MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE YEAR ENDED DECEMBER 31, 2018

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PRAIRIESKY ROYALTY LTD

Management's Discussion and Analysis

This Management's Discussion and Analysis ("MD&A") for PrairieSky Royalty Ltd. ("PrairieSky" or the "Company") should be read in conjunction with the audited annual consolidated financial statements as at and for the year ended December 31, 2018 ("financial statements"). This MD&A has been prepared as of February 11, 2019.

The financial statements and comparative information have been prepared in Canadian dollars and in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"). PrairieSky receives royalty income on production; as such, the production volumes are equivalent on a gross and net basis.

Certain measures in this document do not have any standardized meaning as prescribed by International Financial Reporting Standards ("IFRS") and, therefore, are considered Non-GAAP measures. Non-GAAP measures are commonly used in the oil and gas industry and by PrairieSky to provide potential investors with additional information regarding the Company's liquidity and its ability to generate funds to conduct its business. Non-GAAP measures include Operating Netback, Operating Netback per BOE, Funds from Operations per Share, basic and diluted, Cash Administrative Expenses, and Cash Administrative Expenses per BOE. Further information can be found in the Non-GAAP Measures section of this MD&A.

The following volumetric measures may be abbreviated throughout this MD&A: barrel ("bbl") per day ("bbls/d"), barrel of oil equivalent ("BOE") per day ("BOE/d"), thousand cubic feet ("Mcf"), and million cubic feet ("MMcf") per day ("MMcf/d"). BOE is an industry measurement to summarize the amount of energy equivalent found in a barrel of crude oil. See the discussion on energy conversions in the Advisory section of this MD&A for further explanation.

Readers should also read the Advisory section located at the end of this MD&A, which provides information on Forward-Looking Statements, natural gas, oil and natural gas liquids ("NGL") conversions, currency and references to PrairieSky.

FINANCIAL AND OPERATIONAL RESULTS

(millions, except per share or as otherwise noted)	Three months ended December 31 2018	Three months ended December 31 2017	Year ended December 31 2018	Year ended December 31 2017
FINANCIAL				
Revenues	**$ 51.6**	$ 91.5	**$ 273.8**	$ 345.7
Funds from Operations	**48.5**	81.1	**229.7**	290.2
Per Share – basic and diluted[1][4]	**0.21**	0.34	**0.98**	1.23
Net Earnings and Comprehensive Income	**6.0**	39.9	**79.4**	120.6
Per Share - basic and diluted[1]	**0.03**	0.17	**0.34**	0.51
Dividends declared[2]	**45.7**	44.2	**182.1**	176.2
Per Share	**0.1950**	0.1875	**0.7750**	0.7450
Acquisitions, including non-cash consideration	**13.7**	80.8	**58.6**	380.5
Working Capital (Deficiency) at period end	**(10.4)**	45.7	**(10.4)**	45.7
Shares outstanding				
Shares outstanding at period end	**234.2**	236.0	**234.2**	236.0
Weighted average - basic	**234.4**	236.2	**235.1**	236.5
Weighted average - diluted	**234.7**	236.5	**235.4**	236.7
OPERATIONAL				
Royalty Production Volumes				
Crude Oil (bbls/d)	**9,163**	9,419	**9,004**	9,565
NGL (bbls/d)	**2,676**	2,454	**2,463**	2,677
Natural Gas (MMcf/d)	**70.0**	75.2	**71.3**	78.1
Royalty Production (BOE/d)[3]	**23,506**	24,406	**23,358**	25,259
Realized Pricing				
Crude Oil ($/bbl)	**33.17**	58.35	**56.18**	52.99
NGL ($/bbl)	**23.04**	34.80	**34.75**	29.80
Natural Gas ($/Mcf)	**1.35**	1.56	**1.23**	1.81
Total ($/BOE)[3]	**19.61**	30.82	**29.09**	28.84
Operating Netback per BOE[4]	**$ 17.07**	$ 27.22	**$ 26.14**	$ 24.92
Funds from Operations per BOE	**$ 22.43**	$ 36.12	**$ 26.94**	$ 31.48
Oil Price Benchmarks				
West Texas Intermediate (WTI) (US$/bbl)	**61.05**	54.83	**64.98**	51.26
Edmonton Light Sweet ($/bbl)	**42.71**	66.70	**69.35**	63.32
Western Canadian Select (WCS) crude oil differential to WTI (US$/bbl)	**(39.43)**	(12.46)	**(26.29)**	(12.02)
Natural Gas Price Benchmark				
AECO monthly index ($/Mcf)	**1.90**	1.96	**1.52**	2.43
AECO daily index ($/Mcf)	**1.59**	1.65	**1.51**	2.19
Foreign Exchange Rate (US$/CAD$)	**0.7557**	0.7865	**0.7715**	0.7703

(1) Net Earnings and Comprehensive Income and Funds from Operations per Share are calculated using the weighted average number of common shares outstanding.
(2) A dividend of $0.065 per common share was declared on December 11, 2018. The dividend was paid on January 15, 2019 to shareholders of record as at December 31, 2018.
(3) See "Conversions of Natural Gas to BOE".
(4) Funds from Operations per Share and Operating Netback per BOE are defined under the Non-GAAP Measures section in this MD&A.

RESULTS OVERVIEW

HIGHLIGHTS

Highlights of PrairieSky's financial results for the three-month period ended December 31, 2018 ("Q4 2018") include:

- Revenues totaled $51.6 million, consisting of $42.4 million of royalty production revenue, $2.3 million of lease rental income, $6.4 million of bonus consideration and $0.5 million of other income.
- Funds from operations totaled $48.5 million ($0.21 per share basic and diluted).
- Royalty production averaged 23,506 BOE per day consisting of average crude oil production volumes of 9,163 bbls per day, average NGL production volumes of 2,676 bbls per day and average natural gas production volumes of 70.0 MMcf per day.
- Completed acquisitions of gross overriding royalties on producing properties and emerging plays, as well as seismic, in the period for cash consideration of $13.7 million.
- Maintained a strong balance sheet.
- Dividends declared of $45.7 million ($0.1950 per share).
- Purchased for cancellation 493,180 common shares at a weighted average price of $19.84 per common share for total consideration of $9.8 million under the normal course issuer bid ("NCIB").

Highlights of PrairieSky's financial results for the year ended December 31, 2018 ("YE 2018") include:

- Revenues totaled $273.8 million, consisting of $248.0 million of royalty production revenue, $7.9 million of lease rental income, $16.5 million of bonus consideration and $1.4 million of other income.
- Funds from operations totaled $229.7 million ($0.98 per share basic and diluted).
- Royalty production averaged 23,358 BOE per day consisting of average crude oil production volumes of 9,004 bbls per day, average NGL production volumes of 2,463 bbls per day and average natural gas production volumes of 71.3 MMcf per day.
- Completed acquisitions of gross overriding royalties on both producing and non-producing properties, including on emerging plays, as well as seismic, in the year for cash consideration of $58.6 million.
- Dividends declared of $182.1 million ($0.7750 per share).
- Purchased for cancellation 1,804,480 common shares at a weighted average price of $25.31 per common share for total consideration of $45.7 million under the NCIB.
- Entered into a three-year, extendible $200 million revolving and $25 million operating credit facility agreement with a syndicate of lenders.

BUSINESS OVERVIEW

PRAIRIESKY ROYALTY

PrairieSky's asset base includes a geologically and geographically diverse portfolio of Fee Lands (as defined herein) that encompasses approximately 7.8 million acres with petroleum and/or natural gas rights, an additional 1.1 million acres in coal only titles, and approximately 7.8 million acres of GORR Lands (as defined herein) and other acreage (collectively, the "Royalty Properties").

The Royalty Properties are comprised of: (i) fee simple mineral title in lands prospective for petroleum, natural gas, NGL and certain other minerals located predominantly in central and southern Alberta and western Saskatchewan (the "Fee Lands"); (ii) lessor interests in and to leases that are currently issued in respect of certain Fee Lands ("Lessor Interests"); and (iii) overriding royalty interests ("GORR Interests") on lands ("GORR Lands") across Western Canada.

PrairieSky is focused on encouraging third parties to actively develop the Royalty Properties and growing our royalty ownership by strategically seeking additional petroleum and natural gas royalty assets that provide PrairieSky with medium-term to long-term value enhancement potential. The Company does not directly conduct operations to explore for, develop or produce petroleum or natural gas; rather, third-party development of the Royalty Properties provides the Company with royalty production revenues as petroleum and natural gas are produced from such properties. PrairieSky carries on business in the provinces of Alberta, Saskatchewan, British Columbia and Manitoba.

PrairieSky's operations include royalty income earned through crude oil, NGL and natural gas produced on the Royalty Properties. The Company's royalty revenues are derived from: (i) the Lessor Interests that are leased out by the Company and upon which lessees pay lessor royalties, and (ii) GORR Interests on GORR Lands leased by third parties.

PrairieSky receives royalty production revenue from over 38,000 wells and receives payments from approximately 340 different industry payors. The Company receives approximately 75% of its monthly revenue from 31 payors. Royalties are calculated on a fixed percentage, step or sliding scale formula. Some royalty agreements allow for the deduction of certain costs. The average royalty rate for Q4 2018 was approximately 6.0%.

Petroleum and natural gas royalty structures are typically linked directly to production volumes from the lands, with certain royalty structures linked to production volumes and/or price. As a result, the Company's net earnings can be significantly impacted by fluctuations in commodity prices and production volumes. Production volumes can be influenced by various factors, including the extent of exploration and development activity by third parties on the Royalty Properties, the timing and amount of capital expenditures, and the expertise and financial resources of third-party lessees. Commodity pricing is influenced by market supply and demand as well as other factors such as weather, quality of product, access to markets, foreign currency fluctuations, and geopolitical risk. The Company is able to mitigate some of these risks to the extent that there are a multitude of third parties actively exploring and developing the Royalty Properties and the production of natural gas, crude oil, and NGL is diversified.

