22 years of experience. He joined Rife in December 2011 as Manager, Engineering, and most recently was Chief Engineer.

Land and Reserves

Freehold is unique in that the majority of our assets are royalty interests. However, under National Instrument 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 and finding and development costs to others in our industry. We believe the most appropriate measure of reserves and finding and development costs for Freehold is on a net basis.

As at year-end 2013, our undeveloped land was independently valued at $89.1 million by Seaton-Jordan & Associates Ltd. Our total land holdings encompass approximately 3.1 million gross acres, 93% of which are royalties. Of this, our mineral title lands (including royalty assumption lands), which we own in perpetuity, cover nearly 630,000 acres; all but approximately 100,000 gross acres of which are currently leased to third parties. In addition, we have gross overriding royalty interests in over 2.2 million acres.

These royalty interest lands are significant to Freehold. The majority of these lands are leased to third party operators. As a royalty owner, we have no operational control over the operator's future development activities. As such, the extent of drilling and development activity in future years can be difficult to predict. However, these operators have historically invested significant amounts to generate future reserve additions, and production from which Freehold receives certain royalties. Reserve values include minimal reserve additions that may occur as a result of future drilling on our royalty lands. In addition, based on an internal estimate, we have estimated the net present value of the future royalty revenue from our potash reserves at $17.7 million before tax (discounted at 10%).

Our oil and gas reserves were independently evaluated by Trimble Engineering Associates Ltd. (Trimble) as at December 31, 2013. The evaluation was conducted in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in National Instrument 51-101. Our Reserves Committee met with Trimble to review the findings and procedures, and the reserves report has been accepted by our Board.

Summary oil and gas reserves information is provided below. Complete reserves disclosure as required under National Instrument 51-101 will be included in our Annual Information Form.

Summary of Oil and Gas Reserves
As of December 31, 2013

Forecast Prices and Costs (1)	Light and Medium Oil		Heavy Oil		Total Crude Oil	
Reserves Category	Gross (2) (Mbbls)	Net (3) (Mbbls)	Gross (2) (Mbbls)	Net (3) (Mbbls)	Gross (2) (Mbbls)	Net (3) (Mbbls)
Proved						
Developed producing	1,722	3,415	748	4,167	2,471	7,582
Developed non-producing	104	91	16	14	120	105
Undeveloped	-	-	-	-	-	-
Total proved	1,827	3,506	764	4,181	2,591	7,687
Probable	1,456	2,322	851	2,730	2,307	5,052
Total proved plus probable	3,283	5,828	1,615	6,911	4,898	12,739

	Natural Gas		Natural Gas Liquids		Oil Equivalent	
Reserves Category	Gross (2) (MMcf)	Net (3) (MMcf)	Gross (2) (Mbbls)	Net (3) (Mbbls)	Gross (2) (Mboe)	Net (3) (Mboe)
Proved						
Developed producing	3,400	30,887	131	846	3,168	13,576
Developed non-producing	586	622	44	35	262	244
Undeveloped	-	3,734	-	42	-	664
Total proved	3,986	35,243	175	923	3,430	14,483
Probable	4,363	18,385	237	513	3,271	8,629
Total proved plus probable	8,349	53,627	412	1,436	6,702	23,113

(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 defined as our share of working interest properties minus royalties payable to others, plus royalties receivable on our royalty lands.

The reserves data below is presented on a net basis (our share of working interest properties minus royalties payable to others, plus royalties receivable on our royalty lands).

