Freehold Royalties Ltd. Announces 2014 Fourth Quarter Results and Year-End Reserves

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CALGARY, ALBERTA--(Marketwired - Mar 5, 2015) - Freehold Royalties Ltd. (Freehold) (TSX:FRU) today announced 2014 fourth quarter results and reserves as at December 31, 2014.

Results at a Glance

	Three Months Ended December 31			Twelve Months Ended December 31		
FINANCIAL ($000s, except as noted)	2014	2013	Change	2014	2013	Change
Gross revenue	43,631	45,287	-4%	199,850	181,578	10%
Net income	11,082	14,106	-21%	66,447	57,852	15%
Per share, basic and diluted ($)	0.15	0.21	-29%	0.94	0.86	9%
Funds from operations (1)	30,774	29,092	6%	138,447	119,431	16%
Per share, basic ($) (1)	0.41	0.43	-5%	1.95	1.79	9%
Operating income (1)	37,584	37,954	-1%	175,192	155,844	12%
Operating income from royalties (%)	80	74	8%	78	73	7%
Property and royalty acquisitions	60,566	6,891	779%	248,274	10,091	2360%
Capital expenditures	13,500	5,335	153%	33,701	29,287	15%
Dividends declared	31,353	28,373	11%	119,788	112,495	6%
Per share ($) (2)	0.42	0.42	0%	1.68	1.68	0%
Net debt obligations (1)	135,810	45,385	199%	135,810	45,385	199%
Shares outstanding, period end (000s)	74,919	67,746	11%	74,919	67,746	11%
Average shares outstanding (000s) (3)	74,545	67,483	10%	71,029	66,900	6%
OPERATING						
Average daily production (boe/d) (4)	9,836	9,173	7%	9,180	8,913	3%
Average price realizations ($/boe) (4)	47.46	52.99	-10%	58.91	55.06	7%
Operating netback ($/boe) (1) (4)	41.54	44.97	-8%	52.30	47.91	9%

(1) See Additional GAAP Measures and Non-GAAP Financial Measures.
(2) Based on the number of shares issued and outstanding at each record date.
(3) Weighted average number of shares outstanding during the period, basic.
(4) See Conversion of Natural Gas to Barrels of Oil Equivalent (boe).

March Dividend Announcement

The Board of Directors has declared the March dividend of $0.09 per share, which will be paid on April 15, 2015 to shareholders of record on March 31, 2015. Including the April 15 payment, our 12-month trailing cash dividends total $1.53 per share. This dividend is designated as an eligible dividend for Canadian income tax purposes.

2014 Fourth Quarter Highlights

Freehold delivered strong operational results in the fourth quarter of 2014. Some of the highlights included:

- Production for Q4-2014 averaged 9,836 boe/d, a 7% increase over Q4-2013 and a 4% increase over Q3-2014. The key driver behind the year over year increase in volumes was primarily acquisitions completed by Freehold. In total, our royalty production grew by 17% versus Q4-2013.
- Gross revenue for Q4-2014 totalled $43.6 million compared to $45.3 million in Q4-2013. Revenue was down slightly primarily associated with a reduction in our realized oil price, offset by increased natural gas volumes and pricing.
- Funds from operations totalled $30.8 million in Q4-2014 compared to $29.1 million in Q4-2013. The increase versus 2013 was due to a lower tax expense primarily associated with our East Edson joint venture and the tax pools we created through the development of that asset, with negative offsets from gross revenue as mentioned above.

- Net income for Q4-2014 of $11.1 million was 21% lower than Q4-2013. Variance in earnings versus Q4-2013 was primarily driven by higher depletion and depreciation, lower revenues, lower taxes and recoveries to share based and other compensation expense.
- Dividends for Q4-2014 totalled $0.42 per share, unchanged from last year.
- Announced four separate transactions over Q4-2014 showcasing Freehold's flexibility in enhancing value for shareholders. Based on the consolidated transaction price of $49.6 million (all deals were funded through our bank line), the transactions imply approximately $95,000 per expected boe/d and will add approximately 450 boe/d to 2015 average production.
- Capital expenditures on our working interest properties totalled $13.5 million in Q4-2014 with the majority of spending allocated to southeast Saskatchewan.
- Freehold continues to maintain a strong balance sheet with net debt obligations at year-end of $135.8 million. This implies a net debt to Q4-2014 annualized funds from operations ratio of approximately 1.1 times. Increased leverage reflected acquisitions over Q4-2014 with Freehold facilitating the transactions through its existing credit line.
- Average DRIP participation was 35% in Q4-2014 (Q4-2013 - 27%), allowing us to retain $10.9 million (Q4 2013 - $7.6 million) in dividend payments by issuing shares from treasury for the year.

Subsequent Events

Change to Dividend

On January 14, 2015 Freehold announced that its Board of Directors had approved an adjustment to its monthly dividend to $0.09 per share from $0.14 per share. The revision to the dividend is reflective of the current oil and gas price environment.

