Freehold Royalties Ltd. Announces 2012 Fourth Quarter Results and Year-end Reserves

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CALGARY, ALBERTA -- (Marketwire - March 7, 2013) - Freehold Royalties Ltd. (Freehold) (TSX:FRU) today announced 2012 fourth quarter results and reserves as at December 31, 2012.

Results at a Glance

Three Months Ended Twelve Months Ended
FINANCIAL HIGHLIGHTS December 31 December 31
($000s, except as noted) 2012 2011 Change 2012 2011 Change
Gross revenue 45,794 45,304 1 % 168,134 157,910 6 %
Net income 13,431 16,033 -16 % 46,328 55,259 -16 %
Per share, basic and diluted ($) 0.20 0.26 -23 % 0.71 0.92 -23 %
Cash flow from operating activities 38,183 32,595 17 % 138,132 118,370 17 %
Per share ($) 0.58 0.54 7 % 2.13 1.97 8 %
Capital expenditures 7,743 10,910 -29 % 36,746 25,649 43 %
Property and royalty acquisitions (net) 243 (195) - 60,852 7,467 -
Dividends paid in cash (1) 21,060 15,262 38 % 81,436 67,204 21 %
Dividends paid in shares (DRIP) (1) 6,672 10,232 -35 % 27,414 33,490 -18 %
Average DRIP participation rate (%) (2) 24 40 -40 % 25 33 -24 %
Dividends declared (3) 27,787 25,585 9 % 109,568 100,968 9 %
Per share ($) (4) 0.42 0.42 0 % 1.68 1.68 0 %
Long-term debt, period end 18,000 48,000 -63 % 18,000 48,000 -63 %
Shares outstanding, period end (000s) 66,270 61,141 8 % 66,270 61,141 8 %
Average shares outstanding (000s) (5) 66,091 60,811 9 % 64,880 60,022 8 %

OPERATING HIGHLIGHTS
Average daily production (boe/d) (6) (7) 9,510 7,773 22 % 8,850 7,476 18 %
Average realized price ($/boe) (6) 51.55 61.90 -17 % 51.00 56.31 -9 %
Operating netback ($/boe) (6) (8) 44.59 56.56 -21 % 45.09 51.65 -13 %

(1) Excludes dividend declared in December and paid in January.
(2) Participation in Freehold's dividend reinvestment plan (DRIP) ranged between 17% and 41% in 2012 and is subject to change monthly at the participants' discretion.
(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 2012 was approximately 36% natural gas and 64% liquids (34% light and medium oil, 25% heavy oil, and 5% NGL).
(8) See Non-GAAP Financial Measures.

March Dividend Announcement

The Board of Directors has declared the March dividend of $0.14 per share, which will be paid on April 15, 2013 to shareholders of record on March 31, 2013. 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 16 years, we have paid out over $1.1 billion to our shareholders.

2012 Fourth Quarter Highlights

Freehold delivered strong operational results in the fourth quarter of 2012. Robust production volumes drove increases in revenue and cash flow from operating activities despite lower average realized prices.

- Average production for the fourth quarter was 22% higher than last year. Drilling activities, including flush production from newly completed horizontal wells, accounted for about two-thirds of the increase; prior period adjustments (650 boe per day versus 350 boe per day in fourth quarter last year) and acquisitions during 2012 accounted for the remainder.

- Dividends for the fourth quarter of 2012 totalled $0.42 per share, unchanged from last year.

- Average DRIP participation was 24% in the fourth quarter of 2012 (Q4 2011 - 40%), allowing us to retain $6.7 million (Q4 2011 - $10.2 million) in dividend payments by issuing shares from treasury.

- Net income of $13.4 million was 16% lower than last year, mainly as a result of increased depletion and depreciation expense, higher royalty expense, and higher operating expense due to a higher production base. Non-cash charges (excluding current income tax) included in net income amounted to $18.1 million (Q4 2011 - $22.3 million).

- Net capital expenditures on our working interest properties totalled $7.7 million in the fourth quarter (Q4 2011 - $10.9 million), the majority of which was incurred on horizontal drilling and multi-stage fracture well completions in southeast Saskatchewan.

- Long-term debt was $18.0 million at December 31, 2012, down $7.0 million from the third quarter as excess funds from operations were applied to debt repayment.

2012 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, 2012 totalled 24.4 MMboe, with reserves assigned to 22,589 wells. Net proved plus probable royalty interest reserves increased 10% year-over-year, and net proved plus probable working interest reserves increased 12%. Approximately 62% of our net reserves are in the proved category, and 93% of our net proved reserves are producing. On a boe basis, net reserves are 60% liquids (30% heavy oil, 24% light and medium oil, 6% natural gas liquids) and 40% natural gas.

- Net proved plus probable reserve additions totalled 5.3 MMboe (45% liquids). Drilling on our royalty lands added 1.0 MMboe (19%) of net proved plus probable reserves, development activities added 0.8 MMboe (15%), and acquisitions added 3.5 MMboe (66%). Based on this, we replaced approximately 167% of 2012 production.

