

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following Management's Discussion and Analysis (MD&A) was prepared as of May 11, 2016, and is management's opinion about the consolidated operating and financial results of Freehold Royalties Ltd. and its wholly-owned subsidiaries (collectively, Freehold) for the three months ended March 31, 2016, and previous periods, and the outlook for Freehold based on information available as of May 11, 2016.

The financial information contained herein is based on information in the interim condensed consolidated financial statements prepared in accordance with International Financial Reporting Standards (IFRS), which are the Canadian generally accepted accounting principles (GAAP) for publicly accountable enterprises. All comparative percentages are between the quarters ended March 31, 2016 and March 31, 2015, and all dollar amounts are expressed in Canadian currency, unless otherwise noted. This discussion should be read in conjunction with Freehold's annual MD&A and audited financial statements for the year ended December 31, 2015, together with the accompanying notes. Information contained in the 2015 annual MD&A that is not discussed in this document remains materially unchanged.

This MD&A contains non-GAAP financial measures and forward-looking statements that are intended to help readers better understand our business and prospects. Readers are cautioned that the MD&A should be read in conjunction with our disclosure under "Non-GAAP Financial Measures" and "Forward-Looking Statements" included at the end of this MD&A.

Unless otherwise noted, all information excludes the effects of the royalty and fee titles acquisition and financing announced on May 2, 2016 (see Subsequent Events).

Business Overview

Freehold is a dividend-paying corporation incorporated under the laws of the Province of Alberta and trades on the Toronto Stock Exchange under the symbol FRU. Freehold is directly and indirectly involved in the development and production of oil and natural gas, predominantly in western Canada. We receive revenue from oil and natural gas properties as reserves are produced over the economic life of the properties. Our primary focus is acquiring and managing oil and natural gas royalties.

The Royalty Advantage

We manage one of the largest non-government portfolios of oil and natural gas royalties in Canada. Our total land holdings encompass approximately 3.7 million gross acres, greater than 90% of which are royalties (expected to be 5.9 million gross acres assuming closing of the transaction detailed under Subsequent Events). Of this, our mineral title lands (including royalty assumption lands), which we own in perpetuity, cover more than 750,000 acres. In addition, we have gross overriding royalty interests in over 2.5 million acres.

We have interests in more than 36,000 wells (of which over 34,000 are royalty wells including over 18,000 unitized wells). We receive royalty income from over 200 industry operators. Royalty rates vary from less than 1.0% (for some gross overriding royalties) to 22.5% (for some lessor royalties). This diversity lowers our risk, while we benefit from the drilling activity of other operators on our lands.

As a royalty interest owner, we generally do not pay any of the capital costs to drill and equip the wells for production on most of our properties, nor do we incur costs to operate the wells, maintain production, and ultimately restore the land to its original state. Generally all of these costs are paid by others. On the majority of our production, we receive royalty income from gross production revenue (revenue before any royalty expenses and operating costs are deducted). Our high percentage of operating income from royalties (97% in Q1-2016) results in strong netbacks.

When Freehold was formed in 1996, all of our royalty lands were leased to third parties and producing. Over the years, our unleased mineral title acreage has grown – through acquisitions, lease expiries, surrenders, and defaults. We now have approximately 300,000 gross undeveloped acres.

Our Strategy

We effectively manage and grow our assets to consistently deliver attractive returns to shareholders over the long term. Our vision is to be recognized as a leading royalty focused oil and gas corporation in Canada. We employ the following strategies in order to achieve this goal:

- Acquire appropriate assets with a focus on royalty interests, to provide long-term growth in value. The key criteria are:
 - quality assets;
 - attractive returns;
 - acceptable risk profile; and
 - long economic life.
- Maintain an aggressive audit program.
- Optimize assets and production.
- Manage debt prudently.
- Deliver long-term dividend sustainability.

Outlook

Business Environment

While 2016 represents a new year, the first quarter saw a continuation of weakness in prices both within North America and worldwide. West Texas Intermediate (WTI) prices averaged US\$33.45/bbl down 31% when compared to the same period in 2015 and down 21% when compared to the previous quarter. Western Canadian Select (WCS) prices averaged \$26.32/bbl, a 38% decrease versus Q1-2015 and down 29% when compared to Q4-2015. Offsetting some of the weakness in oil prices, the Canadian/U.S. dollar exchange averaged \$0.73 in Q1-2016, down 10% when compared to the same period in 2015. For every cent change in the Canadian/U.S. dollar exchange, Freehold's funds from operations are impacted by approximately \$0.02/share.

Key macro drivers of crude oil prices in Q1-2016 included concerns associated with Chinese and worldwide demand and oversupply of the North American and world crude oil markets. While prices have declined materially since late 2014, we have yet to see a fundamental increase in overall demand for crude products from regions of the world that have historically generated growth. There is still no set strategy within OPEC, as the cartel recently met in April and it appears that until all members are willing to agree on individual production ceilings, it is unlikely the group will be able to set a firm quota moving forward. While we have seen a steady trending down in the North American rig count, with production now showing early signs of decline, the North American crude market remains oversupplied. Current sentiment is that demand/supply will come more in balance through the back half of 2016 and into early 2017.

On the natural gas side, AECO prices (30-day firm contract) averaged \$2.11/mcf in Q1-2016, a 28% decrease versus the same period in 2015. Similar to the macro environment for oil, natural gas fundamentals continue to be challenged by growing supplies within North America despite prices remaining relatively weak. U.S. natural gas production remains resilient with shale plays such as the Marcellus and Utica displaying material growth despite bottlenecks in infrastructure and material price discounts. Looking further into 2016/2017, Canadian pricing is expected to remain challenged as volumes become further displaced by growth out of the U.S.

Industry Activity

In 2015, a total of 5,292 wells were drilled and completed within the Western Canadian Sedimentary Basin, down materially from 11,534 in 2014. In April, the Petroleum Services Association of Canada (PSAC) updated its 2016 drilling forecast. The group is currently projecting 3,315 wells drilled through 2016, representing a decrease of 1,835 wells and an approximate 36% decline from PSAC's original 2016 forecast unveiled in November 2015. PSAC based its updated 2016 forecast on average natural gas prices of \$1.60/mcf AECO, and WTI crude oil prices of US\$35/bbl.

Through Q1-2016, it is estimated that 801 wells were drilled within the Western Canadian Sedimentary Basin compared to 2,075 in 2015 and 3,135 locations in 2014.

ROYALTY INTEREST DRILLING

| | Three Months Ended March 31 | | | |
|--------------------------------------|-----------------------------|-------------------------------|-------|-------------------------------|
| | 2016 | | 2015 | |
| | Gross | Equivalent Net ⁽¹⁾ | Gross | Equivalent Net ⁽¹⁾ |
| Non-unitized wells | 48 | 3.2 | 28 | 1.3 |
| Unitized wells ⁽²⁾ | 37 | 0.2 | 46 | 0.3 |
| Total | 85 | 3.4 | 74 | 1.6 |
| Royalty joint venture ⁽³⁾ | - | | 4 | |

(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 various royalty joint venture lands, where equivalent net wells cannot be calculated.

Including drilling associated with acquisitions, 85 (3.4 equivalent net) wells were drilled on our royalty lands through Q1-2016. This represented a 15% increase on a gross measure but a 113% improvement on a net basis versus the same period in 2015, a testament to the quality of underlying asset base during weakened commodity prices. Our royalty lands give us exposure to some of the most economic resource plays currently being pursued in the Western Canadian Sedimentary Basin. Through 2016, we have seen an increase in activity on our lands largely as a result of the quality of our southeast Saskatchewan acreage position, which has maintained strong activity levels.

In Q1-2016, we saw continued activity in the Viking zone with operators tying in horizontal wells in the Dodsland area of southwest Saskatchewan. Collectively, producers put on production 13 gross Viking horizontal wells. Initial production rates from these wells have been strong, averaging 100-250 boe/d in the first 30 days of production.