As a royalty owner, PrairieSky does not bear the operational risks typically associated with the upstream oil and natural gas exploration and production business. The Company does not bear the operational or financial risks of drilling, completing or operating wells and related infrastructure. The Company is not responsible for site restoration and abandonment costs. Capital, operational and abandonment costs are the responsibility of the third parties conducting operations on the Royalty Properties. Substantially all the capital expenditures made by PrairieSky are discretionary.

Costs incurred by the Company are primarily production and mineral taxes, administrative expenses and corporate income taxes. Administrative expenses include lease administration costs such as land title management, contract administration, technical evaluation, negotiations and compliance costs to secure mineral rights and ensure accurate royalty revenue receipts.

Management's discussion and analysis for this reporting period focuses on the three months and year ended December 31, 2018.

PRAIRIESKY'S 2019 OUTLOOK

Management does not provide guidance. As such, this discussion relates only to general economic conditions experienced by the Company as of the date of this MD&A. The near-term economic environment in which PrairieSky operates remains challenged with continued low natural gas prices, higher discounts for Canadian light and heavy crude oil on lower WTI, and constrained takeaway capacity for both crude oil and natural gas. There continues to be limited access to capital for many industry participants, which is further impacted by changes to legislative and regulatory frameworks in the jurisdictions in which the Company and royalty payors carry on business, including but not limited to, tariffs, environmental assessments, and limits related to carbon emissions, and less competitive corporate tax rates than other jurisdictions. The Government of the Province of Alberta recently announced that it would mandate curtailment of oil production in Alberta, which will impact many of the producers operating on the Royalty Properties and in turn the royalty production volumes and revenue received from the Royalty Properties in Alberta. Management continues to deploy its risk mitigating strategies including proactive monitoring of economic conditions, a constant and proactive compliance and collections program, paying close attention to controllable costs and a disciplined approach to acquisitions. PrairieSky maintains a strong balance sheet and continues to employ a conservative capital structure.

On February 11, 2019, the Company announced that the Board would maintain the monthly dividend of $0.78 per common share on an annualized basis.

Management continues to monitor current commodity prices, currency exchange rates, industry activity levels and third-party guidance for anticipated capital expenditures during 2019 and beyond. Given PrairieSky has no operational control over capital expenditures on its lands, it is difficult to predict activity levels and the timing thereof with a high degree of certainty.

PrairieSky's diversity in crude oil and natural gas plays and payors, along with an active royalty compliance program, assists in reducing collection and credit risk. The Company takes certain royalty production volumes in-kind which, in conjunction with the above processes, further assists in managing collection and credit risk.

PRAIRIESKY'S STRATEGY

The Company's objective is to generate significant cash flow and growth for shareholders through indirect crude oil and natural gas investment at relatively low risk and low cost to the Company. The Company seeks to achieve this objective by: (i) focusing on leasing activity and organic growth of royalty production revenue from the Royalty Properties; (ii) proactively monitoring and managing the portfolio of Royalty Properties to ensure third-party adherence to lease terms and contractual provisions (including offset well obligations); (iii) managing controllable costs; and (iv) selectively pursuing strategic business development opportunities that are relatively low risk to the Company and accretive to shareholders. The Company intends to distribute the majority of cash flow in the form of dividends and share repurchases and cancellations over time.

ROYALTY PRODUCTION

ROYALTY PRODUCTION VOLUMES

	Three months ended December 31		Year ended December 31	
(Average daily)	2018	2017	2018	2017
Crude Oil (bbls/d)	**9,163**	9,419	**9,004**	9,565
NGL (bbls/d)	**2,676**	2,454	**2,463**	2,677
Natural Gas (MMcf/d)	**70.0**	75.2	**71.3**	78.1
Total Royalty Production (BOE/d)	**23,506**	24,406	**23,358**	25,259

PrairieSky's average daily royalty production volumes for Q4 2018 were 39% crude oil, 11% NGL and 50% natural gas as compared to the three-month period ended December 31, 2017 ("Q4 2017") when the production volume split was 39% crude oil, 10% NGL and 51% natural gas. The average daily royalty production volume split for YE 2018 was 39% crude oil, 10% NGL and 51% natural gas as compared to the year ended December 31, 2017 ("YE 2017") when the production volume split was 38% oil, 10% NGL and 52% natural gas. There is a natural delay between the timing of production and when PrairieSky receives its royalty interest production and revenue from operators. Due to this delay, positive and negative adjustments related to prior periods may be included in PrairieSky's royalty production volumes and/or revenue. In addition, collections related to compliance recoveries result in adjustments to royalty production volumes and royalty revenue related to prior periods. PrairieSky's compliance department continually reviews leasing agreements and royalty calculations. Compliance adjustments are not recorded in the financial statements until collection is certain.

PrairieSky's crude oil, NGL and natural gas production volumes are primarily marketed with lessees' production. The Company actively reviews its counterparties and takes certain royalty volumes in-kind to mitigate credit risk, as appropriate. PrairieSky is exposed to commodity price volatility. The Company has no commodity price hedges in place and does not currently intend to enter into any commodity price hedges.

For the three months ended December 31, 2018

Crude oil production volumes for Q4 2018 of 9,163 bbls per day have decreased 3% from 9,419 bbls per day reported in Q4 2017 as royalty production volumes from new drilling on the Royalty Properties, including on the Clearwater and Duvernay crude oil plays, and acquisitions were outweighed by the effect of a decreasing price on sliding scale royalty volumes, certain shut-in volumes related to low commodity pricing, and natural declines. Crude oil production volumes in Q4 2018 were also negatively impacted as a result of declines on a Nisku oil pool and a Bakken oil pool, both in Alberta. Both Q4 2017 and Q4 2018 were impacted by positive volume adjustments from prior periods; however, Q4 2017 crude oil volumes included additional compliance recoveries that were not repeated in Q4 2018.

NGL production volumes for Q4 2018 of 2,676 bbls per day have increased 9% from 2,454 bbls per day reported in Q4 2017 as royalty production volumes from new drilling on the Royalty Properties outweighed natural declines. NGL production increased despite natural gas production volume declines due to increased yields from liquids rich natural gas. Both Q4 2017 and Q4 2018 were impacted by positive volume adjustments from prior periods; however, Q4 2017 NGL volumes included additional compliance recoveries that were not repeated in Q4 2018.

Natural gas production volumes for Q4 2018 of 70.0 MMcf per day were 7% lower than the 75.2 MMcf per day reported in Q4 2017 as royalty production volumes from new drilling on the Royalty Properties and acquisitions were outweighed by natural declines. Challenging natural gas pricing has resulted in a slow-down in both drilling and workover activity across Western Canada which has impacted natural gas royalty production. Both Q4 2017 and Q4 2018 were impacted by positive volume adjustments from prior periods; however, Q4 2017 natural gas volumes included additional compliance recoveries that were not repeated in Q4 2018.

For the year ended December 31, 2018

Crude oil production volumes for YE 2018 of 9,004 bbls per day were 6% lower than the 9,565 bbls per day reported in YE 2017 as royalty production volumes from new drilling on the Royalty Properties and acquisitions were outweighed by natural declines including declines on a Nisku oil pool and a Bakken oil pool, both in Alberta.

NGL production volumes for YE 2018 of 2,463 bbls per day have decreased 8% from 2,677 bbls per day reported in YE 2017 as royalty production volumes from new drilling on the Royalty Properties were outweighed by natural declines. During the early part of YE 2018, there was a reduction in ethane volumes due to curtailments resulting in lower corporate NGL yields as compared to YE 2017. During Q4 2018, NGL yields increased due to liquids rich natural gas production additions. Both YE 2017 and YE 2018 periods were impacted by positive volume adjustments from prior periods; however, YE 2017 NGL volumes included additional compliance recoveries that were not repeated in YE 2018.

Natural gas production volumes for YE 2018 of 71.3 MMcf per day were 9% lower than the 78.1 MMcf per day reported in YE 2017 as royalty production volumes from new drilling on the Royalty Properties and acquisitions were outweighed by natural declines. Challenging natural gas pricing has resulted in a slow-down in both drilling and workover activity across Western Canada which has impacted natural gas royalty production. Both YE 2017 and YE 2018 periods were impacted by positive volume adjustments from prior periods; however, YE 2017 natural gas volumes included additional compliance recoveries that were not repeated in YE 2018.

FINANCIAL RESULTS

OPERATING RESULTS

	Three months ended December 31, 2018		Three months ended December 31, 2017	
	($ millions)	**($/BOE)[2]**	**($ millions)**	**($/BOE)[2]**
Royalty Production Revenue	**$ 42.4**	**$ 19.61**	$ 69.2	$ 30.82
Administrative Expenses	**(4.2)**	**(1.94)**	(6.5)	(2.89)
Production and Mineral Taxes	**(1.3)**	**(0.60)**	(1.6)	(0.71)
Operating Netback[1]	**$ 36.9**	**$ 17.07**	$ 61.1	$ 27.22

	Year ended December 31, 2018		Year ended December 31, 2017	
	($ millions)	**($/BOE)[2]**	**($ millions)**	**($/BOE)[2]**
Royalty Production Revenue	**$ 248.0**	**$ 29.09**	$ 265.9	$ 28.84
Administrative Expenses	**(20.0)**	**(2.35)**	(30.1)	(3.26)
Production and Mineral Taxes	**(5.1)**	**(0.60)**	(6.1)	(0.66)
Operating Netback[1]	**$ 222.9**	**$ 26.14**	$ 229.7	$ 24.92

(1) Non-GAAP measure. See “Non-GAAP Measures” in the MD&A

(2) See “Conversions of Natural Gas to BOE”.

