

SATURN OIL & GAS INC.

Q1 2026 MANAGEMENT DISCUSSION AND ANALYSIS

The following Management's Discussion and Analysis ("MD&A") is a review of the operational and financial results and outlook for Saturn Oil & Gas Inc. ("Saturn" or the "Company") as at March 31, 2026 and for the three months ended March 31, 2026 and 2025. This MD&A is dated and based on information available as at May 6, 2026 and should be read in conjunction with the Company's unaudited condensed consolidated interim financial statements ("financial statements") and the notes thereto as at March 31, 2026 and for the three months ended March 31, 2026 and 2025. Additional information relating to Saturn, including Saturn's Annual Information Form for the year ended December 31, 2025, is available on SEDAR+ at www.sedarplus.ca and Saturn's website at www.saturnoil.com.

Throughout this MD&A and in other materials disclosed by the Company, Saturn adheres to generally accepted accounting principles ("GAAP") and IFRS Accounting Standards ("IFRS") as issued by the International Accounting Standards Board (the "IASB"), however the Company also uses various specified financial measures (as defined in National Instrument 52-112 - *Non-GAAP and Other Financial Measures* ("NI 52-112")) including "non-GAAP financial measures", "non-GAAP ratios", "capital management measures" and "supplementary financial measures" to analyze financial performance including: "adjusted EBITDA", "adjusted funds flow", "adjusted funds flow per share", "annualized quarterly adjusted funds flow", "free funds flow", "free funds flow per share", "capital expenditures", "finding and development expenditures", "finding, development, and acquisition expenditures", "gross petroleum and natural gas sales", "royalties as a percentage of gross petroleum and natural gas sales", "net operating expense", "operating netbacks", "operating netback, net of derivatives", "adjusted working capital", "net debt", "net debt to annualized quarterly adjusted funds flow" and "enterprise value". These non-GAAP and other financial measures do not have any standardized meaning prescribed under IFRS and therefore may not be comparable to similar measures presented by other entities. The non-GAAP and other financial measures should not be considered to be more meaningful than GAAP measures which are determined in accordance with IFRS, such as net income (loss), cash flow from operating activities, and cash flow used in investing activities, as indicators of Saturn's performance.

Readers are cautioned that the MD&A should be read in conjunction with disclosures in the sections entitled "Non-GAAP and Other Financial Measures" and "Advisories and Forward-Looking Information".

DESCRIPTION OF THE BUSINESS

Saturn is a Canadian resource company engaged in the business of acquisition, exploration and development of petroleum and natural gas resource deposits in Western Canada. The Company's focus is to advance the development of its oil and gas properties in Alberta and Saskatchewan.

Q1 2026 HIGHLIGHTS

- Achieved quarterly average production of 43,116 boe/d, compared to 41,680 boe/d in the first quarter of 2025 reflecting production contributions from the acquisitions of oil and gas properties in Southeast Saskatchewan, which closed on July 31, 2025, Clearview Resources Ltd. in Central Alberta, which closed October 20, 2025 and new well production additions from the Company's drilling programs;
- Recognized petroleum and natural gas sales of \$270.2 million, compared to \$278.1 million in the first quarter of 2025;
- Generated quarterly adjusted EBITDA⁽¹⁾ of \$126.5 million, compared to \$153.2 million in the first quarter of 2025;
- Achieved quarterly adjusted funds flow⁽¹⁾ of \$107.2 million or \$0.59/share, compared to \$131.1 million or \$0.66/share, in the first quarter of 2025;
- Invested \$44.8 million in capital expenditures⁽¹⁾ during the first quarter of 2026, drilling 23 gross (18.7 net) wells; including 21 in Southeast Saskatchewan; and two in Central Alberta;
- Generated free funds flow⁽¹⁾ of \$62.5 million, up from \$57.8 million in the first quarter of 2025;
- Exited the first quarter of 2026 with \$724.8 million of net debt⁽¹⁾, equating to a net debt to annualized quarterly adjusted funds flow⁽¹⁾ of 1.7x; and
- Repurchased 3,673,180 common shares for cancellation under the Company's Normal Course Issuer Bid ("NCIB") at a weighted average price of \$3.29 per share for a cost of \$12.1 million.