Summary of Net Present Values of Future Net Revenue
As of December 31, 2013

Forecast Prices and Costs ($000s) (1)	Before Income Taxes, Discounted at (% per year)				
	0%	5%	10%	15%	20%
Proved					
Developed producing	756,691	558,106	448,309	379,056	331,345
Developed non-producing	6,640	4,908	3,989	3,423	3,036
Undeveloped	20,139	13,417	9,422	6,882	5,184
Total proved	783,470	576,431	461,721	389,361	339,566
Probable	532,947	280,416	184,316	136,501	108,128

Total proved plus probable	1,316,417	856,847	646,037	525,862	447,693

	After Income Taxes, Discounted at (% per year) (2)				
Reserves Category	0%	5%	10%	15%	20%
Proved					
Developed producing	634,088	467,455	375,628	317,755	277,886
Developed non-producing	4,938	3,595	2,879	2,438	2,137
Undeveloped	15,042	10,021	7,036	5,139	3,870
Total proved	654,068	481,071	385,544	325,331	283,893
Probable	396,944	208,014	136,175	100,447	79,257
Total proved plus probable	1,051,012	689,085	521,719	425,778	363,150

(1) Based on the December 31, 2013 escalated oil and gas price forecasts by an independent qualified reserves evaluator. Future net revenue values do not represent fair market value. Columns may not add due to rounding.

(2) The after-tax net present value calculation reflects the tax burden on the properties on a standalone basis, utilizing our tax pools to the maximum depreciation rate as currently permitted. It does not consider the corporate-level tax situation, or tax planning. It does not provide an estimate of the value at the corporate level, which may be significantly different. See our financial statements and accompanying MD&A for additional tax information.

Total Future Net Revenue (Undiscounted)

As of December 31, 2013

Forecast Prices and Costs ($000s) (1)	Reserves Category	
	Proved Reserves	Proved Plus Probable Reserves
Royalty income	684,094	1,113,378
Revenue from working interest properties	286,536	565,905
Royalty expense on working interest	(44,686)	(95,158)
Operating costs	(130,578)	(240,560)
Development costs	(2,583)	(16,007)
Well abandonment and reclamation costs	(9,312)	(11,141)
Future net revenue before income taxes	783,470	1,316,417
Future income taxes (2)	(129,402)	(265,404)
Future net revenue after income taxes (2)	654,068	1,051,012

(1) Future net revenue calculation includes future capital expenditures required to bring booked non-producing and undeveloped reserves on production. Future net revenue values do not represent fair market value. Columns may not add due to rounding.

(2) The after-tax net present value calculation reflects the tax burden on the properties on a standalone basis, utilizing our tax pools to the maximum depreciation rate as currently permitted. It does not consider the corporate-level tax situation, or tax planning. It does not provide an estimate of the value at the corporate level, which may be significantly different. See our financial statements and accompanying MD&A for additional tax information.

Future Development Costs (Undiscounted) ($000s)

Forecast Prices and Costs (1)	Proved Reserves	Proved Plus Probable Reserves
2014	1,388	8,228
2015	237	5,290
2016	180	1,509
2017	628	664
2018	74	127
Remainder	76	189
Total	2,583	16,007

(1) 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. Columns may not add due to rounding.

Reserve Life Index

As of December 31, 2013 (1)

	Proved Producing	Total Proved	Proved Plus Probable
Net reserves (Mboe)	13,576	14,483	23,113
Net production (Mboe)	2,357	2,409	2,707
Reserve life index (years)	5.8	6.0	8.5

(1) Reflects the theoretical production life of a property if the remaining reserves were produced out at current rates. The index is calculated by dividing the reserves in the selected reserve category at a certain date by the estimated production for the first year's production period (calculated by dividing the Trimble forecast of 2014 net production into the remaining net reserves).