- Freehold's finding costs are calculated based on net reserves. In 2012, finding and development costs for net proved plus probable reserves were $21.37 per boe, while acquisition costs were $17.47 per boe and the all-in finding, development and acquisition (FD&A) cost was $18.80 per boe (including changes in future development capital). Based on an operating netback of $45.09 per boe in 2012, these activities resulted in a recycle ratio of 2.4 times the capital invested, and a three-year average recycle ratio of 2.1.

- Our land holdings as at December 31, 2012 encompassed 3.0 million gross acres, up 9% from last year mainly as a result of acquisitions. Royalty interests comprised 94% of our acreage. Our undeveloped land was independently valued by Seaton-Jordan & Associates Ltd., at $80.2 million.

Royalty Interest Activity

On an equivalent net basis, 85% of the royalty wells drilled on our lands during 2012 were oil wells (2011 - 78%) due to the oil-prone nature of our lands. As well, over 66% of the equivalent net wells drilled on our royalty lands in 2012 were horizontal wells, up from 59% 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. Over one quarter of the royalty wells drilled in the fourth quarter of 2012 had a Cardium target. Continued success with horizontal drilling (for both oil and liquids-rich natural gas) is positive and bodes well for improved well productivity.

As at December 31, 2012, there were 99 (5.9 equivalent net) licensed drilling locations on our royalty lands, compared with 106 (5.4 equivalent net) at the same time last year. We view continued well licence activity as a positive indicator of the ongoing and future development potential on our royalty lands.

ROYALTY INTEREST WELLS DRILLED

Three Months Ended
December 31 Twelve Months Ended
December 31
2012 2011 2012 2011
Gross Equiv.
Net (1) Gross Equiv.
Net (1) Gross Equiv.
Net (1) Gross Equiv.
Net (1)
Non-unitized 57 2.6 102 4.9 231 11.6 301 14.4
Unitized (2) 30 0.1 60 0.4 200 1.2 322 1.3
Total 87 2.7 162 5.3 431 12.8 623 15.7

(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 2012, capital expenditures amounted to $7.7 million, the majority of which was spent to complete, equip, and tie-in wells drilled in southeast Saskatchewan during the third quarter. We participated in the drilling of seven (1.3 net) wells with a 100% success rate.

- In Saskatchewan, we participated in the drilling of two (0.3 net) vertical and one (0.1 net) horizontal Frobisher oil wells, as well as two (0.6 net) Bakken horizontal oil wells.

- In Alberta, we participated in one (0.1 net) horizontal Viking light oil well at Redwater and one (0.2 net) horizontal Cardium oil well at Minnehik Buck Lake.

This drilling activity had little effect on production levels in the fourth quarter but is expected to add to our production base in 2013.

WORKING INTEREST WELLS DRILLED (1)

Three Months Ended
December 31 Twelve Months Ended
December 31
2012 2011 2012 2011
Gross Net Gross Net Gross Net Gross Net
Oil 7 1.3 9 3.8 36 13.5 29 11.1
Natural gas - - - - - - 3 0.4
Other - - 1 0.1 1 0.6 2 0.1
Total 7 1.3 10 3.9 37 14.1 34 11.6

(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 $4.8 million ($5.51 per boe) was 28% higher than the fourth quarter last year (4% higher on a per boe basis). The increase correlates to the increase in working interest production volumes, as we do not incur operating expense on our royalty interest production.

GROSS REVENUE BY PRODUCT

Three Months Ended Twelve Months Ended
December 31 December 31
($000s) 2012 2011 Change 2012 2011 Change
Royalty Interest
Oil 20,503 25,419 -19 % 87,721 85,231 3 %
NGL 1,512 2,014 -25 % 6,887 6,495 6 %
Natural gas 3,831 3,402 13 % 10,501 15,581 -33 %
Other (1) 556 808 -31 % 2,525 3,206 -21 %
Total royalty interest revenue 26,402 31,643 -17 % 107,634 110,513 -3 %
Working Interest
Oil 17,801 11,847 50 % 55,577 40,786 36 %
NGL 476 655 -27 % 1,870 2,100 -11 %
Natural gas 978 922 6 % 2,640 3,447 -23 %
Other (1) 137 237 -42 % 413 1,064 -61 %
Total working interest revenue 19,392 13,661 42 % 60,500 47,397 28 %
Total
Oil 38,304 37,266 3 % 143,298 126,017 14 %
NGL 1,988 2,669 -26 % 8,757 8,595 2 %
Natural gas 4,809 4,324 11 % 13,141 19,028 -31 %
Other (1) 693 1,045 -34 % 2,938 4,270 -31 %
Total gross revenue 45,794 45,304 1 % 168,134 157,910 6 %
(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

Average production in the fourth quarter of 2012 was 1,737 boe per day higher than last year. Oil and natural gas liquids (NGL) production rose 22%, and natural gas production rose 26%.

