MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE YEARS ENDED DECEMBER 31, 2025 AND 2024

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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 and related notes as at and for the years ended December 31, 2025 and 2024 ("audited annual consolidated financial statements"). This MD&A has been prepared as of February 9, 2026. 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 MD&A to the "Company", "we", "us", "our", and "its" may, where applicable, refer only to PrairieSky.

The audited annual consolidated financial statements and comparative information have been prepared in Canadian dollars and in accordance with IFRS Accounting Standards as issued by the International Accounting Standards Board ("IASB") and also referred to in this MD&A as Generally Accepted Accounting Principles ("GAAP"). PrairieSky receives royalty income on production; as such, the production volumes are equivalent on a gross and net basis.

Certain measures and ratios in this document do not have any standardized meaning as prescribed by IFRS Accounting Standards and, therefore, are considered non-GAAP measures and ratios. Non-GAAP measures and ratios are commonly used in the oil and natural 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 and ratios include operating netback, operating netback per BOE, operating margin, cash administrative expenses, cash administrative expenses per BOE and dividend payout ratio. Further information can be found in the Non-GAAP Measures and Ratios section of this MD&A.

Readers should also read the Advisory section located at the end of this MD&A, which provides information on forward-looking statements, conversions of natural gas to BOE, abbreviations and definitions, and additional information.

FINANCIAL AND OPERATIONAL RESULTS

($ millions, except $ per share or as otherwise noted)	Three months ended December 31 2025	Three months ended December 31 2024	Year ended December 31 2025	Year ended December 31 2024
FINANCIAL				
Royalty production revenue	**102.9**	115.6	**441.7**	465.8
Other revenue	**8.8**	20.0	**36.5**	43.4
Revenues	**111.7**	135.6	**478.2**	509.2
Funds from operations	**80.5**	99.0	**353.0**	380.5
Per share - basic and diluted(1)	**0.35**	0.41	**1.50**	1.59
Net earnings	**44.4**	60.2	**205.0**	215.3
Per share - basic and diluted(1)	**0.19**	0.25	**0.87**	0.90
Dividends declared(2)	**60.5**	59.9	**243.4**	239.0
Per share	**0.26**	0.25	**1.04**	1.00
Dividend payout ratio(3)	**75%**	61%	**69%**	63%
Acquisitions - including non-cash consideration(4)	**19.9**	31.5	**99.9**	57.3
Net debt(5)	**276.5**	134.9	**276.5**	134.9
Common share repurchases, inclusive of all costs	**-**	-	**161.7**	-
Shares outstanding (millions)				
Shares outstanding at period end	**232.7**	239.0	**232.7**	239.0
Weighted average - basic and diluted	**232.7**	239.0	**235.2**	239.0
OPERATIONAL				
Royalty production volumes				
Crude oil (bbls/d)	**13,750**	13,317	**13,940**	13,125
NGL (bbls/d)	**2,915**	2,482	**2,498**	2,378
Natural gas (MMcf/d)	**55.8**	55.1	**56.5**	58.1
Royalty Production (BOE/d)(6)	**25,965**	24,982	**25,855**	25,186
Realized pricing				
Crude oil ($/bbl)	**66.10**	81.66	**74.34**	84.12
NGL ($/bbl)	**36.51**	40.68	**38.21**	43.28
Natural gas ($/Mcf)	**1.85**	1.23	**1.39**	1.13
Total ($/BOE)(6)	**43.08**	50.30	**46.80**	50.53
Operating netback per BOE ($)(7)	**36.68**	45.86	**41.17**	45.82
Funds from operations per BOE ($)	**33.70**	43.07	**37.41**	41.28
Oil price benchmarks				
West Texas Intermediate (WTI) (US$/bbl)	**59.14**	70.27	**64.81**	75.72
Edmonton light sweet ($/bbl)	**76.57**	94.90	**85.63**	97.55
Western Canadian Select (WCS) crude oil differential to WTI (US$/bbl)	**(11.20)**	(12.55)	**(11.13)**	(14.76)
Natural gas price benchmarks				
AECO Monthly Index ($/Mcf)	**2.34**	1.46	**1.86**	1.44
AECO Daily Index ($/Mcf)	**2.23**	1.48	**1.68**	1.46
Foreign exchange rate (US$/CAD$)	**0.7169**	0.7147	**0.7154**	0.7299

(1) Funds from operations and net earnings per share are calculated using the weighted average number of basic and diluted common shares outstanding.
(2) A dividend of $0.26 per common share was declared on December 2, 2025. The dividend was paid on January 15, 2026 to shareholders of record as at December 31, 2025.
(3) Dividend payout ratio is defined under the "Non-GAAP Measures and Ratios" section in this MD&A.
(4) Excluding right-of-use asset additions.
(5) See Note 15 "Capital Management" in the audited annual consolidated financial statements and the section "Capital Management" contained in this MD&A.
(6) See "Conversions of Natural Gas to BOE" in this MD&A.
(7) Operating Netback per BOE is defined under the "Non-GAAP Measures and Ratios" section in this MD&A.

Results Overview

HIGHLIGHTS

Highlights of PrairieSky's financial results for the three months ended December 31, 2025 ("Q4 2025") include:

- Royalty production averaged 25,965 BOE per day (64% liquids), including oil royalty production of 13,750 barrels per day, which increased 3% over the three months ended December 31, 2024 ("Q4 2024") and NGL royalty production of 2,915 barrels per day, an increase of 17% over Q4 2024.
- Revenues totaled $111.7 million and consisted of $102.9 million of royalty production revenue, $2.7 million of lease rental income, $4.3 million of lease bonus consideration and $1.8 million of other income. Lease bonus consideration was earned on entering into 46 new leasing arrangements with 36 different counterparties.
- Funds from operations totaled $80.5 million ($0.35 per share, basic and diluted).
- Dividends declared of $60.5 million ($0.26 per share) in Q4 2025, representing a dividend payout ratio of 75%.
- Completed acquisitions during the quarter totaling $19.9 million, primarily of producing and non-producing GORR Interests targeting light oil plays in Central and Southern Alberta, including the West Shale Basin Duvernay and Basal Quartz.
- On February 9, 2026, PrairieSky announced a 2% increase in its annual dividend policy to $1.06 per common share, to be paid on a quarterly basis ($0.265 per common share quarterly). The Board of Directors (the "Board") has approved the first quarter 2026 dividend of $0.265 per common share effective for the March 31, 2026 record date.

Highlights of PrairieSky's financial results for the year ended December 31, 2025 ("YE 2025") include:

- Royalty production averaged 25,855 BOE per day (64% liquids), including oil royalty production of 13,940 barrels per day, which increased 6% over the year ended December 31, 2024 ("YE 2024") and NGL royalty production of 2,498 barrels per day, a 5% increase over YE 2024.
- Revenues totaled $478.2 million and consisted of $441.7 million of royalty production revenue, $7.4 million of lease rental income, $22.6 million of lease bonus consideration and $6.5 million of other income. Lease bonus consideration was earned on entering into 189 new leasing arrangements with 90 different counterparties.
- Funds from operations totaled $353.0 million ($1.50 per share, basic and diluted).
- Dividends declared of $243.4 million ($1.04 per share) for YE 2025, representing a dividend payout ratio of 69%.
- Purchased and cancelled 6,239,507 common shares at a weighted average price of $25.40 per share for total consideration of $158.5 million, including commissions and before tax, under the Company's normal course issuer bid ("NCIB").
- Completed acquisitions during the year totaling $99.9 million which included the purchase of Fee Lands, Lessor Interests and GORR Interests primarily in Central Alberta and Southeast Saskatchewan for cash consideration of $50.4 million, after customary closing adjustments, from a private company (the "Private Co. Royalty Acquisition") which closed on January 10, 2025, as well as incremental royalties targeting both light and heavy oil lands in Alberta and Saskatchewan.

PrairieSky’s 2026 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. Activity on PrairieSky's Royalty Properties (as defined below) was focused on oil plays across Alberta and Saskatchewan throughout 2025, including in the West Shale Basin light oil Duvernay play and the Clearwater and Mannville low-cost heavy oil plays where third-party operators are using multilateral drilling techniques. Based on current third-party operator plans, PrairieSky anticipates continued activity in these plays in 2026 and beyond; however, the level of activity on these plays and across Western Canada will be dependent on commodity pricing, which in turn is subject to many market factors including geopolitical uncertainty that can lead to fluctuations in demand, global trade and financial markets. Weaker benchmark pricing and wider differentials to benchmarks may result in the slowdown of drilling activity by third-party operators on PrairieSky's Royalty Properties along with lower royalty revenue. PrairieSky’s management continues to monitor commodity prices, industry activity levels and anticipated third-party capital expenditures for 2026 and beyond. Further, adverse changes in trade relations between Canada and the United States, may result in tariffs or other restrictive trade measures being implemented, the result of which may affect the demand and/or market price for commodities. PrairieSky is insulated from many direct inflationary pressures as we have no capital program or field operating costs; however, PrairieSky may be impacted indirectly as third-party operators review and adjust their capital programs to respond to incremental costs, or as inflationary pressures may impact the economic returns achievable on certain projects. Although PrairieSky has no operational control over third-party capital expenditures, making it difficult to predict activity levels and the timing thereof, our expansive royalty land position provides diversification of exposure to producers and plays across Western Canada.

PrairieSky’s Strategy

PrairieSky's objective is to generate significant cash flow and returns for shareholders through indirect 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, drilling commitments and other terms and conditions); (iii) managing controllable costs; and (iv) selectively pursuing strategic business development opportunities that are accretive to shareholders over the short, medium and long-term and are relatively low risk to the Company. The Company is focused on creating per share value for shareholders, including but not limited to distributing cash flow to shareholders in the form of dividends and opportunistic share repurchases and cancellations over time.

PrairieSky remains disciplined in its strategy and business model which provides robust operating margins in all commodity cycles. 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 has consistently maintained a strong balance sheet and employs a conservative capital structure. On February 9, 2026, PrairieSky announced a 2% increase to its annual dividend policy to $1.06 per common share ($0.265 per common share quarterly). The Board has approved the first quarter 2026 dividend effective for the March 31, 2026 record date.

Business Overview

PRAIRIESKY ROYALTY

PrairieSky’s asset base includes a geologically and geographically diverse portfolio of Fee Lands (as defined herein) that encompasses approximately 9.9 million acres with petroleum and/or natural gas rights and approximately 8.7 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 lands prospective for crude oil, natural gas, NGL and other minerals located predominantly in Central and Southern Alberta and 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) oil and natural gas overriding royalty interests, gross overriding royalty interests, net profit interests and production payments ("GORR Interests") on lands ("GORR Lands") across Western Canada.