⁽¹⁾ See Non-GAAP and Other Financial Measures

FINANCIAL AND OPERATING HIGHLIGHTS

(\$000s, except per share amounts)	Three months ended		
	March 31, 2026	December 31, 2025	March 31, 2025
FINANCIAL HIGHLIGHTS			
Petroleum and natural gas sales	270,237	233,554	278,081
Cash flow from operating activities	113,246	76,065	165,372
Operating netback, net of derivatives ⁽¹⁾	132,740	136,600	157,567
Adjusted EBITDA ⁽¹⁾	126,528	140,854	153,185
Adjusted funds flow ⁽¹⁾	107,228	120,697	131,121
per share - Basic ⁽¹⁾	0.59	0.64	0.66
- Diluted ⁽¹⁾	0.59	0.61	0.65
Free funds flow ⁽¹⁾	62,478	55,933	57,826
per share - Basic ⁽¹⁾	0.34	0.30	0.29
- Diluted ⁽¹⁾	0.34	0.28	0.29
Net income (loss)	(97,324)	31,230	37,819
per share - Basic	(0.53)	0.17	0.19
- Diluted	(0.53)	0.16	0.19
Acquisitions, net of cash acquired	(1,713)	23,469	-
Proceeds from dispositions	(3,503)	-	-
Capital expenditures ⁽¹⁾	44,750	64,764	73,295
Total assets	2,174,597	2,190,825	2,188,307
Net debt ⁽¹⁾ , end of period	724,763	761,476	813,893
Shareholders' equity	845,780	946,591	837,958
Common shares outstanding, end of period	179,987	184,084	196,212
Weighted average, basic	181,989	187,135	198,113
Weighted average, diluted	181,989	197,604	202,727
OPERATING HIGHLIGHTS			
Average production volumes			
Crude oil (bbls/d)	30,844	31,287	31,142
NGLs (bbls/d)	3,938	4,052	3,318
Natural gas (mcf/d)	50,004	49,906	43,319
Total boe/d	43,116	43,657	41,680
% Oil and NGLs	81%	81%	83%
Average realized prices			
Crude oil (\$/bbl)	88.94	72.52	90.48
NGLs (\$/bbl)	43.08	38.72	52.95
Natural gas (\$/mcf)	2.19	2.44	2.48
Processing expenses (\$/boe)	(0.46)	(0.21)	(0.26)
Petroleum and natural gas sales (\$/boe)	69.64	58.15	74.13
Operating netback (\$/boe)			
Petroleum and natural gas sales	69.64	58.15	74.13
Royalties	(7.76)	(6.65)	(9.04)
Net operating expenses ⁽¹⁾	(20.49)	(19.24)	(19.58)
Transportation expenses	(1.73)	(1.57)	(1.56)
Operating netback ⁽¹⁾	39.66	30.69	43.95
Realized gain (loss) on derivatives	(5.45)	3.32	(1.96)
Operating netback, net of derivatives ⁽¹⁾	34.21	34.01	41.99

⁽¹⁾ See Non-GAAP and Other Financial Measures.

ACQUISITIONS AND DISPOSITIONS

Central Alberta Disposition

On January 30, 2026, the Company disposed of non-core properties in Central Alberta (the “Central Alberta Disposition”) for cash consideration of \$3.5 million with a carrying value of \$3.3 million, net of \$0.8 million in decommissioning obligations, resulting in a gain of \$0.2 million.

Clearview Resources Ltd.

On October 20, 2025, the Company completed the acquisition of Clearview Resources Ltd. (the “Clearview Acquisition”) for total cash consideration of \$22.7 million. The Company passed the optional IFRS 3 *Business Combinations* (“IFRS 3”) concentration test which resulted in the acquisition being recorded at cost with associated capitalized transaction costs of \$0.4 million.

Southeast Saskatchewan Acquisition

On July 31, 2025, the Company acquired certain oil and gas properties primarily in Southeast Saskatchewan for approximately \$61.7 million (the “Southeast Saskatchewan Acquisition”). The Company passed the optional IFRS 3 concentration test which resulted in the acquisition being recorded at cost with associated capitalized transaction costs of \$1.9 million.

Capital Energy Corp

On June 6, 2025, the Company completed the acquisition of Capital Energy Corp. (the “CEC Acquisition”) for total cash consideration of \$4.5 million. The Company passed the optional IFRS 3 concentration test which resulted in the acquisition being recorded at cost with associated capitalized transaction costs of \$0.7 million.

PRODUCTION

	March 31, 2026	December 31, 2025	Three months ended March 31, 2025
Crude oil (bbls/d) ⁽¹⁾	30,844	31,287	31,142
NGLs (bbls/d) ⁽¹⁾	3,938	4,052	3,318
Natural gas (mcf/d) ⁽¹⁾	50,004	49,906	43,319
Total boe/d ⁽²⁾	43,116	43,657	41,680
Oil and liquids %	81%	81%	83%

(1) “Crude oil” refers to light and medium crude oil and heavy crude oil combined. Natural gas liquids (“NGLs”) refers to ethane, propane, butane, and pentane combined. “Natural gas” refers to conventional natural gas. For further breakdown of crude oil and natural gas production volumes, refer to the “Product Type Information” section of this MD&A.

(2) Disclosure of production on a per boe basis in this MD&A consists of the constituent product types and their respective quantities disclosed in the “Product Type Information” section of this MD&A. Also refer to the “BOE Presentation” section of this MD&A.

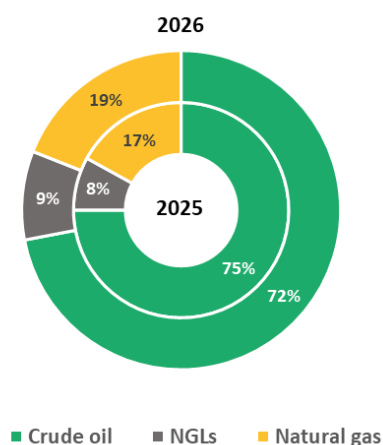
For the three months ended March 31, 2026, production volumes increased to 43,116 boe/d from 41,680 boe/d in the comparative quarter of 2025. The increase is attributed to production contributions from the Southeast Saskatchewan Acquisition and Clearview Acquisition completed during 2025 and new well production additions from the 2025 and Q1 2026 development capital programs, which more than offset natural well declines. The Southeast Saskatchewan Acquisition increased the amount of natural gas volumes in the production mix, reducing the crude oil and liquids ratio to 81% from 83% in the comparative quarter of 2025.

Production volumes decreased by 541 boe/d during the three months ended March 31, 2026 compared to the three months ended December 31, 2025, due to production sold in the Central Alberta disposition and the impact of natural well declines, which exceeded production additions from new well development during the first quarter of 2026.