The Q4 2018 operating netback of $36.9 million ($17.07 per BOE) has decreased from $61.1 million ($27.22 per BOE) in Q4 2017 primarily as a result of decreases in realized commodity pricing for all products and total royalty production volumes. The operating netback was positively impacted by lower administrative expenses and production and mineral taxes in Q4 2018 as compared to Q4 2017. These changes are described in detail below. YE 2018, the operating netback of $222.9 million has decreased from $229.7 million in YE 2017, but has improved on a per BOE basis to $26.14 per BOE from $24.92 per BOE. The decrease in royalty production revenue in YE 2018 was driven by lower royalty production volumes, as previously described. Average realized commodity prices for the two periods were relatively flat. Both administrative expenses and production and mineral taxes decreased in YE 2018 which positively impacted the YE 2018 operating netback. These changes are further discussed below.

REVENUES

Royalty Revenue by Product (millions)	Three months ended December 31 2018	2017	Year ended December 31 2018	2017
Crude Oil	**$ 28.0**	$ 50.6	**$ 184.7**	$ 185.0
NGL	**5.6**	7.8	**31.2**	29.1
Natural Gas	**8.8**	10.8	**32.1**	51.8
	42.4	69.2	**248.0**	265.9
Other Revenue				
Lease Rental Income	**$ 2.3**	$ 3.0	**$ 7.9**	$ 10.7
Bonus Consideration	**6.4**	19.0	**16.5**	67.0
Other Income	**0.5**	0.3	**1.4**	2.1
	9.2	22.3	**25.8**	79.8
Total Revenue	**$ 51.6**	$ 91.5	**$ 273.8**	$ 345.7

Revenues by Classification (millions)	Three months ended December 31 2018	2017	Year ended December 31 2018	2017
Lessor Interests on Fee Lands	**$ 28.4**	$ 52.2	**$ 177.2**	$ 200.3
GORR Interests	**14.0**	17.0	**70.8**	65.6
Royalty Revenue	**42.4**	69.2	**248.0**	265.9
Other Revenue	**9.2**	22.3	**25.8**	79.8
Total Revenue	**$ 51.6**	$ 91.5	**$ 273.8**	$ 345.7

Pricing	Three months ended December 31 2018	2017	Year ended December 31 2018	2017
Benchmark				
WTI (US$/bbl)	**61.05**	54.83	**64.98**	51.26
Edmonton Light Sweet ($/bbl)	**42.71**	66.70	**69.35**	63.32
WCS differential to WTI (US$/bbl)	**(39.43)**	(12.46)	**(26.29)**	(12.02)
AECO monthly index ($/mcf)	**1.90**	1.96	**1.52**	2.43
AECO daily index ($/mcf)	**1.59**	1.65	**1.51**	2.19
Foreign Exchange Rate (US$/CAD$)	**0.7557**	0.7865	**0.7715**	0.7703
Realized				
Crude Oil ($/bbl)	**33.17**	58.35	**56.18**	52.99
NGL ($/bbl)	**23.04**	34.80	**34.75**	29.80
Natural Gas ($/Mcf)	**1.35**	1.56	**1.23**	1.81
Total ($/BOE)	**19.61**	30.82	**29.09**	28.84

The Company's average royalty rate for Q4 2018 and Q4 2017 was approximately 6.0% and 6.2%, respectively. The average royalty rate has declined due to an increased weighting of GORR production volumes which are generally at lower royalty rates. During Q4 2018, royalty revenue was $42.4 million compared to $69.2 million for the same period in 2017, a decrease of 39% primarily as a result of lower average realized pricing for all commodities in addition to lower total production volumes.

During Q4 2018, revenue from Lessor Interests on Fee Lands was $28.4 million or 67% of total royalty production revenue. Revenue from GORR Interests was $14.0 million or 33% of total royalty production revenue for the same time period. In the comparative period, $52.2 million or 75% and $17.0 million or 25%, respectively, of royalty production revenue was generated from Lessor Interests on Fee Lands and GORR Interests. The increase in revenue generated from GORR Interests as a percentage of total royalty production revenue is reflective of the impact of revenues from GORR acquisitions and land fund arrangements and increased activity on GORR lands. In addition to royalty revenue from Lessor Interests, all lease rental income and bonus consideration are generated from Fee Lands.

The Company's average royalty rate for YE 2018 and YE 2017 was approximately 6.0% and 6.1%, respectively. The average royalty rate is slightly lower due to an increased weighting of GORR production volumes which are generally at lower royalty rates. During YE 2018, royalty production revenue was $248.0 million compared to $265.9 million for the same period in 2017. YE 2018 royalty production revenue decreased by 7% compared to YE 2017 primarily due to weak natural gas benchmark pricing which resulted in lower average realized pricing for natural gas and lower production volumes due to limited natural gas activity.

During YE 2018, revenue from the Lessor Interests was $177.2 million or 71% of total royalty production revenue. Revenue from GORR Interests was $70.8 million or 29% of total royalty production revenue for the same period. In the comparative period, $200.3 million or 75% and $65.6 million or 25%, respectively, of royalty production revenue was generated from Lessor Interests and GORR Interests. The increase in revenue generated from GORR Interests as a percentage of total royalty revenue is reflective of the impact of revenues from GORR acquisitions and increased near-term activity on GORR Lands.

During Q4 2018, the Company averaged realized crude oil pricing of $33.17 per bbl, NGL pricing of $23.04 per bbl and natural gas pricing of $1.35 per Mcf. Liquids pricing decreased from Q4 2017 when the Company averaged realized crude oil pricing of $58.35 per bbl and NGL pricing of $34.80 per bbl due to decreased benchmark pricing combined with wider light and heavy oil differentials. Realized natural gas pricing declined to $1.35 per Mcf in Q4 2018 from $1.56 per Mcf in Q4 2017 due to decreases in benchmark pricing. YE 2018, the Company averaged realized crude oil pricing of $56.18 per bbl, NGL pricing of $34.75 per bbl and natural gas pricing of $1.23 per Mcf. Liquids pricing increased with 2018 benchmark pricing partially offset by wider differentials for light and heavy oil compared to YE 2017 when the Company averaged realized crude oil pricing of $52.99 per bbl and NGL pricing of $29.80 per bbl. Realized natural gas pricing decreased to $1.23 per Mcf in YE 2018 from $1.81 per Mcf in the prior year due to decreases in benchmark pricing.

Royalty compliance recoveries are the cash payments received as a result of the extensive process of identifying, analyzing, resolving and collecting corrected payments from royalty payors. Cash received from compliance recoveries can cover a number of periods. PrairieSky's compliance department continually reviews leasing agreements and royalty calculations. Compliance adjustments are not recorded in the financial statements until collection is certain. For Q4 2018 and YE 2018, the Company collected $1.5 million (Q4 2017 - $5.1 million) and $9.2 million (YE 2017 - $10.6 million), respectively, in compliance recoveries. Compliance recoveries are included in royalty production revenue for the period.

Other revenue consisted primarily of lease rental income from leases that are currently issued in respect of certain Fee Lands and lease bonus consideration. Bonus consideration revenue for Q4 2018 and YE 2018 was $6.4 million (Q4 2017 - $19.0 million) and $16.5 million (YE 2017 - $67.0 million), respectively. Both the amount and timing of bonus consideration revenue can vary significantly from quarter to quarter as it relates to the unique circumstances of each transaction.

ADMINISTRATIVE EXPENSES

	Three months ended December 31		Year ended December 31	
(millions)	**2018**	2017	**2018**	2017
Salaries and Benefits	**$ 3.1**	$ 3.9	**$ 13.4**	$ 14.3
Share-Based Compensation	**(0.2)**	1.7	**(1.3)**	9.8
Office Expense	**0.9**	-	**4.3**	2.5
Public Company Expense	**0.1**	0.2	**1.3**	1.4
Information Technology and Other	**0.3**	0.7	**2.3**	2.1
Total Administrative Expenses	**$ 4.2**	$ 6.5	**$ 20.0**	$ 30.1
Administrative Expenses per BOE(1)	**$ 1.94**	$ 2.89	**$ 2.35**	$ 3.26
Cash Administrative Expenses(2)	**$ 4.4**	$ 5.8	**$ 26.4**	$ 27.7
Cash Administrative Expenses per BOE(1)(2)	**$ 2.03**	$ 2.58	**$ 3.10**	$ 3.00

(1) See "Conversions of Natural Gas to BOE".
(2) Non-GAAP measure. See "Non-GAAP Measures" in the MD&A.

PrairieSky is committed to cost control in its business. Administrative expenses for Q4 2018 and YE 2018 were $1.94 per BOE (Q4 2017 - $2.89 per BOE) and $2.35 per BOE (YE 2017 - $3.26 per BOE), respectively.

Administrative expenses include both cash and non-cash charges which relate to share-based compensation plans. Administrative expenses related to restricted share units (“RSUs”), preferred share units (“PSUs”) and deferred share units (“DSUs”) are impacted by the closing share price at period end and as such, are subject to variability. In Q4 2017, the Company received a $1.0 million GORR asset as reimbursement for legal and administrative expenses incurred in connection with a dispute which was settled among the Company and several arms-length parties. Cash administrative expenses for Q4 2018 and YE 2018 were $2.03 per BOE (Q4 2017 - $2.58 per BOE) and $3.10 per BOE (YE 2017 - $3.00 per BOE), which were relatively flat period over period.

The Company payouts related to share-based compensation during Q4 2018 were $nil (Q4 2017 - $nil million) and $5.1 million during YE 2018 (YE 2017 - $6.4 million). There were no cash payments in Q4 2018. Under the RSU and PSU plans, units vested in the first quarter of 2018.

Of the total share-based compensation expense for Q4 2018, $0.6 million (Q4 2017 - $0.3 million) related to the stock option plan and there was a $0.3 million recovery (Q4 2017 - $1.4 million expense) related to the RSU and PSU plans. The Company recorded a $0.5 million recovery (Q4 2017 - $nil) related to the Company’s DSU plan in Q4 2018.

Of the total share-based compensation expense for YE 2018, $2.0 million (YE 2017 - $1.8 million) related to the stock option plan and there was a $2.5 million recovery (YE 2017 - $7.2 million expense) related to the RSU and PSU plans. The Company recorded a $0.8 million recovery (YE 2017 - $0.8 million expense) related to the Company’s DSU plan for YE 2018.