As stated in "PrairieSky's Strategy" above, the Company is focused on encouraging third parties to actively develop the Royalty Properties and growing our royalty ownership by strategically seeking additional royalty assets that provide PrairieSky with medium-term to long-term value enhancement potential. PrairieSky has focused its activities over a number of years on growing its land base in areas where multilateral drilling technologies are being used to develop highly economic oil plays which PrairieSky expects will result in significant value potential over a number of years. The Company does not directly conduct operations to explore for, develop or produce crude oil, NGL or natural gas; rather, third-party development of the Royalty Properties provides the Company with royalty production revenues as crude oil, NGL and natural gas are produced from such properties. PrairieSky's operations include royalty income earned through crude oil, NGL and natural gas produced on the Royalty Properties, as well as upfront bonus consideration earned on entering into new leases and annual rental fees to maintain leases. The Company's royalty production 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 and upon which operators pay overriding royalties.

Oil and natural gas royalty structures are typically linked directly to production volumes from the Royalty Properties, 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. 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, geopolitical risks and international conflicts, and macroeconomic events. 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 field operations, and the expertise and financial resources of third-party lessees, as well as other factors such as seasonal weather impacts and from time to time, the effects of severe weather events and natural disasters, including forest fires. The Company is able to mitigate some of these risks to the extent that there is a diversity of third parties exploring and developing the Royalty Properties, with a balanced production mix of crude oil, natural gas and NGL, and by maintaining a low-cost business with a conservative and sustainable capital structure and actively managing the Company's fee title lands to maximize operator activities on our lands.

At December 31, 2025, PrairieSky earned royalty production revenue from approximately 42,000 wells and received payments from approximately 335 different industry payors. The Company received approximately 75% of its monthly revenue from 27 payors. Royalties are calculated on a fixed percentage, step or sliding scale formula. Some royalty agreements allow for the deduction of certain handling, processing and transportation costs.

As a royalty owner, PrairieSky does not bear the operational risks typically associated with the upstream oil and natural gas exploration and production business. Capital, operational expenses and abandonment costs are the responsibility of the third parties conducting these operations on the Royalty Properties. Substantially all capital expenditures made by PrairieSky are discretionary. Costs incurred by the Company are primarily production and mineral taxes, administrative expenses, finance expenses and corporate income taxes.

Royalty Production

ROYALTY PRODUCTION VOLUMES

	Three months ended December 31			Year ended December 31		
(Average daily)	2025	2024	% Change	2025	2024	% Change
Crude oil (bbls/d)	**13,750**	13,317	**3**	**13,940**	13,125	**6**
NGL (bbls/d)	**2,915**	2,482	**17**	**2,498**	2,378	**5**
Natural gas (MMcf/d)	**55.8**	55.1	**1**	**56.5**	58.1	**(3)**
Total royalty production (BOE/d)	**25,965**	24,982	**4**	**25,855**	25,186	**3**

PrairieSky's average daily royalty production volumes for Q4 2025 were comprised of 53% crude oil, 11% NGL and 36% natural gas as compared to Q4 2024 when the royalty production volume split was 53% crude oil, 10% NGL and 37% natural gas. PrairieSky's average daily royalty production volumes for YE 2025 were comprised of 54% crude oil, 10% NGL and 36% natural gas as compared to YE 2024 when the royalty production volume split was 52% crude oil, 10% NGL and 38% natural gas. There is a natural delay between the timing of production and when PrairieSky collects its royalty production volumes and revenue from operators. In addition, PrairieSky's compliance department continually reviews leasing agreements and royalty calculations. Due to the natural delay and compliance review process, positive and negative adjustments related to prior periods may be included in PrairieSky's royalty production volumes and/or revenue.

PrairieSky's crude oil, NGL and natural gas royalty production volumes are primarily marketed with lessees' or operators' production. The Company actively reviews its counterparties and takes certain royalty production 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 three months ended December 31, 2025

Royalty production volumes averaged 25,965 BOE per day for Q4 2025, an increase of 4% from Q4 2024 royalty production volumes of 24,982 BOE per day. A breakdown of changes by product is as follows:

- Average crude oil royalty production volumes for Q4 2025 of 13,750 barrels per day increased 3% from 13,317 barrels per day for Q4 2024 with organic growth from new wells on stream more than offsetting natural declines. The Clearwater heavy oil and the Duvernay light oil plays were the strongest contributors to the growth in royalty volumes, partially offset by lower thermal oil royalty volumes.
- Average NGL royalty production volumes for Q4 2025 of 2,915 barrels per day increased 17% from Q4 2024 production volumes of 2,482 barrels per day with growth driven by activity in the Duvernay light oil play and the Montney liquids-rich natural gas play.
- Average natural gas royalty production volumes for Q4 2025 of 55.8 MMcf per day remained relatively consistent with Q4 2024 production volumes of 55.1 MMcf per day with new wells on stream being partially offset by natural declines.

For the year ended December 31, 2025

Royalty production volumes averaged 25,855 BOE per day for YE 2025, a 3% increase over YE 2024 royalty production volumes of 25,186 BOE per day. A breakdown of changes by product is as follows:

- Average crude oil royalty production volumes for YE 2025 of 13,940 barrels per day increased 6% from 13,125 barrels per day for YE 2024 primarily as a result of organic growth from new wells on stream which more than offset natural declines. Year over year oil royalty production grew in a number of plays, including the Clearwater heavy oil play, the Mannville heavy oil play and the Duvernay light oil play. These increases were partially offset by lower thermal oil royalty volumes.

- Average NGL royalty production volumes for YE 2025 of 2,498 barrels per day increased 5% from YE 2024 royalty production volumes of 2,378 barrels per day due to organic growth in the Duvernay light oil play and in the Montney liquids-rich natural gas play in the second half of the year.
- Average natural gas royalty production volumes for YE 2025 of 56.5 MMcf per day decreased 3% from 58.1 MMcf per day for YE 2024 as natural declines offset the positive impact of new wells on stream.

Financial Results

OPERATING RESULTS

	Three months ended December 31, 2025		Three months ended December 31, 2024	
	($ millions)	**($/BOE)[2]**	**($ millions)**	**($/BOE)[2]**
Royalty production revenue	**102.9**	**43.08**	115.6	50.30
Production and mineral taxes	**(1.2)**	**(0.50)**	(1.2)	(0.52)
Cash administrative expenses[1]	**(14.1)**	**(5.90)**	(9.0)	(3.92)
Operating netback[1]	**87.6**	**36.68**	105.4	45.86
Operating margin[1]	**85%**	**85%**	91%	91%

	Year ended December 31, 2025		Year ended December 31, 2024	
	($ millions)	**($/BOE)[2]**	**($ millions)**	**($/BOE)[2]**
Royalty production revenue	**441.7**	**46.80**	465.8	50.53
Production and mineral taxes	**(4.5)**	**(0.48)**	(3.9)	(0.42)
Cash administrative expenses[1]	**(48.6)**	**(5.15)**	(39.5)	(4.29)
Operating netback[1]	**388.6**	**41.17**	422.4	45.82
Operating margin[1]	**88%**	**88%**	91%	91%

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

The Q4 2025 operating netback of $87.6 million ($36.68 per BOE) decreased 17% from $105.4 million ($45.86 per BOE) in Q4 2024. The Q4 2025 operating margin of 85% decreased 6% from Q4 2024 due to lower US$ WTI benchmark pricing, which negatively impacted crude oil royalty production revenue and higher cash administrative expenses, as further discussed below.

The YE 2025 operating netback of $388.6 million ($41.17 per BOE) decreased 8% from $422.4 million ($45.82 per BOE) in YE 2024. The YE 2025 operating margin of 88% decreased 3% driven by lower US$ WTI benchmark pricing negatively impacting oil royalty production revenue and higher cash administrative expenses as further discussed below.

REVENUE

($ millions) Royalty production revenue by product	Three months ended December 31 2025	2024	% Change	Year ended December 31 2025	2024	% Change
Crude oil	**83.6**	100.0	**(16)**	**378.2**	404.1	**(6)**
NGL	**9.7**	9.3	**4**	**34.8**	37.7	**(8)**
Natural gas	**9.6**	6.3	**52**	**28.7**	24.0	**20**
	102.9	115.6	**(11)**	**441.7**	465.8	**(5)**
Other revenue						
Lease rental income	**2.7**	3.2	**(16)**	**7.4**	8.1	**(9)**
Bonus consideration	**4.3**	15.8	**(73)**	**22.6**	30.8	**(27)**
Other income	**1.8**	1.0	**80**	**6.5**	4.5	**44**
	8.8	20.0	**(56)**	**36.5**	43.4	**(16)**
Revenues	**111.7**	135.6	**(18)**	**478.2**	509.2	**(6)**

($ millions) Revenues by classification	Three months ended December 31 2025	2024	Year ended December 31 2025	2024
Lessor Interests on Fee Lands	**61.8**	74.9	**273.5**	305.2
GORR Interests	**41.1**	40.7	**168.2**	160.6
Royalty production revenue	**102.9**	115.6	**441.7**	465.8
Other revenue	**8.8**	20.0	**36.5**	43.4
Revenues	**111.7**	135.6	**478.2**	509.2

Pricing	Three months ended December 31 2025	2024	% Change	Year ended December 31 2025	2024	% Change
Benchmark						
WTI (US$/bbl)	**59.14**	70.27	**(16)**	**64.81**	75.72	**(14)**
Edmonton light sweet ($/bbl)	**76.57**	94.90	**(19)**	**85.63**	97.55	**(12)**
WCS differential to WTI (US$/bbl)	**(11.20)**	(12.55)	**(11)**	**(11.13)**	(14.76)	**(25)**
AECO Monthly Index ($/Mcf)	**2.34**	1.46	**60**	**1.86**	1.44	**29**
AECO Daily Index ($/Mcf)	**2.23**	1.48	**51**	**1.68**	1.46	**15**
Foreign exchange rate (US$/CAD$)	**0.7169**	0.7147	**-**	**0.7154**	0.7299	**(2)**

Realized pricing	Three months ended December 31 2025	2024	% Change	Year ended December 31 2025	2024	% Change
Crude oil ($/bbl)	**66.10**	81.66	**(19)**	**74.34**	84.12	**(12)**
NGL ($/bbl)	**36.51**	40.68	**(10)**	**38.21**	43.28	**(12)**
Natural gas ($/Mcf)	**1.85**	1.23	**50**	**1.39**	1.13	**23**
Total ($/BOE)	**43.08**	50.30	**(14)**	**46.80**	50.53	**(7)**

The Company's average royalty rate for all producing wells on the Royalty Properties was approximately 5.8% for Q4 2025 (Q4 2024 - 6.1%). The decrease in the average royalty rate is primarily attributable to a higher proportion of revenue from GORR Interests, which generally bear lower royalty rates than Lessor Interests on Fee Lands. During Q4 2025, royalty production revenue was $102.9 million, as compared to $115.6 million for Q4 2024, a decrease of 11% driven by lower US$ WTI benchmark pricing. The impacts on realized pricing are further detailed below.