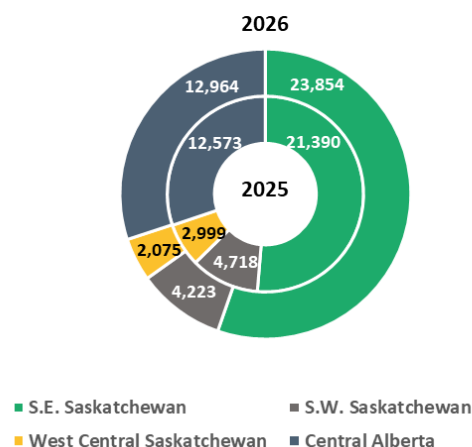
The following table summarizes average production by business unit for the three months ended March 31, 2026 and 2025:

	Three months ended March 31, 2026				Three months ended March 31, 2025			
	Crude oil (bbls/d)	NGLs (bbls/d)	Natural gas (mcf/d)	Total (boe/d)	Crude oil (bbls/d)	NGLs (bbls/d)	Natural gas (mcf/d)	Total (boe/d)
Southeast Saskatchewan	19,251	2,176	14,560	23,854	18,512	1,585	7,756	21,390
Southwest Saskatchewan	4,198	1	143	4,223	4,684	2	192	4,718
West Central Saskatchewan	1,952	24	595	2,075	2,839	26	803	2,999
Central Alberta	5,443	1,737	34,706	12,964	5,107	1,705	34,568	12,573
Total boe/d	30,844	3,938	50,004	43,116	31,142	3,318	43,319	41,680

Production by Volume
Three Months Ended March 31



Production by Area
Three Months Ended March 31



Southeast Saskatchewan

The Company's core producing properties in Southeast Saskatchewan include our Oxbow assets, which are geologically concentrated within the Mississippian-aged, Midale and Frobisher oil formations and also the Bakken and Flat Lake assets geologically concentrated in the Bakken formation of Southeast Saskatchewan. For the three months ended March 31, 2026, Southeast Saskatchewan produced 23,854 boe/d, an increase of 12% from 21,390 boe/d in the prior year comparative period. The increase is attributed to acquired production and new well production from our 2025 and Q1 2026 capital programs, which were highly concentrated in Southeast Saskatchewan.

Southwest Saskatchewan

The core producing properties in Southwest Saskatchewan include our low decline oil-weighted Battrum assets, which are geologically concentrated within the Success and Roseray formations. For the three months ended March 31, 2026, Southwest Saskatchewan produced 4,223 boe/d compared to 4,718 boe/d in the prior year comparative period. The decrease is attributed to natural well declines on account of limited new well development in this business unit during 2025 and Q1 2026.

West Central Saskatchewan

The core producing properties in West Central Saskatchewan consist of our Viking assets, which produced 2,075 boe/d for the three months ended March 31, 2026, compared to 2,999 boe/d in the prior year comparative period. The decrease is attributed to natural declines on account of reduced development capital directed towards the West Central Saskatchewan business unit during 2025 and in Q1 2026.

Central Alberta

The core producing properties in Central Alberta consist of our Cardium assets and our Kaybob assets located in the Montney formation. For the three months ended March 31, 2026, Central Alberta produced 12,964 boe/d, an increase of 3% from 12,573 boe/d in the prior year comparative period, as production additions from new well development and the Clearview Acquisition more than offset natural well declines.

BENCHMARK AND REALIZED PRICES

	Three months ended		
	March 31, 2026	December 31, 2025	March 31, 2025
Average benchmark prices			
WTI (US\$/bbl) ⁽¹⁾	72.17	59.14	71.42
Exchange rate (US\$/CA\$)	1.37	1.39	1.44
WTI (CA\$/bbl)	99.00	82.49	102.49
MSW (\$/bbl) ⁽²⁾	93.86	76.57	95.34
Midale (\$/bbl) ⁽³⁾	90.34	74.50	92.39
LSB (\$/bbl) ⁽⁴⁾	91.82	75.50	93.62
Fosterton (\$/bbl) ⁽⁵⁾	80.86	67.98	85.42
WCS (\$/bbl) ⁽⁶⁾	79.58	66.87	84.30
AECO (\$/mcf) ⁽⁷⁾	2.02	2.23	2.16
Average differentials			
MSW (US\$/bbl) ⁽²⁾	(3.75)	(4.25)	(4.98)
Midale (\$/bbl) ⁽³⁾	(8.67)	(8.00)	(10.10)
LSB (\$/bbl) ⁽⁴⁾	(7.18)	(6.99)	(8.88)
WCS (US\$/bbl) ⁽⁶⁾	(14.16)	(11.21)	(12.68)
Average realized prices			
Crude oil (\$/bbl)	88.94	72.52	90.48
NGLs (\$/bbl)	43.08	38.72	52.95
Natural gas (\$/mcf)	2.19	2.44	2.48
Processing expenses (\$/boe)	(0.46)	(0.21)	(0.26)
Petroleum and natural gas sales (\$/boe)	69.64	58.15	74.13

- (1) West Texas Intermediate (“WTI”)
(2) Mixed Sweet Blend (“MSW”) Par at Edmonton
(3) Midale Par at Cromer
(4) Light Sour Blend (“LSB”) Par at Cromer
(5) Fosterton Par at Regina
(6) Western Canadian Select (“WCS”) at Hardisty
(7) Alberta Energy Company (“AECO”) 5A Daily Index Price for natural gas

For the three months ended March 31, 2026, the Company realized an average combined price for petroleum and natural gas sales of \$69.64 per boe versus \$74.13 per boe in the comparative 2025 period. The decrease in average combined price was primarily due to lower Canadian benchmark commodity prices for crude oil and natural gas.