Anderson Energy Ltd. Acquisition and Corporate Restructuring

On January 23, 2015 Freehold acquired all of the outstanding shares of Anderson Energy Ltd. ("Anderson") pursuant to a plan of arrangement under the Business Corporations Act (Alberta) for total consideration of $35 million (subject to certain adjustments) with Freehold funding the deal through its existing credit facilities. Pursuant to the plan of arrangement, Anderson shareholders exchanged their shares for shares of a newly formed publicly listed company, Anderson Energy Inc. ("New Anderson"). In addition, prior to Freehold acquiring the outstanding shares, Anderson transferred certain assets and liabilities to New Anderson. The liabilities transferred to New Anderson included Anderson's liabilities and obligations for its currently outstanding convertible debentures.

Immediately following the completion of the acquisition of Anderson, Freehold completed a corporate restructuring pursuant to which Freehold first amalgamated with Anderson and subsequently amalgamated with its wholly-owned subsidiary, Freehold Resources Ltd. In addition, pursuant to the restructuring, Freehold Holdings Trust was established and became a partner in the Freehold Royalties Partnership.

Increase to Credit Line

On January 23, 2015 Freehold increased its credit facilities from $210 to $260 million through a syndicate of four Canadian chartered banks. This increase allows Freehold to maintain its financial flexibility.

Royalty and Mineral Title Acquisition

On January 23, 2015 Freehold closed an agreement purchasing royalty and mineral title assets in Alberta, British Columbia and Saskatchewan for $12.4 million. These assets produced 72 boe/d (60% gas) in October 2014 and included 35,600 mineral title acres.

Income Tax

The above mentioned acquisitions have added approximately $235 million to our existing December 31, 2014 tax pool balances.

2014 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), as 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 exploration and development companies. 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, 2014 totalled 29.7 MMboe, with reserves assigned to 23,514 wells. Net proved plus probable royalty interest reserves increased 35% year-over-year, and net proved plus probable working interest reserves were up 7%. Approximately 66% of our net reserves are in the proved category, and 72% of our net proved reserves are producing. On a boe basis, net reserves are 53% liquids (22% heavy oil, 24% light and medium oil, 7% natural gas liquids) and 47% natural gas.
- Net proved plus probable reserve additions totalled 9.4 MMboe (60% natural gas). Drilling on our royalty lands added 1.1 MMboe of net proved plus probable reserves, development activities added 0.6 MMboe of net proved plus probable reserves, and acquisitions added 7.8 MMboe of net proved plus probable reserves. Based on this, we replaced approximately 286% of 2014 production.
- Freehold's finding costs are calculated based on net reserves. In 2014, finding and development costs for net proved plus probable reserves were $21.87 per boe, while acquisition costs were $30.04 per boe and the all-in finding, development and acquisition (FD&A) cost was $28.60 per boe (including changes in future development capital). Based on an operating netback of $52.30 per boe in 2014, these activities resulted in a recycle ratio of 1.8, and a three-year average recycle ratio of 2.0.
- Our land holdings as at December 31, 2014 encompassed approximately 3.2 million gross acres, up 4% from last year mainly as a result of acquisitions completed throughout the year. Royalty interests comprised 93% of our acreage. Our undeveloped land was independently valued by Seaton-Jordan & Associates Ltd., at $114.0 million.

Royalty Interest Activity

In total, 443 (15.1 equivalent net) wells were drilled on our royalty lands through 2014 representing a 27% improvement versus 2013 on an equivalent net basis (excluding the East Edson joint venture). The increase was the result of a combination of royalty acquisitions made through the year along with the overall prospectivity of our title land.

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. 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, 2014, there were 82 (6.0 equivalent net) licensed drilling locations on our royalty lands; this compares to 51 (3.6 equivalent net) licensed wells seen one year ago.

	Three Months Ended December 31				Twelve Months Ended December 31			
	2014		2013		2014		2013	
	Gross	Equivalent Net (1)	Gross	Equivalent Net (1)	Gross	Equivalent Net (1)	Gross	Equivalent Net (1)
Non-unit-ized wells	73	4.0	68	4.3	258	14.0	197	11.3
Unitized wells (2)	65	0.3	38	0.2	185	1.1	141	0.6
Total	138	4.3	106	4.5	443	15.1	338	11.9
East Edson joint venture (3)	9				13			

(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.

(3) Wells drilled on our East Edson joint venture lands, where equivalent net wells cannot be calculated.

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 Q4-2014, capital expenditures totalled $13.5 million, the majority of which was spent to complete, equip, and tie-in wells drilled in southeast Saskatchewan. We participated in the drilling of 25 (5.7 net) wells with a 100% success rate.

- In southeast Saskatchewan there were six (1.9 net) Frobisher oil wells, three (0.8 net) Midale oil wells and three (0.5 net) Bakken oil wells drilled. All of these wells were drilled horizontally.
- The Lloydminster area saw one (0.5 net) vertical oil well drilled in Q4-2014.
- In Alberta, there were three (0.8 net) vertical Glacuonite gas wells and nine (1.2 net) horizontal Cardium oil wells drilled over the quarter.

Freehold spent almost 40% of its 2014 capital in Q4-2014. This spending is expected to add to Q1/15 production levels as these wells are brought onstream.