In southeast Saskatchewan, royalty drilling activity outpaced expectations given the weak commodity environment. Overall 22 gross Mississippian subcrop horizontal wells and five gross Bakken horizontal wells were drilled and completed by the end of Q1-2016. Ten of these wells were new royalty locations that targeted the Midale multistage frac play with 30 day initial production rates ranging between 100-160 boe/d. Bakken infill locations, drilled at 200 meter spacing, attained rates ranging between 80-120 boe/d in the first 30 days of production. In Manitoba, Freehold's royalty lands were drilled for Bakken and Lodgepole targets.

In Alberta, two additional Nisku horizontals were drilled on royalty lands in 2016 with initial production rates as large as 200 boe/d in the first 30 days of production . Additionally, in the Deep Basin, two Montney horizontal wells were drilled on royalty lands, with updates to production expected in the coming quarters.

WORKING INTEREST DRILLING

| | Three Months Ended March 31 | | | |
|-------------|-----------------------------|--------------------|-------|--------------------|
| | 2016 | | 2015 | |
| | Gross | Net ⁽¹⁾ | Gross | Net ⁽¹⁾ |
| Oil | 4 | 0.3 | 16 | 1.8 |
| Natural gas | - | - | 4 | 0.2 |
| Other | - | - | - | - |
| Total | 4 | 0.3 | 20 | 2.0 |

(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 Drilling table above.

In Q1-2016 all of Freehold's working interest drilling was in southeast Saskatchewan with one minor oil well drilled in the Frobisher and three (0.3 net) wells drilled in the Bakken.

Subsequent Events

On May 2, 2016, Freehold entered into a definitive agreement with certain affiliates of Husky Energy Inc. to acquire an extensive suite of royalty production and fee lands for an aggregate purchase price of \$165 million, prior to normal closing adjustments (the Husky Transaction). The effective date of the Husky Transaction is January 1, 2016, with closing expected to occur on or about May 25, 2016, subject to regulatory approval and certain other closing conditions.

Highlights include (based on relevant assumptions from our 2016 Key Operating Assumptions):

- Adds approximately 2.5 million acres of royalty lands (including 0.3 million acres of mineral title land), increasing our royalty lands acreage by 74% to 5.9 million acres.
- Expected 2016 annualized average royalty production of 1,700 boe/d and annualized operating income of \$11.4 million.
- Expected to increase royalties as a percentage of 2016 operating income to approximately 94%.
- The production base is expected to have a low decline of approximately 17% per year in 2016.

The Husky Transaction will be funded by a concurrent \$165 million public equity financing (before 15% over-allotment option and underwriters' fees) and an approximate \$20 million concurrent private placement to CN Pension Trust Funds (see Related Party Transactions), with remaining funds allocated to debt repayment. 16,018,000 common shares at a price of \$11.55 per share will be issued through the financings (excluding potential effects of the over-allotment option). If the over-allotment option is exercised in full by the underwriters an additional 2,142,900 common shares will be issued at a price of \$11.55 per share for gross proceeds of approximately \$25 million. The underwriters will receive a commission of 4% on the common shares issued pursuant to the financing (other than the common shares issued pursuant to the concurrent private placement).

Guidance Update

The table below summarizes our key operating assumptions for 2016, updated to reflect actual statistics for the first three months and our current expectations for the remainder of the year. The assumptions and guidance reflects the Husky Transaction and the financings (before over-allotment option) discussed in Subsequent Events.

- The increase in our production guidance on May 2, 2016 from 9,800 boe/d to 11,400 boe/d was a function of the Husky Transaction, higher than expected drilling activity on our royalty lands, lower than expected shut-in heavy oil volumes and positive prior period adjustments. Volumes are expected to be weighted approximately 59% oil and natural gas liquids (NGL's) and 41% natural gas. We continue to maintain our royalty focus with royalty production accounting for 80% of forecasted 2016 production and 94% of operating income.
- We have increased our WTI and WCS pricing to US\$40.00/bbl and \$34.00/bbl respectively (previously US\$35.00/bbl and \$31.00/bbl respectively), due to recent price momentum. We have revised downward our 2016 AECO natural gas price assumption from \$2.00/mcf to \$1.80/mcf.
- Based on our key operating assumptions, we forecast our 2016 basic payout ratio to total approximately 82%.
- Operating costs have been reduced from \$4.75/boe to \$4.00/boe as a result of increased royalty production as a percentage of total production.
- Our capital spending budget remains at \$7 million.
- G&A costs have decreased to \$2.50/boe as a result of production added through the Husky Transaction, offset somewhat by expected acquisition integration costs
- Weighted average shares outstanding have increased due to the financings detailed in Subsequent Events.

KEY OPERATING ASSUMPTIONS ⁽¹⁾

| 2016 Annual Average | | May 11, 2016 | Mar. 3, 2016 | Nov. 12, 2015 |
|---|-------------|--------------|--------------|---------------|
| Daily production | boe/d | 11,400 | 9,800 | 9,800 |
| WTI oil price | US\$/bbl | 40.00 | 35.00 | 50.00 |
| Western Canadian Select (WCS) | Cdn\$/bbl | 34.00 | 31.00 | 47.00 |
| AECO natural gas price | Cdn\$/Mcf | 1.80 | 2.00 | 2.75 |
| Exchange rate | Cdn\$/US\$ | 0.77 | 0.72 | 0.76 |
| Operating costs | \$/boe | 4.00 | 4.75 | 5.00 |
| General and administrative costs ⁽²⁾ | \$/boe | 2.50 | 2.65 | 2.85 |
| Capital expenditures | \$ millions | 7 | 7 | 15 |
| Dividends paid in shares (DRIP) ⁽³⁾ | \$ millions | 8 | 8 | 13 |
| Weighted average shares outstanding | millions | 109 | 100 | 100 |

(1) Production guidance was updated to 11,400 on May 2, 2016 but no other assumptions were changed at that time.

(2) Excludes share based and other compensation.

(3) Assumes an average 15% 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 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.

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 through the next quarter. We will continue to evaluate the commodity price environment with the expectation to increase dividend levels as the environment stabilizes or improves (subject to the quarterly review and approval of our Board of Directors - see Dividend Policy).

Director Succession

Two of Freehold's long standing directors, Nolan Blades (Chair of the Board) and David Sandmeyer are not standing for re-election and after 19 years of service will retire from the Board at the Annual and Special Meeting of Shareholders

(the Meeting) being held May 11, 2016. Mr. Blades joined the Board in 1996 and was appointed Chair of the Board in May 2009. Mr. Sandmeyer was appointed to the Board in 1996 and served as President and Chief Executive Officer of Rife Resources Ltd. and Freehold until his retirement in May 2009. We would like to thank them for their dedication, wisdom and leadership throughout their tenure on the Board. It is planned that Marvin Romanow will succeed Mr. Blades as Chair of the Board following the Meeting. Mr. Romanow has over 30 years of experience in the oil and gas industry.

We are pleased to announce that Douglas Kay has agreed to stand for election at the Meeting. Mr. Kay is a Corporate Director and former oil and gas executive with over 35 years industry experience.

Results of Operations

2016 First Quarter Highlights:

- Production for Q1-2016 averaged 11,974 boe/d, a 19% increase over Q1-2015 and a 1% increase over Q4-2015.
- Royalties accounted for 97% of operating income and 79% of production, reinforcing our royalty focus.
- Royalty production was up 33% compared to Q1-2015, averaging 9,495 boe/d. Growth in volumes was associated with a combination of production acquired through the year, new production from drilling on our royalty lands and a strong quarter from our audit function; which was largely responsible for approximately 600 boe/d of prior period adjustments, including compensatory royalties on our mineral title lands.
- Working interest production averaged 2,479 boe/d for the quarter, down 14% when compared to the same period last year, reflecting reduced spending through a weaker commodity price environment.
- Funds from operations totaled \$15.5 million (\$0.16/share) in Q1-2016, down 29% from the same period last year owing to continued weakness in oil and natural gas prices.
- Though average commodity price realizations decreased 25%, reduced revenues were partly offset by the increase in production volumes, resulting in a 10% decrease in gross revenue compared to Q1-2015.
- Q1-2016 net loss was \$8.6 million (Q1-2015 net income of \$21.6 million - without a \$24.3 million gain on corporate acquisition it would have been a \$2.7 million net loss) primarily due to lower revenues and increased depletion and depreciation expense as a result of higher production volumes. Dividends declared for Q1-2016 totaled \$0.18 per share, down from \$0.27 per share one year ago. On March 3, 2016, Freehold adjusted its monthly dividend to \$0.04 per share from \$0.07 per share as a result of reduced funds from operations within the weak commodity price environment.
- Average participation in our dividend reinvestment plan (DRIP) was 11% (Q1-2015 – 35%). DRIP proceeds for Q1-2016 totaled \$2.4 million.
- Net capital expenditures on our working interest properties totaled \$2.1 million over the quarter.
- Basic payout ratio (dividends declared/funds from operations) for Q1-2016 totaled 115% while the adjusted payout ratio (cash dividends plus capital expenditures/funds from operations) for the same period was 132%. However, based on our 2016 key operating assumptions our current dividend level remains well funded with our basic payout ratio expected to total approximately 82% for 2016.
- At March 31, 2016, net debt obligations totaled \$149.2 million, up \$2.3 million from \$146.9 million at December 31, 2015. This implies a net debt to 12-month trailing funds from operations ratio of 1.5 times (excluding the proforma effects of acquisitions).