Most of the Company’s revenue is from the sale of crude oil which varies based on sales point and certain par prices. The Company’s realized price for crude oil from Southeast Saskatchewan is primarily based on the LSB and Midale par prices at Cromer which historically trades at a small discount to the MSW par price at Edmonton. Realized prices for heavier crude oil produced by our Battrum assets in Southwest Saskatchewan are based on Fosterton which historically trades at a small premium to the WCS par price at Hardisty. Realized prices for crude oil in Central Alberta and West Central Saskatchewan are primarily based on the MSW par price at Edmonton.

The Company’s average realized oil price for the three months ended March 31, 2026 was \$88.94 per bbl, a 2% decrease from \$90.48 per bbl in the prior year comparative period. The decrease in realized crude oil pricing for the first quarter of 2026 is due to the impact of a stronger Canadian dollar on crude oil sales denominated in US dollars.

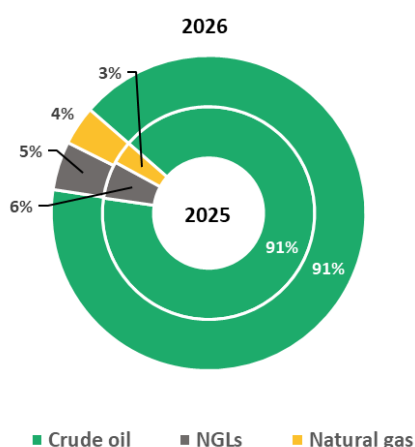
The Company’s average realized oil price increased 23% during the three months ended March 31, 2026 compared to the three months ended December 31, 2025 due primarily to an increase in the US\$WTI benchmark price, offset slightly by widening Canadian crude oil differentials.

PETROLEUM AND NATURAL GAS SALES

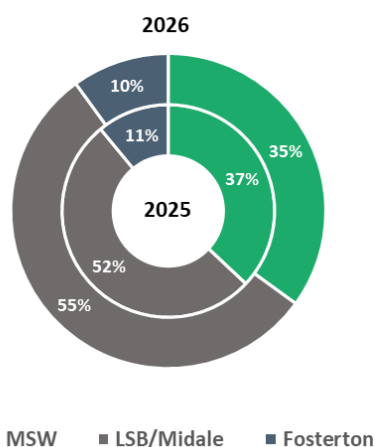
(\$000s)	Three months ended		
	March 31, 2026	December 31, 2025	March 31, 2025
Crude oil	246,888	208,749	253,587
NGLs	15,268	14,435	15,812
Natural gas	9,857	11,210	9,651
Gross petroleum and natural gas sales ⁽¹⁾	272,013	234,394	279,050
Less: Processing expenses	(1,776)	(840)	(969)
Petroleum and natural gas sales	270,237	233,554	278,081

(1) See “Non-GAAP and Other Financial Measures”.

**Petroleum and Natural Gas Sales
Three Months Ended March 31**



**Crude Oil Sales by Index
Three Months Ended March 31**



Gross petroleum and natural gas sales decreased for the three months ended March 31, 2026 compared to prior year, due to lower average realized commodity prices, partially offset by increased volumes.

Gross petroleum and natural gas sales increased for the three months ended March 31, 2026 compared to the three months ended December 31, 2025 due primarily to the increase in average realized crude oil prices driven by the increase in WTI benchmark price, partially offset by decreased realized natural gas prices due to lower AECO benchmark pricing. Certain gas processing expenses are deducted from gross realized prices received due to product custody transfer at the gas processing terminal inlet. The Company presents this on a gross and net basis to demonstrate the actual realized prices received prior to netting. The above adjustments do not have an impact on the Company’s operating netback.

ROYALTIES

(\$000s, except per boe amounts)	Three months ended		
	March 31, 2026	December 31, 2025	March 31, 2025
Royalties	30,095	26,710	33,893
% of gross petroleum and natural gas sales ⁽¹⁾	11.1%	11.4%	12.1%
\$ per boe	7.76	6.65	9.04

(1) See “Non-GAAP and Other Financial Measures”.

Royalties decreased for the three months ended March 31, 2026 compared to the prior year, on a total basis, consistent with lower crude oil sales. Royalties as a percentage of gross petroleum and natural gas sales decreased for the three months ended March 31, 2026 compared to prior year, due to royalty incentives on newer wells drilled in Alberta during the second half of 2025 and the impact of the sliding scale royalty framework from lower commodity pricing.

Royalties increased for the three months ended March 31, 2026 compared to the three months ended December 31, 2025, consistent with the increase in crude oil sales. Royalties as a percentage of gross petroleum and natural gas sales decreased due to royalty incentives on new wells drilled in Alberta during the fourth quarter of 2025. Saturn pays royalties to the provincial governments, freehold landowners and other third parties by way of contractual overriding royalties.