	Three Months Ended December 31				Twelve Months Ended December 31			
	2014		2013		2014		2013	
	Gross	Net (1)	Gross	Net (1)	Gross	Net (1)	Gross	Net (1)
Oil	22	4.9	6	1.2	47	11.3	41	12.9
Natural gas	3	0.8	-	-	7	0.9	-	-
Other	-	-	-	-	-	-	7	0.7
Total	25	5.7	6	1.2	54	12.2	48	13.6

(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.

Fourth Quarter Production

Production volumes in Q4-2014 averaged 9,836 boe/d, an increase of 7% when compared with levels averaged one-year ago.

- Royalty production averaged 7,320 boe/d in Q4-2014, representing a 17% increase when compared to Q4-2013. Oil and natural gas liquids production was up 8%. On the natural gas side, volumes were up 29% from Q4-2013, largely as the result of a full quarter of operations associated with the East Edson joint venture.
- Working interest production volumes averaged 2,516 boe/d in Q4-2014. This represented a 13% decrease versus Q4-2013 with reduced volumes primarily associated with delayed capital spending.

	Three Months Ended December 31			Twelve Months Ended December 31		
	2014	2013	Change	2014	2013	Change
Royalty interest (1)						
Oil (bbls/d)	3,501	3,336	5%	3,384	3,177	7%
NGL (bbls/d)	403	293	38%	435	332	31%
Natural gas (Mcf/d)	20,494	15,853	29%	17,915	16,115	11%
Oil equivalent (boe/d)	7,320	6,271	17%	6,805	6,195	10%
Working interest (1)						
Oil (bbls/d)	1,972	2,225	-11%	1,851	2,109	-12%
NGL (bbls/d)	101	91	11%	102	103	-1%
Natural gas (Mcf/d)	2,657	3,515	-24%	2,531	3,033	-17%
Oil equivalent (boe/d)	2,516	2,902	-13%	2,375	2,718	-13%
Total						
Oil (bbls/d)	5,473	5,561	-2%	5,235	5,286	-1%
NGL (bbls/d)	504	384	31%	537	435	23%
Natural gas (Mcf/d)	23,151	19,368	20%	20,446	19,148	7%
Oil equivalent (boe/d)	9,836	9,173	7%	9,180	8,913	3%
Number of days in period (days)	92	92	0%	365	365	0%
Total volumes during period (Mboe)	905	844	7%	3,350	3,253	3%

(1) On certain properties where we have both a royalty interest and a working interest, production is allocated based on the applicable royalty and working interest percentages.

Business Environment

Through the first six months of 2014, West Texas Intermediate (WTI) averaged greater than US$100/bbl as the market responded to concerns of prolonged production disruptions in Libya, hopes for improving worldwide demand and stimulus provided through the U.S. quantitative easing program. Approximately half way through the year sentiment flipped and prices began to steadily decline. OPEC's announcement in late November 2014 that they would not cut production in the face of weaker demand saw prices retreat another 25% through year-end. WTI oil prices fell by greater than 50% from their highs and has traded between US$45-$55/bbl within the last month.

Through 2014 the benchmark WTI crude oil price averaged US$92.99/bbl, slightly lower when compared to 2013. Within Canada, oil and gas producers have been protected somewhat from depressed prices by prevailing weakness in the Canadian dollar with the US$/Cdn$ exchange rate averaging $0.91 for 2014, a 6% decrease versus 2013. Through 2014, the price of Edmonton Par averaged C$94.58/bbl, a 2% increase over 2013. Heavy oil producers have fared slightly better with Western Canadian Select (WCS) prices averaging C$81.10/bbl for 2014, up 8% when compared to 2013. Through improvements in transportation (proliferation of rail and pipelines) within North America we have seen light heavy oil differentials contract from $17.93/bbl in 2013 to $13.48/bbl in 2014 (Edmonton Par to WCS), with the expectation that these levels should sustain themselves as further advancements are made on the infrastructure side.

Looking forward, 2015 is expected to be a very challenging year for oil and gas producers that are levered to crude oil. Without improving economic conditions outside of the U.S, it is likely that the U.S. dollar will remain strong and energy prices may remain at depressed levels. Global oil demand has been weaker than expected, most notably in Asia. While it is expected that demand will pick-up with lower prices, there may be a timing delay. Finally, it is estimated that global oil demand is approximately 2.0 mmbbl/d oversupplied, primarily due to accelerated spending within non-OPEC members (mainly the U.S.). As a result, barring an unanticipated disruption in supply or a decision by OPEC to cut production, prices are likely to remain weak through a large part of 2015.

On the natural gas side, prices were relatively strong, with AECO averaging C$4.41/mcf in 2014, a 40% increase when compared to last year. Similar to crude oil prices, weakness in the Canadian dollar helped mitigate the pricing gap between Henry Hub and AECO through the year. However, in the near to medium term we expect natural gas prices, particularly AECO, to remain challenged. Growth out of the U.S. shale basins, particularly the Marcellus, continues to have an impact by displacing Canadian volumes. It is expected that the Marcellus gas production itself could grow at greater than 2 bcf/d annually over the near-term. Marcellus production is now greater than Canada's total natural gas output. With no near-term solution outlined for getting natural gas off the continent, particularly as it relates to West Coast LNG, it is expected that Canadian producers may be natural gas price challenged.