During Q4 2025, revenue from Lessor Interests on Fee Lands was $61.8 million or 60% of total royalty production revenue and revenue from GORR Interests was $41.1 million or 40% of total royalty production revenue. During the prior year comparative period, $74.9 million or 65% of total royalty production revenue was generated from Lessor Interests on Fee Lands and $40.7 million or 35% from GORR Interests. In addition to royalty production revenue from Lessor Interests, all lease rental income and bonus consideration is generated from Fee Lands.

The Company’s average royalty rate for all producing wells on the Royalty Properties was approximately 5.9% for YE 2025 (YE 2024 - 6.1%). The decrease in the average royalty rate is primarily attributable to a higher proportion of revenue from GORR Interests, which generally bear lower royalty rates than Lessor Interests on Fee Lands. During YE 2025, royalty production revenue was $441.7 million as compared to $465.8 million for YE 2024, a decrease of 5% driven by lower US$ WTI benchmark pricing. The impacts on realized pricing are further detailed below.

During YE 2025, revenue from Lessor Interests on Fee Lands was $273.5 million or 62% of total royalty production revenue and revenue from GORR Interests was $168.2 million or 38% of total royalty production revenue. During the prior year comparative period, $305.2 million or 66% of total royalty production revenue was generated from Lessor Interests on Fee Lands and $160.6 million or 34% from GORR Interests. In addition to royalty production revenue from Lessor Interests, all lease rental income and bonus consideration is generated from Fee Lands.

The Company's overall realized pricing of $43.08 per BOE in Q4 2025 decreased 14% from Q4 2024. Realized oil pricing averaged $66.10 per barrel, down 19% from Q4 2024, as the 16% decrease in average US$ WTI crude oil benchmark pricing was further impacted by wider light oil differentials to WTI and only partially offset by narrowed heavy oil price differentials to WTI. Q4 2025 realized NGL pricing of $36.51 per barrel decreased 10% from Q4 2024 due to lower benchmark pricing. Pricing for NGLs were positively impacted by the growth in condensate volumes which partially offset lower benchmark pricing. Realized natural gas pricing of $1.85 per Mcf increased 50% in Q4 2025 as compared to Q4 2024 due to stronger AECO benchmark pricing.

The Company's overall realized pricing of $46.80 per BOE for YE 2025 decreased 7% from YE 2024. Realized oil pricing averaged $74.34 per barrel, down 12% from YE 2024, as the 14% decrease in average US$ WTI crude oil benchmark pricing more than offset narrowed light and heavy oil differentials to WTI and a weaker Canadian dollar relative to the US dollar. YE 2025 realized NGL pricing of $38.21 per barrel decreased 12% from YE 2024 due to lower benchmark pricing. Realized natural gas pricing of $1.39 per Mcf increased 23% for YE 2025 as compared to YE 2024 due to stronger AECO benchmark pricing.

Royalty compliance recoveries are the cash payments received as a result of the extensive process of identifying, analyzing and collecting payments from royalty payors. Cash received from compliance recoveries can relate to the current or prior period. Compliance recoveries are not recorded until collection of outstanding amounts is certain or overpayments are validated. Compliance recoveries totaled $2.8 million for Q4 2025 (Q4 2024 - $1.7 million) and $8.3 million for YE 2025 (YE 2024 - $7.5 million). Compliance recoveries are included in royalty production revenue for the period.

Other revenue consisted primarily of lease bonus consideration and lease rentals from new and historical leasing arrangements on Fee Lands. Lease rental income for Q4 2025 and YE 2025 was $2.7 million (Q4 2024 - $3.2 million) and $7.4 million (YE 2024 - $8.1 million), respectively. Lease bonus consideration revenue for Q4 2025 and YE 2025 was $4.3 million (Q4 2024 - $15.8 million) and $22.6 million (YE 2024 - $30.8 million), respectively, as industry continued to add acreage to their drilling inventory. Included in Q4 2024 bonus consideration was $8.2 million in non-cash consideration received related to issuing a new lease in exchange for a non-producing GORR Interest in a Mannville heavy oil play. During Q4 2025, lease bonus consideration was earned on entering into 46 new leasing arrangements (Q4 2024 - 60 new leasing arrangements) with 36 counterparties (Q4 2024 - 47 counterparties). During YE 2025, lease bonus consideration was earned on entering into 189 new leasing arrangements (YE 2024 - 219 new leasing arrangements) with 90 counterparties (YE 2024 - 101 counterparties). Both the amount and timing of lease bonus consideration revenue can vary significantly from period to period as it relates to the unique circumstances of each transaction. Other income totaled $1.8 million for Q4 2025 (Q4 2024 - $1.0 million) with the increase over Q4 2024 attributable to increased pipeline royalty income. Other income totaled $6.5

million for YE 2025 (YE 2024 - $4.5 million) with the increase over YE 2024 related to interest income associated with a funding arrangement established in Q4 2024 and concluding in Q4 2025 and increased pipeline royalty income.

ADMINISTRATIVE EXPENSES

	Three months ended December 31		Year ended December 31	
($ millions, except per BOE amounts)	**2025**	**2024**	**2025**	**2024**
Salaries and benefits	**5.2**	5.8	**18.7**	17.6
Share-based compensation	**3.5**	3.9	**9.0**	21.2
Office expense	**0.8**	0.8	**3.5**	3.2
Public company expense	**0.2**	0.2	**2.1**	2.1
Information technology	**0.7**	0.6	**3.4**	2.9
Total administrative expenses	**10.4**	11.3	**36.7**	47.0
Administrative expenses per BOE ($)(1)	**4.35**	4.92	**3.89**	5.10
Total administrative expenses	**10.4**	11.3	**36.7**	47.0
Share-based compensation expense	**(3.5)**	(3.9)	**(9.0)**	(21.2)
Cash payments made – share unit plans	**7.2**	1.6	**20.9**	13.7
Total cash administrative expenses(2)	**14.1**	9.0	**48.6**	39.5
Cash administrative expenses per BOE ($)(1)(2)	**5.90**	3.92	**5.15**	4.29

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

Administrative expenses for Q4 2025 were $4.35 per BOE as compared to $4.92 per BOE in Q4 2024 due to decreases in salaries and benefits and share-based compensation expense as further discussed below. Administrative expenses for YE 2025 were $3.89 per BOE (YE 2024 - $5.10 per BOE). The decrease in administrative expenses for YE 2025 from YE 2024 is primarily a result of lower share-based compensation expense which more than offset increases in salaries and benefits, office expense and information technology.

Administrative expenses include both cash and non-cash charges which relate to share-based compensation plans. When cash share-based compensation payouts are made, there is an increase in cash administrative expenses in the period. Cash administrative expenses for Q4 2025 were $14.1 million ($5.90 per BOE) as compared to Q4 2024 cash administrative expenses of $9.0 million ($3.92 per BOE), primarily as a result of the redemptions of deferred share units ("DSUs") as further discussed below.

The increase in cash administrative expenses for YE 2025 as compared to YE 2024 was driven by $7.2 million of DSU redemptions for two retired directors (YE 2024 - $2.3 million for two retired directors) and higher annual long-term incentive payouts as a result of strong share price performance from the date of grant to the date of vesting. Cash administrative expenses for YE 2025 were $5.15 per BOE, as compared to YE 2024 cash administrative expenses of $4.29 per BOE.

For more information, see the Company's Information Circular and Proxy Statement dated March 12, 2025, which is available on SEDAR+ at www.sedarplus.ca or the Company's website at www.prairiesky.com.

($ millions)	Three months ended December 31		Year ended December 31	
Share-based compensation	**2025**	**2024**	**2025**	**2024**
PSU expense	**1.5**	2.4	**4.5**	11.3
RSU expense	**0.5**	0.4	**1.7**	2.0
ODSU expense	**0.9**	0.7	**1.9**	3.5
DSU expense	**0.6**	0.4	**0.9**	4.4
Share-based compensation expense	**3.5**	3.9	**9.0**	21.2

Administrative expenses related to restricted share units ("RSUs"), preferred share units ("PSUs"), officer deferred share units ("ODSUs") and DSUs are impacted by the closing share price at period end and as such, are subject to variability. The common share price used in the fair value calculation of share-based compensation at December 31, 2025 was $27.03, as compared to $28.03 at December 31, 2024. Share-based compensation expense is calculated based on the change in the share price in the period and the number of outstanding share-based awards at period end, with an estimate of the ultimate performance multiplier applied to PSUs. There are no outstanding units under any employee, officer or director incentive plan that can be settled in common shares at December 31, 2025.

PRODUCTION AND MINERAL TAXES

	Three months ended December 31		Year ended December 31	
($ millions, except per BOE amounts)	**2025**	**2024**	**2025**	**2024**
Production and mineral taxes	**1.2**	1.2	**4.5**	3.9
$/BOE(1)	**0.50**	0.52	**0.48**	0.42

(1) See "Conversions of Natural Gas to BOE" in this MD&A.

Production and mineral taxes are levied on an annual basis. In Alberta, the Freehold Mineral Tax is calculated with a formula based on price and production volumes in the province; whereas, in Saskatchewan there is an acreage tax based on a flat per acre amount for non-Crown lands.

Q4 2025 and YE 2025 production and mineral taxes were 1.2% (Q4 2024 - 1.0%) and 1.0% (YE 2024 - 0.8%), respectively, of royalty production revenue. The increase over the prior year comparative periods were a result of variances related to price and production and the addition of incremental Fee Lands in the year.

Production and mineral taxes are based on an annual estimate which can result in variances from quarter to quarter based on commodity prices, changes in royalty production volumes and incremental acreage acquired, if any.

DEPLETION, DEPRECIATION AND AMORTIZATION ("DD&A")

	Three months ended December 31		Year ended December 31	
($ millions, except per BOE amounts)	**2025**	**2024**	**2025**	**2024**
Depletion, depreciation and amortization	**36.8**	36.3	**150.4**	147.0
$/BOE(1)	**15.41**	15.79	**15.94**	15.95

(1) See "Conversions of Natural Gas to BOE" in this MD&A.

The Company depletes its royalty assets using the unit-of-production method based on the total proved and probable reserves of its Royalty Properties. DD&A expense increased in Q4 2025 and YE 2025 as compared to Q4 2024 and YE 2024 due to higher royalty production. DD&A per BOE decreased in Q4 2025 due to a smaller change in the depletable base relative to the change in reserves. DD&A per BOE for YE 2025 remained relatively flat with the prior year. DD&A per BOE will fluctuate depending on the royalty assets acquired, if any, the transfers from exploration and evaluation assets and the amount of reserves added.

EXPLORATION AND EVALUATION EXPENSE ("E&E")

	Three months ended December 31		Year ended December 31	
($ millions, except per BOE amounts)	**2025**	**2024**	**2025**	**2024**
Exploration and evaluation expense	**0.9**	7.8	**4.2**	18.5
$/BOE(1)	**0.38**	3.39	**0.45**	2.01

(1) See "Conversions of Natural Gas to BOE" in this MD&A.