- Royalty production volumes were 594 boe per day higher than last year, mainly as a result of royalty interests acquired during 2012 (which were 90% natural gas) and prior period adjustments due to the ongoing work of our audit team. Natural gas production was up 30%, while oil and NGL production declined 2%.

- Working interest production volumes were 1,143 boe per day higher than last year as a result of high activity levels in 2012 and flush production from newly completed wells in southeast Saskatchewan. Oil and NGL production was up 69% and natural gas production was up 12%.

AVERAGE DAILY PRODUCTION

Royalty Interest Working Interest Total
Three months ended December 31 2012 2011 2012 2011 2012 2011
Oil (bbls/d) 3,190 3,262 2,561 1,461 5,751 4,723
NGL (bbls/d) 267 252 88 106 355 358
Total oil and NGL (bbls/d) 3,457 3,514 2,649 1,567 6,106 5,081
Natural gas (Mcf/d) 17,105 13,198 3,315 2,952 20,420 16,150
Oil equivalent (boe/d) 6,308 5,714 3,202 2,059 9,510 7,773

Commodity Prices

In the fourth quarter of 2012, the benchmark West Texas Intermediate (WTI) crude oil price averaged US$88.18 per barrel, 6% lower than the prior year. Prices deteriorated during the quarter, and WTI also continues to trade at a discount to Brent crude, the global benchmark. Historically, WTI has traded at a slight premium over Brent; however during the last two years, WTI has traded consistently at a discount to Brent as a result of market access constraints.

Crude oil supply in North America is growing, primarily from the Canadian oil sands and tight oil plays in western Canada, North Dakota, Montana, and Texas, and global demand remains strong. However, refinery outages and pipeline bottlenecks in the U.S. Midwest have severely reduced access to the Texas and Louisiana Gulf Coast where there is greater refinery demand.

Growing supplies of light crude oil from the United States and a lack of spare pipeline capacity has blends like Edmonton Par and Western Canadian Select (WCS) being steeply discounted against WTI. The widening differentials have been an ongoing issue for Canadian producers throughout 2012 and are expected to remain a concern in 2013.

Natural gas, because it is less readily transported abroad, is subject to supply and demand factors within North America. Although the low price environment of the past three years has served to curtail dry gas drilling, horizontal well technology in shale gas plays and liquids-rich gas development led to record North American production in 2012.

The average benchmark AECO natural gas price was 14% lower in the fourth quarter of 2012 versus Q4 2011. The pricing outlook is bearish in the near term due to the oversupply situation. Longer-term, we believe demand growth, driven by the phasing out of coal-fired power plants in favour of cleaner-burning natural gas, increasing transportation and industrial use, and developing offshore markets, will support stronger natural gas pricing.

Our average selling prices reflect product quality and transportation differences from benchmark prices. In the fourth quarter of 2012, our average realized oil price was $72.40 (Q4 2011 - $85.78) per barrel and our average realized natural gas price was $2.56 (Q4 2011 - $2.91) per Mcf.

Guidance Update

The following table compares changes in our key operating assumptions during 2012 to our actual results for the year. Compared to our November guidance:

- Average production for the fourth quarter was 856 boe per day higher than the third quarter of 2012 and annual production came in 3% above guidance, mainly due to prior period adjustments and flush production from successful drilling in Southeast Saskatchewan.

- Average oil prices were slightly lower than our assumptions, while natural gas prices were slightly higher.

- General and administrative costs per boe were lower than forecast as a result of higher a production base.

- Capital expenditures were $1.7 million higher than forecast, as we completed and equipped more oil wells than anticipated in the fourth quarter.

2012 Key Operating Assumptions

Previous Guidance
Annual Average 2012 Actual Results Nov. 8, 2012 Aug. 9, 2012 May 9, 2012 Mar. 14, 2012
Daily production boe/d 8,850 8,600 8,300 8,100 7,600
WTI oil price US$/bbl 94.20 (1) 95.00 93.00 100.00 100.00
Western Canada Select (WCS) Cdn$/bbl 73.08 (1) 75.00 72.00 75.00 81.00
AECO natural gas price Cdn$/Mcf 2.39 (1) 2.25 2.25 2.00 2.50
Exchange rate Cdn$/US$ 1.00 1.00 1.00 1.00 1.00
Operating costs $/boe 4.82 4.80 4.80 4.80 4.60
General and administrative costs (2) $/boe 2.39 2.65 3.00 3.00 3.00
Capital expenditures $ millions 36.7 35 30 30 30
Dividends paid in shares (DRIP) $ millions 27.4 27 27 27 27
Long-term debt at year end $ millions 18 18 21 18 15
Cash taxes paid in 2012 $ millions 4.7 4.6 4.6 - -
Weighted average shares outstanding millions 64.9 65 65 65 65
(1) As reported by the Canadian Association of Petroleum Producers (CAPP).
(2) Excludes share based and other compensation.