Drilling Activity

In 2014, a total of 10,920 wells were drilled and completed within the Western Canadian Sedimentary Basin (the "Basin"), up slightly from 10,883 in 2013. While activity was relatively flat through 2014, with the retreat in commodity prices we have seen a material reduction in drilling activity within the Basin. On January 22, 2015, the Canadian Association of Oilwell Drilling Contractors (CAODC) published an updated drilling activity forecast. CAODC is now estimating a total of 6,612 wells will be completed within the Basin through 2015 representing a 39% decrease from 2014. CAODC ran its forecasts under the assumption that WTI and AECO average US$55.00/bbl and AECO $3.00/mcf respectively through 2015.

Given the diversity of our asset base, drilling activity on our lands typically mirrors activity within the Basin. In our guidance we are forecasting drilling on our royalty lands will decline by approximately 50% versus 2014.

2014 Performance Compared to Guidance

The following table compares our key operating assumptions during 2014 to our actual results for the year.

Compared to our November guidance:

- Average production for the year was 80 boe/d higher than November guidance. Gains in production were driven primarily by acquisitions.
- Average oil prices, both for WTI and WCS were slightly below our forecasts as prices retreated materially through the fourth quarter.

- Current income tax expense was lower than expected due to benefits obtained from our East Edson joint venture.

2014 Key Operating Assumptions

2014 Annual Average		2014 Actual Results	Previous Guidance Nov. 13, 2014	Aug. 7, 2014	May 14, 2014	Mar. 6, 2014
Daily production	boe/d	9,180	9,100	9,500	9,100	8,700
WTI oil price	US$/bbl	92.99	94.00	99.00	98.00	97.00
Western Canadian Select (WCS)	Cdn$/bbl	81.10	83.00	85.00	85.00	83.00
AECO natural gas price	Cdn$/Mcf	4.41	4.25	4.25	4.50	4.50
Exchange rate	Cdn$/US$	0.91	0.91	0.92	0.90	0.90
Operating costs	$/boe	5.67	5.70	6.00	6.00	6.00
General and administrative costs (1)	$/boe	2.59	2.60	2.60	2.60	2.60
Capital expenditures	$ millions	34	35	35	35	35
Dividends paid in shares (DRIP)	$ millions	32	29	31	29	29
Long-term debt at year end	$ millions	139	142	131	137	38
Current income tax expense	$ millions	22	26	28	33	32
Weighted average shares outstanding	millions	71	71	71	68	68

(1) Excludes share based and other compensation.

Guidance Update

For 2015, the Board has approved a capital budget of $25 million with our focus continuing to center on oil development within our mineral title lands. Approximately 65% of our spending will be in southeast Saskatchewan (light oil), with 30% allocated to Western Alberta (Cardium light oil) and the remaining balance to heavy oil. Capital may be adjusted as the year progresses, depending on the operating environment and individual well results. Also, an increasing percentage of our capital expenditures are non-operated and therefore dependent on the budgets and changing plans of our partners.

Freehold's royalty drilling for 2015 is expected to see a significant drop-off in activity reflecting commodity weakness. While it remains early in our forecast, we anticipate drilling on our lands could be down as much as 50% relative to 2014 activity levels. We expect light oil development in southeast Saskatchewan, horizontal drilling for shallow heavy oil targets and deeper Cardium oil drilling will be the key plays in 2015.

Based on this level of capital investment, anticipated drilling activity by lessees on our royalty lands, normal production declines, and acquisitions closed to date (but excluding any potential acquisitions), we expect 2015 production to average approximately 9,800 boe per day. Volumes will be comprised of approximately 59% oil and NGL's and 41% natural gas. We continue to maintain our royalty focus with royalty production expected to account for approximately 68% of forecasted 2015 production.

Royalties are expected to be approximately 78% of Freehold's 2015 operating income.

2015 Key Operating Assumptions

2015 Annual Average		Guidance Dated Mar. 5, 2015	Jan. 14, 2015	Nov. 13, 2014
Daily production	boe/d	9,800	9,800	9,700
WTI oil price	US$/bbl	60.00	60.00	85.00
Western Canadian Select (WCS)	Cdn$/bbl	56.00	54.00	77.00
AECO natural gas price	Cdn$/Mcf	3.00	3.00	3.75
Exchange rate	Cdn$/US$	0.80	0.84	0.87
Operating costs	$/boe	6.60	6.60	6.60
General and administrative costs (1)	$/boe	2.60	2.60	2.90
Capital expenditures	$ millions	25	25	30
Dividends paid in shares (DRIP) (2)	$ millions	26	26	27
Weighted average shares outstanding	millions	76	76	75

(1) Excludes share based and other compensation.

(2) Assumes average 30% participation rate in Freehold's dividend reinvestment plan, which is subject to change at the participants' discretion.

Recognizing the cyclical nature of the oil and gas industry, we continue to closely monitor commodity prices and industry trends for signs of changing 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.