Reconciliation of Net Reserves (1)

By Principal Product Type

Forecast Prices and Costs	Light and Medium Oil		Heavy Oil	
		Proved Plus		Proved Plus

	Proved (Mbbls)	Probable (Mbbls)	Probable (Mbbls)	Proved (Mbbls)	Probable (Mbbls)	Probable (Mbbls)
December 31, 2012	3,554	2,301	5,855	4,178	3,197	7,376
Extensions	495	382	878	155	81	236
Improved recovery	-	-	-	-	-	-
Technical revisions	374	(356)	18	636	(677)	(41)
Discoveries	-	-	-	-	-	-
Acquisitions	-	-	-	82	128	210
Dispositions	-	-	-	-	-	-
Economic factors	(4)	(5)	(9)	(1)	-	-
Production	(914)	-	(914)	(870)	-	(870)
December 31, 2013	3,506	2,322	5,828	4,181	2,730	6,911

	Natural Gas			Natural Gas Liquids		
	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)	Proved (Mbbls)	Probable (Mbbls)	Proved Plus Probable (Mbbls)
December 31, 2012	38,736	20,212	58,949	893	476	1,369
Extensions	814	1,494	2,309	48	102	150
Improved recovery	-	-	-	-	-	-
Technical revisions	1,831	(3,433)	(1,602)	181	(64)	117
Discoveries	-	-	-	-	-	-
Acquisitions	361	140	501	-	-	-
Dispositions	-	-	-	-	-	-
Economic factors	(55)	(29)	(84)	(0)	(1)	(1)
Production	(6,445)	-	(6,445)	(199)	-	(199)
December 31, 2013	35,243	18,385	53,627	923	513	1,436

	Oil Equivalent		
	Proved (Mboe)	Probable (Mboe)	Proved Plus Probable (Mboe)
December 31, 2012	15,082	9,343	24,425
Extensions	835	814	1,649
Improved recovery	-	-	-
Technical revisions	1,496	(1,669)	(174)
Discoveries	-	-	-
Acquisitions	142	152	293
Dispositions	-	-	-
Economic factors	(14)	(11)	(25)
Production	(3,057)	-	(3,057)
December 31, 2013	14,483	8,629	23,113

(1) Net reserves are our share of working interest properties minus royalties payable to others, plus royalties receivable on our royalty lands. Numbers may not add due to rounding.

Finding, Development and Acquisition (FD&A) Costs (1)

Net Proved Reserves	2013	2012	2011	Three-Year Results
Finding and development expenditures ($000s)	29,287	36,746	25,649	91,682
Change in future development capital estimates ($000s)	1,142	(934)	1,556	1,764
Net reserve additions by development (Mboe)	834	1,071	581	2,486
Finding and development costs ($/boe)	36.47	33.45	46.81	37.59
Acquisition expenditures ($000s)	10,091	60,852	7,467	78,410
Net reserve additions by acquisition (Mboe)	142	2,300	103	2,545
Acquisition costs ($/boe)	71.21	26.46	72.42	30.81
Total expenditures ($000s)	39,378	97,598	33,116	170,092
Change in future development capital estimates ($000s)	1,142	(934)	1,556	1,764
Net reserve additions (Mboe)	976	3,371	684	5,031
Finding, development and acquisition costs ($/boe)	41.52	28.68	50.67	34.16

Net Proved Plus Probable Reserves	2013	2012	2011	Three-Year Results
Finding and development expenditures ($000s)	29,287	36,746	25,649	91,682

Change in future development capital estimates ($000s)	3,448	1,916	4,959	10,323
Net reserve additions by development (Mboe)	1,649	1,809	1,085	4,543
Finding and development costs ($/boe)	19.85	21.37	28.20	22.45
Acquisition expenditures ($000s)	10,091	60,852	7,467	78,410
Net reserve additions by acquisition (Mboe)	294	3,483	207	3,983
Acquisition costs ($/boe)	34.38	17.47	36.12	19.68
Total expenditures ($000s)	39,378	97,598	33,116	170,092
Change in future development capital estimates ($000s)	3,447	1,916	4,959	10,322
Net reserve additions (Mboe)	1,943	5,292	1,292	8,527
Finding, development and acquisition costs ($/boe)	22.04	18.80	29.47	21.16

(1) Freehold did not incur any exploration expenditures in any of the applicable years. 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 Freehold's ongoing reserve replacement costs. Because acquisitions can have a significant impact on annual reserve replacement costs, excluding these amounts could result in an inaccurate portrayal of Freehold's cost structure. Accordingly, we also provide costs that incorporate all acquisitions during the year. 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.