During Q4 2025 and YE 2025, $0.9 million (Q4 2024 - $7.8 million) and $4.2 million (YE 2024 - $18.5 million), respectively, of costs associated with expired Crown mineral leases and GORR Interests were recognized as an expense. The expense will vary period to period as a result of the timing of lease expiries, if any.

FINANCE

	Three months ended December 31		Year ended December 31	
($ millions)	**2025**	**2024**	**2025**	**2024**
Finance expense	**3.9**	2.3	**13.3**	12.2
Effective interest rate	**6.1%**	5.5%	**5.7%**	6.1%

Finance expense of $3.9 million in Q4 2025 increased from $2.3 million in Q4 2024 as a result of a higher bank debt balance and fees related to the letter of credit as discussed in the "Bank Debt" section contained in this MD&A. Finance expense of $13.3 million in YE 2025 increased from $12.2 million in YE 2024 as a result of a higher bank debt balance and fees related to the letter of credit as discussed in the "Bank Debt" section contained in this MD&A, partially offset by lower interest rates.

INCOME TAX

	Three months ended December 31		Year ended December 31	
($ millions)	**2025**	**2024**	**2025**	**2024**
Current tax expense	**12.2**	16.2	**59.5**	65.5
Deferred tax expense (recovery)	**1.9**	0.3	**4.6**	(0.2)
Income tax expense	**14.1**	16.5	**64.1**	65.3

The Company's income tax expense is determined using the estimated annual income tax rate applied to estimated annual taxable income, prorated for the period. During Q4 2025, the Company recorded a $12.2 million (Q4 2024 - $16.2 million) current tax expense and a deferred tax expense of $1.9 million (Q4 2024 - $0.3 million) with lower current income tax reflecting the decrease in royalty production revenue relative to Q4 2024. During YE 2025, the Company recorded a $59.5 million (YE 2024 - $65.5 million) current tax expense and a deferred tax expense of $4.6 million (YE 2024 - $0.2 million recovery). Lower current income tax expense is a result of decreased revenue and higher cash administrative expense, partially offset by lower tax pool deductions relative to YE 2024.

The approximate tax pool balances available at year end were:

	Year ended December 31	
($ millions)	**2025**	**2024**
Canadian oil and gas property expense ("COGPE")	**1,175.2**	1,285.1
Undepreciated capital cost ("UCC")	**6.0**	4.6
Share issue costs	**1.4**	2.0
Total tax pools	**1,182.6**	1,291.7

NET EARNINGS AND COMPREHENSIVE INCOME

($ millions, except $ per share amounts)	Three months ended December 31 2025	2024	Year ended December 31 2025	2024
Net earnings and comprehensive income	**44.4**	60.2	**205.0**	215.3
Net earnings and comprehensive income per common share - basic and diluted(1)	**0.19**	0.25	**0.87**	0.90

(1) Net earnings and comprehensive income per share are calculated using the weighted average number of basic and diluted common shares outstanding.

Net earnings for Q4 2025 were $44.4 million ($0.19 per share, basic and diluted) as compared to net earnings of $60.2 million ($0.25 per share, basic and diluted) for Q4 2024. Net earnings were lower primarily as a result of weaker US$ WTI pricing negatively affecting oil royalty production revenue and lower bonus consideration partially offset by the positive impacts of lower E&E expense, as described above.

Net earnings for YE 2025 were $205.0 million ($0.87 per share, basic and diluted) as compared to net earnings of $215.3 million ($0.90 per share, basic and diluted) for YE 2024. Net earnings for YE 2025 were lower primarily as a result of weaker US$ WTI pricing negatively affecting oil royalty production revenue and lower bonus consideration partially offset by the positive impacts of lower administrative expense and lower E&E expense, as described above.

ACQUISITIONS

During Q4 2025, the Company completed acquisitions totaling $19.9 million (Q4 2024 - $31.5 million). Acquisitions included $15.2 million of royalty interests on non-producing properties recorded in E&E assets (Q4 2024 - $17.1 million royalty interests on non-producing properties). Additionally, $4.7 million related to royalty interest acquisitions on producing properties were recorded in royalty assets (Q4 2024 - $14.4 million). Acquisitions of royalty interests were focused in light oil plays, including the West Shale Basin Duvernay in Central Alberta and the Basal Quartz in Southern Alberta.

During YE 2025, the Company completed acquisitions totaling $99.9 million (YE 2024 - $57.3 million). Royalty interest asset acquisitions included $58.1 million of royalty interests on non-producing properties and complementary seismic recorded in E&E assets (YE 2024 - $42.3 million of royalty interests on non-producing properties recorded in E&E assets). Additionally, $41.8 million related to royalty interest acquisitions on producing properties was recorded in royalty assets (YE 2024 - $14.7 million of royalty interests on producing properties and $0.3 million related to information technology equipment). Acquisitions included the Private Co. Royalty Acquisition which was allocated $32.1 million to royalty assets which represented the value attributed to producing royalty assets, after customary closing adjustments, and $18.3 million to E&E assets which represented the value attributed to non-producing royalty assets. Acquisitions were focused on oil opportunities in Alberta and Saskatchewan targeting the Clearwater, Basal Quartz, Duvernay, Mannville and Mississippian plays.

Liquidity and Capital Resources

($ millions)	Three months ended December 31 2025	2024	Year ended December 31 2025	2024
Net cash from (used in)				
Operating activities	**84.0**	91.3	**357.4**	379.9
Investing activities	**(19.9)**	(23.3)	**(99.2)**	(49.1)
Financing activities	**(64.1)**	(68.0)	**(258.2)**	(330.8)
Change in cash and cash equivalents	**-**	-	**-**	-
Cash and cash equivalents, beginning of period	**-**	-	**-**	-
Cash and cash equivalents, end of period	**-**	-	**-**	-

OPERATING ACTIVITIES

Cash from operating activities is generated from funds from operations and the net change in non-cash working capital. 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, repurchase common shares under the NCIB, fund complementary acquisitions and repay bank debt. 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 2025 and YE 2025 were $80.5 million (Q4 2024 - $99.0 million) and $353.0 million (YE 2024 - $380.5 million), respectively, below the prior year comparative periods primarily due to the decrease in revenues and higher cash administrative expense as previously discussed.

Net cash from operating activities for Q4 2025 and YE 2025 were $84.0 million (Q4 2024 - $91.3 million) and $357.4 million (YE 2024 - $379.9 million), respectively, down from the prior year comparative periods as a result of lower funds from operations partially offset by positive changes in non-cash working capital in the current periods. Working capital fluctuates primarily due to royalty production volume and commodity price changes impacting the royalty revenue accrual. Working capital is further influenced by changes to accrued liabilities at each period end.

INVESTING ACTIVITIES

For Q4 2025 and YE 2025, cash used in investing activities was $19.9 million (Q4 2024 - $23.3 million) and $99.2 million (YE 2024 - $49.1 million), respectively, and included royalty and E&E asset acquisitions as outlined in the "Acquisitions" section of this MD&A.

FINANCING ACTIVITIES

For Q4 2025, cash used in financing activities was $64.1 million (Q4 2024 - $68.0 million) and included dividends paid on common shares of $60.5 million (Q4 2024 - $59.7 million) and $3.6 million for the repayment of bank debt (Q4 2024 - $7.0 million).

For YE 2025, cash used in financing activities was $258.2 million (YE 2024 - $330.8 million) and included dividends paid on common shares of $242.8 million (YE 2024 - $236.4 million) and the repurchase of common shares under the NCIB of $161.7 million, inclusive of all costs, as described below (YE 2024 - $nil). These outflows were partially funded by bank debt draws of $147.2 million (YE 2024 - $93.0 million of bank debt repayments).

Since the initial public offering in May 2014 (the "IPO"), PrairieSky has declared $2,043.4 million in dividends to shareholders. Since inception of the NCIB in 2016, PrairieSky has purchased for cancellation 22.9 million common shares at an average cost of $17.66 per share for total consideration of $405.0 million.

Changes in Net Debt

At December 31, 2025, the Company had net debt of $276.5 million, an increase from $134.9 million at December 31, 2024. Borrowings were used to partially fund share repurchases under the Company's NCIB. (See Note 15 "Capital Management" in the audited annual consolidated financial statements and the section "Capital Management" contained in this MD&A). At December 31, 2025, accounts receivable and accrued royalty revenue consisted primarily of royalty revenue accruals. In the oil and natural gas industry, accounts receivable from industry partners are typically settled in the month following production; 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. Accounts payable also included $7.6 million (December 31, 2024 - $13.9 million) related to the liability for vested cash-settled DSUs for directors of the Company which become payable only when a director is no longer a member of the Board. Net debt also includes the dividend payable of $60.5 million (December 31, 2024 - $59.9 million) which was paid on January 15, 2026.

Bank Debt

At December 31, 2025, the Company had a $575 million extendible revolving credit facility (the "Revolving Facility") and a $25 million extendible operating credit facility (the "Operating Facility", and together with the Revolving Facility, the "Credit Facility"), with a syndicate of Canadian banks. During YE 2025, the Company exercised the accordion feature of the Credit Facility, increasing it from $350 million to the full $600 million permitted. All other terms under the Credit Facility are unchanged. The Credit Facility may be extended on an annual basis, subject to lender consent and has a maturity date of February 28, 2028.

At December 31, 2025, $242.7 million was drawn on the Credit Facility (December 31, 2024 - $95.5 million). Borrowings under the Credit Facility bear interest at a Canadian bank prime rate, U.S. base rate, Canadian Overnight Repo Rate Average ("CORRA"), or Secured Overnight Financing Rate ("SOFR"), plus applicable margin on a variable grid based on certain financial ratios, over the prevailing applicable rate for the type of loan. The effective interest rate for Q4 2025 and YE 2025 was 6.1% (Q4 2024 - 5.5%) and 5.7% (YE 2024 - 6.1%), respectively.

Debt issuance costs incurred during YE 2025 of $0.8 million (YE 2024 - $1.3 million) have been netted against bank debt and are being amortized over the remaining term. For Q4 2025 and YE 2025, total amortization of debt issuance costs related to current and prior years was $0.2 million (Q4 2024 - $0.2 million) and $0.6 million (YE 2024 - $0.5 million).

During the fourth quarter of 2024, PrairieSky entered into an arrangement with a third-party operator to provide a letter of credit up to a maximum of $45.0 million to secure their bank facility, providing capital to the operator to advance its Montney oil drilling program where PrairieSky has a royalty interest. PrairieSky earned interest relating to the funding arrangement which was included in other income. Costs incurred by PrairieSky relating to the funding arrangement were included in finance expense and reimbursed by the third-party, with reimbursements included in other income. During the fourth quarter of 2025, the third-party operator secured its own funding arrangement due to the success of the capital program, and the letter of credit was returned and the funding arrangement terminated.