2013 Key Operating Assumptions (1)

Guidance Updated
Annual Average March 7, 2013 November 8, 2012
Daily production boe/d 8,500 8,400
WTI oil price US$/bbl 95.00 95.00

Western Canada Select (WCS) Cdn$/bbl 71.00 76.00
AECO natural gas price Cdn$/Mcf 3.10 3.25
Exchange rate Cdn$/US$ 1.00 1.00
Operating costs $/boe 5.00 5.00
General and administrative costs (2) $/boe 2.60 2.60
Capital expenditures $ millions 30 33
Dividends paid in shares (DRIP) (3) $ millions 28 28
Long-term debt at year end $ millions 48 48
Cash taxes payable in 2013 for 2012 tax year (4) $ millions 23 25
Cash taxes payable for 2013 tax year (instalments) (4) $ millions 25 25
Weighted average shares outstanding millions 67 67

(1) A sensitivity analysis of the potential impact of key variables on funds from operations per share is provided in our 2012 Annual MD&A.

(2) Excludes share based and other compensation.

(3) Assumes average 25% participation rate in Freehold's dividend reinvestment plan, which is subject to change at the participants' discretion.

(4) Corporate tax estimates will vary depending on commodity prices and other factors.

As 2012 capital was ahead of guidance, we have revised our 2013 capital budget to $30 million. Our development plans are primarily oil related, focused almost entirely on our mineral title lands, and include approximately 40 gross (13 net) wells. Roughly half of our capital will be deployed in southeast Saskatchewan (light oil), with the balance allocated to our expanding mineral title opportunity base in both the Lloydminster area (heavy oil) and western Alberta (Cardium oil). Almost half of our total capital for the year will be spent in the first quarter of 2013, with area allocations similar to our annual budget. Spending may be adjusted as the year progresses, depending on the operating environment and well results.

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 2013 production to average approximately 8,500 boe per day. On a boe basis, production volumes for 2013 are expected to be approximately 64% oil and NGL and 36% natural gas. We continue to maintain our royalty focus with royalty production accounting for 67% of forecasted 2013 production.

In February 2013, we remitted $23 million for estimated 2012 corporate taxes. We expect to pay approximately $25 million for the 2013 tax year by way of monthly instalments. The large cash outlay for income taxes in 2013 is an anomaly that we have prepared for and have the financial capacity to handle. We expect our tax bill will normalize in 2014, at approximately 20% of pre-tax cash flow.

As our results demonstrate, we continue to benefit from activity on our oil-weighted asset base, and from relatively strong, if somewhat volatile, crude oil pricing. Of significance, natural gas accounted for 36% of production volumes in the fourth quarter (Q4 2011 - 35%), but only 11% of gross revenue (Q4 2011 - 10%). Clearly, we would benefit from any improvement in natural gas prices. However, despite a significant decline in revenue from natural gas, we have been able to maintain a steady monthly dividend rate of $0.14 ($1.68 annually) per share since January 2010.

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 2013 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 2013, subject to the Board's quarterly review and approval.

Succession Planning

After more than 16 years with Freehold and 29 years with Rife Resources Ltd. (the Manager of Freehold), Mr. William O. Ingram has announced that he plans to retire as President and CEO in May 2013. Mr. Ingram will step down as a director of Freehold but will continue to serve on the boards of Rife and Canpar Holdings Ltd. As well, Dr. P. Michael Maher, who has been a director of Freehold since 1996, will be retiring from the Board in May. The directors of Freehold thank Dr. Maher and Mr. Ingram for their many years of service to Freehold, and wish them both well in their retirement.

Following the retirement of Mr. Ingram in May, the Board plans to appoint Mr. Thomas J. Mullane as President and CEO, and he will stand for election as a director of Freehold at the annual meeting of shareholders to be held on May 15, 2013. Mr. Mullane joined Freehold in 2012 as Executive Vice-President and Chief Operating Officer, and brings a solid background of industry experience and knowledge at a senior level that will be an asset to Freehold in the years to come.

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 2012, our undeveloped land was independently valued at $80.2 million by Seaton-Jordan & Associates Ltd. Our total land holdings encompass approximately three million gross acres, 94% of which are royalties. Of this, our mineral title lands (including royalty assumption lands), which we own in perpetuity, cover more than 630,000 acres; all but approximately 107,000 gross acres of which are currently leased to third parties. In addition, we have gross overriding royalty interests in nearly 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 do not include potential reserve additions that may occur as a result of future drilling on most of 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 $20.7 million before tax (discounted at 10%).