NET OPERATING EXPENSES

(\$000s, except per boe amounts)	Three months ended		
	March 31, 2026	December 31, 2025	March 31, 2025
Operating expenses	84,251	81,040	76,982
Less: processing income	(4,733)	(3,768)	(3,541)
Net operating expenses ⁽¹⁾	79,518	77,272	73,441
\$ per boe ⁽¹⁾	20.49	19.24	19.58

(1) See "Non-GAAP and Other Financial Measures".

Net operating expenses increased for the three months ended March 31, 2026 compared to prior year, due to increased costs associated with expanded field activity following the Southeast Saskatchewan Acquisition in July 2025 and Clearview Acquisition in October 2025. Net operating expenses per boe increased for the three months ended March 31, 2026 compared to the prior year comparative period, due to higher fixed operating costs associated with the acquisitions completed in 2025.

Net operating expenses increased for the three months ended March 31, 2026 compared to the three months ended December 31, 2025 due to a full quarter of expanded operations with the Clearview Acquisition and the planned increase in workover activity. Net operating expenses per boe increased for the three months ended March 31, 2026 compared to the three months ended December 31, 2025, due to additional fixed costs associated with the Clearview Acquisition, which offset the dilutive effect of adding production.

TRANSPORTATION EXPENSES

(\$000s, except per boe amounts)	Three months ended		
	March 31, 2026	December 31, 2025	March 31, 2025
Transportation expenses	6,716	6,317	5,845
\$ per boe	1.73	1.57	1.56

Transportation expenses increased for the three months ended March 31, 2026 compared to prior year, on a total basis, due to the increase in pipeline tariffs and clean oil trucking costs associated with increased production volumes as a result of the South Saskatchewan Acquisition and the Clearview Acquisition.

Transportation expenses increased for the three months ended March 31, 2026 compared to the three months ended December 31, 2025 due to a full quarter of pipeline tariffs associated with the Clearview Acquisition.

Certain pipeline shipping arrangements result in pipeline tariffs being included in transportation expenses. Conversely, pipeline tariffs incurred by commodity purchasers subsequent to delivery of the Company's product are charged back to Saturn and are netted against petroleum and natural gas sales.

RISK MANAGEMENT AND COMMODITY FINANCIAL DERIVATIVES

(\$000s, except per boe amounts)	Three months ended		
	March 31, 2026	December 31, 2025	March 31, 2025
Realized gain (loss) on derivatives	(21,168)	13,345	(7,335)
Unrealized gain (loss) on derivatives	(153,748)	8,055	1,688
Realized gain (loss) on derivatives \$ per boe	(5.45)	3.32	(1.96)

The Company uses commodity risk management contracts which are classified as financial derivatives to manage exposure to commodity price volatility. Details of open commodity contracts as at March 31, 2026 are described in the “Market Risk” section below. Unrealized gains (losses) on derivatives reflect a non-cash increase (decrease) in value resulting from the decline (improvement) in future estimated commodity prices relative to the Company’s contract positions. Realized gains (losses) occur on commodity derivative contracts when market prices for crude oil or natural gas settle at levels below (above) those set in the Company’s derivative contracts. Realized gains (losses) occur on differential derivative contracts when crude oil differentials settle at levels above (below) those set in the Company’s derivative contracts.

For the three months ended March 31, 2026, the Company realized a loss on its financial commodity contracts of \$21.2 million, compared to a loss of \$7.3 million in the prior year comparative period. The increased realized loss on derivatives reflects the increase in market prices from those in the comparative 2025 period, relative to the Company’s contract positions.

The realized loss on derivatives during the three months ended March 31, 2026 compared to a realized gain on derivatives during the three months ended December 31, 2025 is due to the increase in market prices.

Saturn has not designated any financial commodity contracts as hedges, and as a result the unrealized gains and losses reflect the non-cash change in the mark-to-market values period over period. At March 31, 2026, the outstanding financial commodity contracts had a net liability value of \$129.5 million (December 31, 2025 - \$24.3 million asset).

GENERAL AND ADMINISTRATIVE EXPENSES

(\$000s, except per boe amounts)	Three months ended		
	March 31, 2026	December 31, 2025	March 31, 2025
General and administrative expenses	6,698	6,567	5,995
\$ per boe	1.73	1.64	1.60

General and administrative (“G&A”) expenses increased for the three months ended March 31, 2026, due to increased personnel and office related costs as a result of the Company’s growth over the prior year.

G&A expenses increased for the three months ended March 31, 2026 compared to the three months ended December 31, 2025, due to increased personnel costs associated with increased salaries and statutory payments for employees.

DEPLETION, DEPRECIATION AND AMORTIZATION

(\$000s, except per boe amounts)	Three months ended		
	March 31, 2026	December 31, 2025	March 31, 2025
Depletion, depreciation and amortization	74,979	79,921	74,098
\$ per boe	19.32	19.90	19.75

Saturn records depletion, depreciation and amortization (“DD&A”) on its property, plant and equipment (“PP&E”) over the useful lives of the assets employing the unit of production method using proved plus probable oil and natural gas reserves and associated future development capital required for its petroleum and natural gas assets, and a straight line method for its corporate administrative assets.

DD&A expense increased for the three months ended March 31, 2026 compared to prior year, due to an increase in the carrying value of PP&E attributed to the Company’s acquisitions and associated increase in production volumes. The decrease in DD&A on a per boe basis for the three months ended March 31, 2026 compared to the prior year, reflects a lower relative increase in the depletable base compared to reserve value as a result of the Company’s acquisitions.

DD&A expense decreased for the three months ended March 31, 2026 compared to the three months ended December 31, 2025 due to decreased production volumes.