Quarterly Performance and Seasonality

Quarterly variances in revenues, net income (loss) and funds from operations are caused mainly by fluctuations in commodity prices and production volumes. Crude oil prices are generally determined by global supply and demand factors, and the variances do not have seasonable predictability. Natural gas is a typically seasonal, weather-dependent fuel; demand is generally higher during the winter (for heating) and summer (for cooling), and lower during the spring and fall. Over most of the past eight quarters, this seasonality has been muted by ample supply. Natural gas prices are affected by weather conditions, industrial demand, and North American natural gas inventories.

Our financial results over the last eight quarters were influenced by the following significant changes:

- OPEC decided in late 2014 to maintain production despite signs of increasing supply. The decision to keep production at existing levels resulted in a material retreat in worldwide crude oil prices with prices remaining weak through 2015 and early 2016.
- Fluctuations in foreign exchange rates affected our oil price realizations, resulting in recent positive impacts on our Canadian dollar oil revenues relative to the benchmark WTI, which is referenced in U.S. dollars.
- AECO prices are affected by supply outstripping demand in recent quarters. Strong gains in North American natural gas supply associated with horizontal drilling within shale gas plays has resulted in increased production deliverability.
- The largest effect on our dividends is from funds from operations, which is mainly a function of revenues and cash expenses. The collapse in oil prices in late 2014 and through early 2016 resulted in changes to our monthly dividend from \$0.14 to \$0.09 in Q1-2015 from \$0.09 to \$0.07 in Q3-2015 and from \$0.07 to \$0.04 in Q1-2016.
- Dividends paid in shares through the DRIP are dependent on the participation levels of our shareholders, which is subject to change at their discretion.
- Production has been affected by drilling activity and acquisitions, as well as a number of one-time adjustments. We use government reporting databases and past production receipts to estimate revenue accruals. Due to the large number of wells in which we have royalty interests, the nature of royalty interests, the lag in receiving production receipts from the operators, and our audit program, our reported royalty volumes usually include both positive and negative adjustments related to prior periods.
- Over the past eight quarters, we have acquired \$658 million of mainly royalty assets in Alberta and Saskatchewan. This activity affects our revenues, percentage royalty interests, oil/gas production split and debt levels, among others.

The accompanying table illustrates the fluctuations experienced over the past eight quarters and the resulting effect on our financial results. Additional information about our quarterly results is provided in our interim reports, copies of which are available on SEDAR and on our website.

QUARTERLY REVIEW

| | 2016 | 2015 | | | | 2014 | | |
|--|---------|---------|----------|---------|---------|---------|---------|---------|
| | Q1 | Q4 | Q3 | Q2 | Q1 | Q4 | Q3 | Q2 |
| Financial (\$000s, except as noted) | | | | | | | | |
| Revenue, net of royalty expense | 24,670 | 33,728 | 35,391 | 37,222 | 27,026 | 42,597 | 50,625 | 52,793 |
| Funds from operations | 15,500 | 25,509 | 27,643 | 28,730 | 21,938 | 30,774 | 39,561 | 37,319 |
| Per share, basic (\$) | 0.16 | 0.26 | 0.28 | 0.32 | 0.29 | 0.41 | 0.54 | 0.55 |
| Net income (loss) | (8,590) | (7,423) | (22,193) | 3,919 | 21,617 | 11,082 | 17,913 | 19,598 |
| Per share, basic and diluted (\$) | (0.09) | (0.08) | (0.23) | 0.04 | 0.29 | 0.15 | 0.24 | 0.29 |
| Dividends declared | 17,845 | 20,747 | 24,604 | 24,459 | 20,329 | 31,353 | 31,148 | 28,711 |
| Per share (\$) ⁽¹⁾ | 0.18 | 0.21 | 0.25 | 0.27 | 0.27 | 0.42 | 0.42 | 0.42 |
| Basic payout ratio (%) ⁽²⁾ | 115 | 81 | 89 | 85 | 93 | 102 | 79 | 77 |
| Operating Income ⁽²⁾ | 20,292 | 29,186 | 30,601 | 32,733 | 22,632 | 37,584 | 46,012 | 47,801 |
| Operating income from royalties (%) | 97 | 89 | 90 | 85 | 83 | 80 | 78 | 77 |
| Dividends paid in shares (DRIP) | 2,384 | 2,758 | 3,708 | 2,398 | 8,361 | 10,915 | 6,170 | 7,588 |
| Average DRIP participation rate (%) ⁽³⁾ | 11 | 13 | 14 | 11 | 35 | 35 | 20 | 26 |
| Acquisitions | 219 | (143) | 815 | 342,310 | 68,370 | 60,566 | 76,780 | 109,044 |
| Capital expenditures | 2,084 | 5,607 | 7,969 | 2,750 | 5,969 | 13,500 | 2,811 | 6,284 |
| Net debt obligations ⁽²⁾ | 149,197 | 146,949 | 148,994 | 146,992 | 198,834 | 135,810 | 122,091 | 160,061 |
| Shares outstanding | | | | | | | | |
| Weighted average, basic (000s) | 99,093 | 98,731 | 98,357 | 89,388 | 75,199 | 74,545 | 73,214 | 68,296 |
| At quarter end (000s) | 99,284 | 98,940 | 98,599 | 98,203 | 75,457 | 74,919 | 74,286 | 68,520 |
| Operating (\$/boe, except as noted) | | | | | | | | |
| Daily production (boe/d) ⁽⁴⁾ | 11,974 | 11,815 | 11,266 | 10,617 | 10,058 | 9,836 | 9,430 | 8,810 |
| Royalty interest (%) | 79 | 78 | 78 | 76 | 71 | 74 | 75 | 74 |
| Average selling price | 22.23 | 30.34 | 34.11 | 38.63 | 29.80 | 47.46 | 59.54 | 67.45 |
| Operating netback ⁽²⁾ | 18.62 | 26.85 | 29.52 | 33.88 | 25.01 | 41.54 | 53.03 | 59.62 |
| Operating expenses | 4.02 | 4.18 | 4.62 | 4.65 | 4.85 | 5.54 | 5.32 | 6.23 |
| Working interest properties | 19.41 | 19.24 | 20.78 | 19.14 | 16.87 | 21.66 | 21.05 | 23.61 |
| Net general and administrative expenses ⁽⁵⁾ | 3.05 | 2.23 | 2.33 | 2.34 | 3.92 | 2.32 | 2.16 | 2.36 |
| Benchmark Prices | | | | | | | | |
| WTI crude oil (US\$/bbl) | 33.45 | 42.18 | 46.43 | 57.94 | 48.64 | 73.15 | 97.15 | 102.99 |
| Exchange rate (US\$/Cdn\$) | 0.73 | 0.75 | 0.76 | 0.81 | 0.81 | 0.88 | 0.92 | 0.92 |
| Edmonton Par crude oil (Cdn\$/bbl) | 40.84 | 52.89 | 56.23 | 67.75 | 51.95 | 75.79 | 97.10 | 105.70 |
| Western Canadian Select (WCS) (Cdn\$/bbl) | 26.32 | 36.86 | 43.29 | 56.97 | 42.14 | 66.74 | 83.82 | 90.44 |
| AECO natural gas (Cdn\$/Mcf) | 2.11 | 2.65 | 2.80 | 2.67 | 2.95 | 4.01 | 4.22 | 4.68 |
| Share Trading Performance | | | | | | | | |
| High (\$) | 12.05 | 13.52 | 16.07 | 19.04 | 20.62 | 23.27 | 26.92 | 28.15 |
| Low (\$) | 8.29 | 9.00 | 8.73 | 15.86 | 16.14 | 17.02 | 22.64 | 23.01 |
| Close (\$) | 10.54 | 10.86 | 10.82 | 16.14 | 17.94 | 19.12 | 23.16 | 26.78 |
| Volume (000s) | 19,690 | 19,312 | 22,753 | 18,912 | 14,297 | 18,607 | 10,412 | 7,232 |

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

(2) See Non-GAAP Financial Measures

(3) Participation in our DRIP is subject to change monthly at the participants' discretion.