Total outstanding units and options from all employee incentive plans is 0.6% of total common shares outstanding at December 31, 2018, consistent with prior years.

PRODUCTION AND MINERAL TAXES

	Three months ended December 31		Year ended December 31	
(millions, except per BOE amounts)	**2018**	**2017**	**2018**	**2017**
Production and mineral taxes	**$ 1.3**	$ 1.6	**$ 5.1**	$ 6.1
$/BOE(1)	**$ 0.60**	$ 0.71	**$ 0.60**	$ 0.66

(1) See “Conversions of Natural Gas to BOE”.

Production and mineral taxes are levied on an annual basis on the value of crude oil and natural gas production or amount of acreage from non-Crown lands. For Q4 2018, production and mineral taxes, which includes Alberta Freehold Mineral Tax and Saskatchewan acreage tax, averaged 3.1% of royalty revenues compared to 2.3% in the comparable 2017 period. For YE 2018, production and mineral taxes averaged 2.1% compared to 2.3% for YE 2017. Saskatchewan acreage tax does not vary with pricing while Alberta Freehold Mineral Taxes are impacted by both production and pricing. Production and mineral taxes are based on an annual estimate which can result in variances from quarter to quarter.

DEPLETION, DEPRECIATION AND AMORTIZATION (“DD&A”)

	Three months ended December 31		Year ended December 31	
(millions, except per BOE amounts)	**2018**	**2017**	**2018**	**2017**
Depletion, Depreciation and Amortization	**$ 34.7**	$ 37.4	**$ 139.9**	$ 166.7
$/BOE(1)	**$ 16.05**	$ 16.66	**$ 16.41**	$ 18.08

(1) See “Conversions of Natural Gas to BOE”.

The Company depletes its royalty assets using the unit-of-production method based on the total proved and probable reserves of its Royalty Properties. Corporate assets are depreciated on a straight-line basis. DD&A per BOE is lower in Q4 2018 and YE 2018 than the prior year comparative periods due to a lower depletable base and increased reserves. DD&A per BOE will fluctuate depending on the royalty assets acquired, if any, the amount of reserves added, and production volumes in the period.

EXPLORATION AND EVALUATION EXPENSE ("E&E")

(millions, except per BOE amounts)	Three months ended December 31 2018	2017	Year ended December 31 2018	2017
Exploration and Evaluation Expense	**$ 4.5**	$ 0.2	**$ 5.4**	$ 4.9
$/BOE[(1)]	**$ 2.08**	$ 0.09	**$ 0.63**	$ 0.53

(1) See "Conversions of Natural Gas to BOE".

During Q4 2018 and YE 2018, $4.5 million (Q4 2017 - $0.2 million) and $5.4 million (YE 2017 - $4.9 million), respectively, of costs associated with expired Crown mineral leases and gross overriding royalties were recognized as an expense. The expense will vary period to period as a result of the timing of lease expiries, if any.

FINANCE

($ millions)	Three months ended December 31 2018	2017	Year ended December 31 2018	2017
Finance Income	**$ -**	$ (0.4)	**$ (0.3)**	$ (1.3)
Finance Expense	**0.3**	-	**0.8**	0.1
Net Finance Items	**$ 0.3**	(0.4)	**$ 0.5**	(1.2)

Finance income includes interest on funds on deposit, short term investments and the royalty note receivable. Finance income decreased in Q4 2018 and YE 2018 as a result of the decrease in the cash balance due to acquisitions completed for cash consideration during YE 2018 and YE 2017. Finance expense has increased from Q4 2017 and YE 2017 as a result of the renewal and extension of the credit facility and short-term interest expense as outlined below in the "Financing Activities" section of this MD&A.

INCOME TAX

(millions)	Three months ended December 31 2018	2017	Year ended December 31 2018	2017
Current Tax Expense (Recovery)	**$ (1.9)**	$ 4.4	**$ 16.0**	$ 11.6
Deferred Tax Expense	**2.5**	1.9	**7.5**	6.9
Income Tax Expense	**0.6**	6.3	**23.5**	18.5

For the year ended December 31, 2018, the Company recorded a $16.0 million (YE 2017 - $11.6 million) current tax expense and a deferred tax expense of $7.5 million (YE 2017 - $6.9 million). PrairieSky's effective tax rate was approximately 23% for YE 2018 (YE 2017 - 13%). The Company's effective tax rate differs from the Canadian statutory tax rate of 27% primarily as a result of the reversal of the initial difference between the carrying value of net assets transferred and the tax pools acquired on May 27, 2014, for which no deferred tax asset was recognized, partially offset by non-deductible employee-related expenses. The rate at which this reversal was realized decreased in YE 2018, increasing the effective tax rate for YE 2018 compared to YE 2017. The Company has a current tax receivable at December 31, 2018 of $4.0 million (YE 2017 - $11.3 million current tax payable).

The approximate tax pools balances available at year end are:

(millions)	Year ended December 31, 2018	Year ended December 31, 2017
Canadian oil and gas property expense ("COGPE")	**$ 1,435.2**	$ 1,556.6
Canadian development expense ("CDE")	**0.1**	0.2
Canadian exploration expense ("CEE")	**-**	-
Undepreciated capital cost ("UCC")	**0.7**	0.6
Non-capital loss carryforwards	**-**	-
Share issue costs	**9.1**	13.4
	$ 1,445.1	$ 1,570.8

NET EARNINGS

Net earnings for Q4 2018 and YE 2018 were $6.0 million ($0.03 per share, basic and diluted) and $79.4 million ($0.34 per share, basic and diluted), respectively, compared to $39.9 million for Q4 2017 ($0.17 per share, basic and diluted) and $120.6 million for YE 2017 ($0.51 per share, basic and diluted). Net earnings for Q4 2018 was lower than Q4 2017 as decreased royalty production revenue and bonus consideration more than offset the benefit of lower administrative, DD&A and income tax expenses. Net earnings for YE 2018 was lower than YE 2017 as the benefits of lower DD&A and administrative expenses were more than offset by lower total revenues and higher annual income taxes.

ACQUISITIONS

During Q4 2018, the Company completed acquisitions totaling $13.7 million (Q4 2017 - $80.8 million) comprised of royalty assets of $6.1 million (Q4 2017 - $20.8 million) and E&E assets, consisting of royalty interests on non-producing properties and seismic, of $7.6 million (Q4 2017 - $60.0 million).

YE 2018, the Company completed acquisitions totaling $58.6 million (YE 2017 - $380.5 million) comprised of royalty assets of $19.6 million (YE 2017 - $59.3 million) and E&E assets, consisting of royalty interests on non-producing properties and seismic, of $39.0 million (YE 2017 - $321.2 million).

YE 2017 included the acquisition of a 4% gross overriding royalty on current and future phases of the Lindbergh SAGD thermal oil project, as well as seismic over certain lands in British Columbia and Alberta, for cash consideration of $250 million, before customary closing adjustments.

LIQUIDITY AND CAPITAL RESOURCES

	Three months ended December 31		Year ended December 31	
(millions)	2018	2017	2018	2017
Net Cash From (Used In)				
Operating Activities	**$ 63.8**	$ 77.2	**$ 235.2**	$ 298.6
Investing Activities	**(13.7)**	(78.2)	**(58.6)**	(346.3)
Financing Activities	**(50.1)**	(55.9)	**(221.7)**	58.8
Increase (Decrease) in Cash and Cash Equivalents	**-**	(56.9)	**(45.1)**	11.1
Cash and Cash Equivalents, Beginning of Period	**$ -**	$ 102.0	**$ 45.1**	$ 34.0
Cash and Cash Equivalents, End of Year	**$ -**	$ 45.1	**$ -**	$ 45.1

OPERATING ACTIVITIES

Net cash from operating activities for Q4 2018 was $63.8 million compared to $77.2 million for the comparable period in 2017, primarily as a result of lower total revenues from lower realized commodity pricing and bonus consideration.

Net cash from operating activities for YE 2018 was $235.2 million compared to $298.6 million for the comparable period in 2017, primarily as a result of lower total revenues from lower royalty production volumes and lower realized commodity pricing on natural gas royalty production, as well as bonus consideration.

Funds from operations is utilized by management to evaluate the ability of the Company to generate cash from its operations. This is considered a measure of operating performance as it demonstrates the Company's ability, on an ongoing basis, to fund distributions of cash flow to shareholders as dividends, to repurchase common shares under the Company's NCIB, as well as fund complementary acquisitions. Such a measure provides a useful indicator of the Company's operations, on an ongoing basis, by eliminating certain non-cash charges. Funds from operations in Q4 2018 and YE 2018 were $48.5 million and $229.7 million, respectively, a 40% decrease from $81.1 million in Q4 2017 and a 21% decrease from $290.2 million in YE 2017. The decreases in both 2018 periods were due to lower total revenues due to lower total royalty production volumes, decreases in benchmark pricing for natural gas and wider light and heavy oil differentials negatively impacting realized pricing, as well as lower bonus consideration which was more in line with historical averages.

The Company had a working capital deficiency of $10.4 million as at December 31, 2018. The working capital deficiency at December 31, 2018 was due to the combined effect of lower realized prices in Q4 2018 and the resulting effect on the accrued revenue balance, as well as acquisitions completed during YE 2018. At December 31, 2018, accounts receivable and accrued revenue consisted primarily of accrued revenue related to lease and royalty payments. In the crude oil and natural gas industry, accounts receivable from industry partners are typically settled in the following month; however, payments to royalty owners are often delayed longer, and as a result, actual payments may differ from estimates recorded. Accounts payable and accrued liabilities consisted primarily of production and mineral taxes payable, share-based compensation and salary related accruals.