Our oil and gas reserves were independently evaluated by Trimble Engineering Associates Ltd. (Trimble) as at December 31, 2012. 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, 2012
Forecast Prices and Costs (1) Light and Medium Oil Heavy Oil Total Crude Oil
Gross (2) Net (3) Gross (2) Net (3) Gross (2) Net (3)
Reserves Category (Mbbls) (Mbbls) (Mbbls) (Mbbls) (Mbbls) (Mbbls)
Proved
Developed producing 1,754 3,490 827 4,150 2,581 7,640
Developed non-producing 73 64 - 6 73 70
Undeveloped - - 28 23 28 23
Total proved 1,826 3,554 856 4,178 2,682 7,733
Probable 1,346 2,301 916 3,197 2,262 5,498
Total proved plus probable 3,173 5,855 1,771 7,376 4,944 13,231

Natural Gas Natural Gas Liquids Oil Equivalent
Gross (2) Net (3) Gross (2) Net (3) Gross (2) Net (3)
Reserves Category (MMcf) (MMcf) (Mbbls) (Mbbls) (Mboe) (Mboe)
Proved
Developed producing 4,024 33,628 146 841 3,398 14,085
Developed non-producing 59 794 7 7 90 209
Undeveloped - 4,314 - 46 28 788

Total proved 4,083 38,736 154 893 3,516 15,082
Probable 3,042 20,212 124 476 2,893 9,343
Total proved plus probable 7,125 58,949 277 1,369 6,409 24,425

(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, 2012
Forecast Prices and Costs ($000s) (1) Before Income Taxes, Discounted at (% per year)
0% 5% 10% 15% 20%
Proved
Developed producing 730,246 537,722 431,272 364,055 317,704
Developed non-producing 4,259 2,773 1,986 1,517 1,211
Undeveloped 23,328 16,185 11,818 8,958 6,987
Total proved 757,833 556,679 445,076 374,529 325,902
Probable 564,863 295,635 193,236 142,680 112,973
Total proved plus probable 1,322,696 852,314 638,312 517,209 438,875

After Income Taxes, Discounted at (% per year) (2)
Reserves Category 0% 5% 10% 15% 20%
Proved
Developed producing 616,012 453,317 363,687 307,156 268,186
Developed non-producing 3,194 2,060 1,458 1,099 865
Undeveloped 17,434 12,070 8,789 6,639 5,158
Total proved 636,639 467,447 373,934 314,894 274,210
Probable 420,690 219,454 142,981 105,240 83,075
Total proved plus probable 1,057,329 686,902 516,915 420,134 357,284

(1) Based on the December 31, 2012 escalated oil and gas price forecasts by an independent qualified reserves evaluator. Future net revenue values do not represent fair market value. Reserve values do not include potential reserve additions that may occur as a result of future drilling on our royalty lands. 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, 2012
Forecast Prices and Costs ($000s) (1) Reserves Category
Proved Reserves Proved Plus Probable Reserves
Royalty income 660,266 1,136,234
Revenue from working interest properties 269,358 506,074
Royalty expense on working interest properties (40,759) (83,190)
Operating costs (121,380) (214,202)
Development costs (1,441) (12,560)
Well abandonment and reclamation costs (8,212) (9,661)
Future net revenue before income taxes 757,833 1,322,696
Future income taxes (2) (121,194) (265,367)
Future net revenue after income taxes (2) 636,639 1,057,329

(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. Reserve values do not include potential reserve additions that may occur as a result of future drilling on our royalty lands. 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
2013	773	5,538
2014	519	6,525
2015	29	131
2016	29	117
2017	30	119
Remainder	61	130
Total	1,441	12,560

(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, 2012 (1)

	Proved Producing	Total Proved	Proved Plus Probable
Net reserves (Mboe)	14,085	15,082	24,425
Net production (Mboe)	2,518	2,546	2,878
Reserve life index (years)	5.6	5.9	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 2013 net production into the remaining net reserves).

Reconciliation of Net Reserves (1)

By Principal Product Type
Forecast Prices and Costs (1) Light and Medium Oil Heavy Oil
Proved Plus Proved Plus
Proved Probable Probable Proved Probable Probable
(Mbbls) (Mbbls) (Mbbls) (Mbbls) (Mbbls) (Mbbls)
December 31, 2011 3,445 1,885 5,330 4,533 2,841 7,373
Extensions 569 426 995 324 199 523
Improved recovery - - - - - -
Technical revisions 319 (178) 142 167 (74) 93
Discoveries - - - - - -
Acquisitions 87 165 253 46 232 278
Dispositions - - - - - -
Economic factors 16 3 19 5 - 5
Production (883) - (883) (897) - (897)
December 31, 2012 3,554 2,301 5,855 4,178 3,197 7,376

Natural Gas Natural Gas Liquids
Proved Plus Proved Plus
Proved Probable Probable Proved Probable Probable
(MMcf) (MMcf) (MMcf) (Mbbls) (Mbbls) (Mbbls)
December 31, 2011 32,560 17,113 49,673 802 405 1,206

Extensions 810 523 1,333 42 27 69
Improved recovery - - - - - -
Technical revisions 771 (1,677) (906) 42 (31) 11
Discoveries - - - - - -
Acquisitions 11,765 4,263 16,028 206 75 281
Dispositions - - - - - -
Economic factors (21) (10) (31) - - -
Production (7,149) - (7,149) (198) - (198)
December 31, 2012 38,736 20,212 58,949 893 476 1,369