Based on our current guidance and commodity price assumptions, and assuming no significant changes in the current business environment, we expect to maintain the current monthly dividend rate of $0.09/share through 2015, subject to the Board's quarterly review and approval.

A sensitivity analysis of the potential impact of key variables on funds from operations per share is provided below. For the purposes of the sensitivity analysis, the effect of a change in a particular variable is calculated independently of any change in another variable. In reality, changes in one factor will contribute to changes in another, which can magnify or counteract the sensitivities. For instance, trends have shown a correlation between the movement in the foreign exchange rate of the Canadian dollar relative to the U.S. dollar and the benchmark WTI crude oil price.

Land and Reserves

The majority of our assets are royalty interests and 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 exploration and development companies. We believe the most appropriate measure of reserves and finding and development costs for Freehold is on a net basis.

As at year-end 2014, our undeveloped land was independently valued at $114.0 million by Seaton-Jordan & Associates Ltd. Our total land holdings encompass approximately 3.2 million gross acres, 93% of which are royalties. Of this, our mineral title lands (including royalty assumption lands), which we own in perpetuity, cover more than 693,000 acres; all but approximately 145,000 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 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 $11.1 million before tax (discounted at 10%).

Our oil and gas reserves were independently evaluated by Trimble Engineering Associates Ltd. (Trimble) as at December 31, 2014. 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, 2014

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) (MMcf')	Net (3) (MMcf)
Proved						
Developed producing	1,612	3,837	723	3,994	2,334	7,831
Developed non-producing	109	97	15	16	124	113
Undeveloped	38	80	-	-	38	80
Total proved	1,758	4,014	738	4,010	2,496	8,024
Probable	1,508	3,106	779	2,592	2,287	5,698

Total proved plus probable	3,267	7,120	1,517	6,602	4,783	13,722

	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	4,199	32,458	157	857	3,191	14,098
Developed non-producing	1,463	3,279	80	113	448	772
Undeveloped	-	24,633	-	566	38	4,752
Total proved	5,663	60,369	237	1,536	3,676	19,622
Probable	5,076	22,525	230	639	3,363	10,091
Total proved plus probable	10,738	82,894	466	2,175	7,040	29,713

(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, 2014

Forecast Prices and Costs (000's) (1) (2)

	Before Income Taxes, Discounted at (% per year)				
Reserves Category	0%	5%	10%	15%	20%
Proved					
Developed producing	749,329	560,979	452,343	382,233	333,297
Developed non-producing	18,449	15,640	13,824	12,493	11,446
Undeveloped	175,073	122,089	88,731	66,761	51,718
Total proved	942,852	698,708	554,898	461,487	396,461
Probable	639,091	349,404	231,220	170,513	134,181
Total proved plus probable	1,581,943	1,048,112	786,118	632,000	530,642

	After Income Taxes, Discounted at (% per year)				
Reserves Category	0%	5%	10%	15%	20%
Proved					
Developed producing	673,485	503,987	406,649	343,939	300,190
Developed non-producing	13,814	11,607	10,202	9,181	8,383
Undeveloped	130,878	91,214	66,255	49,821	38,571
Total proved	818,176	606,809	483,106	402,941	347,144
Probable	478,079	259,528	170,927	125,555	98,444
Total proved plus probable	1,296,255	866,337	654,033	528,496	445,588

(1) Based on the December 31, 2014 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, 2014

Forecast Prices and Costs (000's) (1)	Reserves Category	
	Proved	Proved Plus Probable
Royalty income	856,783	1,384,193
Revenue from working interest properties	275,941	554,334
Royalty expense on working interest	(36,916)	(77,122)
Operating costs	(139,502)	(249,933)
Development costs	(4,221)	(18,708)
Well abandonment and reclamation costs	(9,232)	(10,820)
Future net revenue before income taxes	942,852	1,581,943
Future income taxes (2)	(124,676)	(285,688)
Future net revenue after income taxes	818,176	1,296,255

(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)(1)

	Forecast Prices and Costs	
Year	Proved Reserves (undiscounted)	Proved Plus Probable Reserves (undiscounted)
2015	2,453	8,215
2016	178	7,930
2017	1,443	1,993
2018	73	406
2019	50	86
Remainder	25	79
Total	4,221	18,709

(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, 2014 (1)

	Proved Producing	Total Proved	Proved Plus Probable
Net reserves (Mboe)	14,098	19,622	29,713
Net production (Mboe)	2,889	2,975	3,313
Reserve life index (years)	4.9	6.6	9.0

(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 (Mbbls)	Probable (Mbbls)	Proved Plus Probable (Mbbls)	Proved (Mbbls)	Probable (Mbbls)	Proved Plus Probable (Mbbls)
December 31, 2013	3,506	2,322	5,828	4,181	2,730	6,911
Extensions	392	315	707	327	158	485
Improved recovery	-	-	-	-	-	-
Technical revisions	389	(342)	47	367	(375)	(8)
Discoveries	-	-	-	-	-	-
Acquisitions	670	832	1,501	34	76	110
Dispositions	-	-	-	-	-	-
Economic factors	41	(21)	20	(6)	4	(2)
Production	(983)	-	(983)	(893)	-	(893)
December 31, 2014	4,014	3,106	7,120	4,010	2,592	6,602