INVESTING ACTIVITIES

For Q4 2018 and YE 2018, cash used in investing activities was $13.7 million (Q4 2017 - $78.2 million) and $58.6 million (YE 2017 - $346.3 million), respectively, and related to royalty and E&E asset acquisitions as outlined in the "Acquisitions" section of this MD&A.

FINANCING ACTIVITIES

For Q4 2018, cash used in financing activities was $50.1 million (Q4 2017 - $55.9 million). YE 2018, cash used in financing activities was $221.7 million (YE 2017 - cash from financing activities of $58.8 million). The dividends paid in Q4 2018 and YE 2018 of $45.7 million and $181.6 million, respectively, were higher than in the comparable 2017 periods due to the increased dividend announced in February 2018 to $0.065 per common share per month. In addition, the Company repurchased $9.8 million in common shares under the NCIB in Q4 2018 (Q4 2017 - $11.0 million) as described below. During YE 2018, $45.7 million in common shares have been repurchased (YE 2017 - $42.2 million) under the NCIB.

Since the initial public offering in May 2014 (the "IPO"), PrairieSky has declared $849.8 million in dividends to shareholders. Since inception of the NCIB in 2016, PrairieSky has purchased for cancellation 4,166,780 common shares at an average cost of $27.31 per share for total consideration of $113.8 million.

Bank Debt

On May 15, 2018, the Company entered into a $200 million extendible revolving credit facility (the "Revolving Facility"), with a permitted increase to $250 million, and renewed the $25 million extendible operating credit facility (the "Operating Facility", and together with the Revolving Facility, the "Credit Facility"), with a syndicate of Canadian banks.

The Credit Facility includes borrowing options of Canadian prime rate-based advances, U.S. base rate advances, LIBOR loans, bankers' acceptances and letters of credit, and will bear interest on a variable grid based on certain financial ratios, over the prevailing applicable rate for the type of loan. The Credit Facility is unsecured and does not have a borrowing base restriction. The Revolving Facility and the Operating Facility are each for three-year terms maturing on May 15, 2021 and, subject to certain requirements, are extendible annually. The credit facility has three financial covenants, whereby the Company's ratio of adjusted consolidated senior debt to EBITDA will not exceed 3.5:1.0, adjusted consolidated total debt to EBITDA will not exceed 4.0:1.0, and the adjusted consolidated total debt to capitalization ratio will not exceed 55%. EBITDA used in the covenant calculation is net earnings adjusted for non-cash items, interest expense and income taxes. As at December 31, 2018, the Company was compliant with all covenants provided for in the lending agreement.

As at December 31, 2018, the Company had $5.8 million in bank debt outstanding on the Operating Facility (December 31, 2017 - $nil). The Revolving Facility remains undrawn. The effective interest rate for both the three months and year ended December 31, 2018 was 4.2% (three months and year ended December 31, 2017 – nil%).

Dividends and Dividend Policy

PrairieSky currently pays a monthly dividend to shareholders at the discretion of the Board. Dividends declared were $45.7 million or $0.1950 per share for Q4 2018. On February 11, 2019, the Company announced that the Board had maintained the monthly dividend at $0.065 per common share per month or $0.78 per common share on an annualized basis.

The Board of Directors reviews and determines the dividend rate annually after considering expected commodity prices, foreign exchange rates, economic conditions, production volumes, income taxes, and PrairieSky's capacity to fund operating expenses and investing opportunities. The dividend rate is established with the intent of absorbing short-term market volatility over several months. It also recognizes the intention of maintaining a strong financial position to take advantage of business development opportunities and withstanding periods of commodity price volatility.

Outstanding Share Data

As at December 31, 2018, PrairieSky had 234.2 million common shares outstanding (December 31, 2017 - 236.0 million) and 1.0 million outstanding stock options (December 31, 2017 - 0.8 million). As at February 11, 2019, there were 234.0 million common shares outstanding.

Capital Management

The Company's objective when managing its capital structure is to maintain financial flexibility in order to distribute cash to shareholders in the form of dividends and to repurchase shares for cancellation after consideration of the Company's financial requirements for its business and future growth opportunities. As a royalty company, PrairieSky does not incur capital expenditures for crude oil and natural gas development, which enhances its financial flexibility.

The Company's capital structure is comprised of shareholders' equity and working capital. The Company's capital structure is managed by taking into account operating activities, dividends paid to shareholders, common share repurchases, income taxes, available Credit Facility, share issuance costs and other factors. The Company's operating results and capital structure are impacted by the level of leasing and development activity by third parties on the Royalty Properties, commodity prices and the resultant royalty revenues, as well as the costs incurred by the Company.

Stewardship of the Company's capital structure is managed through its financial and operating forecast process. The Company's forecast of future cash flows is based on estimates of production, crude oil, natural gas and NGL prices, production and mineral tax expense, administrative expenses, income taxes and other investing and financing activities. The forecast is regularly updated based on changes in commodity prices, production expectations and other factors that, in the Company's view, would impact future cash flows.

On April 30, 2018 the Company announced the approval of the renewal of its NCIB by the Toronto Stock Exchange ("TSX"). The NCIB allows the Company to purchase for cancellation up to a maximum of 1,750,000 common shares over a twelve-month period which commenced on May 4, 2018 and expires no later than May 3, 2019. The Company allocated $50.0 million to repurchase common shares under the NCIB over the twelve-month period. Future amounts to be allocated to the NCIB will be announced prior to expiration of the current NCIB. Purchases are made on the open market through the TSX or alternative platforms at the market price of such common shares. All common shares purchased under the NCIB are cancelled.

During Q4 2018, the Company purchased for cancellation 493,180 common shares (Q4 2017 - 336,700 common shares) at a weighted average price of $19.84 per common share (Q4 2017 - $32.66 per common share) including commissions for total consideration of $9.8 million (Q4 2017 - $11.0 million). The total cost paid, including commissions and fees, was first charged to share capital to the extent of the average carrying value of the common shares purchased and the excess of $2.8 million (Q4 2017 - $6.2 million) was charged to the deficit.

YE 2018, the Company has purchased for cancellation 1,804,480 common shares (YE 2017 - 1,402,300 common shares) at a weighted average price of $25.31 per common share (YE 2017 - $30.09 per common share) including commissions for total consideration of $45.7 million (YE 2017 - $42.2 million). The total cost paid, including commissions and fees, was first charged to share capital to the extent of the average carrying value of the common shares purchased and the excess of $20.2 million (YE 2017 - $22.4 million) was charged to the deficit. Since the inception of the NCIB in 2016, the Company has purchased for cancellation 4,166,780 common shares at an average price of $27.31 per share for total consideration of $113.8 million.

COMMITMENTS

CONTRACTUAL COMMITMENTS

(millions)			Expected Future Payments				
(undiscounted)	2019	2020	2021	2022	2023	Thereafter	Total
Office lease commitments(1)	$ 0.6	$ 0.6	$ 0.7	$ 0.7	$ 0.7	$ 0.1	$ 3.4

(1) Excludes operating costs

The Company has in place four royalty acquisition agreements with unrelated parties, all of which expire by October 31, 2020. At December 31, 2018, the total remaining commitments under these agreements is $12.5 million.

RISK MANAGEMENT

FINANCIAL RISKS

The Company is exposed to financial risks arising from its financial assets and liabilities. Financial risks include market risk (commodity prices and interest rates), credit risk and liquidity risk.

Commodity Price Risk

Commodity price risk is the risk the Company will encounter fluctuations in future royalty production revenues with changes in commodity prices. Commodity prices for crude oil, NGL and natural gas are influenced by global and regional factors, including levels of supply and demand, transportation constraints, weather and geopolitical factors. The Company has not hedged its commodity price risk.

Interest Rate Risk

Interest rate risk arises from changes in market interest rates that may affect the fair value or future cash flows from the Company's financial assets or liabilities. The Company has minimal interest rate risk as its bank debt is $5.8 million and it is only drawn on the Operating Facility. The Revolving Facility remains undrawn.

Credit Risk

Credit risk arises from the potential that the Company may incur a loss if a counterparty to a financial instrument fails to meet its obligation in accordance with agreed terms. The Company's diversified revenue stream limits the size of any one property or industry operator with respect to total receivables.

The Company maintains a compliance program to ensure royalties are paid correctly on production from the Royalty Properties in accordance with the terms of the agreements. This includes reviewing and analyzing prices obtained by the royalty payor and ensuring that unwarranted or excessive deductions are not being taken.

A substantial portion of the Company's accounts receivable are from leases, overriding royalties and other agreements with crude oil and natural gas industry operators and are subject to normal industry credit risks. The Company's leasing arrangements typically provide for termination of the lease in the event of non-payment of royalties which would result in a return of the petroleum and natural gas rights to the Company. In addition, the Company actively reviews its counterparties and takes its production in-kind to mitigate credit risk as appropriate.

As at December 31, 2018, there was one counterparty whose accounts receivable individually accounted for more than 10% of the total accounts receivable balance. The maximum credit risk exposure associated with accounts receivable and accrued revenue is the total carrying value. As at December 31, 2018, the Company has provided an allowance for doubtful accounts of $1.0 million (December 31, 2017 - $nil) calculated using a lifetime expected credit loss assessment for specifically identifiable customer balances which are assessed to be impaired.

Liquidity Risk

Liquidity risk is the risk that the Company will encounter difficulties funding its financial liabilities as they come due. Liquidity risk is managed by maintaining sufficient liquid financial resources to fund obligations as they come due. At December 31, 2018, the Company had a working capital deficiency of $10.4 million. The working capital deficiency is a result of the decrease in accrued revenue at the end of the year stemming from the sharp decline in realized crude oil pricing in Q4 2018, as previously discussed. In addition, capital expenditures of $13.7 million were completed in Q4 2018. Realized crude oil pricing has improved subsequent to year-end with improved Canadian light and heavy oil differentials to WTI. The Company also has access to funding alternatives through its Credit Facility.