(4) Reported production for a period may include adjustments from previous production periods.

(5) Excludes share based and other compensation.

AVERAGE DAILY PRODUCTION

| | Three Months Ended | | |
|--|--------------------|--------|--------|
| | March 31 | | |
| | 2016 | 2015 | Change |
| Royalty interest ⁽¹⁾ | | | |
| Oil (bbls/d) | 5,215 | 3,515 | 48% |
| NGL (bbls/d) | 612 | 424 | 44% |
| Natural gas (Mcf/d) | 22,009 | 19,348 | 14% |
| Oil equivalent (boe/d) | 9,495 | 7,164 | 33% |
| Working interest ⁽¹⁾ | | | |
| Oil (bbls/d) | 1,531 | 1,940 | -21% |
| NGL (bbls/d) | 187 | 159 | 18% |
| Natural gas (Mcf/d) | 4,563 | 4,771 | -4% |
| Oil equivalent (boe/d) | 2,479 | 2,894 | -14% |
| Total | | | |
| Oil (bbls/d) | 6,746 | 5,455 | 24% |
| NGL (bbls/d) | 799 | 583 | 37% |
| Natural gas (Mcf/d) | 26,572 | 24,119 | 10% |
| Oil equivalent (boe/d) | 11,974 | 10,058 | 19% |
| Number of days in period (days) | 91 | 90 | 1% |
| Total volumes during period (Mboe) | 1,090 | 905 | 20% |

(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.

Our production mix through the first three months of 2016 was 37% natural gas, 36% light and medium oil, 20% heavy oil and 7% NGL's. Over the past three years, the composition of our liquids volumes has become lighter in composition, driven by acquisitions which added royalty assets in southeast Saskatchewan and the Dodsland area of southwest Saskatchewan.

Compared to the same period in 2015, oil and NGL production increased 25% in the quarter, while natural gas production rose 10%. Much of these gains in production are attributed to the 2015 acquisition activity. In Q1-2016, there were also positive prior period adjustments of approximately 600 boe/d (approximately 80% oil and NGL), the majority resulting from our strong audit function, including compensatory royalties on our mineral title lands. In Q1-2015 prior period adjustments were 80 boe/d (40% oil).

Working interest production decreased 14% versus Q1-2015 largely due to decreased spending through 2015/2016.

Marketing and Hedging

Our royalty lands consist of a large number of properties with generally small volumes per property. A provision of most leases calls for our natural gas to be marketed with the lessees' production. Some of our leases allow us to take our oil production in-kind. In the first quarter, we took in kind and marketed approximately 10% of our royalty oil production using 30-day contracts.

We market most of our working interest oil production using 30-day contracts to ensure competitive pricing. In the first quarter, approximately 60% of our working interest natural gas production was sold under marketing arrangements tied to the Alberta monthly or daily spot price (AECO) or other indexed referenced prices, and the balance was marketed with the operators' production.

To date we have not hedged any of our production. Hedging is monitored on an ongoing basis and is reviewed quarterly by the Board.

AVERAGE BENCHMARK PRICES

| | Three Months Ended | | |
|---|--------------------|--------|--------|
| | March 31 | | |
| | 2016 | 2015 | Change |
| WTI crude oil (US\$/bbl) | 33.45 | 48.64 | -31% |
| Exchange rate (US\$/Cdn\$) | 0.73 | 0.81 | -10% |
| Edmonton Par crude oil (Cdn\$/bbl) | 40.84 | 51.95 | -21% |
| Western Canadian Select (WCS) (Cdn\$/bbl) | 26.32 | 42.14 | -38% |
| WTI/Edmonton Par differential (\$/bbl) | 7.39 | 3.31 | 123% |
| Edmonton Par/WCS differential (Cdn\$/bbl) | (14.52) | (9.81) | 48% |
| AECO natural gas (Cdn\$/Mcf) | 2.11 | 2.95 | -28% |

WTI is an important benchmark for Canadian crude oil as it reflects onshore North American prices. The price we receive for our production is primarily driven by the U.S. dollar price of WTI, adjusted to western Canada. Therefore, a decrease in the value of the Canadian dollar relative to the U.S. dollar will increase the revenue received, which happened in Q1-2016.

Commodity prices were down significantly year over year due to weakening supply/demand fundamentals. WTI was down 31% and the Canadian blends realized similar weakness, while AECO natural gas was down 28%. The effect on WCS was worsened by a widening differential to Edmonton Par, as the Edmonton Par/WCS differential increased by 48%.

AVERAGE SELLING PRICES

| | Three Months Ended | | |
|-------------------------|--------------------|-------|--------|
| | March 31 | | |
| | 2016 | 2015 | Change |
| Oil (\$/bbl) | 30.07 | 42.25 | -29% |
| NGL (\$/bbl) | 27.38 | 23.43 | 17% |
| Oil and NGL (\$/bbl) | 29.79 | 40.43 | -26% |
| Natural gas (\$/Mcf) | 1.56 | 2.30 | -32% |
| Oil equivalent (\$/boe) | 22.23 | 29.80 | -25% |

As the key driver behind a reduction in overall cash flows, liquids pricing continued to retreat over the quarter with our average realized oil and NGL price declining by 26% versus the first quarter of last year. Our average selling prices reflect production quality and transportation differences from benchmark prices. Our realized price improved relative to WCS as a result of our 2015 royalty acquisitions which were largely lighter oil and our compensatory royalties which are also lighter oil and from prior periods when pricing was higher.

Similar to oil, natural gas prices trended down over the quarter, decreasing 32% from the same period last year. Our natural gas price realizations are discounted compared to AECO pricing as they include transportation and processing fees netted from some natural gas royalty payments.

Revenue

Gross revenue decreased 10% in Q1-2016 versus Q1-2015 due to lower commodity prices, partly offset by an increase in production.

GROSS REVENUE BY PRODUCT

| (\$000s) | Three Months Ended | | |
|---------------------------------|--------------------|---------------|-------------|
| | March 31 | | |
| | 2016 | 2015 | Change |
| Royalty interest revenue | | | |
| Oil | 14,256 | 13,245 | 8% |
| NGL | 1,778 | 957 | 86% |
| Natural gas | 3,060 | 3,885 | -21% |
| Other ⁽¹⁾ | 561 | 624 | -10% |
| | 19,655 | 18,711 | 5% |
| Working interest revenue | | | |
| Oil | 4,205 | 7,499 | -44% |
| NGL | 212 | 273 | -22% |
| Natural gas | 714 | 1,116 | -36% |
| Other ⁽¹⁾ | 147 | 152 | -3% |
| | 5,278 | 9,040 | -42% |
| Total gross revenue | | | |
| Oil | 18,461 | 20,744 | -11% |
| NGL | 1,990 | 1,230 | 62% |
| Natural gas | 3,774 | 5,001 | -25% |
| Other ⁽¹⁾ | 708 | 776 | -9% |
| | 24,933 | 27,751 | -10% |

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

The following table demonstrates the effect of price and volume variances on gross revenues. In Q1-2016 our volumes for both liquids and gas increased but weakness in commodity prices drove underperformance relative to Q1-2015.