	Natural Gas			Natural Gas Liquids		
	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)	Proved (Mbbls)	Probable (Mbbls)	Proved Plus Probable (Mbbls)
December 31, 2013	35,243	18,385	53,627	923	513	1,436
Extensions	1,003	940	1,943	69	79	148
Improved recovery	-	-	-	-	-	-
Technical revisions	4,321	(1,734)	2,588	61	(79)	(18)
Discoveries	-	-	-	-	-	-
Acquisitions	26,974	4,973	31,947	704	126	830
Dispositions	-	-	-	-	-	-
Economic factors	39	(39)	-	-	-	-
Production	(7,210)	-	(7,210)	(221)	-	(221)
December 31, 2014	60,369	22,525	82,894	1,536	639	2,175

				Oil Equivalent		
				Proved (Mboe)	Probable (Mboe)	Proved Plus Probable (Mboe)
December 31, 2013				14,483	8,629	23,113

Extensions	956	709	1,665
Improved recovery	-	-	-
Technical revisions	1,537	(1,086)	452
Discoveries	-	-	-
Acquisitions	5,903	1,862	7,765
Dispositions	-	-	-
Economic factors	42	(24)	18
Production	(3,299)	-	(3,299)
December 31, 2014	19,622	10,091	29,713

(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	2014	2013	2012	Three-Year Results
Finding and development expenditures ($000s)	33,701	29,287	36,746	99,734
Change in future development capital estimates ($000s)	1,638	1,142	(934)	1,846
Net reserve additions by development (Mboe)	956	834	1,071	2,860
Finding and development costs ($/boe)	36.98	36.47	33.45	35.51
Acquisition expenditures ($000s)	233,274	10,091	60,852	304,217
Net reserve additions by acquisition (Mboe)	5,902	142	2,300	8,344
Acquisition costs ($/boe)	39.52	71.21	26.46	36.46
Total expenditures ($000s)	266,975	39,378	97,598	403,951
Change in future development capital estimates ($000s)	1,638	1,142	(934)	1,846
Net reserve additions (Mboe)	6,858	976	3,371	11,205
Finding, development and acquisition costs ($/boe)	39.17	41.52	28.68	36.22

Net Proved Plus Probable Reserves	2014	2013	2012	Three-Year Results
Finding and development expenditures ($000s)	33,701	29,287	36,746	99,734
Change in future development capital estimates ($000s)	2,702	3,448	1,916	8,065
Net reserve additions by development (Mboe)	1,665	1,649	1,809	5,123
Finding and development costs ($/boe)	21.87	19.85	21.37	21.04
Acquisition expenditures ($000s)	233,274	10,091	60,852	304,217
Net reserve additions by acquisition (Mboe)	7,765	294	3,483	11,542
Acquisition costs ($/boe)	30.04	34.38	17.47	26.36
Total expenditures ($000s)	266,975	39,378	97,598	403,951
Change in future development capital estimates ($000s)	2,702	3,447	1,916	8,065
Net reserve additions (Mboe)	9,430	1,943	5,292	16,665
Finding, development and acquisition costs ($/boe)	28.60	22.04	18.80	24.72

(1) Included in 2014 acquisition costs are $15.2 million of exploration costs from four wells drilled on the East Edson joint venture lands and included in 2014 finding and development costs are $0.1 million of miscellaneous exploration costs. Excluded from 2014 acquisition costs are $15.0 million of costs for undeveloped land acquired during the year. 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)	2014	2013	2012	Three-Year Results
Operating netback (1) (4)	52.30	47.91	45.09	48.47
Finding, development and acquisition costs (2) (4)	28.60	22.04	18.80	24.72
Recycle ratio (times) (3)	1.8	2.2	2.4	2.0

(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, 2014

LANDHOLDINGS AS OF DECEMBER 31, 2014

(gross acres) (1)	Developed	Undeveloped	Total
Mineral title lands (2)	372,122	224,711	596,833
Royalty assumption lands (3)	75,391	20,875	96,266
Total title lands (4)	447,513	245,586	693,099
Gross overriding royalty (GORR) lands (5)	1,671,219	586,021	2,257,240
Total royalty lands	2,118,732	831,607	2,950,339
Working interest properties	173,758	41,213	214,971
Total Land Holdings	2,292,490	872,820	3,165,310

Land Holdings by Province

	Royalty Interest		Working Interest				Total
	Developed	Undeveloped	Developed		Undeveloped		Developed
	Gross	Gross	Gross	Net	Gross	Net	Gross
Alberta	1,613,627	391,285	136,256	19,692	27,710	5,743	1,749,883
Saskatchewan	321,692	213,853	18,097	5,787	7,293	4,000	339,789
Ontario	88,799	173,305	-	-	-	-	88,799
British Columbia	84,098	25,884	19,247	1,265	6,131	101	103,345
Manitoba	10,516	27,280	158	37	79	18	10,674
Total	2,118,732	831,607	173,758	26,781	41,213	9,862	2,292,490

(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 145,000 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