The Company's royalty production volumes and resultant revenues with high operating netbacks provide significant liquidity. The primary uses of funds are acquisitions, administrative expenses, production and mineral taxes, income taxes, dividends, and the repurchase and cancellation of PrairieSky common shares. The Company's dividend, common share repurchases and capital commitments are discretionary. The Company has unused capacity under its Credit Facility of up to $219.2 million.

The timing of expected cash outflows relating to bank debt of $5.8 million, accounts payable and accrued liabilities of $10.0 million, and the dividend payable of $15.2 million is less than one year. Included in accounts payable and accrued liabilities is $2.0 million related to vested DSUs which may or may not be cash settled in the next year.

OPERATIONAL AND BUSINESS RISKS

PrairieSky has identified the following key operational and business risks that may impact financial results. The most significant of these risks are as follows:

- Volatility in commodity prices and quality differentials as a result of global and North American market forces and/or shifts in the balance between supply and demand for crude oil and natural gas;
- Access to transportation, including pipelines or other methods, for bringing crude oil and natural gas to market;
- Dependence on lessees and/or third-party operators to develop the Royalty Properties and the risks associated with exploration, development and production of crude oil and natural gas, including environmental risks;
- Ability of participants in the crude oil and natural gas industry in Western Canada to access capital to develop the Royalty Properties and the industry as a whole;
- Third-party operator activity levels on the Royalty Properties and intense competition for land, goods and services, qualified personnel and capital funding;
- Variations in currency exchange rates;
- Imprecision of reserve estimates and uncertainty of depletion and recoverability of reserves. Our reserves will deplete over time through continued production and our industry partners and royalty payors may not be able to replace the reserves on the Royalty Properties on an economic basis;
- Stock market volatility and the ability to access sufficient capital from internal and external sources;
- Third-party operational or marketing risks, including take in-kind production volumes, resulting in delivery interruptions, delays, lower realized pricing and/or unanticipated production declines;
- Changes in government regulations, including taxation, environmental and Crown royalty rates; and
- Dividends may vary based on PrairieSky's financial performance and/or market conditions.

The Company employs the following strategies to mitigate these risks:

- Our Royalty Properties are diversified which limits the exposure to any one royalty payor, commodity or operator;
- We are a royalty interest holder and have no direct exposure to environmental claims and regulation or the associated costs;
- We are focused on controlling direct costs in order to maximize our funds from operations;
- Our royalty interest agreements and contracts provide mechanisms to ensure that our interests are protected;
- Systems and compliance processes are in place to identify any unpaid or incorrect revenues; and
- We maintain levels of liability insurance that meet or exceed industry standards.

ENVIRONMENTAL RISKS

The Canadian crude oil and natural gas industry is currently subject to environmental regulation under a variety of Canadian federal, provincial, territorial and municipal laws and regulations, all of which are subject to governmental review and revision from time to time. Such regulations provide for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain crude oil and natural gas industry operations, including the abandonment and reclamation of well, facility and pipeline sites. Compliance with such regulations can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licences and authorizations, civil liability and the imposition of material fines and penalties. In addition to these specific, known requirements, future changes to environmental legislation, including anticipated legislation for air pollution and greenhouse gas emissions, may impose further requirements on operators and other companies in the crude oil and natural gas industry. PrairieSky requires third-party lessees on the Royalty Properties to adhere to governmental regulation and works with the Alberta Energy Regulator to ensure compliance.

Lessees and third-party operators of the Royalty Properties are responsible for the costs associated with environmental regulation and adherence to regulation. PrairieSky may be indirectly impacted by reduced industry activity or the inability to collect royalty payments. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact of those requirements on our operations and financial condition.

FURTHER INFORMATION ON RISK FACTORS AND INDUSTRY CONDITIONS

For a detailed discussion of the risks, uncertainties and industry conditions associated with PrairieSky's business, refer to PrairieSky's Annual Information Form dated February 11, 2019 which is available under PrairieSky's SEDAR profile at www.sedar.com and at www.prairiesky.com.

ACCOUNTING JUDGMENTS, ESTIMATES AND ACCOUNTING POLICIES

Management is required to make judgments, estimates, and assumptions through the application of the Company's accounting policies and practices, which have a significant impact on the financial results. A summary of PrairieSky's significant accounting policies can be found in Note 3 to the audited annual consolidated financial statements. The following discussion outlines the accounting policies and practices involving the use of judgments and estimates that are critical to determining PrairieSky's financial results.

Critical judgments are those judgments made by Management in the process of applying the Company's accounting policies and that have the most significant impact on the amounts recognized in the audited annual consolidated financial statements.

Significant estimates primarily relate to fair value estimates and unsettled transactions and events as at the date of the financial statements and accordingly, actual results could differ from the estimates.

Identification of CGUs

The identification of cash generating units ("CGUs") requires judgment. CGUs are defined as the lowest level of integrated assets for which there are separately identifiable cash flows that are largely independent of cash flows from other assets or groups of assets. The classification of assets and allocation of corporate assets into CGUs requires judgment and interpretation. Factors considered in the classification include how management monitors the entity's operations, how management makes decisions about continuing or disposing of assets and operations, and the nature of the assets. Upon assessment of the Royalty Properties, the Company determined it has one CGU.

Business Combinations

Management's judgment is required to determine whether a transaction constitutes a business combination or asset acquisition as determined based on the criteria in IFRS 3, "Business Combinations". Business combinations are accounted for using the acquisition method of accounting and are differentiated from an asset acquisition when business processes are associated with the assets.

Business combinations within the scope of IFRS 3 are accounted for using the acquisition method. The acquired identifiable net assets are measured at their fair value at the date of acquisition. Deferred taxes are recognized for any differences between the fair value and the tax basis of net assets acquired. Any excess of the purchase price over the fair value of the net assets acquired is recognized as goodwill.

Reserve Estimates, Depletion and Impairments

Reserve estimates are not recorded in the Company's financial statements but they can have a significant impact on net earnings, as they are a key input to DD&A calculations. Royalty assets are depleted using the unit-of-production method based on proved and probable reserves. A downward revision in reserve estimates could result in the recognition of a higher DD&A charge to net earnings in future periods. Reserve estimates are also used to determine the fair value of royalty assets that are acquired through asset acquisitions and business combinations.

All of PrairieSky's oil and gas reserves are evaluated and reported on by independent qualified reserves evaluators. The estimation of reserves is a subjective process. Forecasts are based on engineering data, projected future rates of production, estimated commodity price forecasts and future costs, all of which are subject to numerous uncertainties and various interpretations. No future development capital is included in preparing PrairieSky's reserve estimates as the Company has no operational control over the development of the Royalty Properties. The impact of changes to reserves estimates on the Company's financial statements could be material.

The application of the Company's accounting policy to transfer assets from E&E to royalty assets or to expense capitalized E&E assets requires management to make certain judgments based on the estimated proved and probable reserves used in the determination of an area's technical feasibility and commercial viability.

PrairieSky's royalty assets relating to crude oil, NGL and natural gas plus other mineral rights and E&E are aggregated into one CGU. If the carrying value of the CGU exceeds the recoverable amount, the CGU is written down with an impairment recognized in net earnings. The recoverable amount of the CGU is the greater of its fair value less costs of disposal and its value in use. Fair value less costs of disposal is estimated using cash flow multiples from production of same or similar assets. Value in use is determined by estimating the present value of the future net cash flows expected to be derived from continued use of the CGU.

Judgments are required to assess when impairment indicators, or reversal indicators, exist and impairment testing is required with respect to the carrying value of long-term assets. In determining the recoverable amount of assets, in the absence of quoted market prices, impairment tests are based on estimates of reserves, production rates, future crude oil and natural gas prices, future costs, discount rates, cash flow multiples, market value of land and other relevant assumptions.

Reversals of impairments are recognized when there has been a subsequent increase in the recoverable amount. In this event, the carrying amount of the asset or CGU is increased to its revised recoverable amount with an impairment reversal recognized in net earnings. The recoverable amount is limited to the original earnings amount less accumulated depletion as if no impairment had been recognized for the asset or CGU for prior periods.

Oil and Gas Revenue Accruals and Royalty Interests

PrairieSky follows the accrual method of accounting, making estimates in its financial and operating results. This may include estimates of royalty revenues, production and related expenses for the period being reported for which actual results have not yet been received. The Company has no operational control over the Royalty Properties and as a result, the Company uses historical production information to estimate revenue accruals. These accrual estimates are expected to be revised, based on the receipt of actual production results and realized prices.

Share-Based Compensation

The Company's long-term incentive plans include a Stock Option Plan and share unit award plans (RSU, PSU and DSU plans). Obligations for payments of cash or common shares under the Company's long-term incentive plans are accrued over the vesting period using fair values.

For the equity-settled Stock Option Plan, fair values are determined at the grant date and are recognized over the vesting period as compensation costs with a corresponding increase to contributed surplus. When the awards are exercised, the associated contributed surplus is recognized in shareholders' capital. The Company uses the Black-Scholes option pricing model which requires that management make assumptions for the expected life of the option, the anticipated volatility of the share price over the life of the option, the risk-free interest rate for the life of the option, and the number of options that will ultimately vest. Judgments include which valuation is most appropriate to estimate the fair value of awards granted under the Company's Stock Option Plan.

For share unit awards, fair values are determined at grant date and subsequently revalued at each reporting date based on the market value of the Company's common shares and are recognized over the vesting period as compensation costs, with a corresponding change to liabilities. The valuation incorporates the period-end share price, dividends declared during the period, the number of units outstanding at each period end and certain management estimates, such as estimated forfeiture rates and a performance multiplier for PSUs. Judgement is required to determine the peer group used to calculate the total shareholder return under the PSU plan. Classification of the associated short-term and long-term liabilities is dependent on the expected payout dates.

Goodwill

Upon acquisition, goodwill is attributed to the applicable CGU that is expected to benefit from the business combination's synergies. This represents the lowest level that goodwill is monitored for internal management purposes. Subsequent measurement of goodwill is at cost less any accumulated impairments.