Recycle Statistics, Net Proved Plus Probable Reserves

($ per boe, except as noted)	2013	2012	2011	Three-Year Results
Operating netback (1) (4)	47.91	45.09	51.65	48.03
Finding, development and acquisition costs (2) (4)	22.04	18.80	29.47	21.16
Recycle ratio (times) (3)	2.2	2.4	1.8	2.3

(1) Total revenue, less operating costs and royalty expenses.

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

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

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

Land Holdings

As of December 31, 2013

(gross acres) (1)	Developed	Undeveloped	Total
Mineral title lands (2)	361,246	170,821	532,067
Royalty assumption lands (3)	73,624	21,198	94,822
Total title lands (4)	434,870	192,019	626,889
Gross overriding royalty (GORR) lands (5)	1,631,848	588,363	2,220,211
Total royalty lands	2,066,718	780,382	2,847,100
Working interest properties	169,429	41,691	211,120
Total land holdings	2,236,147	822,073	3,058,220

Land Holdings by Province

	Royalty Interest		Working Interest				Total Acreage	
	Developed	Undeveloped	Developed		Undeveloped		Developed	Undeveloped
	Gross (1)	Gross (1)	Gross (1)	Net	Gross (1)	Net	Gross (1)	Gross (1)
Alberta	1,601,021	390,976	132,927	19,692	28,188	5,743	1,733,948	419,164
British Columbia	85,152	24,523	19,247	1,265	6,131	101	104,399	30,654
Saskatchewan	285,488	188,881	17,097	5,787	7,293	4,000	302,585	196,174
Manitoba	6,258	1,422	158	37	79	18	6,416	1,501
Ontario	88,799	174,580	-	-	-	-	88,799	174,580
Total	2,066,718	780,382	169,429	26,781	41,691	9,862	2,236,147	822,073

(1) Gross acres are 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. All but approximately 107,000 gross acres of our mineral title lands are currently leased to third parties.

(3) 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.

(4) Title lands are held in perpetuity.

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

Quarterly Review

	2013				2012			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
FINANCIAL ($000s, except as noted)								