The Credit Facility has three financial covenants, whereby the Company’s ratio of adjusted consolidated senior debt to EBITDA for the trailing 12 months will not exceed 3.5:1.0, adjusted consolidated total debt to EBITDA for the trailing 12 months will not exceed 4.0:1.0, and 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. All covenants are calculated as at, and for the 12 months ended December 31, 2025. As at December 31, 2025, the Company was in compliance with all covenants provided for in the lending agreement and expects to remain in compliance with all covenants over the next 12 months.

The following table provides a list of the financial covenants as at December 31, 2025:

Covenant description[(1)]	Ratio	December 31, 2025
Adjusted Consolidated Senior Debt to EBITDA	Maximum 3.5:1	0.58
Adjusted Consolidated Total Debt to EBITDA	Maximum 4.0:1	0.58
Adjusted Consolidated Total Debt to Capitalization	Maximum 55%	8.8%

(1) Capitalized terms are as defined in the Credit Facility agreement.

The covenants noted above are subject to specific definitions in the Credit Facility agreement.

Dividends and Dividend Policy

PrairieSky pays dividends to shareholders at the discretion of the Board. Dividends declared were $0.26 per share for Q4 2025 and $1.04 per share for YE 2025.

Since inception in 2014, PrairieSky has declared $2,043.4 million in dividends ($9.44 per share) to our shareholders.

($ millions, except per share data)	Three months ended December 31		Year ended December 31	
Accumulated dividends	**2025**	**2024**	**2025**	**2024**
Accumulated, beginning of period	**1,982.9**	1,740.1	**1,800.0**	1,561.0
Dividends declared	**60.5**	59.9	**243.4**	239.0
Accumulated, end of period	**2,043.4**	1,800.0	**2,043.4**	1,800.0
Dividends per share ($)				
Accumulated, beginning of period	**9.18**	8.15	**8.40**	7.40
Dividends declared	**0.26**	0.25	**1.04**	1.00
Accumulated, end of period	**9.44**	8.40	**9.44**	8.40

For Q4 2025, PrairieSky's dividend payout ratio(1) was 75% (Q4 2024 - 61%). Excess funds from operations for Q4 2025 were used to fund acquisitions of $19.9 million (Q4 2024 - $23.3 million).

For YE 2025, PrairieSky's dividend payout ratio(1) was 69% (YE 2024 - 63%). Excess funds from operations for YE 2025 were used to fund acquisitions of $99.9 million (YE 2024 - $49.1 million) and to repurchase 6,239,507 (YE 2024 - nil) common shares for total consideration of $161.7 million (YE 2024 - $nil) inclusive of all costs.

	Three months ended December 31		Year ended December 31	
($ millions, except otherwise noted)	**2025**	**2024**	**2025**	**2024**
Funds from operations	**80.5**	99.0	**353.0**	380.5
Dividends declared	**60.5**	59.9	**243.4**	239.0
Dividend payout ratio(1)	**75%**	61%	**69%**	63%

(1) Dividend payout ratio is defined under the "Non-GAAP Measures and Ratios" section in this MD&A.

On February 9, 2026, PrairieSky announced a 2% increase in its annual dividend policy to $1.06 per common share, to be paid on a quarterly basis ($0.265 per common share quarterly). The first quarterly dividend of $0.265 per common share is effective for the March 31, 2026 record date.

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

Outstanding Share Data

As at December 31, 2025 and the date hereof, PrairieSky had 232.7 million common shares outstanding (December 31, 2024 - 239.0 million). As at December 31, 2025 and the date hereof, PrairieSky has no dilutive instruments outstanding (December 31, 2024 - nil).

Capital Management

The Company's objective when managing its capital structure is to maintain financial flexibility to meet the financial requirements for its business and future business development activities, as well as to distribute cash to shareholders in the form of dividends and to repurchase shares for cancellation. As a royalty company, PrairieSky does not incur capital expenditures for oil and natural gas development, which differentiates its cost structure from producers and enhances its financial flexibility.

The Company’s capital structure is comprised of bank debt, working capital, and shareholders’ equity. The Company’s capital structure is managed by taking into account operating activities, dividends paid to shareholders, common share repurchases, income taxes, liquidity available under the Credit Facility 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, realized commodity prices and the resultant royalty production revenues, as well as the costs incurred by the Company.

The Company defines capitalization as net debt plus shareholders’ equity. The net debt to capitalization ratio is a financial leverage measure that shows the portion of capital relating to debt. The Company continues to maintain a low net debt to capitalization ratio at December 31, 2025 of 10% (December 31, 2024 - 5%) which reflects its manageable debt levels and lower financial risk.

($ millions)	As at December 31, 2025	As at December 31, 2024
Shareholders' equity	**2,542.6**	2,742.7
Working capital deficiency	**35.3**	40.7
Bank debt	**241.2**	94.2
Net debt	**276.5**	134.9
Capitalization	**2,819.1**	2,877.6
Net debt to capitalization	**10%**	5%

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 taxes, 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. The preparation of financial forecasts requires management to make assumptions and estimates which may prove incorrect over time. As a result, there may be adverse changes in cash flows, working capital or debt levels that are currently unforeseen.

On May 30, 2025, 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 15,355,946 common shares over a twelve-month period which commenced on June 4, 2025 and expires no later than June 3, 2026. 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. The actual number of common shares that may be purchased will be determined by the Company based on current and forecasted funds from operations, the annual dividend and the level of bank debt.

There were no common shares repurchased during Q4 2025 or Q4 2024.

During YE 2025, the Company purchased for cancellation 6,239,507 common shares (YE 2024 - nil common shares) at an average cost of $25.40 per share for total consideration of $158.5 million (YE 2024 - $nil), inclusive of commissions and before tax of $3.2 million. The total cost paid, including commissions, was first charged to share capital up to the average carrying value of the common shares purchased. The remaining amount of $72.8 million (YE 2024 - $nil), inclusive of tax, was recorded to the deficit.

Risk Management

FINANCIAL RISKS

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

Commodity Price Risk

Commodity price risk is the risk the Company will encounter fluctuations in its future royalty production revenue with changes in commodity prices. Commodity prices for crude oil, NGL and natural gas may be impacted by global and regional factors, including levels of supply and demand, weather, geopolitical factors, including the imposition of tariffs, and the Canadian to US dollar exchange rate. The Company does not hedge its commodity price risk.

Interest Rate Risk

The Company is exposed to interest rate risk in connection with the Credit Facility. 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. Assuming all other variables held constant for Q4 2025 and YE 2025, a 1% change (plus or minus) in the interest rate would have resulted in a corresponding change to net earnings before taxes of $0.6 million and $2.3 million, respectively. Bank debt bears interest at a floating market rate with applicable variable margins.

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.

A substantial portion of the Company's accounts receivable are from leases, overriding royalty contracts and other agreements with 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 oil and natural gas rights to the Company. 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. In addition, the Company actively reviews its counterparties and takes its production in-kind to mitigate credit risk, as appropriate, and has letters of credit in place with certain producers.

As at December 31, 2025, one counterparty has a balance owing that individually accounted for approximately 15% of the total accounts receivable balance. The maximum credit risk exposure associated with accounts receivable and accrued revenue is the total carrying value.

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 these obligations. At December 31, 2025, the Company had net debt of $276.5 million with unused capacity under its Credit Facility of up to $357.3 million.

The Company's royalty production volumes and resultant revenues with high operating netbacks provide significant liquidity and may be used to fund administrative expenses, production and mineral taxes, finance expenses, income taxes, dividends, debt repayment, the repurchase and cancellation of PrairieSky's common shares and acquisitions. The Company's dividend, common share repurchases and capital acquisitions are discretionary.

The timing of expected cash outflows relating to accounts payable and accrued liabilities of $37.7 million, income taxes payable of $1.1 million and the dividend payable of $60.5 million is less than one year. In addition, accounts payable and accrued liabilities include $7.6 million related to vested cash-settled DSUs issued to non-executive directors which become payable only when a director is no longer a member of the Board.

OPERATIONAL AND BUSINESS RISKS

The Company, as a royalty owner, does not conduct any operations on its Royalty Properties and is therefore an indirect participant in the development of oil and natural gas on its Royalty Properties through the lessees and/or operators of such properties. Accordingly, PrairieSky has identified 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, geopolitical risk and/or shifts in the balance between supply and demand for crude oil, NGL and natural gas;
- Risks and impacts of tariffs imposed between Canada and the United States (and other countries) or other restrictive trade measures, retaliatory or countermeasures implemented by such governments affecting trade between Canada and the United States (and other countries), including the potential introduction of regulatory barriers to trade and the effect on the demand and/or market price for crude oil, NGL and natural gas;
- Lack of capacity and/or access to transportation, including pipelines or other methods, for bringing crude oil, NGL 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 oil and natural gas, including environmental risks and climate change, as further discussed below;
- Ability of participants in the oil and natural gas industry in Western Canada to access capital to develop the Royalty Properties and the industry as a whole, including the risk that third-party lenders may reduce their borrowings to the oil and natural gas industry;
- The impacts of increased interest rates and inflationary pressures on third-party exploration and development activity;
- Third-party operator activity levels on the Royalty Properties and 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. The Company's reserves will deplete over time through continued production and 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 risks, including facility restrictions and seasonal weather impacts, and/or marketing risks, including take-in-kind production volumes, resulting in delivery interruptions, delays, lower realized pricing and/or unanticipated production declines;
- The effects of inclement and severe weather events and natural disasters, including fire, drought and flooding on third-party operations;
- Changes in government regulations and policies, including environmental, taxation and Crown royalty rates;
- Changing environmental laws in relation to the operations conducted on the Royalty Properties;
- Potential breakdown, invasion, virus, cyber-attack, security breach or destruction of information technology systems;
- Increased borrowing costs due to increased lending rates from prime rate increases and/or increased lender pricing margins and/or negative changes to financial metrics evaluated under the Credit Facility financial covenants;
- Ability to renegotiate or replace the Credit Facility before the end of its term in February 2028 or obtain alternate financing at competitive market rates; and
- Variability of dividends based on PrairieSky's financial performance and/or market conditions.

Through the Company's Enterprise Risk Management processes, 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, area, region or operator;
- We are a royalty interest holder and PrairieSky does not bear the operational risks typically associated with the upstream oil and natural gas exploration and production business, as capital, operational expenses and abandonment costs are the responsibility of the third parties conducting these operations on the Royalty Properties;
- 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 and pursue any unpaid or incorrect revenues;
- Measures and processes, which include a recovery plan, are in place to reduce the risk of cyber-attacks, protecting our information systems from being breached;
- We maintain a conservative and sustainable capital structure; and
- We maintain levels of liability insurance that meet or exceed industry standards.