Oil Equivalent
Proved Plus
Proved Probable Probable
(Mboe) (Mboe) (Mboe)
December 31, 2011 14,206 7,982 22,189
Extensions 1,071 738 1,809
Improved recovery - - -
Technical revisions 657 (562) 95
Discoveries - - -
Acquisitions 2,300 1,183 3,483
Dispositions - - -
Economic factors 17 1 19
Production (3,169) - (3,169)
December 31, 2012 15,082 9,343 24,425

(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 2012 2011 2010 Three-Year Results
Finding and development expenditures ($000s) 36,746 25,649 18,054 80,449
Change in future development capital estimates ($000s) (934) 1,556 (59) 563
Net reserve additions by development (Mboe) 1,071 581 465 2,117
Finding and development costs ($/boe) 33.45 46.81 38.67 38.27
Acquisition expenditures ($000s) 60,852 7,467 38,600 106,919
Net reserve additions by acquisition (Mboe) 2,300 103 857 3,260
Acquisition costs ($/boe) 26.46 72.42 45.05 32.80
Total expenditures ($000s) 97,598 33,116 56,654 187,368
Change in future development capital estimates ($000s) (934) 1,556 (59) 563
Net reserve additions (Mboe) 3,371 684 1,322 5,377
Finding, development and acquisition costs ($/boe) 28.68 50.67 42.81 34.95

Net Proved Plus Probable Reserves 2012 2011 2010 Three-Year Results
Finding and development expenditures ($000s) 36,746 25,649 18,054 80,449
Change in future development capital estimates ($000s) 1,916 4,959 35 6,910
Net reserve additions by development (Mboe) 1,809 1,085 950 3,845
Finding and development costs ($/boe) 21.37 28.20 19.04 22.72
Acquisition expenditures ($000s) 60,852 7,467 38,600 106,919
Net reserve additions by acquisition (Mboe) 3,483 207 1,352 5,042
Acquisition costs ($/boe) 17.47 36.12 28.56 21.21
Total expenditures ($000s) 97,598 33,116 56,654 187,368
Change in future development capital estimates ($000s) 1,916 4,959 35 6,910
Net reserve additions (Mboe) 5,292 1,292 2,302 8,886
Finding, development and acquisition costs ($/boe) 18.80 29.47 24.63 21.86

(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) 2012 2011 2010 Three-Year Results
Operating netback (1) (4) 45.09 51.65 44.08 46.81
Finding, development and acquisition costs (2) (4) 18.80 29.47 24.63 21.86
Recycle ratio (times) (3) 2.4 1.8 1.8 2.1

(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, 2012
(gross acres) (1) Developed Undeveloped Total
Mineral title lands (2) 367,071 168,364 535,435
Royalty assumption lands (3) 73,940 20,882 94,822
Total title lands (4) 441,011 189,246 630,257
Gross overriding royalty (GORR) lands (5) 1,571,533 603,548 2,175,081
Total royalty lands 2,012,544 792,794 2,805,338
Working interest properties 147,781 40,253 188,034
Total land holdings 2,160,325 833,047 2,993,372
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 1,537,959 380,780 111,672 16,793 26,695 5,480 1,649,631 407,475
Saskatchewan 294,474 199,025 16,703 5,062 7,427 4,417 311,177 206,452
Ontario 88,858 184,834 - - - - 88,858 184,834
British Columbia 84,996 26,571 19,247 1,265 6,131 101 104,243 32,702
Manitoba 6,257 1,584 159 37 - - 6,416 1,584
Total 2,012,544 792,794 147,781 23,157 40,253 9,998 2,160,325 833,047

(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
2012 2011
Q4 Q3 Q2 Q1 Q4 Q3 Q2 Q1
FINANCIAL ($000s, except as noted)
Revenue, net of royalty expense 43,832 40,294 34,498 43,036 44,217 34,614 39,560 35,322
Dividends declared 27,787 27,616 27,399 26,766 25,585 25,322 25,111 24,950
Per share ($) (1) 0.42 0.42 0.42 0.42 0.42 0.42 0.42 0.42
Net income (2) 13,431 11,975 7,862 13,060 16,033 11,290 16,717 11,219
Per share, basic and diluted ($) (2) 0.20 0.18 0.12 0.21 0.26 0.19 0.28 0.19
Cash flow from operating activities 38,183 36,212 27,402 36,335 32,595 30,255 31,424 24,096
Per share ($) 0.58 0.55 0.42 0.58 0.54 0.50 0.53 0.41
Funds from operations (3) 31,475 26,272 20,522 25,613 38,245 28,772 33,891 27,322