Revenue, net of royalty expense	43,436	49,728	42,704	39,332	43,832	40,294	34,498	43,036
Dividends declared	28,373	28,206	28,019	27,897	27,787	27,616	27,399	26,766
Per share ($) (1)	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42
Net income	14,106	18,961	14,292	10,493	13,431	11,975	7,862	13,060
Per share, basic and diluted ($)	0.21	0.28	0.21	0.16	0.20	0.18	0.12	0.21
Funds from operations (2)	29,092	36,407	30,115	23,817	31,475	26,272	20,522	25,613
Per share ($) (2)	0.43	0.54	0.45	0.36	0.48	0.40	0.31	0.41
Dividends paid in shares (DRIP)	7,617	9,076	6,874	4,381	6,672	7,013	6,940	6,789
Average DRIP participation rate (%)	27	32	25	16	24	25	25	26
Property and royalty acquisitions (net)	6,891	2,542	658	-	243	10,789	(99)	49,919
Capital expenditures	5,335	5,725	3,313	14,914	7,743	9,160	6,598	13,245
Long-term debt	49,000	49,000	55,000	47,000	18,000	25,000	23,000	18,000
SHARES OUTSTANDING								
Weighted average, basic (000s)	67,483	67,078	66,649	66,375	66,091	65,677	65,159	62,571
At quarter end (000s)	67,746	67,326	66,874	66,522	66,270	65,879	65,440	64,993
OPERATING ($/boe, except as noted)								
Daily production (boe/d) (3)	9,173	8,699	8,714	9,067	9,510	8,654	8,501	8,733
Royalty interest production (%)	68	67	71	71	66	68	76	74
Average selling price	52.99	63.74	54.66	49.09	51.55	51.71	45.74	54.80
Operating netback (2)	44.97	55.79	47.80	43.32	44.59	45.59	40.64	49.48
Operating expenses	6.50	6.36	6.06	4.88	5.51	5.02	3.96	4.68
Working interest properties	20.53	19.50	21.00	16.91	16.36	15.47	16.47	17.86
Net general and administrative expenses (4)	2.13	1.74	2.04	3.47	2.25	1.88	2.13	3.31
BENCHMARK PRICES								
WTI crude oil (US$/bbl)	97.46	105.83	94.22	94.37	88.18	92.22	93.49	102.93
Exchange rate (Cdn$/US$)	0.95	0.96	0.98	0.99	1.01	1.01	0.99	1.00
Edmonton Par crude oil (Cdn$)	86.28	104.69	92.55	88.16	83.99	84.33	83.95	92.23
Western Canada Select (WCS) (Cdn$/bbl)	68.44	91.71	76.78	62.96	69.43	69.99	71.29	81.61
WTI/Edmonton Par differential ($/bbl)	(11.18)	(1.14)	(1.67)	(6.21)	(4.19)	(7.89)	(9.54)	(10.70)
Edmonton Par/WCS differential (Cdn$/bbl)	(17.84)	(12.98)	(15.77)	(25.20)	(14.56)	(14.34)	(12.66)	(10.62)
AECO natural gas (Cdn$/Mcf)	3.15	2.82	3.59	3.08	3.06	2.19	1.83	2.52
SHARE TRADING PERFORMANCE								
High ($)	24.63	24.88	24.58	24.48	22.45	20.34	19.67	21.59
Low ($)	21.54	22.50	22.46	21.00	19.62	17.83	17.25	19.16
Close ($)	22.11	23.78	23.57	23.38	22.40	19.76	18.44	19.59
Volume (000s)	6,077	4,374	8,108	7,203	7,435	5,656	7,483	8,076

(1) Based on the number of shares issued and outstanding at each record date.
(2) See Additional GAAP Measures and Non-GAAP Financial Measures.
(3) Reported production for a period may include minor adjustments from previous production periods.
(4) Excludes share based and other compensation.

Consolidated Balance Sheets

($000s) (unaudited)	December 31 2013	December 31 2012
Assets		
Current assets:		
Cash	$ 158	$ 102
Accounts receivable	25,587	23,225
	25,745	23,327
Exploration and evaluation assets	24,858	25,905
Petroleum and natural gas interests	377,262	399,005
	$ 427,865	$ 448,237
Liabilities and Shareholders' Equity		
Current liabilities:		
Dividends payable	$ 9,485	$ 9,278
Accounts payable and accrued liabilities	10,813	12,743
Current taxes payable	730	23,095
Current portion of share based and other compensation payable	1,102	2,108
	22,130	47,224
Decommissioning liability	15,781	16,714
Share based and other compensation payable	1,240	1,290

Long-term debt	49,000	18,000
Deferred income tax liability	45,642	49,194
Shareholders' equity:		
Shareholders' capital	455,497	422,728
Contributed surplus	2,167	2,036
Deficit	(163,592)	(108,949)
	294,072	315,815
	$ 427,865	$ 448,237