	2014				2013			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Financial ($000s, except as noted)								
Revenue, net of royalty expense	42,597	50,625	52,793	48,169	43,436	49,728	42,704	39,332
Dividends declared	31,353	31,148	28,711	28,576	28,373	28,206	28,019	27,897
Per share ($) (1)	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42
Net income	11,082	17,913	19,598	17,854	14,106	18,961	14,292	10,493
Per share, basic and diluted ($)	0.15	0.24	0.29	0.26	0.21	0.28	0.21	0.16
Funds from operations (2)	30,774	39,561	37,319	30,793	29,092	36,407	30,115	23,817
Per share, basic ($) (2)	0.41	0.54	0.55	0.45	0.43	0.54	0.45	0.36
Operating Income (2)	37,584	46,012	47,801	43,795	37,954	44,642	37,898	35,350
Net operating income from royalties (%)	80	78	77	77	74	69	74	74
Dividends paid in shares (DRIP)	10,915	6,170	7,588	7,591	7,617	9,076	6,874	4,381
Average DRIP participation rate (%) (3)	35	20	26	27	27	32	25	16
Property and royalty acquisitions	60,566	76,780	109,044	1,884	6,891	2,542	658	-
Capital expenditures	13,500	2,811	6,284	11,106	5,335	5,725	3,313	14,914
Net debt obligations	135,810	122,091	160,061	48,600	45,385	41,715	50,564	55,466
Shares outstanding								
Weighted average (000s)	74,545	73,214	68,296	67,965	67,483	67,078	66,649	66,375
At quarter end (000s)	74,919	74,286	68,520	68,157	67,746	67,326	66,874	66,522
Operating ($/boe, except as noted)								
Daily production (boe/d) (4)	9,836	9,430	8,810	8,623	9,173	8,699	8,714	9,067
Royalty interest (%)	74	75	74	74	68	67	71	71
Average selling price	47.46	59.54	67.45	62.72	52.99	63.74	54.66	49.09
Operating netback (2)	41.54	53.03	59.62	56.43	44.97	55.79	47.80	43.32
Operating expenses	5.54	5.32	6.23	5.64	6.50	6.36	6.06	4.88

Working interest properties	21.66	21.05	23.61	21.40	20.53	19.50	21.00	16.91
Net general and administrative expenses (5)	2.32	2.16	2.36	3.62	2.13	1.74	2.04	3.47
Benchmark Prices								
WTI crude oil (US$/bbl)	73.15	97.15	102.99	98.68	97.46	105.83	94.22	94.37
Exchange rate (US$/Cdn$)	0.88	0.92	0.92	0.91	0.95	0.96	0.98	0.99
Edmonton Par crude oil (Cdn$/bbl)	75.79	97.10	105.70	99.73	86.28	104.69	92.55	88.16
Western Canadian Select (WCS) (Cdn$/bbl)	66.74	83.82	90.44	83.40	68.44	91.71	76.78	62.96
AECO natural gas (Cdn$/Mcf)	4.01	4.22	4.68	4.75	3.15	2.82	3.59	3.08
Share Trading Performance								
High ($)	23.27	26.92	28.15	23.47	24.63	24.88	24.58	24.48
Low ($)	17.02	22.64	23.01	21.41	21.54	22.50	22.46	21.00
Close ($)	19.12	23.16	26.78	23.28	22.11	23.78	23.57	23.38
Volume (000s)	18,607	10,412	7,232	7,322	6,077	4,374	8,108	7,203

(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) Participation in Freehold's DRIP is subject to change at the participants discretion.
(4) Reported production for a period may include minor adjustments from previous production periods.
(5) Excludes share based and other compensation.

Consolidated Balance Sheets

($000s) (unaudited)	December 31 2014	December 31 2013
Assets		
Current assets:		
Cash	$ 1,126	$ 158
Accounts receivable	26,430	25,587
Current taxes receivable	2,597	-
	30,153	25,745
Acquistion advance	949	-
Exploration and evaluation assets	37,852	24,858
Petroleum and natural gas interests	584,323	377,262
	$ 653,277	$ 427,865
Liabilities and Shareholders' Equity		
Current liabilities:		
Dividends payable	$ 10,488	$ 9,485
Accounts payable and accrued liabilities	15,864	10,813
Current taxes payable	-	730
Current portion of share based and other compensation payable	611	1,102
	26,963	22,130
Decommissioning liability	21,279	15,781
Share based and other compensation payable	321	1,240
Long-term debt	139,000	49,000
Deferred income tax liability	44,847	45,642
Shareholders' equity:		
Shareholders' capital	635,223	455,497
Contributed surplus	2,577	2,167
Deficit	(216,933)	(163,592)
	420,867	294,072
	$ 653,277	$ 427,865

Consolidated Statements of Income and Comprehensive Income

(unaudited)	Three Months Ended December 31		Twelve Months Ended December 31	
($000s, except per share and weighted average data)	2014	2013	2014	2013