GROSS REVENUE VARIANCES

| (\$000s) | Three Months Ended | |
|-----------------------------|--------------------|-----------------|
| | 2016 vs. 2015 | 2015 vs. 2014 |
| Oil and NGL | | |
| Production increase | 4,262 | 2,507 |
| Price decrease | (5,785) | (20,900) |
| Net decrease | (1,523) | (18,393) |
| Natural gas | | |
| Production increase | 386 | 928 |
| Price increase decrease | (1,613) | (4,229) |
| Net decrease | (1,227) | (3,301) |
| Other ⁽¹⁾ | (68) | 245 |
| Gross revenue decrease | (2,818) | (21,449) |

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

NET REVENUE

| (\$000s) | Three Months Ended | | |
|--------------------------------|--------------------|--------|--------|
| | March 31 | | |
| | 2016 | 2015 | Change |
| Gross revenue | 24,933 | 27,751 | -10% |
| Royalty expense ⁽¹⁾ | (263) | (725) | -64% |
| Net revenue | 24,670 | 27,026 | -9% |

(1) Royalty expense includes both Crown charges and royalty payments to third parties.

Expenses

ROYALTY EXPENSE ⁽¹⁾

| (\$000s, except as noted) | Three Months Ended | | |
|---------------------------------|--------------------|------|--------|
| | March 31 | | |
| | 2016 | 2015 | Change |
| Working interest | 261 | 723 | -64% |
| Per boe (\$) | 1.16 | 2.78 | -58% |
| Royalty interest ⁽²⁾ | 2 | 2 | 0% |
| Per boe (\$) | - | - | - |
| Total | 263 | 725 | -64% |
| Per boe (\$) | 0.24 | 0.80 | -70% |

(1) Royalty expense includes both Crown charges and royalty payments to third parties.

(2) Comprised of freehold mineral tax.

Oil and gas producers pay royalties to the owners of mineral rights from whom they have acquired leases. These are paid to the Crown (provincial and federal governments) and freehold mineral title owners. Crown royalty rates are tied to commodity prices and the level of oil and gas sales.

At a corporate level, royalty charges were down 70% on a boe basis versus the same period in 2015 due to the retreat in pricing and increased royalty production as a percentage of total production. We do not incur Crown or third party royalty expenses on production from our royalty interest properties other than minor freehold mineral taxes. As the royalty owner, we receive the royalty as income from other companies.

OPERATING EXPENSES

| (\$000s, except as noted) | Three Months Ended | | |
|---------------------------------|--------------------|-------|--------|
| | March 31 | | |
| | 2016 | 2015 | Change |
| Working interest | 4,378 | 4,394 | 0% |
| Per boe (\$) | 19.41 | 16.87 | 15% |
| Royalty interest ⁽¹⁾ | - | - | - |
| Per boe (\$) | - | - | - |
| Total operating expenses | 4,378 | 4,394 | 0% |
| Total (\$/boe) | 4.02 | 4.85 | -17% |

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

On certain properties where we have both a royalty interest and a working interest, production is allocated based on the royalty/working interest percentages. However, all of the operating costs relating to that production have been

allocated to the working interest properties. Freehold does not operate the majority of its working interest properties and as a result has little control over expenses.

On a total boe basis Q1-2016 averaged \$4.02/boe, a 17% decrease from the same period in 2015, reflecting increased royalty production as a percentage of total production. On a working interest per boe basis operating expenses increased 15% over Q1-2015 as a result of various prior period charges expensed in the quarter.

Netback Analysis

As a royalty owner, we share in production revenue without incurring the operational costs, risks, and responsibilities typically associated with oil and natural gas operations. The table below demonstrates the advantage of our royalty lands, which have no operating or royalty expenses (other than minor freehold mineral taxes). Royalty interests accounted for 79% of gross revenue in Q1-2016, however contributed 97% of operating income.

OPERATING INCOME ⁽¹⁾

| (\$000s) | Three months ended March 31, 2016 | | |
|--------------------------------|-----------------------------------|------------------|----------------|
| | Royalty Interest | Working Interest | Total |
| Gross revenue ⁽²⁾ | 19,655 | 5,278 | 24,933 |
| Royalty expense ⁽³⁾ | (2) | (261) | (263) |
| Net revenue | 19,653 | 5,017 | 24,670 |
| Operating expense | - | (4,378) | (4,378) |
| Operating income | 19,653 | 639 | 20,292 |
| Percentage by category | 97% | 3% | 100% |

(1) See Non-GAAP Financial Measures.

(2) Gross revenue includes potash, sulphur, lease rentals, processing fees, interest and other.

(3) Royalty expense includes both Crown charges and royalty payments to third parties.

OPERATING NETBACK

| (\$/boe) | Three Months Ended | | |
|----------------------------------|--------------------|--------|--------|
| | March 31 | | |
| | 2016 | 2015 | Change |
| Gross revenue ⁽¹⁾ | 22.88 | 30.66 | -25% |
| Royalty expense ⁽²⁾ | (0.24) | (0.80) | -70% |
| Operating expenses | (4.02) | (4.85) | -17% |
| Operating netback ⁽³⁾ | 18.62 | 25.01 | -26% |

(1) Gross revenue includes potash, sulphur, lease rentals, processing fees, interest and other.

(2) Royalty expense includes both Crown charges and royalty payments to third parties.

(3) Operating netback is calculated by subtracting royalty and operating expenses from gross revenue. See Non-GAAP Financial Measures.

Freehold's operating netback decreased 26% versus Q1-2015 mainly as a result of lower commodity prices.

GENERAL AND ADMINISTRATIVE EXPENSES

| (\$000s, except as noted) | Three Months Ended | | |
|---|--------------------|-------|--------|
| | March 31 | | |
| | 2016 | 2015 | Change |
| Gross general and administrative expenses | 3,829 | 4,085 | -6% |
| Less: capitalized and overhead recoveries | (511) | (536) | -5% |
| Net general and administrative expenses | 3,318 | 3,549 | -7% |
| Per boe (\$) | 3.05 | 3.92 | -22% |

We have significant land administration, accounting and auditing requirements to administer our royalty lands and collect royalty payments. General and administrative (G&A) expenses include direct costs and reimbursement of G&A expenses incurred by the Manager on behalf of Freehold (see Related Party Transactions). In Q1-2016 G&A charges were down 6% versus the same period in 2015. On a boe basis costs were down 22% to \$3.05/boe largely a result of the production volumes we added through acquisitions in 2015. G&A expenses on a boe basis are typically highest in the first quarter and decline throughout the remainder of the year as a number of annual expenses occur in the first quarter.

MANAGEMENT FEES (PAID IN SHARES)

| | Three Months Ended | | |
|---|--------------------|--------|--------|
| | March 31 | | |
| | 2016 | 2015 | Change |
| Shares issued in payment of management fees | 71,912 | 54,488 | 32% |
| Ascribed value (\$000s) ⁽¹⁾ | 758 | 978 | -22% |
| Per boe (\$) | 0.70 | 1.08 | -35% |

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

The Manager (see Related Party Transactions) receives a management fee in shares. In accordance with the previous amended and restated management agreement, the issue of shares from treasury related to equity offerings and the DRIP, result in pro-rata increases in the number of shares issued as the management fee (see Shareholders' Capital). The equity offering in May 2015 was largely the cause of the 32% increase in shares issued compared to last year, however the value decreased due to our lower share price. The agreement was amended in November 2015 and as a result the management fee has been capped at 71,912 shares per quarter for 2016 and will be reduced to a level of 5,500 shares per quarter over the next seven years.

SHARE BASED AND OTHER COMPENSATION

| (\$000s, except as noted) | Three Months Ended | | |
|------------------------------------|--------------------|------|--------|
| | March 31 | | |
| | 2016 | 2015 | Change |
| Gross LTIP | 46 | 46 | 0% |
| Less: capitalized portion | (9) | (8) | 13% |
| Net LTIP | 37 | 38 | -3% |
| Deferred share unit plan | 383 | 497 | -23% |
| Retirement benefit | 3 | 5 | -40% |
| Share based and other compensation | 423 | 540 | -22% |
| Per boe (\$) | 0.39 | 0.60 | -35% |

We are responsible for funding a portion of the long-term incentive compensation plan (the LTIP) for employees of the Manager. The 2013 LTIP grants valued at \$0.1 million were paid out in 2016. The low LTIP expense in Q1-2016 is

largely a result of the decrease in share price quarter over quarter, with share price having the largest effect on the valuation.

