

Results at a Glance

FINANCIAL (\$000s, except as noted)	Three Months Ended			Six Months Ended		
	June 30			June 30		
	2017	2016	Change	2017	2016	Change
Royalty and other revenue	38,430	32,219	19%	79,521	57,152	39%
Net income (loss)	13,084	(2,249)	-	20,172	(10,839)	-
Per share, basic and diluted (\$)	0.11	(0.02)	-	0.17	(0.11)	-
Funds from operations	31,769	24,142	32%	63,838	39,642	61%
Per share, basic (\$)	0.27	0.23	17%	0.54	0.39	38%
Operating income ⁽¹⁾	35,235	28,011	26%	72,319	48,303	50%
Operating income from royalties (%)	97	91	7%	94	94	-
Acquisitions	1,267	162,211	-99%	34,619	162,430	-79%
Capital expenditures	1,139	753	51%	1,851	2,837	-35%
Working interest dispositions	28,808	-	-	29,096	-	-
Dividends declared	17,705	13,380	32%	33,043	31,225	6%
Per share (\$) ⁽²⁾	0.15	0.12	25%	0.28	0.30	-7%
Net debt	49,819	98,191	-49%	49,819	98,191	-49%
Shares outstanding, period end (000s)	118,073	117,652	-	118,073	117,652	-
Average shares outstanding (000s) ⁽³⁾	118,018	106,736	11%	117,987	102,914	15%
OPERATING						
Average daily production (boe/d) ⁽⁴⁾	12,589	12,041	5%	12,670	12,006	6%
Oil and NGL (%)	54	59	-8%	55	61	-10%
Average price realizations (\$/boe) ⁽⁴⁾	32.98	28.48	16%	33.93	25.37	34%
Operating netback (\$/boe) ⁽¹⁾⁽⁴⁾	30.76	25.57	20%	31.54	22.11	43%

(1) See 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).

President's Message

Freehold achieved record royalty production and solid cash flow results in Q2-2017 marking the fourth consecutive quarter of increasing royalty production on a per share basis. We are revising our 2017 production guidance up 500 boe/d to 11,800 – 12,300 boe/d with better than expected audit recoveries and operating results. At current dividend levels we are forecasting an adjusted payout ratio for 2017 of 61%, safely within our target adjusted payout range of 60% – 80%. Not only are we growing royalty production on a per share basis, we exited the quarter with lower debt resulting in net debt to 12-month trailing funds from operations of 0.4 times (net debt of \$50 million). In Q2-2017, Freehold issued 12 new lease agreements for a cumulative total of 37 new leases in the first half of 2017, exceeding the entire 2016 new lease count as we deliver continued organic growth. Our quarter was in line with Freehold's objective to deliver growth and low risk attractive returns to shareholders over the long term.

Tom Mullane

President and CEO

Second Quarter Highlights

- Freehold's production averaged 12,589 boe/d, a 5% improvement over Q2-2016. Gains in production were largely driven by drilling activity on our royalty lands, our strong audit function (over 700 boe/d of prior period adjustments) and royalty acquisitions.
- Royalty production was up 16% compared to Q2-2016, averaging 11,270 boe/d. Royalty production increased 5% on a per share basis versus Q1-2017. We have grown our royalty production nine successive quarters and four quarters on a per share measure.
- Royalty interests accounted for 90% of total production and contributed 97% of operating income in Q2-2017, both being the highest totals in our history.
- Wells drilled on our royalty lands totaled 58 (1.6 net) in Q2-2017, up from 23 (0.4 net) in Q2-2016. Year-to-date we have seen 208 (10.2 net) wells drilled on our royalty lands compared to 108 (3.8 net) locations drilled during the same period in 2016.
- In Q2-2017 Freehold issued 12 new lease agreements for a cumulative total of 37 new leases in the first half of 2017, exceeding the 2016 total new lease count. Freehold's unleased holdings are available for review on our website's Leasing Opportunities page at www.freeholdroyalties.com.
- Freehold closed \$28.9 million dispositions of various working interest assets located in southeast Saskatchewan. Total production and operating income associated with these assets for Q1-2017 was approximately 650 boe/d and \$1.4 million respectively.
- Funds from operations totaled \$31.8 million, an increase of 32% compared to Q2-2016, largely due to the increase in revenue. On a per share basis, funds from operations was \$0.27/share in Q2-2017 up from \$0.23/share in Q2-2016.
- Freehold generated \$12.9 million in free cash flow⁽¹⁾, over and above our dividend, which we applied to outstanding debt. At June 30, 2017, net debt totaled \$49.8 million resulting in a net debt to 12-month trailing funds from operations ratio of 0.4 times.
- Cash costs⁽¹⁾ for the quarter totaled \$5.63/boe, down from \$7.34/boe in Q2-2016 and \$7.66/boe in Q1-2017. With the April 2017 dispositions of our southeast Saskatchewan working interest assets and growth in our royalty production, we have reduced our cash costs and enhanced netbacks.
- Dividends declared for Q2-2017 totaled \$0.15 per share, up 25% from \$0.12 per share one year ago. In March 2017, Freehold announced an increase to its monthly dividend from \$0.04 to \$0.05 per share.
- Basic payout ratio⁽¹⁾ (dividends declared/funds from operations) for Q2-2017 totaled 56% while the adjusted payout ratio⁽¹⁾ ((cash dividends plus capital expenditures)/funds from operations) for the same period was 59%.

(1) See Non-GAAP Financial Measures.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following Management's Discussion and Analysis (MD&A) was prepared as of August 9, 2017, 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 and six months ended June 30, 2017, and previous periods, and the outlook for Freehold based on information available as of August 9, 2017.

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 three and six months ended June 30, 2017 and June 30, 2016, 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, 2016, together with the accompanying notes. Information contained in the 2016 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.

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 6.1 million gross acres, greater than 95% of which are royalty lands. Our mineral title lands (including royalty assumption lands), which we own in perpetuity, cover approximately 1.0 million acres and we have gross overriding royalty interests in approximately 4.9 million acres.

We have interests in more than 42,000 wells (of which over 40,000 are royalty wells including over 20,000 unitized wells). We receive royalty income from over 300 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, and as a royalty owner we benefit from the drilling activity of others 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 Q2-2017) 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 380,000 acres of unleased mineral titles.

Our Strategy

As a leading royalty oil and gas corporation, Freehold's objective is to deliver growth and low risk attractive returns to shareholders over the long term. Freehold accomplishes this by:

- **Creating Value**

- Drive oil and gas development on our lands through our lease out programs.
- Acquire royalty assets with acceptable risk profiles and long economic life.
- Generate gross overriding royalties for revenue growth.

- **Enhancing value**

- Maximize our royalty interests through a comprehensive audit program.
- Manage our debt prudently with a target of 0.5-1.5 times net debt to funds from operations.

- **Delivering value**

- Target a dividend with an adjusted payout ratio of 60%-80%.

Outlook

Business Environment

West Texas Intermediate (WTI) oil price continued to trend down through Q2-2017 averaging US\$48.29/bbl, 7% below levels realized in Q1-2017 but 6% higher than prices seen during the same period in 2016. In Canada, Edmonton Light Sweet prices fared better on a relative basis averaging \$61.84/bbl representing a 13% improvement versus the same period last year. Similarly, Western Canadian Select (WCS) prices averaged \$49.99/bbl, up 20% versus Q2-2016. We continue to see light/heavy differentials (between Edmonton Light Sweet and WCS) narrowing in Canada, averaging \$11.85/bbl for the quarter, compared to \$13.08/bbl during Q2-2016. On the natural gas front, AECO prices averaged \$2.77/mcf, up 122% versus the same period last year.

The Petroleum Services Association of Canada (PSAC) is currently projecting 7,200 wells drilled through 2017, up 8% from its previously forecasted estimate of 6,680 wells and a 96% increase over 2016. PSAC based its 2017 forecast on average natural gas prices of \$2.75/mcf AECO and a WTI price of US\$49.00/bbl.

Drilling Activity

Including drilling associated with acquisitions, 208 (10.2 net) wells were drilled on our royalty lands during the first six months of 2017, a 168% increase versus the same time period in 2016 (on a net basis). While the second quarter typically represents a slower period on the activity front, drilling on our lands came in above expectations with 58 (1.6 net) locations drilled, compared to 23 (0.4 net) during the same period last year.

Activity through the first half of 2017 was primarily focused on oil prospects including the Viking at Redwater and Dodsland, which represented greater than 40% of our net locations through the first two quarters. We also see continued activity in southeast Saskatchewan (Bakken, Mississippian), southwest Saskatchewan (Shaunavon) and the Deep Basin (Montney). Our top payors continue to represent some of the most well capitalized E&P producers in Canada.

ROYALTY INTEREST DRILLING

	Three Months Ended June 30 ⁽¹⁾				Six Months Ended June 30 ⁽¹⁾			
	2017		2016		2017		2016	
	Equivalent		Equivalent		Equivalent		Equivalent	
	Gross	Net ⁽²⁾	Gross	Net ⁽²⁾	Gross	Net ⁽²⁾	Gross	Net ⁽²⁾
Non-unitized wells	35	1.5	11	0.3	175	10.0	59	3.5
Unitized wells ⁽³⁾	23	0.1	12	0.1	33	0.2	49	0.3
Total	58	1.6	23	0.4	208	10.2	108	3.8

(1) Counts include wells drilled on acquired lands from the beginning of the reporting period (this may differ from the closing date of the acquisitions).

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

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

Guidance Update

Below are details of some of the changes made to our key operating assumptions for 2017.