SHARE BASED PAYMENTS

(\$000s, except per boe amounts)	March 31, 2026	Three months ended	
		December 31, 2025	March 31, 2025
Share based payments	1,977	2,366	2,035
\$ per boe	0.51	0.59	0.54

The Company has an omnibus Long Term Incentive Plan, under which it is authorized to grant stock options, restricted share units (“RSUs”), deferred share units (“DSUs”) and performance share units (“PSUs”) to directors, officers, employees and consultants of Saturn.

Share based payments expense decreased for the three months ended March 31, 2026 compared to the prior year, due to graded vesting of performance warrants that were granted in January 2023 and fully vested in January 2026, partially offset by annual grants of RSUs, PSUs and DSUs in 2025.

Share based payments expense decreased for the three months ended March 31, 2026 compared to the three months ended December 31, 2025 due primarily to graded vesting of performance warrants that fully vested in January 2026.

FINANCING EXPENSES

(\$000s, except per boe amounts)	March 31, 2026	Three months ended	
		December 31, 2025	March 31, 2025
Interest expense, cash	19,557	20,332	22,662
Interest income	(257)	(175)	(598)
Amortization of debt issue costs	790	1,216	784
Accretion, leases	1,807	1,758	1,918
Accretion, decommissioning obligations	4,962	5,073	3,925
Financing expenses	26,859	28,204	28,691

Financing expenses decreased for the three months ended March 31, 2026 compared to the prior year, due to lower debt service costs on the Company’s Senior Notes associated with a reduced principal balance following debt repayments made throughout 2025, partially offset by increased accretion on decommissioning obligations associated with the acquisitions completed in 2025.

Financing expenses decreased for the three months ended March 31, 2026 compared to the three months ended December 31, 2025 due to lower debt service costs on the Company’s Senior Notes associated with a reduced principal balance following the debt repayment made in December 2025 and the decrease in non-cash amortization of debt issue costs.

FOREIGN EXCHANGE

(\$000s, except per boe amounts)	March 31, 2026	Three months ended	
		December 31, 2025	March 31, 2025
Realized gain (loss) on foreign exchange	123	10,837	649
Unrealized gain (loss) on foreign exchange	(7,745)	4,654	1,549
Foreign exchange gain (loss)	(7,622)	15,491	2,198

The Company is exposed to fluctuations in the US dollar to Canadian dollar exchange rate with respect to its US dollar denominated Senior Notes and financial derivatives. Unrealized foreign exchange gains (losses) reflect a non-cash change in value of the Senior Notes upon translation from US dollars to Canadian dollars at the end of each reporting period. To mitigate its exposure to changes in the Canadian to US dollar exchange rate, the Company has entered into foreign exchange contracts with respect to its US denominated Senior Notes interest and principal repayments. Unrealized foreign exchange gains (losses) reflect a non-cash change in value of the foreign exchange contracts.

Realized foreign exchange gains (losses) occur upon principal repayment of US dollar denominated Senior Notes or settlement of US dollar denominated commodity derivative contracts.

The decrease in realized foreign exchange gain for the three months ended March 31, 2026 compared to the prior year is due to a stronger Canadian dollar upon settlement of the Company's foreign exchange derivative contracts. The decrease in realized foreign exchange gain for the three months ended March 31, 2026 compared to the three months ended December 31, 2025 is due to the monetization of foreign exchange risk management contracts during the fourth quarter of 2025, resulting in a realized gain on settlement of \$10.7 million.

For the three months ended March 31, 2026, the Company recorded an unrealized foreign exchange loss of \$7.7 million compared to an unrealized foreign exchange gain of \$1.5 million in the prior year comparative period and an unrealized foreign exchange gain of \$4.6 million for the three months ended December 31, 2025. The unrealized foreign exchange loss is due to the impact of a weaker Canadian dollar on the Senior Notes at March 31, 2026 compared to December 31, 2025.

DEFERRED TAXES

For the three months ended March 31, 2026, the Company recognized deferred tax recovery of \$41.7 million, compared to deferred tax expense of \$12.8 million in the comparative 2025 period. The deferred tax expense (recovery) relates to the non-cash change in the Company's deferred tax liabilities, resulting from the change in unrealized derivative contracts during the period.