Pursuant to our deferred share unit plan, fully-vested deferred share units (DSUs) are granted annually in the first quarter to non-management directors and are redeemable for an equal number of shares (less tax withholdings if necessary) after the director's retirement. On January 1, 2016 the Board granted 41,437 DSUs to eligible directors. During Q1-2016 a retired director redeemed 37,627 DSUs, resulting in the issuance of 26,340 shares from treasury and the cancellation of 11,287 DSUs for withholding tax. As at March 31, 2016, there were 184,656 deferred share units outstanding, and as at May 11, 2016, there were 185,334 DSUs outstanding (including notional DSUs granted as a result of dividends paid on our common shares).

Related Party Transactions

Freehold does not have any employees. Rife Resources Management Ltd. (the Manager) is the manager of Freehold. The Manager is a wholly-owned subsidiary of Rife Resources Ltd. (Rife), and two of Rife's directors are also directors of Freehold. Rife is 100% owned by the CN Pension Trust Funds (the pension funds for the employees of the Canadian National Railway Company), which in turn is a shareholder of Freehold. The Manager recovers its general and administrative costs and a portion of its long-term incentive plan costs and retirement benefit costs, and receives a quarterly management fee paid in shares. Canpar Holdings Ltd. (Canpar) is also managed by Rife and owned 100% by the CN Pension Trust Funds, and two of Canpar's directors are also directors of Freehold.

(a) Rife Resources Management Ltd.

The Manager provides certain services for a fee based on a specified number of shares per quarter, pursuant to the amended and restated management agreement. This agreement was recently amended and restated on November 9, 2015. The amended and restated management agreement caps the management fee at 71,912 shares per quarter for 2016 and the number of shares to be issued per quarter as payment of the management fee will be reduced to 5,500 shares over the next seven years. For the three months ended March 31, 2016, Freehold issued 71,912 shares (2015 – 54,488) as payment of the management fee to the Manager pursuant to the management agreement. The ascribed value of \$0.8 million (2015 – \$1.0 million) was based on the closing price of the shares on the last trading day of each quarter.

For the three months ended March 31, 2016, the Manager charged \$2.9 million in general and administrative costs (2015 – \$3.0 million). At March 31, 2016, there was \$0.7 million (December 31, 2015 – \$0.7 million) in accounts payable and accrued liabilities relating to these costs.

(b) Rife Resources Ltd.

Freehold maintains ownership interests in certain oil and gas properties operated by Rife. A portion of net operating revenues and capital expenditures represent joint operations amounts from Rife. At March 31, 2016, there was \$0.1 million (December 31, 2015 - \$nil) in accounts payable and accrued liabilities relating to these transactions. In addition, Freehold receives royalties from Rife pursuant to various royalty agreements. For the three months ended March 31, 2016, Freehold received royalties of approximately \$0.2 million (2015 – \$0.3 million). At March 31, 2016, there was \$0.1 million (December 31, 2015 - \$0.1 million) in accounts receivable relating to these transactions.

(c) Canpar Holdings Ltd.

Freehold and Canpar share mineral title ownership rights in a substantial land base in western Canada. Generally, Canpar owns mineral rights that were below the deepest producing formation at the time that Freehold was created, and Freehold holds the balance of the mineral rights. Given the nature of the mineral rights, which are dependent upon hydrocarbon pool formation classification as well as third party drilling data which is subject to change and revision,

significant uncertainty can exist with respect to the royalty ownership of wells drilled and completed on lands where both Freehold and Canpar hold the mineral rights. At March 31, 2016, there was \$nil (December 31, 2015 – \$nil) in accounts receivable and accounts payable and accrued liabilities relating to transactions with Canpar.

(d) CN Pension Trust Funds

Concurrent with the closing of the bought deal equity offering on May 6, 2015, CN Pension Trust Funds invested approximately \$33 million in Freehold through the purchase of 1,833,334 common shares on a non-brokered private placement basis. In addition, as noted under Subsequent Events, the CN Pension Trust Funds have agreed to invest approximately \$20 million through the purchase of 1,732,000 common shares on a non-brokered private placement basis concurrently with the bought deal equity offering which is expected to close on May 25, 2016.

All amounts owing to/from the Manager, Rife, and Canpar are unsecured, non-interest bearing and due on demand. All transactions were in the normal course of operations and were measured at the amount of consideration established and agreed to by both parties.

INTEREST AND FINANCING

| (\$000s, except as noted) | Three Months Ended | | |
|--------------------------------|--------------------|-------|--------|
| | March 31 | | |
| | 2016 | 2015 | Change |
| Interest and financing expense | 1,210 | 1,544 | -22% |
| Per boe (\$) | 1.11 | 1.71 | -35% |

In Q1-2016, interest and financing expense decreased due to lower average debt levels. The average effective interest rate on advances under our credit facilities was 2.9% (Q1-2015 – 3.1%).

DEPLETION AND DEPRECIATION

| (\$000s, except as noted) | Three Months Ended | | |
|----------------------------|--------------------|--------|--------|
| | March 31 | | |
| | 2016 | 2015 | Change |
| Depletion and depreciation | 26,202 | 19,549 | 34% |
| Per boe (\$) | 24.05 | 21.60 | 11% |

Oil and gas properties and royalty interests, including the cost of production equipment, future capital costs associated with proved plus probable reserves, and the capitalized portion of the decommissioning liability, are depleted on the unit-of-production method based on estimated proved plus probable oil and gas reserves. The increase in depletion is a result of increased production volumes and ongoing acquisition and capital expenditures.

Income Tax

As a corporation, taxable income is based on revenues (which will vary depending on commodity prices and production volumes) less allowable expenses including claims for both accumulated tax pools and tax pools associated with current year expenditures. For the three months ended March 31, 2016, there was no current income tax expense (Q1-2015 - \$5.1 million recovery). Freehold's tax pools at December 31, 2015 were \$966 million.

Liquidity and Capital Resources

Operating Activities

Q1-2016 net loss was \$8.6 million (Q1-2015 net income of \$21.6 million) primarily due to lower revenues and increased depletion and depreciation expense as a result of higher production volumes. In addition, Q1-2015 had a one-time \$24.3 million gain on corporate acquisition.

Funds from operations was down 29% from the same period last year owing to continued weakness in oil and natural gas prices. 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.

NET INCOME AND FUNDS FROM OPERATIONS

| (\$000s, except as noted) | Three Months Ended | | |
|-----------------------------------|--------------------|--------|--------|
| | March 31 | | |
| | 2016 | 2015 | Change |
| Net income (loss) | (8,590) | 21,617 | -140% |
| Per share, basic and diluted (\$) | (0.09) | 0.29 | -131% |
| Funds from operations | 15,500 | 21,938 | -29% |
| Per share (\$) | 0.16 | 0.29 | -45% |

Financing Activities

We retain working capital primarily to fund capital expenditures or acquisitions and reduce bank indebtedness. In the oil and gas industry, accounts receivable from industry partners are typically settled in the following month. However, due to administrative complexity, payments to royalty owners are often delayed longer. Also, working capital at each period end can vary due to volume and price changes at each period end and unpaid capital expenditures.

COMPONENTS OF WORKING CAPITAL

| | Mar. 31 | Dec. 31 | Sep. 30 | Jun. 30 | Mar. 31 |
|---|----------|----------|----------|----------|----------|
| (\$000s) | 2016 | 2015 | 2015 | 2015 | 2015 |
| Cash | 329 | 876 | 263 | 848 | 772 |
| Accounts receivable | 16,305 | 21,046 | 23,795 | 29,714 | 20,870 |
| Current taxes receivable | 73 | 73 | 700 | 7,532 | 7,694 |
| Current assets | 16,707 | 21,995 | 24,758 | 38,094 | 29,336 |
| Dividends payable | (3,970) | (6,924) | (6,900) | (8,838) | (6,791) |
| Accounts payable and accrued liabilities | (8,756) | (9,826) | (11,669) | (12,030) | (11,164) |
| Current portion of share based and other compensation payable | (178) | (194) | (183) | (218) | (215) |
| Current liabilities | (12,904) | (16,944) | (18,752) | (21,086) | (18,170) |
| Working capital | 3,803 | 5,051 | 6,006 | 17,008 | 11,166 |

Working capital decreased by \$1.2 million in the first quarter of 2016 compared to the previous quarter. This was driven by a decrease in accounts receivable with lower commodity prices, but offset by our lower dividend rate and reduced capital activity.