- We are increasing our 2017 production range to 11,800-12,300 boe/d (previously 11,300-11,800 boe/d), as a result of higher than expected results through the first half of the year, mostly due to drilling activity and prior period adjustments. We do not include the effects of future acquisition activity in our forecasts. Also, minimal prior period adjustments are in our forecast as we do not record the effects of audit and compliance activities until revenue collection is certain.
- Volumes are expected to be weighted approximately 55% oil and natural gas liquids (NGL) and 45% natural gas.
- We continue to improve our royalty focus with royalty production accounting for 88% of forecasted 2017 production (up from 87%) and 95% of operating income (up from 94%).
- We are reducing our WTI price assumption to US\$50.00/bbl (previously US\$52.00/bbl). WCS remains unchanged due to positive effects of the declining light/heavy oil differentials. Our AECO natural gas price assumption remains at \$2.60/mcf.
- The Cdn\$/US\$ exchange rate has been adjusted upwards to \$0.77 from \$0.76 as a result of recent Canadian dollar appreciation and market expectations for the remainder of the year.
- Our operating costs forecast is revised downwards to \$2.40/boe (from \$2.50/boe) and general and administrative costs to \$2.50/boe (from \$2.60/boe) as a result of our increased royalty production.
- Based on our current \$0.05 monthly dividend level, we expect our 2017 adjusted payout ratio ((cash dividends plus capital expenditures)/funds from operations) to be approximately 61%.
- We continue to forecast year-end net debt to funds from operations of approximately 0.3 times based on our revised key operating assumptions.

KEY OPERATING ASSUMPTIONS

2017 Annual Average		Aug. 9, 2017	Guidance Dated		
			May 10, 2017	Mar. 2, 2017	Nov. 8, 2016
Daily production	boe/d	11,800-12,300	11,300 - 11,800	11,300 - 11,800	11,000
West Texas Intermediate crude oil	US\$/bbl	50.00	52.00	52.00	50.00
Western Canadian Select crude oil	Cdn\$/bbl	49.00	49.00	49.00	46.00
AECO natural gas	Cdn\$/Mcf	2.60	2.60	2.60	3.00
Exchange rate	Cdn\$/US\$	0.77	0.76	0.76	0.75
Operating costs	\$/boe	2.40	2.50	3.25	3.25
General and administrative costs ⁽¹⁾	\$/boe	2.50	2.60	2.60	2.65
Capital expenditures	\$ millions	4	4	6	6
Weighted average shares outstanding	millions	118	118	118	118

(1) Excludes share based compensation.

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 and adjust the dividend levels as necessary (subject to the quarterly review and approval of our Board of Directors - see Dividend Policy).

Quarterly Performance and Trends

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

- Quarterly variances in revenues, net income (loss) and funds from operations are caused mainly by fluctuations in commodity prices and production volumes.
- Oil prices are impacted significantly by global supply and demand factors, with OPEC decisions on production cuts and U.S. production growth having the largest effects. Supply has continued to outstrip demand which has resulted in the continuation of relatively low prices. Fluctuations in foreign exchange rates also affect our oil price realizations, resulting in positive or negative impacts on our Canadian dollar oil revenues relative to the benchmark WTI, which is referenced in U.S. dollars.
- AECO natural gas prices continue to be negatively impacted by supply outstripping demand.
- The largest effect on our dividends is from funds from operations, which is mainly a function of revenues and cash expenses, however the timing of dividend adjustments is dependent on forward projections and the decisions of our Board of Directors.
- Production has been affected by drilling activity and acquisitions, as well as prior period 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, 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 \$197.9 million of royalty assets in Alberta and Saskatchewan. This activity affects our revenues, percentage royalty interests, oil, NGL and natural gas production mix, debt levels and shares outstanding, among others.
- Freehold disposed of \$28.8 million of its working interest properties in Q2-2017 in an effort to enhance our royalty focus.
- Net income (loss) may be affected by large unique items in any given period, such as the \$30.8 million impairment in Q3-2015, \$8.0 million impairment in Q4-2015, \$5.6 million impairment reversal in Q1-2017 and the \$14.7 million gain on working interest dispositions in Q2-2017.

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

	2017		2016				2015	
	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Financial (\$000s, except as noted)								
Revenue, net of royalty expense	38,036	40,686	39,439	32,639	31,903	24,670	33,728	35,391
Funds from operations	31,769	32,069	30,421	24,148	24,142	15,500	25,509	27,643
Per share, basic (\$)	0.27	0.27	0.26	0.21	0.23	0.16	0.26	0.28
Net income (loss)	13,084	7,088	1,638	(1,962)	(2,249)	(8,590)	(7,423)	(22,193)
Per share, basic and diluted (\$)	0.11	0.06	0.01	(0.02)	(0.02)	(0.09)	(0.08)	(0.23)
Dividends declared	17,705	15,338	14,144	14,133	13,380	17,845	20,747	24,604
Per share (\$) ⁽¹⁾	0.15	0.13	0.12	0.12	0.12	0.18	0.21	0.25
Basic payout ratio (%) ⁽²⁾	56	48	46	59	55	115	81	89
Operating Income ⁽²⁾	35,235	37,084	34,487	28,231	28,011	20,292	29,186	30,601
Operating income from royalties (%)	97	91	93	93	91	97	89	90
Dividends paid in shares (DRIP) ⁽³⁾	-	-	-	1,170	1,443	2,384	2,758	3,708
Average DRIP participation rate (%) ⁽³⁾	-	-	-	8	11	11	13	14
Acquisitions	1,267	33,352	92	68	162,211	219	(143)	815
Capital expenditures	1,139	712	2,172	209	753	2,084	5,607	7,969
Working interest dispositions	28,808	288	-	-	-	-	-	-
Net debt	49,819	76,030	73,161	87,301	98,191	149,197	146,949	148,994
Shares outstanding								
Weighted average, basic (000s)	118,018	117,956	117,847	117,726	106,736	99,093	98,731	98,357
At quarter end (000s)	118,073	118,018	117,918	117,850	117,652	99,284	98,940	98,599
Operating (\$/boe, except as noted)								
Average daily production (boe/d) ⁽⁴⁾	12,589	12,753	12,579	12,281	12,041	11,974	11,815	11,266
Royalty interest (%)	90	84	82	83	81	79	78	78
Average selling price	32.98	34.88	33.72	28.69	28.48	22.23	30.34	34.11
Operating netback ⁽²⁾	30.76	32.31	29.80	24.99	25.57	18.62	26.85	29.52
Operating expenses	2.45	3.14	4.28	3.90	3.55	4.02	4.18	4.62
Working interest properties	23.34	19.51	24.16	22.69	18.47	19.41	19.24	20.78
General and administrative expenses ⁽⁵⁾	2.27	3.01	2.33	1.71	2.04	3.05	2.23	2.33
Benchmark Prices								
West Texas Intermediate crude oil (US\$/bbl)	48.29	51.91	49.29	44.94	45.59	33.45	42.18	46.43
Exchange rate (US\$/Cdn\$)	0.74	0.76	0.75	0.77	0.78	0.73	0.75	0.76
Edmonton Light Sweet crude oil (Cdn\$/bbl)	61.84	64.00	61.54	54.85	54.70	40.84	52.89	56.23
Western Canadian Select crude oil (Cdn\$/bbl)	49.99	49.38	46.63	41.02	41.62	26.32	36.86	43.29
AECO natural gas (Cdn\$/Mcf)	2.77	2.94	2.81	2.20	1.25	2.11	2.65	2.80
Share Trading Performance								
High (\$)	14.37	14.75	15.16	13.09	13.00	12.05	13.52	16.07
Low (\$)	11.96	12.22	11.68	10.61	9.66	8.29	9.00	8.73
Close (\$)	13.05	13.48	14.17	12.65	11.91	10.54	10.86	10.82
Volume (000s)	13,890	17,059	15,440	20,873	23,559	19,690	19,312	22,753

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

(2) See Non-GAAP Financial Measures

(3) The dividend reinvestment plan (DRIP) was suspended effective with the August 2016 dividend, pending further notice.

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

(5) Excludes share based and other compensation.

Revenues

Production

Our production in the current quarter was 12,589 boe/d, up 5% versus the same period last year, and for YTD-2017 was 12,670 boe/d, up 6% from the previous year. These increases were primarily due to royalty acquisitions, increased drilling activity on our royalty lands and the strength of our audit function (over 700 boe/d of prior period adjustments in the current quarter). These results were achieved even with the disposition of approximately 650 boe/d (Q1-2017) of working interest volumes early in the current quarter.

Royalty volumes at 11,270 boe/d were up 16% versus the same period last year and comprised 90% of total production in Q2-2017, up from 81% in Q2-2016. The Q2-2016 acquisition was 100% royalty interests with over 60% natural gas, which largely accounts for the increase in gas royalty production relative to oil (production from the acquisition was recorded from the closing date of May 25, 2016 onwards). NGL production was positively affected by the Q2-2016 acquisition and the drilling of liquid rich natural gas wells on our royalty lands.

Working interest production fell 43% to 1,319 boe/d in Q2-2017 relative to Q2-2016 largely due to reduced volumes from lower capital expenditures and the previously mentioned dispositions.

Our production mix through the first six months of 2017 was 33% light and medium oil, 14% heavy oil, 8% NGL and 45% natural gas.