Per share ($) (3) 0.48 0.40 0.31 0.41 0.63 0.48 0.57 0.46
Dividends paid in shares (DRIP) 6,672 7,013 6,940 6,789 10,232 8,765 7,798 6,695
Average DRIP participation rate (%) (4) 24 25 25 26 40 35 31 27
Property and royalty acquisitions (net) 243 10,789 (99) 49,919 (195) 7,297 44 321
Capital expenditures 7,743 9,160 6,598 13,245 10,910 5,537 4,537 4,665
Long-term debt 18,000 25,000 23,000 18,000 48,000 51,000 54,000 61,000
Shares outstanding
Weighted average, basic (000s) 66,091 65,677 65,159 62,571 60,811 60,198 59,716 59,343
At quarter end (000s) 66,270 65,879 65,440 64,993 61,141 60,492 59,954 59,536
OPERATING ($/boe, except as noted)
Daily production (boe/d) (5) 9,510 8,654 8,501 8,733 7,773 7,195 7,445 7,490
Royalty interest production (%) 66 68 76 74 74 72 77 76
Average selling price 51.55 51.71 45.74 54.80 61.90 52.80 57.61 52.51
Operating netback (3) 44.59 45.59 40.64 49.48 56.56 46.86 53.82 48.96
Operating expenses 5.51 5.02 3.96 4.68 5.28 5.43 4.57 3.44
Working interest properties 16.36 15.47 16.47 17.86 19.91 19.47 19.73 14.32
Net general and administrative expenses (6) 2.25 1.88 2.13 3.31 2.05 2.16 2.36 3.75
BENCHMARK PRICES
WTI crude oil (US$/bbl) 88.18 92.22 93.49 102.93 94.06 89.75 102.56 94.02
Exchange rate (Cdn$/US$) 1.01 1.01 0.99 1.00 0.98 1.02 1.03 1.01
Edmonton Par crude oil (Cdn$) 83.99 84.33 83.95 92.18 97.35 91.74 103.07 87.97
Western Canada Select (WCS) (Cdn$/bbl) 69.43 69.99 71.29 81.61 85.48 70.63 82.09 70.19
WTI/Edmonton Par differential ($/bbl) (4.19) (7.89) (9.54) (10.75) 3.29 1.99 0.51 (6.05)
Edmonton Par/WCS differential (Cdn$/bbl) (14.56) (14.34) (12.66) (10.57) (11.87) (21.11) (20.98) (17.78)
AECO natural gas (Cdn$/Mcf) 3.00 2.19 1.83 2.52 3.47 3.72 3.74 3.77
SHARE TRADING PERFORMANCE
High ($) 22.45 20.34 19.67 21.59 19.75 21.58 23.28 22.93
Low ($) 19.62 17.83 17.25 19.16 14.51 16.04 19.37 19.86
Close ($) 22.40 19.76 18.44 19.59 19.41 16.36 19.64 22.75
Volume (000s) 7,435 5,656 7,483 8,076 7,114 7,780 5,317 7,921

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

(2) Net income and net income per share for the three months ended March 31, 2011 have been restated for revisions made to deferred tax.

(3) See Non-GAAP Financial Measures.

(4) Average participation in Freehold's DRIP ranged between 24% and 40% over the past eight quarters and is subject to change at the participants' discretion.

(5) Reported production for a period may include minor adjustments from previous production periods.
(6) Excludes share based and other compensation.

Consolidated Balance Sheets
December 31 December 31
($000s) (unaudited) 2012 2011

Assets
Current assets:
Cash $ 102 $ 164
Accounts receivable 23,225 34,763
23,327 34,927
Deposit on acquisition - 5,000
Exploration and evaluation assets 25,905 25,045
Petroleum and natural gas interests 399,005 363,967
$ 448,237 $ 428,939

Liabilities and Shareholders' Equity
Current liabilities:
Dividends payable $ 9,278 $ 8,560
Accounts payable and accrued liabilities 12,743 14,883
Current taxes payable 23,095 -
Current portion of share based and other compensation payable 2,108 3,876
47,224 27,319

Asset retirement obligation 16,714 14,282
Share based and other compensation payable 1,290 1,289
Long-term debt 18,000 48,000
Deferred income tax liability 49,194 59,163

Shareholders' equity:
Shareholders' capital 422,728 323,115
Contributed surplus 2,036 1,480
Deficit (108,949) (45,709)
315,815 278,886
$ 448,237 $ 428,939
Consolidated Statements of Income and Comprehensive Income
Three Months Ended Year ended
(unaudited) December 31 December 31
($000s, except per share and weighted average data) 2012 2011 2012 2011

Revenue:
Royalty income and working interest sales $ 45,794 $ 45,304 $ 168,134 $ 157,910
Royalty expense (1,962) (1,087) (6,474) (4,197)
43,832 44,217 161,660 153,713

Expenses:
Operating 4,820 3,772 15,598 12,782
General and administrative 1,972 1,468 7,746 7,029
Share based and other compensation 999 1,268 2,371 2,190
Interest and financing 421 610 2,235 2,907
Depletion and depreciation 16,372 13,603 64,576 49,251
Accretion of asset retirement obligation 107 83 381 344
Management fee 1,072 857 3,808 3,401
25,763 21,661 96,715 77,904

Income before taxes 18,069 22,556 64,945 75,809

Income tax:
Current expense 5,063 80 27,792 80
Deferred expense (recovery) (425) 6,443 (9,175) 20,470
4,638 6,523 18,617 20,550