Consolidated Statements of Income and Comprehensive Income

(unaudited) ($000s, except per share and weighted average data)	Three Months Ended December 31 2013	2012	Year ended December 31 2013	2012
Revenue:				
Royalty income and working interest sales	$ 45,287	$ 45,794	$ 181,578	$ 168,134
Royalty expense	(1,851)	(1,962)	(6,378)	(6,474)
	43,436	43,832	175,200	161,660
Expenses:				
Operating	5,482	4,820	19,356	15,598
General and administrative	1,795	1,972	7,634	7,746
Share based and other compensation	(158)	999	1,531	2,371
Interest and financing	613	421	2,554	2,235
Depletion and depreciation	15,283	16,372	61,320	64,576
Accretion of decommissioning liability	127	107	452	381
Management fee	1,080	1,072	4,495	3,808
	24,222	25,763	97,342	96,715
Income before taxes	19,214	18,069	77,858	64,945
Income tax:				
Current expense	6,214	5,063	23,558	27,792
Deferred recovery	(1,106)	(425)	(3,552)	(9,175)
	5,108	4,638	20,006	18,617
Net income and comprehensive income	$ 14,106	$ 13,431	$ 57,852	$ 46,328
Net income per share, basic and diluted	$ 0.21	$ 0.20	$ 0.86	$ 0.71
Weighted average number of shares:				
Basic	67,483,469	66,090,969	66,899,776	64,880,038
Diluted	67,598,380	66,194,503	67,021,372	64,979,074

Consolidated Statements of Cash Flows

($000s) (unaudited)	Three Months Ended December 31 2013	2012	Year ended December 31 2013	2012
Operating:				
Net income	$ 14,106	$ 13,431	$ 57,852	$ 46,328
Items not involving cash:				
Depletion and depreciation	15,283	16,372	61,320	64,576
Share based and other compensation	(158)	999	1,531	2,371
Deferred income tax recovery	(1,106)	(425)	(3,552)	(9,175)
Accretion of decommissioning liability	127	107	452	381
Management fee	1,080	1,072	4,495	3,808
Expenditures on share based and other compensation	(189)	-	(2,299)	(3,883)
Decommissioning expenditures	(51)	(81)	(368)	(524)
Funds from operations	29,092	31,475	119,431	103,882
Changes in non-cash working capital	1,336	6,708	(26,196)	34,250
	30,428	38,183	93,235	138,132
Financing:				
Issuance of shares, net of issue costs	-	-	-	67,597
Long-term debt	-	(7,000)	31,000	(30,000)

Dividends paid	(20,697)	(21,060)	(84,340)	(81,436)
	(20,697)	(28,060)	(53,340)	(43,839)
Investing:				
Deposit on acquisition	-	-	-	5,000
Property and royalty acquisitions	(6,891)	(243)	(10,091)	(60,852)
Capital expenditures	(5,335)	(7,743)	(29,287)	(36,746)
Changes in non-cash working capital	1,965	(2,149)	(461)	(1,757)
	(10,261)	(10,135)	(39,839)	(94,355)
Increase (decrease) in cash	(530)	(12)	56	(62)
Cash, beginning of period	688	114	102	164
Cash, end of period	$ 158	$ 102	$ 158	$ 102

Consolidated Statements of Changes in Shareholders' Equity

		Year ended December 31
($000s) (unaudited)	2013	2012
Shareholders' capital:		
Balance, beginning of year	$ 422,728	$ 323,115
Shares issued for dividend reinvestment plan	27,948	27,414
Shares issued in lieu of management fee	4,495	3,808
Shares issued for deferred share and plan redemption	326	-
Shares issued for equity offering	-	70,725
Issue costs, net of tax effect	-	(2,334)
Balance, end of year	455,497	422,728
Contributed surplus:		
Balance, beginning of year	2,036	1,480
Share based compensation expense	597	556
Deferred share unit plan redemption	(466)	-
Balance, end of year	2,167	2,036
Deficit:		
Balance, beginning of year	(108,949)	(45,709)
Net income and comprehensive income	57,852	46,328
Dividends declared	(112,495)	(109,568)
Balance, end of year	(163,592)	(108,949)
Total shareholders' equity	$ 294,072	$ 315,815

Forward-Looking Statements

This news release offers our assessment of Freehold's future plans and operations as at March 6, 2014, and contains forward-looking statements that we believe allow readers to better understand our business and prospects. These forward-looking statements include our expectations for the following:

- our outlook for commodity prices including supply and demand factors relating to crude oil, heavy oil, and natural gas;
- light/heavy oil price differentials;
- changing economic conditions;
- foreign exchange rates;
- industry drilling, development activity on our royalty lands, our exposure in emerging resource plays, and the potential impact of horizontal drilling on production and reserves;
- development of working interest properties;
- participation in the DRIP and our use of cash preserved through the DRIP;
- estimated capital budget and expenditures and the timing thereof;
- long-term debt at year end;
- average production and contribution from royalty lands;
- key operating assumptions;
- acquisition opportunities;
- amounts and rates of income taxes and timing of payment thereof;
- maintaining our monthly dividend rate through 2014 and our dividend policy; and
- production rates on properties acquired in 2013.

In addition, statements relating to "reserves" and the future net revenue associated with such reserves are deemed to be forward-looking statements as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated and can be profitably produced in the future.

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, lack of pipeline capacity, currency fluctuations, imprecision of reserve estimates, royalties, environmental risks, taxation, regulation, changes in tax or other legislation, 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.

In this news release, we make references to "flush" production rates, which is the first yield from a flowing oil well during its most productive period. Such "flush" production rates are not determinative of future production rates. Additionally, such rates may also include recovered "load oil" fluids used in well completion stimulation. Readers are cautioned not to place reliance on such rates in estimating future production rates for Freehold.

With respect to forward-looking statements contained in this news release, we have made assumptions regarding, among other things, future commodity prices, future capital expenditure levels, future production levels, future exchange rates, future tax rates, future participation rates in the DRIP and use of cash preserved through the DRIP, future legislation, 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 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 the body of this news release.

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 document 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.

You are further cautioned that the preparation of financial statements in accordance with IFRS requires management to make certain judgments and estimates that affect the reported amounts of assets, liabilities, revenues, and expenses. These estimates may change, having either a positive or negative effect on net income, as further information becomes available and as the economic environment changes.

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. As well, given that the value ratio, based on the current price of crude oil to natural gas, is significantly different from the 6:1 energy equivalency ratio, using a 6:1 conversion ratio may be misleading as an indication of value.

Additional GAAP Measures

This news release contains the term "funds from operations", which does not have a standardized meaning prescribed by GAAP and therefore may not be comparable with the calculations of similar measures for other entities. Funds 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 net income or other measures of financial performance calculated in accordance with GAAP. We consider funds from operations to be a key measure of operating performance as it demonstrates Freehold's ability to generate the necessary funds to fund capital expenditures, sustain dividends, and repay debt. We believe that such a measure provides a useful assessment of Freehold's operations on a continuing basis by eliminating certain non-cash charges. It is also used by research analysts to value and compare oil and gas companies, and it is frequently included in their published research when providing investment recommendations. Funds from operations per share is calculated based on the weighted average number of shares outstanding consistent with the calculation of net income per share.

Non-GAAP Financial Measures

Within this news release, references are made to terms commonly used as key performance indicators in the oil and gas industry, such as operating income, operating netback, finding, development and acquisition (FD&A) costs, and recycle ratio. We believe that these measures are useful supplemental measures for management and investors to analyze operating performance, and we use these terms to facilitate the understanding and comparability of our results of operations. However, these terms do not have any standardized meanings prescribed by GAAP and therefore may not be comparable with the calculations of similar measures for other entities.

Operating income, which is calculated as gross revenue less royalties and operating expenses, represents the cash margin for product sold. 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.

Availability on SEDAR

Freehold's 2013 audited financial statements and accompanying Management's Discussion and Analysis (MD&A) are being filed today with Canadian securities regulators and will be available at www.sedar.com and on our website at www.freeholdroyalties.com. Our Annual Information Form (including reserves disclosure required under National Instrument NI 51-101) is expected to be filed on or about March 10, 2014.

Contact

Freehold Royalties Ltd.
Matt Donohue
Manager, Investor Relations
403.221.0833 or Toll Free: 1.888.257.1873
403.221.0888
mdonohue@rife.com
www.freeholdroyalties.com