AVERAGE DAILY PRODUCTION

	Three Months Ended			Six Months Ended		
	June 30			June 30		
	2017	2016	Change	2017	2016	Change
Royalty interest ⁽¹⁾						
Oil (bbls/d)	5,116	5,030	2%	5,039	5,123	-2%
NGL (bbls/d)	932	530	76%	895	571	57%
Natural gas (Mcf/d)	31,330	24,988	25%	30,312	23,498	29%
Oil equivalent (boe/d)	11,270	9,725	16%	10,986	9,610	14%
Working interest ⁽¹⁾						
Oil (bbls/d)	648	1,366	-53%	900	1,448	-38%
NGL (bbls/d)	107	210	-49%	159	198	-20%
Natural gas (Mcf/d)	3,386	4,439	-24%	3,747	4,501	-17%
Oil equivalent (boe/d)	1,319	2,316	-43%	1,684	2,396	-30%
Total						
Oil (bbls/d)	5,764	6,396	-10%	5,939	6,571	-10%
NGL (bbls/d)	1,039	740	40%	1,054	769	37%
Natural gas (Mcf/d)	34,716	29,427	18%	34,059	27,999	22%
Oil equivalent (boe/d)	12,589	12,041	5%	12,670	12,006	6%
Number of days in period (days)	91	91	0%	181	182	-1%
Total volumes during period (Mboe)	1,146	1,096	5%	2,293	2,185	5%

(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.

Product Prices

The price we receive for our oil production is primarily driven by the U.S. dollar price of WTI, adjusted for the value of the Canadian dollar relative to the U.S. dollar. WTI averaged US\$48.29/bbl, up 6% over the same quarter last year, Edmonton Light Sweet averaged \$61.84/bbl, up 13% versus the same period in 2016 and heavy oil producers benefited the most with WCS averaging \$49.99/bbl for the quarter, up 20% versus Q2-2016. AECO natural gas price averaged \$2.77/mcf, up 122% from \$1.25/mcf in the second quarter last year. Volatility with commodity prices has continued as a result of supply/demand fundamentals.

AVERAGE BENCHMARK PRICES

	Three Months Ended			Six Months Ended		
	June 30			June 30		
	2017	2016	Change	2017	2016	Change
West Texas Intermediate (WTI) crude oil (US\$/bbl)	48.29	45.59	6%	50.10	39.52	27%
Exchange rate (US\$/Cdn\$)	0.74	0.78	-5%	0.75	0.75	0%
Edmonton Light Sweet (EDM) crude oil (Cdn\$/bbl)	61.84	54.70	13%	62.92	47.77	32%
Western Canadian Select (WCS) crude oil (Cdn\$/bbl)	49.99	41.62	20%	49.68	33.97	46%
WTI/EDM differential (\$/bbl)	13.55	9.11	49%	12.82	8.25	55%
EDM/WCS differential (Cdn\$/bbl)	(11.85)	(13.08)	-9%	(13.24)	(13.80)	-4%
AECO natural gas (Cdn\$/Mcf)	2.77	1.25	122%	2.86	1.68	70%

Our average selling prices reflect product quality and transportation differences from benchmark prices. On a boe basis, our average selling price at \$32.98/boe was 16% higher in Q2-2017 versus the same period last year. As the key driver behind an increase in overall cash flows, liquids improved from 2016 with a realized oil and NGL price of \$49.69/bbl improving 14% versus the second quarter of last year. On a year-to-date basis the increase was even higher at 38%, resulting in a \$50.53/bbl realized oil and NGL price.

Natural gas prices were up significantly relative to the prior year at \$2.22/mcf in the second quarter, increasing 104% from the same period last year when concerns peaked over growing supplies in North America. 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.

AVERAGE SELLING PRICES

	Three Months Ended			Six Months Ended		
	June 30			June 30		
	2017	2016	Change	2017	2016	Change
Oil (\$/bbl)	52.42	45.56	15%	53.04	37.61	41%
NGL (\$/bbl)	34.59	26.49	31%	36.43	26.95	35%
Oil and NGL (\$/bbl)	49.69	43.58	14%	50.53	36.49	38%
Natural gas (\$/Mcf)	2.22	1.09	104%	2.24	1.31	71%
Oil equivalent (\$/boe)	32.98	28.48	16%	33.93	25.37	34%

Marketing and Hedging

Our production remained unhedged in Q2-2017. Our hedging policy is reviewed quarterly with the Board of Directors.

Our royalty lands consist of a large number of properties with generally small volumes per property. Many of our leases and royalty agreements allow us to take our share of oil and natural gas in-kind. As part of our risk mitigation program we carefully monitor our royalty receivables and may choose to take our royalty in-kind if there are benefits in doing so. Currently we take in-kind and market approximately 17% of our total royalty production using 30-day contracts.

Royalty and Other Revenue

Royalty and other revenue of \$38.4 million in Q2-2017 was 19% higher than in Q2-2016 and \$79.5 million for YTD-2017 was 39% higher relative to the same period in 2016. Increases were largely due to higher realized pricing and higher production volumes. In the second quarter royalty interest revenue increased by 34% whereas working interest revenue was down 39% versus Q2-2016, with the decrease in working interest revenue resulting from the dispositions occurring early in the second quarter. The other category of revenue includes \$0.5 million of bonus consideration received in the six months ended June 30, 2017 (\$0.1 million -2016) and there was a \$0.7 million prior period adjustment relating to potash received in the second quarter of 2016.

ROYALTY AND OTHER REVENUE

(\$000s)	Three Months Ended			Six Months Ended		
	June 30			June 30		
	2017	2016	Change	2017	2016	Change
Royalty interest revenue ⁽¹⁾	34,416	25,686	34%	67,985	45,341	50%
Working interest revenue ⁽²⁾	4,014	6,533	-39%	11,536	11,811	-2%
	38,430	32,219	19%	79,521	57,152	39%

(1) Royalty interest revenue includes potash, sulphur, bonus consideration and lease rentals.

(2) Working interest revenue includes processing fees, interest and other.

ROYALTY AND OTHER REVENUE BY PRODUCT

(\$000s)	Three Months Ended			Six Months Ended		
	June 30			June 30		
	2017	2016	Change	2017	2016	Change
Oil	27,492	26,518	4%	57,013	44,979	27%
NGL	3,270	1,785	83%	6,951	3,775	84%
Natural gas	7,013	2,907	141%	13,839	6,681	107%
Other ⁽¹⁾	655	1,009	-35%	1,718	1,717	0%
	38,430	32,219	19%	79,521	57,152	39%

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

The following table demonstrates the net effect of price and volume variances on royalty and other revenue. Improved realized oil, NGL and natural gas pricing accounted for most of the positive variance in Q2-2017 and YTD-2017.

ROYALTY AND OTHER REVENUE VARIANCES

(\$000s)	Three Months Ended			Six Months Ended		
	June 30			June 30		
	2017 vs. 2016	2016 vs. 2015		2017 vs. 2016	2016 vs. 2015	
Oil and NGL						
Production increase (decrease)	(1,509)	3,188		(3,549)	7,890	
Price increase (decrease)	3,968	(7,106)		18,759	(13,331)	
Net increase (decrease)	2,459	(3,918)		15,210	(5,441)	
Natural gas						
Production increase	1,068	368		2,394	768	
Price increase (decrease)	3,038	(2,560)		4,764	(4,187)	
Net increase (decrease)	4,106	(2,192)		7,158	(3,419)	
Other ⁽¹⁾	(354)	325		1	257	
Royalty and other revenue increase (decrease)	6,211	(5,785)		22,369	(8,603)	

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

Expenses

Royalty Expense and Mineral Taxes

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.

We do not incur royalty expense on production from our royalty interest lands, other than minor freehold mineral taxes. As the royalty owner, we receive the royalty as income from other companies.

ROYALTY EXPENSE ⁽¹⁾

(\$000s, except as noted)	Three Months Ended			Six Months Ended		
	June 30			June 30		
	2017	2016	Change	2017	2016	Change
Working interest	283	235	20%	686	496	38%
Per boe (\$)	2.36	1.12	111%	2.25	1.14	97%
Royalty interest ⁽²⁾	111	81	37%	113	83	36%
Per boe (\$)	0.11	0.09	22%	0.06	0.05	20%
Total	394	316	25%	799	579	38%
Per boe (\$)	0.34	0.29	17%	0.35	0.26	35%

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

(2) Comprised of freehold mineral tax.

Operating Expenses

Operating expenses are comprised of direct costs incurred and costs allocated among oil, natural gas, and NGL production. Overhead recoveries associated with operated properties are included in operating expenses and accounted for as a reduction to general and administrative (G&A) expenses. A percentage of operating expense is fixed and, as such, per boe operating expenses are highly variable to production volumes.

Operating expenses decreased 28% to \$2.8 million in Q2-2017 versus Q2-2016 and 23% to \$6.4 million YTD-2017 versus YTD-2016. Reductions resulted from the lower working interest production caused by the second quarter dispositions, but were offset by approximately \$0.4 million of prior period adjustments. On a total production per boe basis, operating expenses decreased by 31% in Q2-2017 relative to the same period in 2016, also helped by our increase in the percentage of production from royalties, which have no operating expenses.

OPERATING EXPENSES

(\$000s, except as noted)	Three Months Ended			Six Months Ended		
	June 30			June 30		
	2017	2016	Change	2017	2016	Change
Working interest	2,801	3,892	-28%	6,403	8,270	-23%
Per boe (\$)	23.34	18.47	26%	21.02	18.96	11%
Royalty interest ⁽¹⁾	-	-	-	-	-	-
Per boe (\$)	-	-	-	-	-	-
Total operating expenses	2,801	3,892	-28%	6,403	8,270	-23%
Total (\$/boe)	2.45	3.55	-31%	2.79	3.78	-26%

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

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 following tables demonstrate the advantage of our royalty lands, which have no operating or royalty expenses (other than minor freehold mineral taxes). Royalty interests accounted for 85% of gross revenue YTD-2017, however contributed 94% of operating income. In Q2-2017 royalty interests contributed 97% of operating income. Freehold's operating netback for the second quarter increased 20% to \$30.76/boe versus Q2-2016 and for YTD-2017 increased 43% to \$31.54/boe compared to the same period last year, both periods' improvement driven by higher commodity prices and lower operating expenses.