Net income and comprehensive income $ 13,431 $ 16,033 $ 46,328 $ 55,259
Net income per share, basic and diluted $ 0.20 $ 0.26 $ 0.71 $ 0.92

Weighted average number of shares:
Basic 66,090,969 60,811,300 64,880,038 60,021,736
Diluted 66,194,503 60,886,218 64,979,074 60,093,840
Consolidated Statements of Cash Flows
Three Months Ended Year ended
December 31 December 31
($000s) (unaudited) 2012 2011 2012 2011

Operating:
Net income $ 13,431 $ 16,033 $ 46,328 $ 55,259
Items not involving cash:
Depletion and depreciation 16,372 13,603 64,576 49,251
Share based and other compensation 999 1,268 2,371 2,190
Deferred income tax expense (recovery) (425) 6,443 (9,175) 20,470
Accretion of asset retirement obligation 107 83 381 344
Shares issued in lieu of management fee 1,072 857 3,808 3,401
Expenditures on share based and other compensation - - (3,883) (2,440)
Expenditures on reclamation (81) (42) (524) (245)
Changes in non-cash working capital 6,708 (5,650) 34,250 (9,860)
38,183 32,595 138,132 118,370
Financing:
Issuance of shares, net of issue costs - - 67,597 -
Long-term debt (7,000) (3,000) (30,000) (17,000)
Dividends paid (21,060) (15,262) (81,436) (67,204)
(28,060) (18,262) (43,839) (84,204)
Investing:

Deposit on acquisition - (5,000) 5,000 (5,000)
Property and royalty acquisitions (243) 195 (60,852) (7,467)
Capital expenditures (7,743) (10,910) (36,746) (25,649)
Change in reclamation fund - - - 2,725
Changes in non-cash working capital (2,149) 1,358 (1,757) 980
(10,135) (14,357) (94,355) (34,411)
Decrease in cash (12) (24) (62) (245)
Cash, beginning of period 114 188 164 409
Cash, end of period $ 102 $ 164 $ 102 $ 164

Consolidated Statements of Changes in Shareholders' Equity

($000s)	Year ended December 31 (unaudited)	2012	2011
Shareholders' capital:			
	Balance, beginning of year	$ 323,115	$ 286,224
	Shares issued for dividend reinvestment plan	27,414	33,4
	Shares issued in lieu of management fee	3,808	3,401
	Shares issued for equity offering	70,725	-
	Issue costs, net of tax effect	(2,334)	-
	Balance, end of year	422,728	323,115
Contributed surplus:			
	Balance, beginning of year	1,480	1,084
	Share based compensation expense	556	396
	Balance, end of year	2,036	1,480
Deficit:			
	Balance, beginning of year	(45,709)	-
	Net income and comprehensive income	46,328	55,259
	Dividends declared	(109,568)	(100,968)
	Balance, end of year	(108,949)	(45,709)
Total shareholders' equity		$ 315,815	$ 278,886

Forward-Looking Statements

This news release offers our assessment of Freehold's future plans and operations as at March 7, 2013, 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;
- drilling activity during the fourth quarter of 2012 adding to our production base in 2013;
- 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 2013 and our dividend policy; and
- the appointment of Thomas J. Mullane as President and CEO and his standing for election as a director of Freehold.

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.

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, netback, funds from operations, funds from operations per share, finding, development and acquisition (FD&A) costs, recycle ratio, and net asset value. We believe that these measures 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 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

Funds from operations is a financial term commonly used in the oil and gas industry. It is a key measure of our ability to generate cash, finance operations, and pay monthly dividends. 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 define funds from operations as net income adjusted for non-cash depletion and depreciation, share based and other compensation, deferred tax expense/recovery, accretion of asset retirement obligation, and management fee, and further adjusted for expenditures on reclamation. 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 and repay debt. We believe that such a measure provides a better assessment of Freehold's operations on a continuing basis by eliminating certain non-cash charges. From a business perspective, the most directly comparable measure of funds from operations calculated in accordance with GAAP is net income. 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. A reconciliation of funds from operations to net income is provided below.

Reconciliation of Net Income to Funds from Operations

	Three Months Ended December 31		Twelve Months Ended December 31	
	2012	2011	2012	2011
Net income	13,431	16,033	46,328	
Adjust for non-cash items:				
Depletion and depreciation	16,372	13,603		
Share based and other compensation	999	1,268		
Deferred income tax (recovery)	(425)	6,443	(9,1	
Accretion of asset retirement obligation	107	83		
Management fee	1,072	857	3,808	
Adjust for cash item:				
Expenditures on reclamation	(81)	(42)	(524)	(24
Funds from operations	31,475	38,245	103,882	
Per share	0.48	0.63	1.60	

In addition, we refer to various per boe figures, such as revenues and costs, operating netback, FD&A costs, and NAV, also considered non-GAAP financial 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 gas production during the period, with natural gas converted to equivalent barrels of oil as described above.

Availability on SEDAR

Freehold's 2012 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 next week.

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