DEBT ANALYSIS

| | Mar. 31 | Dec. 31 | Sep. 30 | Jun. 30 | Mar. 31 |
|-------------------------------------|---------|---------|---------|----------|----------|
| (\$000s) | 2016 | 2015 | 2015 | 2015 | 2015 |
| Long-term debt | 153,000 | 152,000 | 155,000 | 164,000 | 210,000 |
| Short-term debt | - | - | - | - | - |
| Total debt | 153,000 | 152,000 | 155,000 | 164,000 | 210,000 |
| Working capital | (3,803) | (5,051) | (6,006) | (17,008) | (11,166) |
| Net debt obligations ⁽¹⁾ | 149,197 | 146,949 | 148,994 | 146,992 | 198,834 |

(1) See Non-GAAP Financial Measures.

Net debt obligations increased \$2.2 million to \$149.2 million from the previous quarter due to the working capital changes mentioned above and lower funds from operations.

We have a \$245 million extendible revolving term credit facility with a syndicate of four Canadian chartered banks and a \$15 million extendible revolving operating facility. Borrowings under the facilities bear interest at the bank's prime lending rate, bankers' acceptance or LIBOR rates plus applicable margins and standby fees. The facilities are secured with \$400 million demand debentures over Freehold's petroleum and natural gas assets but do not contain any financial covenants. At March 31, 2016, we had \$107 million of available capacity under our credit and operating facilities.

Our borrowing base is dependent on our lenders review and interpretation of our reserves and future commodity prices. The lenders at any time can request a redetermination of the borrowing base, which may require a repayment to the lenders within 90 days of receiving notice, of an amount that the indebtedness is in excess of the redetermined borrowing base. The lenders have completed the 2016 annual review and have confirmed the borrowing base at \$260 million and agreed to extend the revolving period of the credit facilities to May 20, 2017, subject to finalization and execution of formal documentation which is expected to occur on or before May 21, 2016.

FINANCIAL LEVERAGE AND COVERAGE RATIOS ⁽¹⁾

| | Mar. 31 2016 | Dec. 31 2015 | Sep. 30 2015 | Jun. 30 2015 | Mar. 31 2015 |
|--|-----------------|-----------------|-----------------|-----------------|-----------------|
| Net debt to funds from operations (times) ⁽²⁾ | 1.5 | 1.4 | 1.4 | 1.2 | 1.5 |
| Net debt to dividends (times) ⁽²⁾ | 1.7 | 1.6 | 1.5 | 1.4 | 1.8 |
| Dividends to interest expense (times) | 16 | 16 | 18 | 19 | 21 |
| Net debt to net debt plus equity (%) ⁽²⁾ | 17 | 17 | 16 | 15 | 32 |

(1) Funds from operations, dividends, and interest expense are 12-months trailing and do not include the proforma effects of our acquisitions.

(2) See Non-GAAP Financial Measures.

At March 31, 2016, net debt was 1.5 times 12-months trailing funds from operations and net debt obligations were 17% of total capitalization.

Under our credit facilities, we are restricted from declaring dividends if we are or would be in default under the facilities or if our borrowings thereunder exceed our borrowing base. As at March 31, 2016, we were in compliance with all such covenants. We are also restricted from declaring dividends if we do not satisfy the liquidity and solvency tests under the *Business Corporations Act* (Alberta).

SHAREHOLDERS' CAPITAL

| | March 31, 2016 | | December 31, 2015 | |
|--|----------------|--------------------|-------------------|--------------------|
| | Shares | Amount (\$000s) | Shares | Amount (\$000s) |
| Balance, beginning of period | 98,940,152 | 1,050,494 | 74,918,711 | 635,223 |
| Issued for dividend reinvestment plan | 245,183 | 2,384 | 1,218,129 | 17,225 |
| Issued in lieu of management fee | 71,912 | 758 | 269,978 | 3,693 |
| Issued for deferred share unit plan redemption | 26,340 | 471 | - | - |
| Issued for equity offering | - | - | 22,533,334 | 405,600 |
| Issue cost, net of tax effect | - | - | - | (11,247) |
| Balance, end of period | 99,283,587 | 1,054,107 | 98,940,152 | 1,050,494 |

SHARES OUTSTANDING

| | Three Months Ended March 31 | | |
|------------------|--------------------------------|------------|--------|
| | 2016 | 2015 | Change |
| Weighted average | | | |
| Basic | 99,093,250 | 75,198,596 | 32% |
| Diluted | 99,093,250 | 75,360,053 | 31% |
| At period end | 99,283,587 | 75,456,671 | 32% |

As at March 31, 2016, there were 99,283,587 shares outstanding, and as at May 11, 2016, there were 99,326,480 shares outstanding. For the three months ended March 31, 2016 DSUs were excluded from the calculation of diluted net loss per share as their effect was anti-dilutive.

Dividend Policy

The Board reviews and determines the monthly dividend rate on a quarterly basis after considering expected commodity prices, foreign exchange rates, economic conditions, production volumes, DRIP participation levels, tax payable, and our capacity to finance operating and investing obligations. The dividend rate is established with the intent of absorbing short-term market volatility over several months. It also recognizes our intention to fund capital expenditures primarily through funds from operations and to maintain a strong balance sheet to take advantage of acquisition opportunities and withstand potential commodity price declines.

Freehold's dividends are designated as eligible dividends for Canadian income tax purposes.

RECONCILIATION OF DIVIDENDS DECLARED

| (\$000s) | Three Months Ended | |
|------------------------|--------------------|----------|
| | March 31 | |
| | 2016 | 2015 |
| Funds from operations | 15,500 | 21,938 |
| Proceeds from the DRIP | 2,384 | 8,361 |
| Debt additions | 1,000 | 71,000 |
| Acquisition advance | - | 949 |
| Acquisitions | (219) | (68,370) |
| Capital expenditures | (2,084) | (5,969) |
| Working capital change | 1,264 | (7,580) |
| Dividends declared | 17,845 | 20,329 |

ACCUMULATED DIVIDENDS

| | Three Months Ended | |
|--|--------------------|-----------|
| | March 31 | |
| | 2016 | 2015 |
| Dividends declared (\$000s) | 17,845 | 20,329 |
| Accumulated, beginning of period | 1,425,971 | 1,335,832 |
| Accumulated, end of period | 1,443,816 | 1,356,161 |
| Dividends per share (\$) ⁽¹⁾ | 0.18 | 0.27 |
| Accumulated, beginning of period | 29.93 | 28.93 |
| Accumulated, end of period | 30.11 | 29.20 |

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

Dividend Reinvestment Plan (DRIP)

In the first quarter of 2016, average participation in Freehold's DRIP was 11% (Q1-2015 – 35%). We issued 245,183 (Q1-2015 – 483,472) shares related to the DRIP with an ascribed value of \$2.4 million (Q1-2015 – \$8.4 million). Participation levels can fluctuate greatly on a month to month basis. The ascribed value was based on the weighted average closing price for the 10 trading days preceding each payment date.

The DRIP allows for the issuance of shares from treasury at a 5% discount to market (i.e. 95% of the weighted average closing price for the 10 trading days preceding each payment date). Registered shareholders who wish to enrol in the DRIP may do so by contacting Computershare Trust Company of Canada, the Plan Agent. Beneficial shareholders who wish to participate in the DRIP should contact the broker or other nominee through which their shares are held to obtain appropriate enrolment instructions, ensuring any deadlines or other requirements that such broker or nominee may impose or be subject to are met. U.S. residents may not participate in the DRIP.