OPERATING INCOME ⁽¹⁾

(\$000s)	Six months ended June 30, 2017		
	Royalty Interest	Working Interest	Total
Royalty and other revenue ⁽²⁾	67,985	11,536	79,521
Royalty expense ⁽³⁾	(113)	(686)	(799)
	67,872	10,850	78,722
Operating expense	-	(6,403)	(6,403)
Operating income	67,872	4,447	72,319
Percentage by category	94%	6%	100%

OPERATING NETBACK ⁽¹⁾

(\$/boe)	Three Months Ended			Six Months Ended		
	June 30			June 30		
	2017	2016	Change	2017	2016	Change
Royalty and other revenue ⁽²⁾	33.55	29.41	14%	34.68	26.15	33%
Royalty expense ⁽³⁾	(0.34)	(0.29)	17%	(0.35)	(0.26)	35%
Operating expenses	(2.45)	(3.55)	-31%	(2.79)	(3.78)	-26%
Operating netback	30.76	25.57	20%	31.54	22.11	43%

(1) See Non-GAAP Financial Measures.

(2) Royalty interest revenue includes potash, sulphur, bonus consideration and lease rentals. Working interest revenue includes processing fees, interest and other.

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

General and Administrative Expenses

We have significant land administration, accounting and auditing requirements to administer and collect royalty payments, including systems to track development activity on the royalty lands. General and administrative (G&A) expenses include direct costs and reimbursement of G&A expenses incurred by Rife Resources Management Ltd. (the Manager) on behalf of Freehold (see Related Party Transactions).

In Q2-2017, G&A expenses were up 11% to \$2.27/boe (YTD-2017 up 4% to \$2.64/boe). Much of the increase for both the current quarter and year-to-date periods is due to higher activity levels with lease outs and dispositions. G&A expenses are typically higher in the first quarter and decline through the remainder of the year, as a number of annual expenses occur in the first quarter.

GENERAL AND ADMINISTRATIVE EXPENSES

(\$000s, except as noted)	Three Months Ended			Six Months Ended		
	June 30			June 30		
	2017	2016	Change	2017	2016	Change
General and administrative expenses,						
before capitalized and overhead recoveries	3,039	2,613	16%	7,010	6,442	9%
Less: capitalized and overhead recoveries	(436)	(374)	17%	(947)	(885)	7%
General and administrative expenses	2,603	2,239	16%	6,063	5,557	9%
Per boe (\$)	2.27	2.04	11%	2.64	2.54	4%

Management Fee

The Manager (see Related Party Transactions) receives a management fee in Freehold common shares. The amended and restated management agreement, entered into in November 2015, capped the management fee at 71,912 Freehold common shares per quarter for 2016 and 55,000 Freehold common shares per quarter for 2017 with the fee decreasing to 5,500 Freehold common shares per quarter by 2022. The value associated with the management fee was down 16% compared to Q2-2016 and 10% on a year-to-date basis, as the effect of reduced Freehold common shares was offset somewhat by a higher Freehold common share price in the current periods.

MANAGEMENT FEE (PAID IN SHARES)

	Three Months Ended			Six Months Ended		
	June 30			June 30		
	2017	2016	Change	2017	2016	Change
Shares issued for management fees	55,000	71,912	-24%	110,000	143,824	-24%
Ascribed value (\$000s) ⁽¹⁾	718	856	-16%	1,459	1,614	-10%
Per boe (\$)	0.63	0.78	-19%	0.64	0.74	-14%

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

Share Based Compensation

In March 2017, Freehold adopted a new long-term incentive plan (LTIP) to replace the previous long-term incentive plan for the employees of Rife Resources Ltd. (see Related Party Transactions). Grants will no longer be made under the previous plan but pre-existing grants will continue until vesting and payout occurs.

In 2017 and in future years, Freehold's long-term incentive compensation will consist of grants of performance share units (PSUs) and restricted share units (RSUs) under the new LTIP. Underlying each PSU and RSU is one notional Freehold common share. The notional Freehold common shares underlying the PSUs and RSUs are adjusted whenever a dividend is paid by Freehold.

Upon vesting of the RSUs the holder is entitled to an amount equal in value to the notional Freehold common shares (as adjusted for dividends paid) underlying such RSUs. The value of the notional Freehold common shares is based on the volume weighted average trading price of Freehold common shares on the TSX for the five trading days prior to the settlement date of such RSUs. Generally, one-third of the granted RSUs will vest on each of the first, second and third anniversaries of the date of grant.

For PSUs, the notional Freehold common shares and value are calculated in the same manner as the RSUs, but with the additional application of a performance multiplier. The metrics used for determining the performance multiplier (which can range from 0 to 2 times) are at the discretion of our Board of Directors at the time of grant. For 2017 grants the performance multiplier target is based 50% on absolute total shareholder return and 50% on relative total shareholder return over a three year performance period. Generally, all of the granted PSUs will vest on the third anniversary of the date of grant.

Since participants receive a cash payment on a fixed vesting date, a liability is determined and recognized as services are rendered based on the fair value of the total rights at each period end. The valuation incorporates the consideration of the Freehold common share price, the number of notional Freehold common shares outstanding at each period end, an estimated performance multiplier and an estimated forfeiture rate. Compensation expense is recognized over the vesting period.

The 2014 grants under the previous LTIP valued at \$0.1 million were paid out in 2017. In March 2017 there were 90,026 RSUs and PSUs granted under the new LTIP (after estimated forfeitures).

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 Freehold common shares (less

tax withholdings if necessary) after the director's retirement. On January 1, 2017 Freehold's Board of Directors granted 27,521 DSUs to eligible directors. During Q1-2017 a retired director redeemed 63,419 DSUs, resulting in the issuance of 44,393 Freehold common shares from treasury and the cancellation of 19,026 DSUs for withholding tax. As at June 30, 2017, there were 114,989 DSUs outstanding, and at August 9, 2017, there were 115,422 DSUs outstanding (including notional DSUs granted as a result of dividends paid on our common shares).

SHARE BASED COMPENSATION

(\$000s, except as noted)	Three Months Ended			Six Months Ended		
	June 30			June 30		
	2017	2016	Change	2017	2016	Change
Long-term incentive plan						
before capitalized portion	339	340	0%	519	385	35%
Less: capitalized portion	(61)	(61)	0%	(93)	(69)	35%
Long-term incentive plan	278	279	0%	426	316	35%
Deferred share unit plan	17	82	-79%	356	465	-23%
Retirement benefit	-	2	-100%	-	5	-100%
Share based compensation	295	363	-19%	782	786	-1%
Per boe (\$)	0.26	0.33	-21%	0.34	0.36	-6%

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 Freehold common 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 Freehold common shares per quarter, pursuant to the amended and restated management agreement. The amended and restated management agreement capped the management fee at 55,000 Freehold common shares per quarter for 2017 with the number of Freehold common shares to be issued per quarter as payment of the management fee reducing to 5,500 Freehold common shares by 2022. For the three months ended June 30, 2017, Freehold issued 55,000 common shares (2016 – 71,912) as payment of the management fee. The ascribed value of \$0.7 million (2016 – \$0.9 million) was based on the closing price of Freehold's common shares on the last trading day of each quarter. The total number of Freehold common shares issued for the six months ended June 30, 2017 was 110,000 (2016 – 143,824) with an ascribed value of \$1.5 million (2016 – \$1.6 million).

For the three months ended June 30, 2017, the Manager charged \$2.4 million in general and administrative costs (three months ended June 30, 2016 – \$2.1 million). For the six months ended June 30, 2017, the Manager charged

\$5.5 million in general and administrative costs (six months ended June 30, 2016 – \$5.0 million). At June 30, 2017, there was \$0.8 million (December 31, 2016 – \$0.9 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 June 30, 2017, there was \$nil (December 31, 2016 - \$0.1 million) in accounts receivable relating to these transactions. At June 30, 2017, there was \$nil (December 31, 2016 - \$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 June 30, 2017, Freehold received royalties of approximately \$0.2 million (2016 – \$0.2 million). For the six months ended June 30, 2017, Freehold received royalties of approximately \$0.5 million (2016 – \$0.4 million). At June 30, 2017, there was \$0.1 million (December 31, 2016 - \$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 June 30, 2017, there was \$nil (December 31, 2016 – \$nil) in accounts receivable and accounts payable and accrued liabilities relating to transactions with Canpar.

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

For both Q2-2017 and YTD-2017 interest and financing expense decreased due to lower average debt levels. The average effective interest rate on advances under our credit facilities in the current quarter was 2.9% (Q2-2016 – 2.9%).

INTEREST AND FINANCING

(\$000s, except as noted)	Three Months Ended			Six Months Ended		
	June 30			June 30		
	2017	2016	Change	2017	2016	Change
Interest and financing expense	651	1,552	-58%	1,537	2,762	-44%
Per boe (\$)	0.57	1.42	-60%	0.67	1.26	-47%

Depletion and Depreciation

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.

DEPLETION AND DEPRECIATION

(\$'000s, except as noted)	Three Months Ended			Six Months Ended		
	June 30			June 30		
	2017	2016	Change	2017	2016	Change
Depletion and depreciation	27,617	25,940	6%	54,904	52,142	5%
Per boe (\$)	24.11	23.67	2%	23.94	23.86	0%

Working Interest Dispositions

In April 2017 Freehold closed the sale of working interest properties in its Southeast Saskatchewan Working Interest cash generating unit (CGU) for proceeds of \$28.9 million (including adjustments). These assets and related liabilities were held for sale at March 31, 2017. For the three months ended June 30, 2017, Freehold recognized a gain on working interest dispositions of \$14.7 million. The gain was based on \$28.9 million of proceeds received, adjustments of \$0.1 million, the removal of assets held for sale of \$18.9 million and the removal of liabilities related to assets held for sale of \$4.8 million.