Goodwill is assessed for impairment at least annually. Judgement is required to assess when indicators exist, and impairment testing is required more frequently. If the carrying amount for the CGU exceeds the recoverable amount of the CGU, the associated goodwill is written down with an impairment recognized in net earnings. The recoverable amounts are determined annually based on the greater of fair value less costs of disposal or value in use. Goodwill impairments are not reversed.

Income Taxes

Income tax is recognized in net earnings except for items directly related to shareholders' equity, which are recognized in shareholders' equity or other comprehensive income. Current income taxes are measured at the amount expected to be recoverable from or payable to the taxation authorities based on the income tax rates enacted or substantively enacted at the end of the reporting period.

The Company follows the asset and liability method of accounting for income taxes. Under this method, deferred income taxes are recorded for the effect of any temporary difference between the accounting and income tax basis of an asset or liability.

Deferred income tax is calculated using the enacted or substantively enacted income tax rates expected to apply when the assets are realized, or liabilities are settled. The effect of a change in the enacted or substantively enacted tax rates is recognized in net earnings or in shareholders' equity depending on the item to which the adjustment relates.

Deferred income tax liabilities and assets are not recognized for temporary differences arising on:

- the initial recognition of goodwill; or
- the initial recognition of an asset or liability in a transaction which is not a business combination and, at the time of the transaction, affects neither accounting net earnings nor taxable earnings.

Deferred income tax assets are recognized to the extent future recovery is probable. Deferred income tax assets are reduced to the extent that it is no longer probable that sufficient taxable earnings will be available to allow all or part of the asset to be recovered.

RECENT ACCOUNTING PRONOUNCEMENTS

New Standards Issued Not Yet Adopted

On January 13, 2016, the IASB issued IFRS 16, "Leases" which replaces IAS 17 "Leases". The standard is required to be adopted either retrospectively or by recognizing the cumulative effect of initially applying IFRS 16 as an adjustment to opening equity at the date of initial application. IFRS 16 is effective for fiscal years beginning on or after January 1, 2019. Under the new standard, companies will recognize new assets and liabilities, bringing off-balance sheet leasing arrangements with a term of more than 12 months onto the balance sheet unless the underlying asset is of low value. The Company's mineral leases are not within the scope of IFRS 16. The Company intends to adopt IFRS 16 in its financial statements for the annual period beginning on January 1, 2019. The Company does not expect the standard to have a material impact on the financial statements as the office lease is the only lease that will be impacted by the new standard.

CONTROL ENVIRONMENT

The Board, through its Audit Committee, is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal controls. The Audit Committee meets at least quarterly with the Company's external auditors to review accounting, internal control, financial reporting, and audit matters.

DISCLOSURE CONTROLS AND PROCEDURES

Disclosure controls and procedures (DC&P), as defined by National Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings, are designed to provide reasonable assurance that information required to be disclosed in the Company's annual filings, interim filings or other reports filed, or submitted by the Company under securities legislation is recorded, processed, summarized and reported within the time periods specified under securities legislation and include controls and procedures designed to ensure that information required to be so disclosed is accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. The Chief Executive Officer and the Chief Financial Officer evaluated the effectiveness of the design and operation of the Company's DC&P. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the Company's DC&P were effective as at December 31, 2018.

INTERNAL CONTROLS OVER FINANCIAL REPORTING

Internal controls over financial reporting ("ICFR") is a process designed to provide reasonable assurance that all assets are safeguarded, transactions are appropriately authorized and to facilitate the preparation of relevant, reliable and timely information. Because of its inherent limitations, ICFR can only provide reasonable, not absolute, assurance that the objective of the control system is met. There were no changes to PrairieSky's ICFR during the period beginning on January 1, 2018 to December 31, 2018 that have materially affected, or are reasonably likely to materially affect, the Company's ICFR. PrairieSky conducted an evaluation of the effectiveness of the Company's ICFR as at December 31, 2018 based on the Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that as of December 31, 2018, PrairieSky maintained effective ICFR.

SELECTED ANNUAL INFORMATION

(millions, except per share)	**2018**	**2017**	**2016**
Revenues	**$ 273.8**	$ 345.7	$ 224.2
Net Earnings and Comprehensive Income	**79.4**	120.6	20.0
Per Share – basic and diluted	**0.34**	0.51	0.09
Total Assets	**2,816.9**	2,971.7	2,770.3
Dividends Declared	**182.1**	176.2	186.7
Per Share	**0.7750**	0.7450	0.8167

In the past three years, PrairieSky has operated its business by leasing lands to third-parties for crude oil and natural gas development and third-party operations, as well as completing accretive acquisitions which are complementary to PrairieSky's business. Over the three years, fluctuations in realized commodity prices due to changing benchmark prices and widening/narrowing differentials have impacted the Company's royalty revenue. Net earnings have fluctuated due to changes in revenues, including a significant increase in bonus consideration in 2017, as well as increased income tax expense over the past two years. Dividends per share are reviewed and set on an annual basis by the Board each year in February.

SUMMARY OF QUARTERLY RESULTS AND TRENDS

(millions, unless otherwise noted)	Q1 2017	Q2 2017	Q3 2017	Q4 2017	Q1 2018	Q2 2018	Q3 2018	**Q4 2018**
FINANCIAL								
Royalty Revenue	$ 73.5	$ 69.0	$ 54.2	$ 69.2	$ 64.1	$ 70.1	$ 71.4	**$ 42.4**
Other Revenue	6.8	33.2	17.5	22.3	3.8	6.1	6.7	**9.2**
Total Revenues	80.3	102.2	71.7	91.5	67.9	76.2	78.1	**51.6**
Funds from Operations	67.3	75.0	66.8	81.1	51.8	62.4	67.0	**48.5**
Per Share – basic(1)(2)	0.28	0.32	0.28	0.34	0.22	0.27	0.29	**0.21**
Per Share - diluted(1)(2)	0.28	0.32	0.28	0.34	0.22	0.26	0.28	**0.21**
Net Earnings and Comprehensive Income	20.8	40.5	19.4	39.9	19.8	25.1	28.5	**6.0**
Per Share – basic and diluted(1)	0.09	0.17	0.08	0.17	0.08	0.11	0.12	**0.03**
Dividends Declared(3)	43.2	44.5	44.3	44.2	44.7	45.9	45.8	**45.7**
Per Share	0.1825	0.1875	0.1875	0.1875	0.1900	0.1950	0.1950	**0.1950**
Working Capital at Period End	97.6	108.0	98.7	45.7	17.3	21.1	10.6	**(10.4)**
OPERATIONAL								
Production Volumes								
Crude Oil (bbls/d)	10,214	9,609	9,033	9,419	8,731	9,098	9,018	**9,163**
NGL (bbls/d)	2,998	2,664	2,600	2,454	2,388	2,279	2,503	**2,676**
Natural Gas (MMcf/d)	81.6	80.6	75.3	75.2	74.5	69.4	71.5	**70.0**
Total (BOE/d)(4)	26,812	25,706	24,183	24,406	23,536	22,944	23,438	**23,506**

(1) Net Earnings and Comprehensive Income and Funds from Operations per Share are calculated using the weighted average number of common shares outstanding.
(2) A Non-GAAP measure, which is defined under the "Non-GAAP Measures" section of this MD&A.
(3) A dividend of $0.065 per common share was declared on December 11, 2018. The dividend was paid on January 15, 2019 to shareholders of record on December 31, 2018.
(4) See "Conversions of Natural Gas to BOE".

- Quarterly variances in revenues, funds from operations and net earnings are primarily due to fluctuations in realized commodity prices, production volumes, and bonus consideration.

- Crude oil prices are generally determined by global and North American market forces, including supply and demand factors. Changes in the USD-CAD currency exchange rate impact the Company's oil revenue realization relative to benchmark WTI, which is referenced in US dollars. In 2018, realized commodity prices have been negatively impacted by wider differentials for both light and heavy crude oil to WTI due to constrained transportation capacity.

- Natural gas prices are influenced by many variables including weather conditions, industrial demand, and North American natural gas inventories. In Western Canada, transportation constraints further impact natural gas prices.

- Production volumes can be influenced by various factors, including the extent of exploration and development activity by third parties on the Royalty Properties, the timing and amount of capital expenditures, the expertise and financial resources of third-party lessees, acquisition of producing properties and natural declines.

- Other revenue is largely affected by the timing of bonus consideration received when new leases are negotiated, which can vary with the individual terms of each agreement.

- Net earnings are affected by revenues, as noted above, as well as depletion, administrative expense and income taxes. Administrative expense can vary in a period due to the effect of the change in share price on the Company's share-based compensation plans.

- Dividends fluctuate as the number of shares outstanding in the quarter is reduced by share repurchases and cancellations under the NCIB. The dividend is set annually by the Board of Directors by considering budgeted funds from operations for the next year.

- The Company has returned $356.8 million in the form of dividends to shareholders and has purchased 3,206,780 common shares for $87.9 million over the past eight quarters.

- Working capital has decreased as cash on hand was used to complete acquisitions of incremental royalty interests and seismic. Declining prices in Q4 2018 resulted in a decrease in accrued revenue at the end of 2018, resulting in the working capital deficiency at December 31, 2018.

NON-GAAP MEASURES

Certain measures in this MD&A do not have any standardized meaning as prescribed by IFRS and therefore, are considered non-GAAP measures. These measures may not be comparable to similar measures presented by other issuers. These measures are commonly used in the crude oil and natural gas industry and by the Company to provide potential investors with additional information regarding the Company's liquidity and its ability to generate funds to finance its operations. Non-GAAP measures include Operating Netback, Operating Netback per BOE, Funds from Operations per Share - basic and diluted, Cash Administrative Expenses and Cash Administrative Expenses per BOE. Management's use of these measures is discussed further below.

"Operating Netback" represents the cash margin for products sold. Operating Netback is calculated as royalty revenues less production and mineral taxes and administrative expenses. Operating Netback provides a consistent measure of the cash generating performance of the Royalty Properties to assess the comparability of the underlying performance between years.