FINANCIAL RESULTS OF OPERATIONS

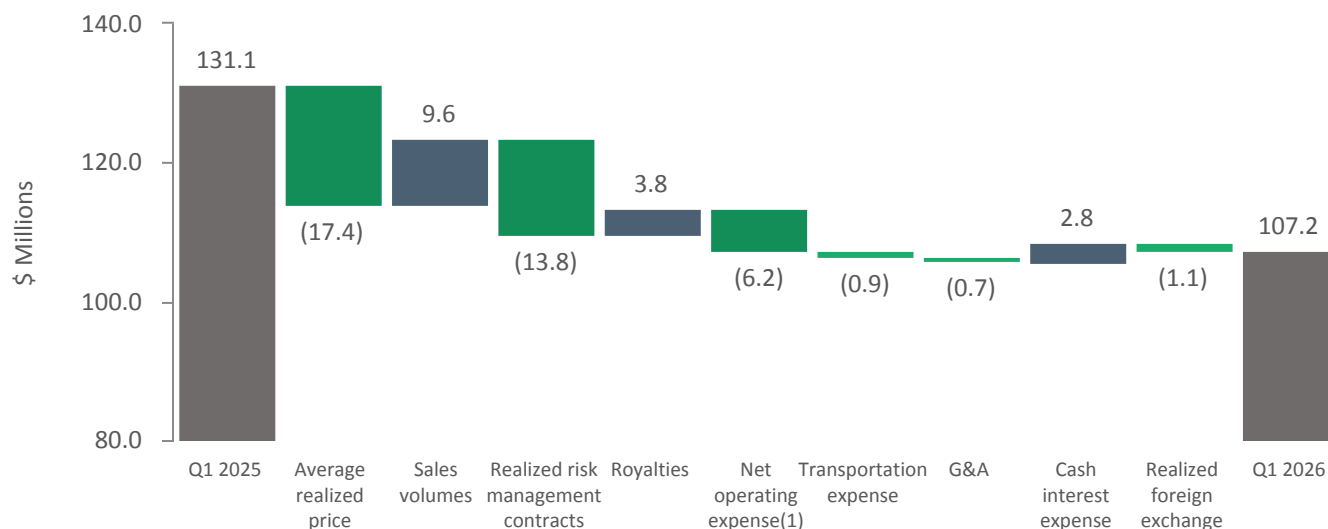
(\$000s, except per boe amounts)	Three months ended		
	March 31, 2026	December 31, 2025	March 31, 2025
Cash flow from operating activities	113,246	76,065	165,372
per share - Basic	0.62	0.41	0.83
- Diluted	0.62	0.38	0.82
Adjusted funds flow ⁽¹⁾	107,228	120,697	131,121
per share - Basic ⁽¹⁾	0.59	0.64	0.66
- Diluted ⁽¹⁾	0.59	0.61	0.65
Free funds flow ⁽¹⁾	62,478	55,933	57,826
per share - Basic ⁽¹⁾	0.34	0.30	0.29
- Diluted ⁽¹⁾	0.34	0.28	0.29
Net income (loss)	(97,324)	31,230	37,819
per share - Basic	(0.53)	0.17	0.19
- Diluted	(0.53)	0.16	0.19

(1) See "Non-GAAP and Other Financial Measures".

Adjusted funds flow decreased for the three months ended March 31, 2026 compared to prior year, due to decreased average realized prices, increased realized loss on derivatives and increased net operating expense, offset in part by increased production volumes, decreased royalties and decreased cash interest expense.

Adjusted funds flow decreased for the three months ended March 31, 2026 compared to the three months ended December 31, 2025 due to a realized loss on derivatives compared to a realized gain previously, a decreased realized foreign exchange gain, increased royalties and increased net operating expenses, offset in part by increased petroleum and natural gas sales and decreased cash interest expense.

Change in Adjusted Funds Flow Three months ended March 31

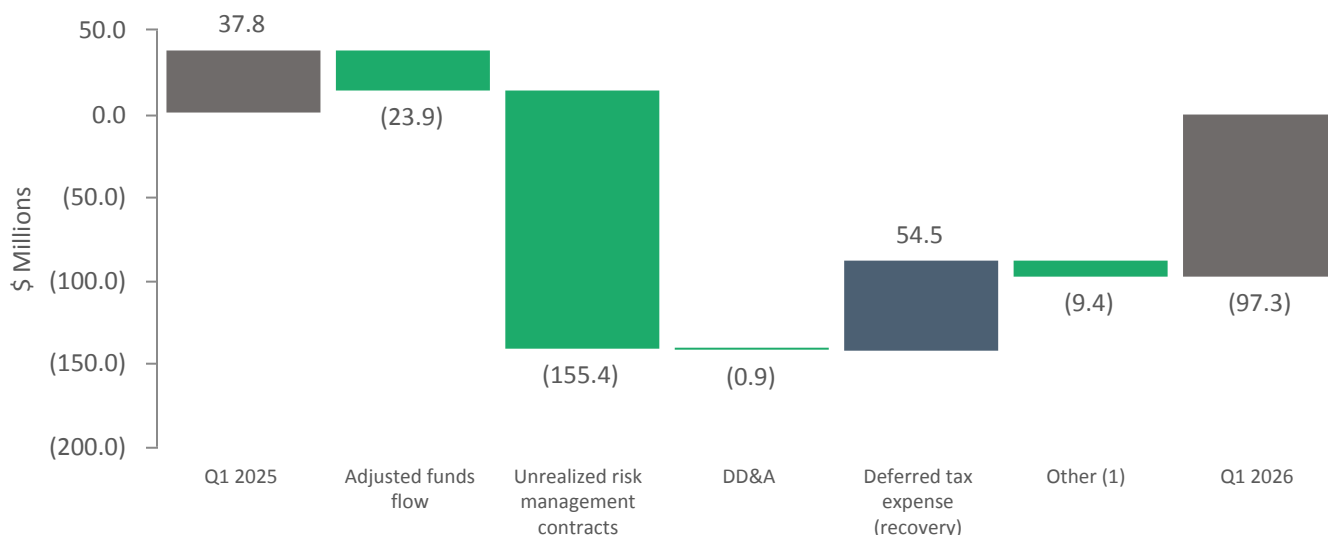


(1) See "Non-GAAP and Other Financial Measures".

Net income decreased for the three months ended March 31, 2026 compared to the prior year, primarily due to an unrealized loss on derivatives compared to an unrealized gain in the prior year period, an unrealized foreign exchange loss on the Company's Senior Notes compared to an unrealized foreign exchange gain in the prior year period, decreased petroleum and natural gas sales, increased net operating expense and increased DD&A, partially offset by a deferred tax recovery compared to a deferred tax expense in the prior period.