At March 31, 2017 these properties were classified as assets held for sale as it was highly probable that their carrying value would be received through a sales transaction rather than continued use. In addition, at March 31, 2017, based on the anticipated sale proceeds, Freehold reviewed the carrying value of the Southeast Saskatchewan Working Interest CGU for any reversal of impairment, as this CGU had a previous impairment charge. The recoverable amount was estimated using a fair value less cost to sell calculation based on the estimated sales price. As a result, there was an impairment reversal of \$5.6 million recognized in the three months ended March 31, 2017, representing the maximum amount of impairment reversal able to be taken, made up of the original \$8.0 million impairment estimate recorded in 2015 net of \$2.4 million depletion calculated as if the impairment never occurred. In conjunction with the above, Freehold reclassified this new recoverable net book value of \$18.9 million to assets held for sale, with \$18.6 million removed from petroleum and natural gas interests and \$0.3 million removed from exploration and evaluation assets. In addition, Freehold reclassified the proportionate share of decommissioning liabilities of \$4.8 million to liabilities related to assets held for sale.

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 June 30, 2017, there was no current income tax expense (2016 - \$nil) and deferred income tax expense was \$4.8 million (Q2-2016 - \$0.8 million

recovery). For YTD-2017 there was no current income tax expense (2016 - \$nil) and deferred income tax expense was \$7.5 million (2016 - \$4.0 million recovery). Freehold's tax pools at December 31, 2016 were \$1,028 million.

Liquidity and Capital Resources

Operating Activities

Q2-2017 net income was \$13.1 million which compared to a Q2-2016 net loss of \$2.2 million and YTD-2017 net income was \$20.2 million versus a \$10.8 million net loss for YTD-2016. A large portion of the differences are attributable to higher revenues. There was also a \$14.7 million gain on working interest dispositions that improved the results for 2017 in addition to a \$5.6 million impairment reversal in the YTD-2017 period. The differences between 2017 and 2016 were reduced by a \$4.8 million deferred income tax expense in Q2-2017 (YTD-2017 - \$7.5 million) compared to deferred income tax recoveries in 2016.

Funds from operations for the current quarter was up 32% to \$31.8 million from \$24.1 million for the same period last year and for the year-to-date period was up 61% to \$63.8 million from \$39.6 million last year, owing to higher revenue resulting from increased production and improved oil, NGL 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 support 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 (loss) per share.

NET INCOME AND FUNDS FROM OPERATIONS

(\$000s, except as noted)	Three Months Ended			Six Months Ended		
	June 30			June 30		
	2017	2016	Change	2017	2016	Change
Net income (loss)	13,084	(2,249)	-	20,172	(10,839)	-
Per share, basic and diluted (\$)	0.11	(0.02)	-	0.17	(0.11)	-
Funds from operations	31,769	24,142	32%	63,838	39,642	61%
Per share (\$)	0.27	0.23	17%	0.54	0.39	38%

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.

Working capital decreased by \$13.8 million in the second quarter of 2017 compared to the previous quarter. This reduction was largely the result of the removal of the assets held for sale (\$18.9 million) and liabilities related to assets held for sale (\$4.8 million) with the closing of the working interest dispositions (see Working Interest Dispositions).

COMPONENTS OF WORKING CAPITAL

	Jun. 30	Mar. 31	Dec. 31	Sep. 30	Jun. 30
(\$000s)	2017	2017	2016	2016	2016
Cash	715	829	892	860	419
Accounts receivable	24,014	23,645	24,064	22,543	22,723
Current taxes receivable	-	-	-	-	73
Assets held for sale	-	18,940	-	-	-
Current assets	24,729	43,414	24,956	23,403	23,215
Dividends payable	(5,902)	(5,900)	(4,716)	(4,713)	(4,704)
Accounts payable and accrued liabilities	(7,406)	(7,619)	(9,219)	(5,813)	(8,542)
Current portion of share based compensation payable	(240)	(165)	(182)	(178)	(160)
Liabilities related to assets held for sale	-	(4,760)	-	-	-
Current liabilities	(13,548)	(18,444)	(14,117)	(10,704)	(13,406)
Working capital	11,181	24,970	10,839	12,699	9,809

Net debt decreased by \$26.2 million from the previous quarter to \$49.8 million in Q2-2017. The reduction resulted from the closing of \$28.9 million of working interest dispositions and from the application of funds from operations in excess of dividends, offset partially by the working capital change mentioned above.

DEBT ANALYSIS

	Jun. 30	Mar. 31	Dec. 31	Sep. 30	Jun. 30
(\$000s)	2017	2017	2016	2016	2016
Long-term debt	61,000	101,000	84,000	100,000	108,000
Short-term debt	-	-	-	-	-
Total debt	61,000	101,000	84,000	100,000	108,000
Working capital	(11,181)	(24,970)	(10,839)	(12,699)	(9,809)
Net debt	49,819	76,030	73,161	87,301	98,191

At June 30, 2017 Freehold had a \$165 million extendible revolving term credit facility with a syndicate of four Canadian chartered banks, on which \$61 million was drawn. In addition, Freehold has available a \$15 million extendible revolving operating facility.

The facilities are secured with \$400 million demand debentures over most of Freehold's petroleum and natural gas assets but do not contain any financial covenants. 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. Freehold's borrowing base is dependent on the lenders review and interpretation of Freehold's reserves and future commodity prices. During the second quarter 2017 the annual review was completed. The next renewal will occur by May 31, 2018. In the event that the

lenders do not consent to an extension, the revolving credit facility would revert to a one-year, non-revolving term facility with repayment due at the termination date.

At June 30, 2017, net debt was 0.4 times 12-months trailing funds from operations and net debt obligations were 5% of total capitalization.

FINANCIAL LEVERAGE AND COVERAGE RATIOS

	Jun. 30 2017	Mar. 31 2017	Dec. 31 2016	Sep. 30 2016	Jun. 30 2016
Net debt to funds from operations (times) ⁽¹⁾	0.4	0.7	0.8	1.0	1.1
Net debt to dividends (times) ⁽¹⁾	0.8	1.3	1.2	1.3	1.3
Dividends to interest expense (times) ⁽¹⁾	18	13	13	13	15
Net debt to net debt plus equity (%)	5	8	8	9	10

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

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 June 30, 2017, 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).

As at June 30, 2017 and as of August 9, 2017, there were 118,072,667 shares outstanding. For the three and six months ended June 30, 2016 deferred share units were excluded from the calculation of diluted net loss per share as their effect was anti-dilutive.

SHAREHOLDERS CAPITAL

	June 30, 2017		December 31, 2016	
	Shares	Amount (\$000s)	Shares	Amount (\$000s)
Balance, beginning of period	117,918,274	1,263,796	98,940,152	1,050,494
Issued for dividend reinvestment plan	-	-	488,060	4,997
Issued for payment of management fee	110,000	1,459	287,648	3,543
Issued for deferred share unit plan redemption	44,393	752	59,198	1,066
Cancelled	-	-	(17,684)	(214)
Issued for equity offering	-	-	18,160,900	209,759
Issue costs, net of tax effect	-	-	-	(5,849)
Balance, end of period	118,072,667	1,266,007	117,918,274	1,263,796

SHARES OUTSTANDING

	Three Months Ended			Six Months Ended		
	June 30			June 30		
	2017	2016	Change	2017	2016	Change
Weighted average						
Basic	118,018,271	106,735,748	11%	117,987,247	102,914,499	15%
Diluted	118,132,624	106,735,748	11%	118,106,283	102,914,499	15%
At period end	118,072,667	117,652,078	0%	118,072,667	117,652,078	0%

Dividend Policy

Freehold's Board of Directors reviews and determines the monthly dividend rate on a quarterly basis, or as conditions necessitate, after considering expected commodity prices, foreign exchange rates, economic conditions, production volumes, 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.

Dividends declared in the second quarter totaled \$17.7 million or \$0.15 per share, a 25% improvement over 2016 on a per share basis and for the year-to-date period dividends were \$33.0 million or \$0.28 per share.

ACCUMULATED DIVIDENDS ⁽¹⁾

	Three Months Ended		Six Months Ended	
	June 30		June 30	
	2017	2016	2017	2016
Dividends declared (\$000s)	17,705	13,380	33,043	31,225
Accumulated, beginning of period	1,500,811	1,443,816	1,485,473	1,425,971
Accumulated, end of period	1,518,516	1,457,196	1,518,516	1,457,196
Dividends per share (\$) ⁽²⁾	0.15	0.12	0.28	0.30
Accumulated, beginning of period	30.60	30.11	30.47	29.93
Accumulated, end of period	30.75	30.23	30.75	30.23

(1) Accumulated dividends reflect distributions paid on trust units of Freehold Royalty Trust (the predecessor of Freehold) from 1996 through 2010 and dividends on common shares of Freehold from 2011 onwards.

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

The following tables show reconciliations of funds from operations and dividends. Our basic payout ratio for Q2-2017 was 56% versus 55% one year ago as both dividends and funds from operations were higher in the current period, leaving the numbers very similar. For the 2017 year-to-date period we had a basic payout ratio of 52%, which was much reduced from 79% last year, as funds from operations increased significantly but dividends were similar. Freehold increased our monthly dividend from \$0.04 to \$0.05, paid in April 2017.