"Operating Netback per BOE" represents the cash margin for products sold on a BOE basis. Operating Netback per BOE is calculated by dividing the Operating Netback by the production volumes for the period. Operating Netback per BOE is used to assess the cash generating performance per unit of product sold. Operating Netback per BOE measures are commonly used in the crude oil and natural gas industry to assess performance comparability. Refer to the Operating Results table in this MD&A document for a summary of this reporting period's Operating Netback calculations.

"Funds from Operations per Share" are calculated on a weighted average basis using basic and diluted common shares outstanding during the period. This measure, together with other measures, are used by the investment community to assess the source, sustainability and cash available for dividends and share repurchases.

"Cash Administrative Expenses" represents administrative expenses excluding the volatility and fluctuations in share-based compensation expense for RSUs, PSUs and DSUs and stock options that were not settled in cash in the current period. Cash administrative expenses is calculated as total administrative expenses, adjusting for share-based compensation expense (recovery) in the period, plus any actual cash payments made under the RSU, PSU or DSU plans. In Q4 2017 and YE 2017, the Company received a $1.0 million GORR asset as reimbursement for incurred legal and administrative expenses, which was excluded from cash administrative expenses amount in those periods. Management believes cash administrative expenses is a common benchmark used by investors when comparing companies to evaluate operating performance.

"Cash Administrative Expenses per BOE" represents cash administrative expenses on a BOE basis. Cash administrative expenses per BOE is calculated by dividing cash administrative expenses by the production volumes for the period. Cash administrative expenses per BOE assists management and investors in evaluating operating performance on a comparable basis.

FUNDS FROM OPERATIONS PER SHARE CALCULATIONS – BASIC AND DILUTED

The following table presents the computation of Funds from Operations per Share:

(millions, except per share data)	Three months ended December 31 2018	2017	Year ended December 31 2018	2017
Funds from Operations	**$ 48.5**	$ 81.1	**$ 229.7**	$ 290.2
Number of common shares:				
Weighted average common shares outstanding – basic	**234.4**	236.2	**235.1**	236.5
Effect of dilutive securities	**0.3**	0.3	**0.3**	0.2
Weighted average common shares outstanding – diluted	**234.7**	236.5	**235.4**	236.7
Funds from Operations per Share Basic and Diluted	**$ 0.21**	$ 0.34	**$ 0.98**	$ 1.23

CASH ADMINISTRATIVE EXPENSES

The following table presents the computation of Cash Administrative Expenses:

(millions)	Three months ended December 31 2018	2017	Year ended December 31 2018	2017
Total Administrative Expenses	**$ 4.2**	$ 6.5	**$ 20.0**	$ 30.1
Share-Based Compensation recovery (expense)	**0.2**	(1.7)	**1.3**	(9.8)
Cash payments made under RSU and PSU plans	**-**	-	**5.1**	6.4
Non-cash reimbursement for administrative expenses	**-**	1.0	**-**	1.0
Cash Administrative Expenses	**$ 4.4**	$ 5.8	**$ 26.4**	$ 27.7

ADVISORY

FORWARD-LOOKING STATEMENTS

This MD&A includes certain statements regarding PrairieSky's future plans and operations as at February 11, 2019 and contains forward-looking statements that we believe allow readers to better understand our business and prospects. Forward-looking statements contained in this MD&A include our expectations with respect to the following:

- commodity prices including supply and demand factors relating to crude oil, natural gas and NGL;
- expected future commitments and payments related thereto;
- PrairieSky's business and growth strategy and anticipated sources of future income;
- PrairieSky's dividend policy and its intention to distribute the majority of cash flow as dividends to shareholders over time, which intention could change with little or no notice;
- PrairieSky's normal course issuer bid and specifically the volume and value of future repurchases under the normal course issuer bid;
- the manner in which PrairieSky manages collection and credit risk and its belief that the diversity of payors and products mitigate this risk;
- possible revisions to accrued estimates based on receipt of actual results;
- impact of compliance activities and recoveries, which vary quarterly;

- impact of bonus consideration, which varies quarterly;
- the Company's expectations regarding production curtailments in Alberta and the impacts thereof;
- impact of PrairieSky's share price on administrative expenses;
- improvement in realized crude oil pricing subsequent to December 31, 2018;
- expected impacts of accounting standards, including those announced but not yet adopted;
- the expectation that there will be no operating costs, capital costs, environmental liabilities, or abandonment and reclamation obligations associated with development of the Royalty Properties;
- changes to the legislative and regulatory frameworks in the jurisdictions in which the Company carries on a business;
- the ability to mitigate the risks of fluctuations in commodity prices and production volumes, including but not limited to impacts from a slowdown in both natural gas drilling and workover activity and ethane curtailments; and
- average production and contribution from the Royalty Properties including the impact of declines.

By their nature, forward-looking statements are subject to numerous risks and uncertainties, some of which are beyond our control, including the impact of general economic conditions, industry conditions, volatility of commodity prices, lack of pipeline capacity, currency fluctuations, imprecision of reserve estimates, royalties, environmental risks, taxation, regulation, changes in tax or other legislation, political and geopolitical instability, competition from other industry participants, the lack of availability of qualified personnel or management, stock market volatility, and our ability to access sufficient capital from internal and external sources. In addition, PrairieSky is subject to numerous risks and uncertainties in relation to acquisitions. These risks and uncertainties include risks relating to title to the assets acquired and the potential for disputes to arise with third parties, and limited ability to recover indemnification from such third parties under certain agreements. The foregoing and other risks are described in more detail in PrairieSky's Annual Information Form and in this MD&A under the heading "Risk Management".

With respect to forward-looking statements contained in this MD&A, we have made assumptions regarding, among other things, the ability of the lessees and working interest owners on the Royalty Properties to maintain or increase production and reserves from these properties; the ability and willingness of the lessees and working interest owners on the Royalty Properties to comply with, and PrairieSky to enforce, lease terms and contractual provisions, as applicable, in order to receive payments; the ability of the lessees or working interest owners on the Royalty Properties to operate in a safe, efficient and effective manner; the timely receipt of any required regulatory approvals by lessees or working interest owners on the Royalty Properties; the willingness and financial capability of the lessees and working interest owners to continue to develop and invest additional capital in the Royalty Properties; the ability of the lessees and working interest owners on the Royalty Properties to obtain financing on acceptable terms to fund capital expenditures; field production rates, decline rates and the well performance and characteristics of the Royalty Properties; the ability to replace and increase crude oil, natural gas and NGL reserves and production associated with the Royalty Properties through third-party development and complementary acquisitions; the timing, cost and ability of third parties to access, maintain or expand necessary facilities and/or secure adequate product transportation and storage; the ability of the operators of the properties in which PrairieSky has a royalty interest in to successfully market their respective petroleum and natural gas products or, for royalty payments taken-in-kind by PrairieSky, the ability of PrairieSky or a third-party marketer to successfully market PrairieSky's in-kind petroleum and natural gas products; surface rights access being granted to third parties on PrairieSky's properties; the benefits of the seismic data anticipated to be used by PrairieSky and sub-licensed to lessees on the PrairieSky properties; the level of costs and expenses to be incurred by PrairieSky, including with respect to interest, administrative expenses and income taxes; the ability of PrairieSky to obtain and retain qualified staff and services in a timely and cost efficient manner; the absence of any material litigation or claims against or involving PrairieSky; the general stability of the economic and political environment and the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which PrairieSky has an interest in crude oil and natural gas properties; future crude oil, natural gas and NGL prices and currency, exchange and interest rates; and PrairieSky's ability execute the volume and/or value of purchases as described under the normal course issuer bid.

Readers are cautioned that the assumptions used in the preparation of such forward-looking information and statements, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. Our actual results, performance, or achievement could differ materially from those expressed in, or implied by, these forward-looking statements. We can give no assurance that any of the events anticipated will transpire or occur, or if any of them do, what benefits we will derive from them. Statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment, based on certain estimates and assumptions that the reserves described can be profitably produced in the future. Readers are cautioned that the foregoing lists of factors are not exhaustive.

Any forward-looking statement is made only as of the date of this MD&A, and PrairieSky undertakes no obligation to update or revise any forward-looking statement or statements to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events, except as required by applicable securities laws. New factors emerge from time to time, and it is not possible for PrairieSky to predict all of these factors or to assess in advance the impact of each such factor on PrairieSky's business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statements.

The forward-looking information contained in this MD&A is expressly qualified by this cautionary statement.

You are further cautioned that the preparation of consolidated 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 earnings, as further information becomes available and as the economic environment changes.

CONVERSIONS OF NATURAL GAS TO BOE

To provide a single unit of production for analytical purposes, natural gas production and reserves volumes are converted mathematically to equivalent barrels of oil (BOE). We use the industry-accepted standard conversion of six thousand cubic feet of natural gas to one barrel of oil (6 Mcf = 1 bbl). The 6:1 BOE ratio is based on an energy equivalency conversion method primarily applicable at the burner tip. It does not represent a value equivalency at the wellhead and is not based on either energy content or current prices. While the BOE ratio is useful for comparative measures and observing trends, it does not accurately reflect individual product values and might be misleading, particularly if used in isolation. As well, given that the value ratio, based on the current price of crude oil to natural gas, is significantly different from the 6:1 energy equivalency ratio, using a 6:1 conversion ratio may be misleading as an indication of value.

CURRENCY AND REFERENCES TO PRAIRIESKY

All information included in this MD&A, and the audited annual consolidated financial statements is shown on a Canadian dollar basis.

For convenience, references in this document to the "Company", "we", "us", "our", and "its" may, where applicable, refer only to PrairieSky.

ADDITIONAL INFORMATION

Additional information about PrairieSky, including the 2018 audited annual consolidated financial statements and notes thereto, and PrairieSky's Annual Information Form, is available on SEDAR at www.sedar.com or PrairieSky's website at www.prairiesky.com.