ENVIRONMENTAL AND CLIMATE CHANGE RISKS

The Canadian 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, as well as judicial scrutiny. Such regulations provide for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain oil and natural gas industry operations, including the abandonment and reclamation of well, facility and pipeline sites and the protection of water resources. Compliance with such regulations can require significant expenditures by the businesses operating on the Royalty Properties and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability and the imposition of material fines and penalties. In addition, compliance with such regulations is required for a third-party to keep a lease on the Fee Lands in good standing. Failure to adhere to applicable regulations and contractual requirements can lead to a default and subsequent termination of a Fee Lands lease by PrairieSky. Further to these specific, known requirements, future changes to environmental legislation, including legislation for air pollution and greenhouse gas emissions, may impose further requirements on operators and other companies in the oil and natural gas industry. From time to time, PrairieSky works with applicable federal, provincial and municipal regulators to ensure compliance with applicable regulations.

Third-party operations and activities associated with the Royalty Properties emit greenhouse gases which may require parties leasing and/or operating the Royalty Properties to comply with federal and/or provincial greenhouse gas emissions legislation. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate measures that are ultimately put in place. 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 directly 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 the Company's operations and financial condition with a high degree of certainty. Lessees and third-party operations may be impacted by environmental risks including both acute and chronic physical risks such as extreme weather and/or long-term shifts in weather patterns and natural disasters, including fire, drought and flooding. In addition, lessees and third-party operators may be impacted by transition risks including regulatory, market, reputational, technological and legal risks. The impact of these risks on lessees, third-party operators and PrairieSky continues to evolve. PrairieSky continually monitors these risks as part of its Enterprise Risk Management process. PrairieSky's Board is responsible for Enterprise Risk Management and management is responsible for implementing mitigating strategies regarding these risks. These mitigating strategies are described above under Operational and Business Risks.

The Company considers the impact of the evolving worldwide demand for energy and global advancement of alternative sources of energy that are not sourced from fossil fuels in its assessment of depletion on its oil and natural gas properties. Depletion of the Company's oil and gas properties is based on proved and probable reserves. The ultimate period in which global energy markets can transition from carbon-based sources to alternative energy is highly uncertain; and there can be no assurances that the Company will be able to predict any such market trends or consumer preferences. Accordingly, there is a risk that the nature of the global energy transition materially adversely affects the Company's business and financial condition. At this time, the Company has not capped its reserve life, the estimated maximum life, for purposes of calculating depletion expense. The Company will continue to monitor its estimates as the energy evolution continues.

Emissions, carbon and other regulations impacting climate and climate-related matters are constantly evolving. With respect to environmental, social and governance ("ESG") and climate reporting, the International Sustainability Standards Board ("ISSB") has issued an IFRS Sustainability Disclosure Standard with the aim to develop sustainability disclosure standards that are globally consistent, comparable and reliable. On June 26, 2023, the ISSB released two standards: IFRS S1 - *General Requirements for Disclosure of Sustainability-related Financial Information* and IFRS S2 - *Climate-related Disclosures*. The Canadian Sustainability Standards Board ("CSSB") was formed to support the adoption of international sustainability standards in Canada. In December 2024, the CSSB released CSDS 1 - *General Requirements for Disclosure of Sustainability-related Financial Information* and CSDS 2 - *Climate-related Disclosures* which are largely aligned with the ISSB standards with the exception of a Canadian-specific effective date and incremental transition relief. The Canadian Securities Administrators ("CSA") have issued a proposed National Instrument 51-107 Disclosure of Climate-related Matters.

On April 23, 2025, the CSA communicated that they are pausing work on the development of new mandatory climate-related disclosure rules. Until the CSA mandates the adoption of CSDS 1 and 2, the CSSB standards will be voluntary standards and as such, the Company has not adopted these standards. The cost to comply with these standards, and others that may be developed or evolve over time, has not yet been quantified and it is possible that the long-term effects of these new regulations will affect the Company's business, results from operations, access to capital and financial condition.

Additional specific risk factors related to the environment and climate change, including a discussion on physical and transition risks, are included in PrairieSky's Annual Information Form dated February 9, 2026, which is available under PrairieSky's SEDAR+ profile at www.sedarplus.ca and on our website at www.prairiesky.com, and readers are encouraged to review such material, as well as PrairieSky's Sustainability Report which is also located on our website at www.prairiesky.com.

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 9, 2026, which is available under PrairieSky's SEDAR+ profile at www.sedarplus.ca and on our website at www.prairiesky.com.

Accounting Policies, Judgments and Estimates

NEW AND AMENDED ACCOUNTING STANDARDS NOT YET ADOPTED

IFRS 9 *Financial Instruments* and IFRS 7 *Financial Instruments: Disclosures*

IFRS 9 *Financial Instruments* and IFRS 7 *Financial Instruments: Disclosures* were amended in May 2024 to clarify the date of recognition and derecognition of financial assets and liabilities. The amendments are effective for fiscal years beginning on or after January 1, 2026, with early adoption permitted. The amendment will not have a material impact on the Company's financial statements.

IFRS 18 *Presentation and Disclosure in Financial Statements*

IFRS 18 *Presentation and Disclosure in Financial Statements* ("IFRS 18") was issued in April 2024 by the International Accounting Standards Board and replaces IAS 1 *Presentation of Financial Statements*. IFRS 18 introduces a defined structure to the statements of earnings and comprehensive income, including new totals, subtotals, and categories for earnings and expenses. In addition, management defined performance measures will require note disclosure. IFRS 18 is required to be adopted retrospectively and is effective for fiscal years beginning on or after January 1, 2027, with early adoption permitted. The Company is evaluating the impact that this standard will have on the consolidated financial statements.

ACCOUNTING JUDGMENTS AND ESTIMATES

Management is required to make judgments, estimates, and assumptions through the application of the Company's accounting policies and practices, which have a material impact on the financial results. A summary of PrairieSky's material accounting policies can be found in Note 3 to the audited annual consolidated financial statements. A summary of PrairieSky's material estimates and judgments can be found in Note 4 to the audited annual consolidated financial statements.

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

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

Identification of Cash Generating Units

Cash generating units ("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. 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. Based on the way management operates, evaluates and monitors the assets and business of the Company, being as a single portfolio of assets, costs capitalized within royalty assets and E&E assets are aggregated into one CGU.

Oil and Gas Reserves

Reserves estimates are not recorded in the Company's financial statements, but they do affect net earnings and assets and liabilities through their impact on DD&A expense, amounts used for impairment calculations, deferred income taxes, and amounts used to determine fair values of assets acquired through acquisitions and business combinations. By their nature, proved and probable oil and gas reserves and the future cash flows derived from them are material estimates, which are subject to measurement uncertainty, and include significant assumptions related to future royalty production from proved and probable oil and gas reserves and future realized commodity prices. Accordingly, the impact to amounts reported in the financial statements for future periods could be material. Reserves have been evaluated at December 31, 2025 by the Company's external independent qualified reserves evaluators and have been determined pursuant to National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities*.

Business Combinations

Management's judgment is required to determine whether a transaction constitutes a business combination or asset acquisition 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. In 2025, all acquisitions were accounted for as asset acquisitions.

Recoverability of Asset Carrying Values

Judgment is required to assess when impairment indicators, or reversal indicators, exist and impairment testing is required with respect to the carrying value of royalty assets, E&E assets and goodwill. Estimation is required in determining internally developed cash flow estimates for undeveloped properties, including the timing of third-party development, as well as determining the discount rate.

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

The market value of royalty assets is estimated with reference to cash flow multiples from production of the same or similar assets, or are based on estimates of the discounted future cash flows from proved and probable oil and gas reserves. The market value of E&E assets is estimated with reference to the market values of current arm's length transactions in comparable locations, or are based on estimates of the discounted future cash flows from undeveloped properties.

The assumptions and estimates with respect to determining the fair value of royalty and E&E assets generally include estimates of discounted future cash flows from proved and probable oil and gas reserves, estimates of future royalty production from undeveloped properties including timing of third-party development, future benchmark commodity prices, reserve life and discount rates. Changes in any of the assumptions or estimates used in determining the fair value of acquired assets and liabilities could impact the amounts assigned to assets, liabilities and goodwill. Future net earnings can be affected by changes in future DD&A expense, asset impairment or goodwill impairment. The value of assets acquired through asset acquisitions is determined by allocating the purchase price based on the relative fair values.

Assumptions and estimates made in determining fair values may change significantly as new information becomes available. Changes in forward price estimates, future production costs and development expenditures for third-party operators, or recovery rates, may change the economic status of reserves estimates that may ultimately result in revision. Forward price estimates of crude oil and natural gas prices are used in the discounted cash flow model. These prices are adjusted for quality location, allowable deductions, or other factors as applicable. Commodity prices may be impacted by multiple factors including supply and demand fundamentals, exchange rates, weather, economic and geopolitical factors and the imposition of tariffs. Changes to the discount rate used to calculate the net present value of cash flows could result in significant changes to this estimate.

When applicable, further information about the assumptions made in determining fair values is disclosed in the notes specific to that asset or liability.

Crude Oil, Natural Gas and NGL Royalty Revenue Accruals

The Company follows the accrual method of accounting, making estimates in its financial and operating results. This includes estimates of royalty revenue and related expenses, which are based on significant assumptions related to royalty production and realized commodity pricing, for the period 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 both historical production information and publicly available production data adjusted pursuant to the terms of the Company's royalty agreements to determine royalty production. Realized commodity prices are based on publicly available benchmark commodity prices, adjusted for quality, location, allowable deductions, or other factors pursuant to the terms of the royalty agreements. These royalty revenue accrual estimates are revised based on actual royalty production volumes and realized commodity prices received in subsequent periods.

Share-based Compensation

Estimates and assumptions are used in the valuation models to determine the fair value of share unit awards, including the number of share unit awards that will ultimately vest under the Share Unit Award Incentive Plan which includes RSUs and PSUs and the ODSU Plan. Estimates of forfeiture rates for RSUs, PSUs and ODSUs are made through the vesting period based on past forfeitures and future expectations and are adjusted for actual forfeitures when RSUs, PSUs and/or ODSUs vest. Fluctuations in share-based compensation may occur due to changes in the underlying share price, and for PSUs, revised management estimates of relevant performance factors. The Board of Directors has adopted a multiple performance criteria methodology, including the Company's total shareholder return ("TSR"), for measuring the payout multiplier upon vesting of the PSUs. TSR is defined as share price appreciation plus dividends, relative to the TSR for a predetermined performance peer group. Based on performance criteria, a range of zero to two times the original PSU grant may be eligible to vest in respect of the three-year trailing period being measured. At each period end, management estimates the impact of performance, including TSR, on PSUs.