RECONCILIATION OF DIVIDENDS DECLARED

(\$000s)	Three Months Ended		Six Months Ended	
	June 30		June 30	
	2017	2016	2017	2016
Funds from operations	31,769	24,142	63,838	39,642
Proceeds from the DRIP	-	1,443	-	3,827
Issuance of shares, net of issue costs	-	201,747	-	201,747
Debt repayment	(40,000)	(45,000)	(23,000)	(44,000)
Acquisitions	(1,267)	(162,211)	(34,619)	(162,430)
Capital expenditures	(1,139)	(753)	(1,851)	(2,837)
Working interest dispositions	28,808	-	29,096	-
Working capital change	(466)	(5,988)	(421)	(4,724)
Dividends declared	17,705	13,380	33,043	31,225

DIVIDENDS ANALYSIS

(\$000s)	Three Months Ended		Six Months Ended	
	June 30		June 30	
	2017	2016	2017	2016
Dividends paid in cash	17,703	11,203	31,878	29,618
Dividends paid in shares (DRIP)	-	1,443	-	3,827
Total dividends paid ⁽¹⁾	17,703	12,646	31,878	33,445
Dividends declared	17,705	13,380	33,043	31,225
Funds from operations	31,769	24,142	63,838	39,642
Capital expenditures	1,139	753	1,851	2,837
Basic payout ratio ⁽²⁾	56%	55%	52%	79%
Adjusted payout ratio ⁽³⁾	59%	50%	53%	82%

(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).

The amended and restated 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). Effective with the August 31, 2016 dividend the Board approved the suspension of the DRIP pending further notice.

Investing Activities

Freehold expended \$1.3 million on acquisitions in Q2-2017 (\$34.6 million – YTD-2017). Of the acquisition expenditures in 2017, \$33.7 million (including adjustments) related to various gross overriding royalties and mineral title lands in the greater Dodsland area of Saskatchewan. Capital expenditures for the current quarter were \$1.1 million and for YTD-2017 were \$1.9 million. In addition, we disposed of \$28.9 million of working interest assets in the current quarter (see Working Interest Dispositions), as we continue our de-emphasis of our working interest activity. We also incurred a \$0.1 million adjustment relating to other disposition activity.

ACQUISITIONS, DISPOSITIONS AND CAPITAL EXPENDITURES

(\$000s)	Three Months Ended			Six Months Ended		
	June 30			June 30		
	2017	2016	Change	2017	2016	Change
Acquisitions	1,267	162,211	-99%	34,619	162,430	-79%
Capital expenditures	1,139	753	51%	1,851	2,837	-35%
Working interest dispositions	(28,808)	-	-	(29,096)	-	-
	(26,402)	162,964	-116%	7,374	165,267	-96%

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 June 30, 2017. 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.

New Accounting Standards

RECENT PRONOUNCEMENTS

In May 2014, the IASB issued IFRS 15 Revenue from Contracts with Customers, which replaces IAS 11 Construction Contracts, IAS 18 Revenue, and other revenue related interpretations. The standard establishes a single revenue recognition framework that applies to contracts with customers. The effective date for adopting IFRS 15 in its entirety is January 1, 2018. Freehold continues to review its royalty and other revenue streams along with underlying contracts to determine the impact on the consolidated financial statements including the enhanced disclosures of disaggregation of revenue.

In July 2014, the IASB completed a three-phase project to replace IAS 39 Financial Instruments: Recognition and Measurement with IFRS 9 Financial Instruments. The first two completed phases replaced the current multiple classification and measurement models for financial assets and liabilities with a single model that has only two classification categories: amortized cost and fair value. The third phase describes a new hedge accounting model. Presently and historically, Freehold has not entered into any transactions in which hedge accounting could be applied and does not anticipate changing this practice. The effective date for adopting IFRS 9 in its entirety is January 1, 2018.

In January, 2016, the IASB issued IFRS 16 Leases, which replaces IAS 17 Leases. The standard establishes a single lessee accounting model and requires a lessee to recognize assets and liabilities for all leases with a term of more than 12 months, unless the underlying asset is of low value. A lessee is required to recognize a right-of-use asset representing its right to use the underlying asset and a lease liability representing its obligation to make lease payments. Other areas of the lease accounting model have been impacted, including the definition of a lease. Transitional provisions have been provided. The effective date for adopting IFRS 16 in its entirety is January 1, 2019.

Freehold's assessment of these recent pronouncements is ongoing and the impact, if any, on the consolidated financial statements and additional disclosure requirements is yet to be fully determined.

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 President's Message, Our Strategy, Business Environment, Guidance Update and Dividend Policy 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;
- 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;
- foreign exchange rates;
- industry drilling and development activity on our royalty lands;
- estimated capital budget and expenditures and the timing thereof;

- Freehold's decommissioning liability and timing of payment thereof;
- forecast 2017 production, including product mix and percentage from royalties;
- forecast 2017 percentage of operating income from royalties;
- forecast 2017 adjusted payout ratio;
- forecast 2017 year end net debt to funds from operations;
- forecast key operating assumptions;
- amounts and rates of income taxes and timing of payment thereof;
- expected production additions from our audit function;
- our tax pools and the expected tax horizon;
- our dividend policy and expectations for future dividends; and
- treatment under governmental regulatory regimes and tax laws.

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; and
- other factors discussed in Freehold's annual MD&A, and audited financial statements for the year ended December 31, 2016 and our Annual Information Form.

Readers are cautioned that the foregoing list of factors is not exhaustive.

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 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 on our royalty lands;
- the impact of increasing competition;
- our ability to obtain financing on acceptable terms; and
- our ability to add production and reserves through our development and acquisition activities.

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, basic payout ratio and adjusted payout ratio, free cash flow and cash costs 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 royalty and other 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).

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.

Free cash flow is calculated by subtracting capital expenditures from funds from operations. Free cash flow is a measure often used by dividend paying companies to determine cash available for payment of dividends, paying down debt or investment.

Cash costs is a total of all recurring costs in the statement of income (loss) deducted in determining funds from operations. For Freehold cash costs are identified as royalty expense, operating expense, G&A expense, interest expense and share based compensation expense (if paid out in the period). It is key to funds from operations, representing the ability to, sustain dividends, repay debt and fund capital expenditures.

We refer to various per boe figures which provide meaningful information on our operational performance. We derive per boe figures by dividing the relevant revenue or cost figures 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.

Condensed Consolidated Balance Sheets

(\$000s) (unaudited)	June 30 2017	December 31 2016
Assets		
Current assets:		
Cash	\$ 715	\$ 892
Accounts receivable	24,014	24,064
	24,729	24,956
Exploration and evaluation assets (note 3)	61,812	64,019
Petroleum and natural gas interests (note 4)	863,332	892,120
Deferred income tax asset	18,894	26,355
	\$ 968,767	\$ 1,007,450
Liabilities and Shareholders' Equity		
Current liabilities:		
Dividends payable	\$ 5,902	\$ 4,716
Accounts payable and accrued liabilities	7,406	9,219
Current portion of share based compensation payable (note 5)	240	182
	13,548	14,117
Decommissioning liability	19,649	23,705
Share based compensation payable (note 5)	1,206	932
Long-term debt (note 6)	61,000	84,000
Shareholders' equity:		
Shareholders' capital (note 7)	1,266,007	1,263,796
Contributed surplus	2,045	2,717
Deficit	(394,688)	(381,817)
	873,364	884,696
	\$ 968,767	\$ 1,007,450

See accompanying notes to interim condensed consolidated financial statements.

Condensed Consolidated Statements of Income (Loss) and Comprehensive Income (Loss)

(unaudited) (\$000s, except per share and weighted average data)	Three Months Ended		Six Months Ended	
	June 30		June 30	
	2017	2016	2017	2016
Revenue:				
Royalty and other revenue (note 9)	\$ 38,430	\$ 32,219	\$ 79,521	\$ 57,152
Royalty expense	(394)	(316)	(799)	(579)
	38,036	31,903	78,722	56,573
Gain on working interest dispositions (note 2)	14,679	-	14,679	-
Expenses:				
Operating	2,801	3,892	6,403	8,270
General and administrative	2,603	2,239	6,063	5,557
Share based compensation (note 5)	295	363	782	786
Interest and financing	651	1,552	1,537	2,762
Depletion and depreciation	27,617	25,940	54,904	52,142
Impairment reversal (note 2)	-	-	(5,625)	-
Accretion of decommissioning liability	108	142	245	290
Management fee (note 8)	718	856	1,459	1,614
	34,793	34,984	65,768	71,421
Income (loss) before taxes	17,922	(3,081)	27,633	(14,848)
Deferred income tax expense (recovery)	4,838	(832)	7,461	(4,009)
Net income (loss) and comprehensive income (loss)	\$ 13,084	\$ (2,249)	\$ 20,172	\$ (10,839)
Net income (loss) per share, basic and diluted	\$ 0.11	\$ (0.02)	\$ 0.17	\$ (0.11)
Weighted average number of shares:				
Basic	118,018,271	106,735,748	117,987,247	102,914,499
Diluted (note 7)	118,132,624	106,735,748	118,106,283	102,914,499

See accompanying notes to interim condensed consolidated financial statements.