DIVIDEND ANALYSIS

| (\$000s) | Three Months Ended | |
|--------------------------------------|--------------------|--------|
| | March 31 | |
| | 2016 | 2015 |
| Dividends paid in cash | 18,415 | 15,665 |
| Dividends paid in shares (DRIP) | 2,384 | 8,361 |
| Total dividends paid ⁽¹⁾ | 20,799 | 24,026 |
| Dividends declared | 17,845 | 20,329 |
| Funds from operations | 15,500 | 21,938 |
| Capital expenditures | 2,084 | 5,969 |
| Basic payout ratio ⁽²⁾ | 115% | 93% |
| Adjusted payout ratio ⁽³⁾ | 132% | 99% |

(1) Based on the dividend payment date which is generally on the 15th day of the month following the month it was declared.

(2) Dividends declared as a percentage of funds from operations (see Non-GAAP Financial Measures).

(3) Dividends paid in cash plus capital expenditures as a percentage of funds from operations (see Non-GAAP Financial Measures).

Our basic payout ratio for the first quarter of 2016 has increased to 115% as a result of the decrease in commodity prices and its effect on our funds from operations. In response Freehold dropped our dividend from \$0.07 to \$0.04 for the March 2016 payment, payable in April 2016.

Investing Activities

ACQUISITIONS AND CAPITAL EXPENDITURES

| (\$000s) | Three Months Ended | | |
|----------------------|--------------------|--------|--------|
| | March 31 | | |
| | 2016 | 2015 | Change |
| Acquisitions | 219 | 68,370 | - |
| Capital expenditures | 2,084 | 5,969 | -65% |
| | 2,303 | 74,339 | -97% |

Freehold expended \$0.2 million in the first quarter of 2016 on minor acquisition activity and adjustments to previously made acquisitions. Capital expenditures were \$2.1 million, down 65% from Q1-2015, with reduced company expenditures mirroring general decreases in industry activity.

Contingency

In May 2009, a statement of claim was filed against Freehold for \$9 million. The claim involves disputed land interests and royalty obligations. After receiving external legal advice, Freehold has assessed the claim and believes it has no merit. The claim's outcome is not determinable and therefore no liability has been recorded in the financial statements.

Additional Information

Additional information about Freehold, including our annual information form (AIF), is available on SEDAR at www.sedar.com and on our website at www.freeholdroyalties.com.

Internal Controls

Freehold is required to comply with National Instrument 52-109, *Certification of Disclosure in Issuers' Annual and Interim Filings*. The certification of interim filings requires us to disclose in the MD&A any changes in our internal controls over financial reporting that have materially affected, or are reasonably likely to materially affect our internal control over financial reporting. We confirm that no such changes were made to the internal controls over financial reporting during the three months ended March 31, 2016. The Chief Executive Officer and Chief Financial Officer have signed form 52-109F2, *Certification of Interim Filings*, which can be found on SEDAR at www.sedar.com.

Forward-looking Statements

Certain statements contained in this MD&A constitute forward-looking statements. These statements relate to future events or our expectations of future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as “seek”, “anticipate”, “plan”, “continue”, “estimate”, “expect”, “may”, “will”, “forecast”, “project”, “predict”, “potential”, “targeting”, “intend”, “could”, “might”, “should”, “believe” and similar expressions (including the negatives thereof). These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. We believe the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and, as such, forward-looking statements included in this MD&A should not be unduly relied upon. These forward-looking statements are provided to allow readers to better understand our business and prospects.

In particular, this MD&A contains forward-looking statements under Business Environment, Industry Activity, Guidance Update, Subsequent Events, and 2016 First Quarter Highlights pertaining to 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;
- our strategies and the expectation that those strategies will sustain production and reserves life;
- our acquisition criteria and the intent that such criteria will result in acquisitions being accretive to shareholders;
- foreign exchange rates;
- industry drilling, development activity on our royalty lands, our exposure in emerging resource plays, and the potential impact of horizontal drilling on production and reserves;
- development of working interest properties;
- participation in the DRIP and our use of cash preserved through the DRIP;
- estimated capital budget and expenditures and the timing thereof;
- Freehold’s decommissioning liability and timing of payment thereof;
- average production and contribution from royalty lands;
- forecast 2016 basic payout ratio;

- key operating assumptions;
- our dividend policy and expectations for future dividends;
- treatment under governmental regulatory regimes and tax laws;
- our assessment of litigation risk;
- expected 2016 annualized net production and operating income from the Husky Transaction;
- expected increase of royalties as a percentage of operating income resulting from the Husky Transaction;
- expected decline rate associated with the assets acquired pursuant to the Husky Transaction;
- the expected closing dates of the Husky Transaction and the concurrent financings;
- the expected use of proceeds from the financings discussed herein; and
- the expectation that the Husky Transaction and concurrent financings will close.

Our actual results could differ materially from those anticipated in these forward-looking statements because of many factors, the most significant of which are as follows:

- volatility in market prices for crude oil and natural gas;
- lack of pipeline capacity;
- currency fluctuations;
- changes in income tax laws or changes in tax laws, regulations, royalties, or incentive programs relating to the oil and gas industry;
- reliance on royalty payors to drill and produce on our lands and their ability to pay their obligations;
- uncertainties or imprecision associated with estimating oil and gas reserves;
- stock market volatility and our ability to access sufficient capital from internal and external sources;
- a significant or prolonged downturn in general economic conditions or industry activity;
- incorrect assessments of the value of acquisitions;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- geological, technical, drilling, and processing problems;
- environmental risks and liabilities inherent in oil and gas operations;
- the closing of the Husky Transaction and concurrent financings; and
- other factors discussed in Freehold's annual MD&A and audited financial statements for the year ended December 31, 2015, and in our AIF.

With respect to forward-looking statements contained in this MD&A, we have made assumptions regarding, among other things, the following:

- future crude oil and natural gas 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 expanding our assets;

- our ability and the ability of our industry partners and royalty payors to obtain equipment in a timely manner to carry out development activities;
- our ability to market our product successfully to current and new customers;
- our expectation for the consumption of crude oil and natural gas;
- our expectation for industry drilling levels;
- the impact of increasing competition;
- our ability to obtain financing on acceptable terms;
- our ability to add production and reserves through our development and acquisition activities; and
- the Husky Transaction and concurrent financings will close on the terms and timings expected.

Key operating assumptions with respect to the forward-looking statements contained in this MD&A are provided in the Guidance Update section.

To the extent any guidance or forward-looking statements herein constitutes a financial outlook, they are included herein to provide readers with an understanding of management's plans and assumptions for budgeting purposes and readers are cautioned that the information may not be appropriate for other purposes. 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 (loss), as further information becomes available and as the economic environment changes.

The forward-looking statements contained in this MD&A are expressly qualified by this cautionary statement and speak only as of the date of this MD&A. Our policy for updating forward-looking statements is to update our key operating assumptions quarterly and, except as required by law, we do not undertake to update any other forward-looking statements.

Conversion of Natural Gas to Barrels of Oil Equivalent (BOE)

To provide a single unit of production for analytical purposes, natural gas production and reserves volumes are converted mathematically to equivalent barrels of oil (boe). We use the industry-accepted standard conversion of six thousand cubic feet of natural gas to one barrel of oil (6 Mcf = 1 barrel). 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, 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 MD&A, references are made to terms commonly used as key performance indicators in the oil and gas industry. We believe that operating income, operating netback, net debt obligations, net debt to funds from operations, basic payout ratio and adjusted payout ratio 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 (see Netback Analysis). 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 obligations as a proportion of funds from operations for the previous twelve months (see Financing Activities). 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, NGL and natural gas production during the period, with natural gas converted to equivalent barrels of oil as described above.

Payout ratios are often used for dividend paying companies in the oil and gas industry to identify its dividend levels in relation to the funds it receives and uses in its capital and operational activities. Basic payout ratio is calculated as dividends declared as a percentage of funds from operations. Adjusted payout ratio is calculated as dividends paid in cash plus capital expenditures as a percentage of funds from operations.

Initial Production Rates

Any references in this MD&A to initial production rates are useful in confirming the presence of hydrocarbons, however, such rates are not determinative of the rates at which such wells will continue production and decline thereafter. While encouraging, readers are cautioned not to place reliance on such rates in calculating the aggregate production for Freehold.