Revenue:				
Royalty income and working interest sales	$ 43,631	$ 45,287	$ 199,850	$ 181,578
Royalty expense	(1,034)	(1,851)	(5,666)	(6,378)
	42,597	43,436	194,184	175,200
Expenses:				
Operating	5,013	5,482	18,992	19,356
General and administrative	2,102	1,795	8,679	7,634
Share based and other compensation	(1,164)	(158)	438	1,531
Interest and financing	1,196	613	4,405	2,554
Depletion and depreciation	19,237	15,283	67,145	61,320
Accretion of decommissioning liability	123	127	498	452
Management fee	1,034	1,080	4,743	4,495
	27,541	24,222	104,900	97,342
Income before taxes	15,056	19,214	89,284	77,858
Income taxes:				
Current expense	3,273	6,214	22,178	23,558
Deferred expense (recovery)	701	(1,106)	659	(3,552)
	3,974	5,108	22,837	20,006
Net income and comprehensive income	$ 11,082	$ 14,106	$ 66,447	$ 57,852
Net income per share, basic and diluted	$ 0.15	$ 0.21	$ 0.94	$ 0.86
Weighted average number of shares:				
Basic	74,544,796	67,483,469	71,029,156	66,899,776
Diluted	74,681,308	67,598,380	71,170,896	67,021,372

Consolidated Statements of Cash Flows

	Three Months Ended December 31		Twelve Months Ended December 31	
($000s) (unaudited)	2014	2013	2014	2013
Operating:				
Net income	$ 11,082	$ 14,106	$ 66,447	$ 57,852
Items not involving cash:				
Depletion and depreciation	19,237	15,283	67,145	61,320
Share based and other compensation	(1,164)	(158)	438	1,531
Deferred income tax expense (recovery)	701	(1,106)	659	(3,552)
Accretion of decommissioning liability	123	127	498	452
Management fee	1,034	1,080	4,743	4,495
Expenditures on share based and other compensation	(91)	(189)	(1,195)	(2,299)
Decommissioning expenditures	(148)	(51)	(288)	(368)
Funds from operations	30,774	29,092	138,447	119,431
Changes in non-cash working capital	3,741	1,336	(4,060)	(26,196)
	34,515	30,428	134,387	93,235
Financing:				
Issuance of shares, net of issue costs	-	-	141,085	-
Long-term debt	6,000	-	90,000	31,000
Dividends paid	(20,350)	(20,697)	(86,521)	(84,340)
	(14,350)	(20,697)	144,564	(53,340)
Investing:				
Acquisition advance	49,211	-	(949)	-
Property and royalty acquisitions	(60,566)	(6,891)	(248,274)	(10,091)
Capital expenditures	(13,500)	(5,335)	(33,701)	(29,287)
Changes in non-cash working capital	5,014	1,965	4,941	(461)
	(19,841)	(10,261)	(277,983)	(39,839)

Increase (decrease) in cash	324	(530)	968	56
Cash, beginning of period	802	688	158	102
Cash, end of period	$ 1,126	$ 158	$ 1,126	$ 158

Consolidated Statements of Changes in Shareholders' Equity

	Twelve Months Ended December 31	
($000s) (unaudited)	2014	2013
Shareholders' capital:		
Balance, beginning of period	$ 455,497	$ 422,728
Shares issued for dividend reinvestment plan	32,264	27,948
Shares issued in lieu of management fee	4,743	4,495
Shares issued for deferred share unit plan redemption	180	326
Shares issued for equity offering	146,810	-
Issue costs, net of tax effect	(4,271)	-
Balance, end of period	635,223	455,497
Contributed surplus:		
Balance, beginning of period	2,167	2,036
Share based compensation expense	666	597
Deferred share unit plan redemption	(256)	(466)
Balance, end of period	2,577	2,167
Deficit:		
Balance, beginning of period	(163,592)	(108,949)
Net income and comprehensive income	66,447	57,852
Dividends declared	(119,788)	(112,495)
Balance, end of period	(216,933)	(163,592)
Total shareholders' equity	$ 420,867	$ 294,072

Forward-Looking Statements

This news release offers our assessment of Freehold's future plans and operations as at March 5, 2015, 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 2015 and the impact on our production base;
- 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;
- average production and contribution from royalty lands;
- key operating assumptions;
- amounts and rates of income taxes and timing of payment thereof;
- maintaining our monthly dividend rate through 2015 and our dividend policy.

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.

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 natural gas industry. We believe that operating income, operating netback, net debt obligations, and net debt to funds from operations are useful supplemental measures for management and investors to analyze operating performance, financial leverage, and liquidity, and we use these terms to facilitate the understanding and comparability of our results of operations and financial position. However, these terms do not have any standardized meanings prescribed by GAAP and therefore may not be comparable with the calculations of similar measures for other entities.

Operating 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. Net debt obligations is long- term debt less working capital (current assets less current liabilities). Net debt to funds from operations is calculated as net debt as a proportion of funds from operations for the previous twelve months. In addition, we refer to various per boe figures, such as revenues and costs, also considered non-GAAP measures, which provide meaningful information on our operational performance. We derive per boe figures by dividing the relevant revenue or cost figure by the total volume of oil and natural gas production during the period, with natural gas converted to equivalent barrels of oil as described above.

Availability on SEDAR

Freehold's 2014 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 9, 2015.

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