Condensed Consolidated Statements of Cash Flows

(\$000s) (unaudited)	Three Months Ended		Six Months Ended	
	June 30		June 30	
	2017	2016	2017	2016
Operating:				
Net income (loss)	\$ 13,084	\$ (2,249)	\$ 20,172	\$ (10,839)
Items not involving cash:				
Depletion and depreciation	27,617	25,940	54,904	52,142
Gain on working interest dispositions	(14,679)	-	(14,679)	-
Impairment reversal	-	-	(5,625)	-
Share based compensation	295	363	782	786
Deferred income tax expense (recovery)	4,838	(832)	7,461	(4,009)
Accretion of decommissioning liability	108	142	245	290
Management fee	718	856	1,459	1,614
Expenditures on share based compensation	-	(42)	(442)	(301)
Decommissioning expenditures	(212)	(36)	(439)	(41)
Funds from operations	31,769	24,142	63,838	39,642
Changes in non-cash working capital	(533)	(6,931)	(728)	(1,970)
	31,236	17,211	63,110	37,672
Financing:				
Issuance of shares, net of issue costs	-	201,747	-	201,747
Long-term debt	(40,000)	(45,000)	(23,000)	(44,000)
Dividends paid	(17,703)	(11,203)	(31,878)	(29,618)
	(57,703)	145,544	(54,878)	128,129
Investing:				
Acquisitions	(1,267)	(162,211)	(34,619)	(162,430)
Capital expenditures	(1,139)	(753)	(1,851)	(2,837)
Working interest dispositions	28,808	-	29,096	-
Changes in non-cash working capital	(49)	299	(1,035)	(991)
	26,353	(162,665)	(8,409)	(166,258)
Increase (decrease) in cash	(114)	90	(177)	(457)
Cash, beginning of period	829	329	892	876
Cash, end of period	\$ 715	\$ 419	\$ 715	\$ 419

See accompanying notes to interim condensed consolidated financial statements.

Condensed Consolidated Statements of Changes in Shareholders' Equity

(\$000s) (unaudited)	Six Months Ended	
	June 30	
	2017	2016
Shareholders' capital:		
Balance, beginning of period	\$ 1,263,796	\$ 1,050,494
Shares issued for dividend reinvestment plan	-	3,827
Shares issued for payment of management fee	1,459	1,614
Shares issued for deferred share unit plan redemption	752	471
Shares issued for equity offering	-	209,759
Issue costs, net of tax effect	-	(5,849)
Balance, end of period	1,266,007	1,260,316
Contributed surplus:		
Balance, beginning of period	2,717	3,282
Share based compensation expense	356	465
Deferred share unit plan redemption and other	(1,028)	(568)
Balance, end of period	2,045	3,179
Deficit:		
Balance, beginning of period	(381,817)	(311,152)
Net income (loss) and comprehensive income (loss)	20,172	(10,839)
Dividends declared	(33,043)	(31,225)
Balance, end of period	(394,688)	(353,216)
Total shareholders' equity	\$ 873,364	\$ 910,279

See accompanying notes to interim condensed consolidated financial statements.

Notes to Interim Condensed Consolidated Financial Statements

For the three and six months ended June 30, 2017 and 2016 (unaudited).

1. Basis of Presentation

Freehold Royalties Ltd. (Freehold) is a dividend-paying corporation incorporated under the laws of the Province of Alberta. Freehold's primary focus is acquiring and managing oil and gas royalties.

Freehold's principal place of business is located at 400, 144 – 4 Avenue SW, Calgary, Alberta, Canada, T2P 3N4.

a) Statement of Compliance

These interim condensed consolidated financial statements have been prepared by management in accordance with International Financial Reporting Standards (IFRS) and International Accounting Standard (IAS) 34 *Interim Financial Reporting*. These interim condensed consolidated financial statements do not include all of the disclosures normally provided in annual financial statements. These interim condensed consolidated financial statements have been prepared following the same accounting policies and methods of computation as the consolidated financial statements and notes for the year ended December 31, 2016 and should be read in conjunction with the audited consolidated financial statements and notes for the year ended December 31, 2016.

These interim condensed consolidated financial statements were approved by the Board of Directors on August 9, 2017.

b) Basis of Measurement and Principles of Consolidation

These interim condensed consolidated financial statements have been prepared on a historical cost basis, with the exception of certain share based compensation payable, and include the accounts of Freehold and its wholly-owned subsidiaries: 1872348 Alberta Ltd., Freehold Holdings Trust and Freehold Royalties Partnership. All inter-entity transactions have been eliminated.

c) Recent Pronouncements

In May 2014, the IASB issued IFRS 15 Revenue from Contracts with Customers, which replaces IAS 11 Construction Contracts, IAS 18 Revenue, and other revenue related interpretations. The standard establishes a single revenue recognition framework that applies to contracts with customers. The effective date for adopting IFRS 15 in its entirety is January 1, 2018. Freehold continues to review its royalty and other revenue streams along with underlying contracts to determine the impact on the consolidated financial statements including the enhanced disclosures of disaggregation of revenue.

In July 2014, the IASB completed a three-phase project to replace IAS 39 Financial Instruments: Recognition and Measurement with IFRS 9 Financial Instruments. The first two completed phases replaced the current multiple classification and measurement models for financial assets and liabilities with a single model that has only two classification categories: amortized cost and fair value. The third phase describes a new hedge accounting model.

Presently and historically, Freehold has not entered into any transactions in which hedge accounting could be applied and does not anticipate changing this practice. The effective date for adopting IFRS 9 in its entirety is January 1, 2018.

In January, 2016, the IASB issued IFRS 16 Leases, which replaces IAS 17 Leases. The standard establishes a single lessee accounting model and requires a lessee to recognize assets and liabilities for all leases with a term of more than 12 months, unless the underlying asset is of low value. A lessee is required to recognize a right-of-use asset representing its right to use the underlying asset and a lease liability representing its obligation to make lease payments. Other areas of the lease accounting model have been impacted, including the definition of a lease. Transitional provisions have been provided. The effective date for adopting IFRS 16 in its entirety is January 1, 2019.

Freehold's assessment of these recent pronouncements is ongoing and the impact, if any, on the consolidated financial statements and additional disclosure requirements is yet to be fully determined.

2. Gain on Working Interest Dispositions

In April 2017 Freehold closed the sale of working interest properties in its Southeast Saskatchewan Working Interest cash generating unit (CGU) for proceeds of \$28.9 million (including adjustments). These assets and related liabilities were held for sale at March 31, 2017. For the three months ended June 30, 2017, Freehold recognized a gain on working interest dispositions of \$14.7 million. The gain was based on \$28.9 million of proceeds received, minor adjustments of \$0.1 million, the removal of assets held for sale of \$18.9 million and the removal of liabilities related to assets held for sale of \$4.8 million.

At March 31, 2017 these properties were classified as assets held for sale as it was highly probable that their carrying value would be received through a sales transaction rather than continued use. In addition, at March 31, 2017, based on the anticipated sale proceeds, Freehold reviewed the carrying value of the Southeast Saskatchewan Working Interest CGU for any reversal of impairment, as this CGU had a previous impairment charge. The recoverable amount was estimated using a fair value less cost to sell calculation based on the estimated sales price. As a result, there was an impairment reversal of \$5.6 million recognized in the three months ended March 31, 2017, representing the maximum amount of impairment reversal able to be taken, made up of the original \$8.0 million impairment estimate recorded in 2015 net of \$2.4 million depletion calculated as if the impairment never occurred. In conjunction with the above, Freehold reclassified this new recoverable net book value of \$18.9 million to assets held for sale, with \$18.6 million removed from petroleum and natural gas interests and \$0.3 million removed from exploration and evaluation assets. In addition, Freehold reclassified the proportionate share of decommissioning liabilities of \$4.8 million to liabilities related to assets held for sale.

3. Exploration and Evaluation Assets

(\$000s)	June 30 2017	December 31 2016
Balance, beginning of period	64,019	49,479
Acquisitions	-	17,980
Transfers to petroleum and natural gas interests (note 4)	(1,940)	(3,440)
Working interest dispositions (note 2)	(267)	-
Balance, end of period	61,812	64,019

4. Petroleum and Natural Gas Interests

(\$000s)	June 30 2017	December 31 2016
Cost		
Balance, beginning of period	1,420,836	1,271,382
Acquisitions	34,619	144,610
Capital expenditures	1,851	5,218
Capitalized portion of long term incentive plan	93	167
Transfers from exploration and evaluation assets (note 3)	1,940	3,440
Decommissioning liability additions and revisions	1,113	(3,981)
Working interest dispositions (note 2)	(87,166)	-
Balance, end of period	1,373,286	1,420,836
Accumulated depletion and depreciation		
Balance, beginning of period	(528,716)	(424,557)
Depletion and depreciation	(54,904)	(104,159)
Impairment reversal (note 2)	5,625	-
Accumulated depletion and depreciation of working interest dispositions (note 2)	68,041	-
Balance, end of period	(509,954)	(528,716)
Net book value, end of period	863,332	892,120

For the three months ended March 31, 2017, Freehold closed an acquisition of various gross overriding royalties and mineral title lands in the greater Dodsland area of Saskatchewan for \$33.7 million (including adjustments). For the three months ended June 30, 2017 Freehold closed a royalty acquisition of \$1.6 million (including adjustments). In addition, for the six months ended June 30, 2017, Freehold had minor adjustments on previous acquisitions resulting in reductions of \$0.7 million to petroleum and natural gas interests.

5. Share Based Compensation

(a) Long-term Incentive Plans

In March 2017, Freehold adopted a new long-term incentive plan (LTIP) to replace the previous long-term incentive plan for the employees of Rife (see Related Party note 8). Grants will no longer be made under the previous plan but pre-existing grants will continue until vesting and payout occurs.

In 2017 and in future years, Freehold's long-term incentive compensation will consist of grants of performance share units (PSUs) and restricted share units (RSUs) under the new LTIP. Underlying each PSU and RSU is one notional Freehold common share. The notional Freehold common shares are adjusted whenever a dividend is paid by Freehold.

Upon vesting of the RSUs the holder is entitled to an amount equal in value to the notional Freehold common shares (as adjusted for dividends paid) underlying such RSUs. The value of the notional Freehold common shares is based on the volume weighted average trading price of Freehold common shares on the TSX for the five trading days prior to the settlement date of such RSUs. Generally, one-third of the granted RSUs will vest on each of the first, second and third anniversaries of the date of grant.