Income Taxes

Tax provisions are based on enacted or substantively enacted laws. Changes in those laws could affect amounts recognized in the period of the change and future periods. In periods of rate change, the Company estimates the period of anticipated reversal of the associated deferred income tax liability to determine the appropriate tax rate to apply to temporary differences. Deferred income tax assets are recognized to the extent future recovery is probable in management's judgment. 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. Deferred income tax liabilities are recognized when it is considered probable that temporary differences will be payable to tax authorities in future periods. Income tax filings are subject to audits and reassessments and changes in facts, circumstances and interpretations of the standards may result in a material increase or decrease in the Company's provision for income taxes.

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* ("NI 52-109"), 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 design and operating effectiveness 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 designed and operating effectively as at December 31, 2025.

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 October 1, 2025 to December 31, 2025 that have materially affected, or are reasonably likely to materially affect, the Company's ICFR. PrairieSky conducted an evaluation of the design and operating effectiveness of the Company's ICFR as at December 31, 2025 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, 2025, PrairieSky maintained effective ICFR as defined in Canada by NI 52-109.

Selected Annual Information

($ millions, except per share)	2025	2024	2023
Revenues	**478.2**	509.2	513.2
Net earnings and comprehensive income	**205.0**	215.3	227.6
Per share - basic and diluted[1]	**0.87**	0.90	0.95
Total assets	**3,147.1**	3,208.4	3,307.7
Long-term financial liabilities	**257.4**	111.9	201.5
Dividends declared	**243.4**	239.0	229.2
Per share	**1.04**	1.00	0.96

1. Net earnings and comprehensive income per share are calculated using the weighted average number of basic and diluted common shares outstanding.

Over the past three years, PrairieSky has operated its business by leasing lands to third parties for oil and natural gas development and third-party operations, managing controllable costs and completing accretive acquisitions which are complementary to PrairieSky's business. During this period, fluctuations in realized commodity prices, driven by changes in benchmark prices and differentials, have impacted the oil and natural gas industry and the Company's royalty production revenue and net earnings.

From 2023 to 2025, benchmark US$ WTI pricing declined overall, negatively impacting royalty production revenue and net earnings over the period. These impacts were partially offset by growth in oil royalty production, a weaker Canadian dollar relative to the US dollar and improved heavy oil differentials due to the Trans Mountain pipeline coming into service, which positively impacted pricing and oil royalty revenue starting in 2024. While AECO pricing improved in 2025 following weakness in 2024, natural gas royalty production volumes decreased as declines outpaced royalty production from new wells on stream.

Total assets declined over the period as cash generated from operations was returned to shareholders through dividends and share repurchases and DD&A expense outpaced royalty acquisitions. Long-term financial liabilities increased in 2025 following draws on the Company's credit facility to partially fund share repurchases.

Dividends per share are reviewed and set on an annual basis by the Board and have increased annually over the last three years. The annual dividend was increased 4% to $1.00 per common share in YE 2024, $0.25 per share paid quarterly, and was further increased in YE 2025 to $1.04 per common share, $0.26 per share paid quarterly.

Summary of Quarterly Results and Trends

($ millions, unless otherwise noted)	Q4 2025	Q3 2025	Q2 2025	Q1 2025	Q4 2024	Q3 2024	Q2 2024	Q1 2024
FINANCIAL								
Revenues								
Crude oil	**83.6**	97.8	95.7	101.1	100.0	100.7	111.1	92.3
NGL	**9.7**	7.4	7.6	10.1	9.3	8.2	10.0	10.2
Natural gas	**9.6**	2.5	7.9	8.7	6.3	2.6	4.4	10.7
Royalty production revenue	**102.9**	107.7	111.2	119.9	115.6	111.5	125.5	113.2
Other revenue	**8.8**	7.1	12.4	8.2	20.0	5.8	10.1	7.5
Revenues	**111.7**	114.8	123.6	128.1	135.6	117.3	135.6	120.7
Funds from operations	**80.5**	90.0	96.7	85.8	99.0	92.4	106.1	83.0
$ per share - basic and diluted(1)	**0.35**	0.38	0.41	0.36	0.41	0.39	0.44	0.35
Net earnings	**44.4**	45.9	56.3	58.4	60.2	47.3	60.3	47.5
$ per share - basic and diluted(1)	**0.19**	0.20	0.24	0.25	0.25	0.20	0.25	0.20
Dividends declared(2)	**60.5**	60.5	61.2	61.2	59.9	59.7	59.7	59.7
$ per share	**0.26**	0.26	0.26	0.26	0.25	0.25	0.25	0.25
Dividend payout ratio(3)	**75%**	67%	63%	71%	61%	65%	56%	72%
Common share repurchases, inclusive of all costs	**-**	67.9	2.0	91.8	-	-	-	-
Net debt(4)	**276.5**	281.7	242.0	258.8	134.9	149.6	174.6	208.3
OPERATIONAL								
Royalty Production Volumes								
Crude oil (bbls/d)	**13,750**	14,127	14,376	13,502	13,317	12,733	13,312	13,142
NGL (bbls/d)	**2,915**	2,210	2,348	2,520	2,482	2,189	2,308	2,535
Natural gas (MMcf/d)	**55.8**	56.1	58.4	55.9	55.1	57.0	58.2	62.1
Total (BOE/d)(5)	**25,965**	25,687	26,457	25,339	24,982	24,422	25,320	26,027
Realized Pricing								
Crude oil	**66.10**	75.30	73.16	83.16	81.66	85.90	91.75	77.18
NGL	**36.51**	36.29	35.47	44.51	40.68	41.10	47.20	44.18
Natural gas	**1.85**	0.48	1.50	1.73	1.23	0.50	0.84	1.89
Total ($/BOE)(5)	**43.08**	45.57	46.19	52.58	50.30	49.63	54.47	47.79
Benchmark Pricing								
West Texas Intermediate (US$/bbl)	**59.14**	64.93	63.76	71.39	70.27	75.10	80.57	76.95
Edmonton light sweet ($/bbl)	**76.57**	86.39	84.24	95.20	94.90	97.77	105.16	92.18
AECO Monthly Index ($/Mcf)	**2.34**	1.00	2.07	2.02	1.46	0.81	1.44	2.05
AECO Daily Index ($/Mcf)	**2.23**	0.63	1.69	2.16	1.48	0.69	1.18	2.50
Foreign exchange rate (US$/CAD$)	**0.7169**	0.7260	0.7228	0.6976	0.7147	0.7341	0.7315	0.7411

(1) Funds from operations and net earnings per share are calculated using the weighted average number of common shares outstanding.
(2) A dividend of $0.26 per common share was declared on December 2, 2025. The dividend was paid on January 15, 2026 to shareholders of record on December 31, 2025.
(3) Dividend payout ratio is defined under the "Non-GAAP Measures and Ratios" section in this MD&A.
(4) See Note 15 "Capital Management" in the audited annual consolidated financial statements and the section "Capital Management" contained within this MD&A.
(5) See "Conversions of Natural Gas to BOE" in this MD&A.

- Quarterly variances in revenues, funds from operations and net earnings are primarily due to fluctuations in realized commodity prices, royalty production volumes, and bonus consideration earned on entering into new leasing arrangements.
- Oil prices are generally determined by global and North American market forces, including supply and demand factors, and geopolitical risk. Changes in the USD-CAD currency exchange rate impact the Company's oil price realization relative to benchmark WTI, which is referenced in US dollars. The Company's realized oil price is also impacted by variances in the differential for light and heavy oil to WTI.

- Natural gas prices are influenced by many variables including weather conditions, industrial demand, and North American natural gas inventories. In Western Canada, transportation constraints, including pipeline maintenance, may further impact natural gas prices. Natural gas benchmark pricing weakened in 2024 due to the variables discussed above. Pricing rebounded during parts of 2025 as seasonal demand and market fundamentals strengthened, though volatility persisted amid ongoing market-wide influences.
- Royalty production volumes can be influenced by various factors, including the extent of exploration and development activity by third parties on the Royalty Properties, operational downtime and transportation constraints, the timing and amount of capital expenditures, the expertise and financial resources of third-party lessees, acquisitions of producing properties, weather and natural declines. Oil royalty production volumes have trended upwards over the last eight quarters generally as a result of organic growth from third-party operator activity. Natural gas royalty production has trended lower in 2024 and into 2025 as weak natural gas benchmark pricing has slowed third-party activity levels. Q3 2025 was among the Company's strongest third quarters, with limited production declines despite spring breakup, as compared to Q3 2024 when royalty production volumes decreased as third-party operator activity slowed during wet conditions.
- 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. In Q4 2024, the Company earned its highest quarterly bonus consideration revenue since 2017.
- Net earnings are affected primarily by revenues, as noted above, as well as DD&A expense, administrative expenses and income taxes. Administrative expenses can vary in a period due to the effect of the change in share price on the Company's share-based compensation plans.
- The dividend is set by the Board after considering forecasted funds from operations. In Q1 2025, the Company increased the dividend policy by 4% to $1.04 per common share on an annualized basis ($0.26 per common share on a quarterly basis). Dividends decline as the number of common shares outstanding in the quarter is reduced by share repurchases and cancellations under the NCIB.
- During YE 2025, the Company repurchased common shares under its NCIB for $161.7 million, inclusive of all costs.
- The Company has declared $482.4 million in dividends to shareholders over the past eight quarters.
- Net debt has increased $54.4 million or 24% since December 31, 2023, as the repurchase of common shares were partially funded by bank debt. Working capital fluctuations are driven by changes in commodity prices and royalty production volumes affecting the royalty production revenue accrual, changes in the Company's share price affecting share-based compensation accruals, changes in amounts payable for income tax and changes in the dividend payable.

Non-GAAP Measures and Ratios

Certain measures and ratios in this MD&A do not have any standardized meaning as prescribed by IFRS and therefore, are considered non-GAAP measures and ratios. These measures and ratios may not be comparable to similar measures and ratios presented by other issuers. These measures and ratios are commonly used in the 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 and ratios include operating netback, operating netback per BOE, operating margin, cash administrative expenses, cash administrative expenses per BOE and dividend payout ratio. Non-GAAP measures should not be considered an alternative to or more meaningful than the most directly comparable financial measure of each such non-GAAP measure described below. Management's use of these measures and ratios are discussed further below.

"Operating netback" represents the cash margin for products sold. Operating netback is calculated as royalty production revenue less production and mineral taxes and cash administrative expenses (defined below). Operating netback provides a consistent measure of the cash generating and operating performance of the Royalty Properties to assess the comparability of the underlying performance between years. Refer to the

Operating Results table in this MD&A document for a summary of operating netback calculations. The table below reconciles cash from operating activities to operating netback on a total dollar basis.

"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 average daily royalty production volumes for the period. Operating netback per BOE is used to assess the cash generating and operating performance per unit of product sold. Operating netback per BOE is commonly used in the oil and natural gas industry to assess performance comparability. Refer to the Operating Results table in this MD&A document for a summary of operating netback calculations.