For PSUs, the notional Freehold common shares and value are calculated in the same manner as the RSUs, but with the additional application of a performance multiplier. The metrics used for determining the performance multiplier (which can range from 0 to 2 times) are at the discretion of our Board of Directors at the time of grant. For 2017 grants the performance multiplier target is based 50% on absolute total shareholder return and 50% on relative total shareholder return over a three year performance period. Generally, all of the granted PSUs will vest on the third anniversary of the date of grant.

Since participants receive a cash payment on a fixed vesting date, a liability is determined and recognized as services are rendered based on the fair value of the total rights at each period end. The valuation incorporates the consideration of the Freehold common share price, the number of notional Freehold common shares outstanding at each period end, an estimated performance multiplier and an estimated forfeiture rate. Compensation expense is recognized over the vesting period.

The 2014 grants under the previous LTIP valued at \$0.1 million were paid out in 2017. In March 2017 there were 90,026 RSUs and PSUs granted under the new LTIP (after estimated forfeitures).

For the three months ended June 30, 2017, Freehold expensed \$0.3 million (2016 – \$0.3 million) of share based compensation. The total expensed for the six months ended June 30, 2017 was \$0.4 million (2016 – \$0.3 million).

The following table reconciles the change in total accrued share-based incentive compensation:

(\$000s)	June 30 2017	December 31 2016
Balance, beginning of period	1,065	257
Increase in liability	519	928
Cash payout	(138)	(120)
Balance, end of period	1,446	1,065
Current portion of liability	240	133
Long-term portion of liability	1,206	932

The following table reconciles the incentive plan activity for the period:

SHARE BASED AWARDS

	June 30 2017	December 31 2016
Balance, beginning of period	214,863	142,108
Issued	90,026	105,735
Dividends reinvested	5,113	11,170
Cash payout	(38,298)	(44,150)
Balance, end of period	271,704	214,863

(b) Deferred Share Unit Plan

Fully-vested deferred share units (DSUs) are granted annually to non-management directors. As at June 30, 2017, there were 114,989 DSUs outstanding (2016 – 191,890), which are redeemable for an equal number of Freehold common shares (less withholding tax if necessary) after the director's retirement.

On January 1, 2017, Freehold's Board of Directors granted a total of 27,521 DSUs to eligible directors as part of their annual compensation. Each eligible director received 4,234 DSUs and the Chair of the Board received 6,351 DSUs. In addition, during the three months ended March 31, 2017, a retired director redeemed 63,419 DSUs, resulting in the issuance of 44,393 shares from treasury. In payment of withholding tax, 19,026 DSUs were canceled and the cash value of \$0.3 million was remitted to the Canada Revenue Agency.

For the three months ended June 30, 2017, Freehold expensed \$17,000 (2016 – \$82,000) of share based compensation with a corresponding offset to contributed surplus. The total expensed for the six months ended June 30, 2017 was \$0.4 million (2016 – \$0.5 million).

DEFERRED SHARE UNITS

	June 30 2017	December 31 2016
Balance, beginning of period	148,499	177,012
Annual grants	27,521	46,663
Additional resulting from dividends	2,388	9,391
Redeemed	(63,419)	(84,567)
Balance, end of period	114,989	148,499

(c) Retirement Benefit

Freehold participates in its proportionate share of a retirement benefit for certain former employees of Rife through the Manager. For the three months ended June 30, 2017, Freehold expensed \$nil (2016 – \$2,000) with a corresponding increase to the obligation. The total expensed for the six months ended June 30, 2017 was \$nil (2016 – \$5,000). This plan is now discontinued with the final payment being made during the three months ended March 31, 2017.

6. Long-term Debt

At June 30, 2017 Freehold had a \$165 million extendible revolving term credit facility with a syndicate of four Canadian chartered banks, on which \$61 million was drawn. In addition, Freehold has available a \$15 million extendible revolving operating facility.

The facilities are secured with \$400 million demand debentures over most of Freehold's petroleum and natural gas assets but do not contain any financial covenants. 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. Freehold's borrowing base is dependent on the lenders review and interpretation of Freehold's reserves and future commodity prices. During the second quarter 2017 the annual review was completed. The next renewal will occur by May 31, 2018. In the event that the lenders do not consent to an extension, the revolving credit facility would revert to a one-year, non-revolving term facility with repayment due at the termination date.

Borrowings under the facilities bear interest at the bank's prime lending rate, bankers' acceptance or LIBOR rates plus applicable margins and standby fees. At June 30, 2017 and December 31, 2016 the fair values of the long-term debt approximated its carrying value, as the long-term debt carries interest at prevailing market rates. For the six months ended June 30, 2017, the average effective interest rate on advances under Freehold's credit facilities was 2.9% (2016 – 2.9%).

7. Shareholders' Capital

SHARES ISSUED AND OUTSTANDING

	June 30, 2017		December 31, 2016	
	Shares	Amount (\$000s)	Shares	Amount (\$000s)
Balance, beginning of period	117,918,274	1,263,796	98,940,152	1,050,494
Issued for dividend reinvestment plan	-	-	488,060	4,997
Issued for payment of management fee (note 8)	110,000	1,459	287,648	3,543
Issued for deferred share unit plan redemption	44,393	752	59,198	1,066
Cancelled	-	-	(17,684)	(214)
Issued for equity offering	-	-	18,160,900	209,759
Issue costs, net of tax effect	-	-	-	(5,849)
Balance, end of period	118,072,667	1,266,007	117,918,274	1,263,796

For the three and six months ended June 30, 2016, deferred share units were excluded from the calculation of diluted net loss per share as their effect was anti-dilutive.

8. 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 Freehold common 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 Freehold common shares per quarter, pursuant to the amended and restated management agreement. The amended and restated management agreement capped the management fee at 55,000 Freehold common shares per quarter for 2017 with the number of Freehold common shares to be issued per quarter as payment of the management fee reducing to 5,500 Freehold common shares by 2022. For the three months ended June 30, 2017, Freehold issued 55,000 common shares (2016 – 71,912) as payment of the management fee. The ascribed value of \$0.7 million (2016 – \$0.9 million) was based on the closing price of Freehold's common shares on the last trading day of each quarter. The total number of Freehold common shares issued for the six months ended June 30, 2017 was 110,000 (2016 – 143,824) with an ascribed value of \$1.5 million (2016 – \$1.6 million).

For the three months ended June 30, 2017, the Manager charged \$2.4 million in general and administrative costs (three months ended June 30, 2016 – \$2.1 million). For the six months ended June 30, 2017, the Manager charged \$5.5 million in general and administrative costs (six months ended June 30, 2016 – \$5.0 million). At June 30, 2017, there was \$0.8 million (December 31, 2016 – \$0.9 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 June 30, 2017, there was \$nil (December 31, 2016 - \$0.1 million) in accounts receivable relating to these transactions. At June 30, 2017, there was \$nil (December 31, 2016 - \$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 June 30, 2017, Freehold received royalties of approximately \$0.2 million (2016 – \$0.2 million). For the six months ended June 30, 2017, Freehold received royalties of approximately \$0.5 million (2016 – \$0.4 million). At June 30, 2017, there was \$0.1 million (December 31, 2016 - \$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 June 30, 2017, there was \$nil (December 31, 2016 – \$nil) in accounts receivable and accounts payable and accrued liabilities relating to transactions with Canpar.

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.

9. Supplemental Disclosure

(a) Supplemental cash flow disclosure

CASH EXPENSES

(\$000s)	Three Months ended		Six Months ended	
	June 30		June 30	
	2017	2016	2017	2016
Interest	644	1,436	1,495	2,633
Taxes	-	-	-	-

(b) Royalty and other revenue

(\$000s)	Three Months ended		Six Months ended	
	June 30		June 30	
	2017	2016	2017	2016
Royalty interest revenue ⁽¹⁾	34,416	25,686	67,985	45,341
Working interest revenue ⁽²⁾	4,014	6,533	11,536	11,811
	38,430	32,219	79,521	57,152

(1) Royalty interest revenue includes potash, sulphur and lease rentals.

(2) Working interest revenue includes processing fees, interest and other.

(c) Net debt

(\$000s)	June 30	December 31
	2017	2016
Long-term debt	61,000	84,000
Working capital	(11,181)	(10,839)
Net debt ⁽¹⁾	49,819	73,161

(1) Net debt as presented does not have any standardized meaning prescribed by IFRS; and therefore may not be comparable to a similar measure of other entities.

Board of Directors

Marvin F. Romanow
Chair of the Board

Gary R. Bugeaud ^{(1) (2)}
Corporate Director

Peter T. Harrison
Manager, Oil and Gas Investments
CN Investment Division

J. Douglas Kay ^{(2) (3)}
Corporate Director

Arthur N. Korpach ^{(1) (2)}
Corporate Director

Susan M. MacKenzie ^{(2) (3)}
Corporate Director

Thomas J. Mullane
President and Chief Executive Officer
Rife Resources Ltd.

Aidan M. Walsh ^{(1) (3)}
Chief Executive Officer
Baccalieu Energy Inc.

(1) Audit Committee

(2) Governance, Nominating and Compensation Committee

(3) Reserves Committee

Officers

Marvin F. Romanow
Chair of the Board

Thomas J. Mullane
President and Chief Executive Officer

Darren G. Gunderson
Vice-President, Finance and Chief Financial Officer

David M. Spyker
Vice-President, Production

Michael J. Stone
Vice-President, Land

Michael J. Mogan
Controller

Karen C. Taylor
Corporate Secretary

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Bank of Montreal
Royal Bank of Canada
The Toronto-Dominion Bank

Legal Counsel

Burnet, Duckworth & Palmer LLP

Reserve Evaluators

Trimble Engineering Associates Ltd.

Stock Exchange and Trading Symbol

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Common Shares: FRU

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