	Three months ended December 31		Year ended December 31	
($ millions)	**2025**	**2024**	**2025**	**2024**
Cash from operating activities	**84.0**	91.3	**357.4**	379.9
Other revenue	**(8.8)**	(20.0)	**(36.5)**	(43.4)
Other revenue - non-cash	**-**	8.2	**-**	8.2
Amortization of debt issuance costs	**(0.2)**	(0.2)	**(0.6)**	(0.5)
Finance expense	**3.9**	2.3	**13.3**	12.2
Current tax expense	**12.2**	16.2	**59.5**	65.5
Interest on lease obligation	**-**	(0.1)	**(0.1)**	(0.1)
Net change in non-cash working capital	**(3.5)**	7.7	**(4.4)**	0.6
Operating netback	**87.6**	105.4	**388.6**	422.4

"Operating margin" represents operating netback as a percentage of royalty revenue. Management uses this measure to demonstrate the comparability between the Company and production and exploration companies in the oil and natural gas industry as it shows net revenue generation from operations. Refer to the Operating Results table in this MD&A document for a summary of operating netback calculations. A summary of the reconciliation from royalty production revenue to operating margin is outlined below:

	Three months ended December 31		Year ended December 31	
($ millions)	**2025**	**2024**	**2025**	**2024**
Royalty production revenue	**102.9**	115.6	**441.7**	465.8
Operating netback	**87.6**	105.4	**388.6**	422.4
Operating margin	**85%**	91%	**88%**	91%

"Cash administrative expenses" represent administrative expenses excluding the volatility and fluctuations in share-based compensation expense for RSUs, PSUs, ODSUs and DSUs that were not settled in cash in the current period. Cash administrative expenses are calculated as total administrative expenses, adjusting for share-based compensation expense in the period, plus any actual cash payments made under the Share Unit Award Incentive Plan, ODSU Plan or DSU Plan. Management believes cash administrative expense is a common benchmark used by investors when comparing companies to evaluate operating performance. Refer to the Administrative Expenses table in this MD&A document for a summary of total cash administrative expenses calculations.

"Cash administrative expenses per BOE" is calculated by dividing cash administrative expenses by the average daily production volumes sold for the period. Cash administrative expenses per BOE assists management and investors in evaluating operating performance on a comparable basis between periods. Refer to the Administrative Expenses table in this MD&A document for a summary of total cash administrative expenses per BOE calculations.

"Dividend payout ratio" is calculated as dividends declared as a percentage of funds from operations. The dividend payout ratio is used by dividend paying companies to assess dividend levels in relation to the funds generated from operations and used in operating activities. Refer to the Dividends and Dividend Policy table in this MD&A document for a summary of dividend payout ratio calculations.

Advisory

FORWARD-LOOKING STATEMENTS

This MD&A includes forward-looking information and forward-looking statements (collectively, "forward-looking statements") within the meaning of applicable Canadian securities legislation which may include, but are not limited to, PrairieSky's future plans, current expectations and views of future performance or operations as at February 9, 2026, and contains forward-looking statements that we believe allow readers to better understand our business and prospects. All statements other than statements of historical fact may be forward-looking statements. The use of any of the words "expect", "expected to", "anticipate", "seek", "contemplate", "continue", "estimate", "objective", "ongoing", "may", "will", "forecast", "project", "should", "could", "would", "likely", "believe", "plans", "intends", "strategy", "potential", "targeting", "capable" and similar expressions (including negative variations) are intended to identify forward-looking statements. This information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. No assurance can be given that these plans, expectations and/or views will prove to be correct and such forward-looking statements should not be unduly relied upon. This information speaks only as of the date of this MD&A or, if applicable, as of the date specified in those documents specifically referenced herein. Without limiting the foregoing, 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, and specifically the effect of market forces including macroeconomic events and geopolitical risk on future commodity prices, royalty production volumes, revenues and cash flow;
- PrairieSky's business and growth strategy, business prospects and anticipated sources of future income;
- PrairieSky's outlook on economic conditions and the effect of geopolitical uncertainty, including tariffs;
- PrairieSky's expectation that third-party operators will remain active on PrairieSky's lands into 2026, and specifically continue to allocate capital to the Clearwater, Duvernay and Mannville oil plays, which activity may be negatively impacted by lower commodity pricing;
- PrairieSky's expectation that its land base in areas where multilateral drilling technologies are being used to develop highly economic oil plays will continue to attract third-party capital in 2026 and beyond and may result in significant value potential over a number of years;
- PrairieSky's expectation that its expansive land position will provide diversification of exposure to producers and plays across Western Canada;
- PrairieSky's dividend policy and its intention to focus on creating value for shareholders by distributing cash flow to shareholders in the form of dividends, which intention could change with little or no notice, and the sustainability of the dividend and the dividend payout ratio;
- Opportunistic share repurchases and cancellations over time under PrairieSky's NCIB and specifically the volume and value of future repurchases under the current NCIB or future NCIBs based on current and forecasted funds from operations, the annual dividend and level of bank debt;
- The manner in which PrairieSky manages collection and credit risk and its belief that the diversity of payors and products mitigate this risk;
- PrairieSky's plan to not enter into any commodity price or foreign exchange hedges;
- The impact of compliance activities and recoveries, which vary quarterly;
- The possibility that the long-term effects of complying with sustainability disclosure standards will affect the Company's business, results of operations, access to capital and financial condition;
- The impact of lease bonus consideration, which varies quarterly;
- The expectation that the Company will be in compliance with financial covenants under the Credit Facility;
- The timing and amount of expected cash outflows relating to bank debt, accounts payable and accrued liabilities, income taxes payable and the dividend payable;

- The impact of incremental costs and inflationary pressures on third-party exploration and development activity;
- The indirect impact to the Company as third-party operators review and adjust their capital programs to respond to incremental costs, or as inflationary pressures impact the economic return on certain projects;
- The ability to mitigate the risks of fluctuations in commodity prices and production volumes;
- Average royalty production volume contributions from the Royalty Properties including the impact of exploration and development activity, acquisitions and/or production declines;
- The impact of PrairieSky's share price on administrative expenses;
- The expectation that there will be no operating costs, capital costs, environmental liabilities, or abandonment and reclamation obligations associated with the development of oil and natural gas on the Royalty Properties by third-party operators; and
- Changes to the legislative and regulatory frameworks, including changes to environmental and climate change legislation, in the jurisdictions in which the Company carries on business.

By their nature, forward-looking statements are subject to numerous risks and uncertainties, some of which are beyond our control, including but not limited to the impact of general economic, market or business conditions, industry conditions, volatility of commodity prices, lack of or access to sufficient pipeline capacity and the impacts of pipeline maintenance on production flows, currency fluctuations, imprecision of reserve estimates, royalties, environmental risks, including physical and acute environmental risks, regulation, changes in tax or other legislation or royalty regimes, as it relates to PrairieSky and to the oil and natural gas industry as a whole, credit and other third-party or counterparty risks, interest rates and inflation, political and geopolitical instability, the risks and impacts of tariffs imposed between Canada and the United States (and other countries) or other restrictive trade measures, retaliatory or countermeasures implemented by such governments affecting trade between Canada and the United States (and other countries), including the potential introduction of regulatory barriers to trade and the effect on the demand and/or market price for commodities, competition from other industry participants, the lack of availability of qualified personnel or management, breaches of the Company's information and technology systems and cyber-security risks, stock market volatility, inaccurate expectations for industry drilling levels on our royalty lands and multilateral horizontal drilling to contribute to total drilling activity across our land base, changing investor sentiment and the demand for and price of the Company's securities 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 acquired assets and the integration thereof, 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, uncertainties and assumptions, including those risks set out in this MD&A under the heading "Risk Management", are described in more detail in PrairieSky's Annual Information Form for the year ended December 31, 2025 under the heading "Risk Management" which is available on SEDAR+ at www.sedarplus.ca and PrairieSky's website at www.prairiesky.com.

With respect to forward-looking statements contained in this MD&A, we have made assumptions regarding, among other things: the ability of the lessees or working interest owners or operators on the Royalty Properties to maintain or increase production and reserves from these properties; the ability and willingness of the lessees or working interest owners or operators 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 or operators 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 or operators on the Royalty Properties; the willingness and financial capability of the lessees or working interest owners or operators to continue to develop and invest additional capital in the Royalty Properties; the ability of the lessees or working interest owners or operators on the Royalty Properties to obtain financing on acceptable terms to fund capital expenditures; the applicability of technologies for recovery and production of oil and natural gas from the Royalty Properties; the impact of inflation on capital budgets and operating costs for lessees or working interest owners or operators on the Royalty Properties; field production rates, decline rates and the well performance and characteristics of the Royalty Properties; the ability to replace and increase oil and gas 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 third-party operators on the Royalty Properties to successfully market their respective crude oil, natural gas and NGL 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 crude oil, natural gas and NGL products; surface rights access being granted to third parties on PrairieSky's Royalty Properties; the benefits of the seismic data anticipated to be used by PrairieSky and sub-licensed to lessees on the Royalty Properties; the level of costs and expenses to be incurred by PrairieSky, including with respect to interest, production and mineral taxes, 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 a royalty interest in oil and natural gas properties; future crude oil, natural gas and NGL prices; future pricing for other leased products; future currency exchange and interest rates; the ability of PrairieSky to obtain financing at acceptable terms including renegotiating its current Credit Facility before the end of its term in February 2028; the effects of global political unrest on global oil and natural gas supply and pricing; the effects of inclement and severe weather events and natural disasters, including fire, drought and flooding, on third-party operations and operational downtime on royalty production volumes and PrairieSky's ability to execute the volume and/or value of purchases as described under the NCIB or future NCIBs, if approved by the TSX.

Readers are cautioned that the assumptions used in the preparation of such forward-looking 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 achievements 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 and such information may not be appropriate for other purposes. Statements relating to "reserves" are also 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 statements contained in this MD&A are 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.

ABBREVIATIONS AND DEFINITIONS

bbls – barrels
bbls/d – barrels per day
BOE – barrels of oil equivalent (6 Mcf = 1 bbl)
BOE/d – barrels of oil equivalent per day
Mcf – thousand cubic feet
Mcf/d – thousand cubic feet per day
MMcf – million cubic feet
MMcf/d – million cubic feet per day
NGL – natural gas liquids
WTI – West Texas Intermediate
WCS – Western Canadian Select

West Shale Basin – Duvernay depositional area located to the west of the Leduc-Meadowbrook reef trend, in the Willesden Green, Gilby, and Pembina regions of Alberta.

ADDITIONAL INFORMATION

Additional information about PrairieSky, including the audited annual consolidated financial statements for the years ended December 31, 2025 and 2024, and notes thereto, together with management's discussion and analysis, and PrairieSky's Annual Information Form, is available on SEDAR+ at www.sedarplus.ca or PrairieSky's website at www.prairiesky.com.