Net income decreased for the three months ended March 31, 2026 compared to the three months ended December 31, 2025, due to a realized loss on derivatives compared to a realized gain previously, an unrealized loss on derivative contracts compared to an unrealized gain previously, an unrealized foreign exchange loss on the Company's Senior Notes compared to an unrealized gain previously, increased net operating expense and increased royalties, partially offset by increased petroleum and natural gas sales, decreased DD&A and a deferred tax recovery compared to a deferred tax expense previously.

Change in Net Income Three months ended March 31



(1) Includes non-cash financing costs, unrealized foreign exchange gains (losses) and gain (loss) on dispositions.

CAPITAL EXPENDITURES

(\$000s)	March 31, 2026	Three months ended	
		December 31, 2025	March 31, 2025
Drilling and Completions	35,219	52,363	54,041
Facilities	4,051	10,938	15,940
Land and lease	2,502	(158)	424
Seismic	579	257	1,368
F&D expenditures⁽¹⁾	42,351	63,400	71,773
Capitalized G&A and other	2,399	1,364	1,522
Capital expenditures	44,750	64,764	73,295
Capitalized G&A and other	(2,399)	(1,364)	(1,522)
Corporate acquisition, net of cash acquired	-	23,469	-
Property acquisitions	(1,713)	-	-
Property disposition	(3,503)	-	-
FD&A expenditures⁽¹⁾	37,135	86,869	71,773

(1) Finding and development ("F&D") and finding, development and acquisition ("FD&A") expenditures. See "Non-GAAP and Other Financial Measures".

Capital expenditures decreased for the three months ended March 31, 2026, compared to the first quarter of 2025, due primarily to decreased drilling and completions activity and reduced spending on facilities, consistent with the Company's capital plan for 2026 given the uncertain commodity price environment and market conditions entering the year.

Capital expenditures decreased during the three months ended March 31, 2026 compared to the three months ended December 31, 2025 due primarily to the Company's planned approach to capital allocation, where spending is more heavily weighted towards the second half of the year when field conditions are optimal.

During the three months ended March 31, 2026, the Company drilled 23 gross (18.7 net) wells: 21 in Southeast Saskatchewan; and two in Central Alberta compared to 33 gross (24.4 net) wells in the prior year comparative period: 26 in Southeast Saskatchewan; one in Southwest Saskatchewan; five in West Central Saskatchewan; and one in Central Alberta.

	2026		Three months ended March 31, 2025	
	Gross	Net	Gross	Net
Wells drilled	23	18.7	33	24.4

DECOMMISSIONING OBLIGATIONS

At March 31, 2026, the Company's decommissioning obligation was \$198.5 million (December 31, 2025 – \$202.9 million) for future abandonment and reclamation of its properties. The decommissioning obligation represents costs to abandon and reclaim the Company's wells and facilities and the estimated timing of the costs to be incurred in future periods. The Company has estimated that the total undiscounted cash flows required to settle the obligations will be \$652.4 million (December 31, 2025 – \$652.6 million) which has been inflated at 2.0% (December 31, 2025 – 2.0%) and discounted using the credit adjusted risk-free rate of 10.0% (December 31, 2025 - 10.0%) with an estimated timeline to abandonment between 1 and 48 years. The Company's assets in both Saskatchewan and Alberta are subject to provincial programs that mandate the minimum spend targets on the Company's decommissioning obligations.

The decrease in the decommissioning liability is primarily due to settlements of obligations, which more than offset the change in estimates and accretion expense recognized during the period.

CAPITAL RESOURCES AND LIQUIDITY

Senior Secured Notes

As at March 31, 2026, the Company has \$724.8 million (US\$520.0 million) of Senior Notes outstanding (the “Senior Notes”). The Senior Notes bear interest at 9.625% per annum, payable semi-annually in arrears, have mandatory repayments of 10% per annum, payable quarterly, and have an original 5-year term maturing on June 15, 2029. The mandatory repayments are due quarterly, no later than 30 days after the end of each fiscal quarter, beginning September 30, 2024 at a redemption price of 104.813%.

The Company may, at any time and from time to time, seek to retire or purchase our outstanding debt through cash purchases and/or exchanges, in open-market purchases, privately negotiated transactions or otherwise. Such repurchases or exchanges, if any, will be upon such terms and at such prices as we may determine, and will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material.

Revolving Credit Facility

As at March 31, 2026, Saturn has a \$150.0 million credit facility (the “Credit Facility”) with a syndicate of banks consisting of a \$100.0 million reserve-based credit facility and a \$50.0 million operating facility. The credit agreement (the “Credit Agreement”) governing the Credit Facility includes an additional \$100.0 million accordion feature allowing for the expansion up to \$250.0 million in total, subject to certain conditions. The Credit Facility is committed on a revolving basis until June 30, 2027, at which time it may be extended at the lenders' option. The Credit Facility is subject to a semi-annual borrowing base review, occurring by June 30th and November 30th of each year, with the next scheduled borrowing base review to occur by June 30, 2026.

As at March 31, 2026, the Company had \$14.3 million drawn on the Credit Facility (December 31, 2025 – \$34.5 million). Amounts borrowed under the Credit Facility bear interest at a floating rate based on the applicable Canadian prime rate, US base rate, Canadian Overnight Repo Rate Average, or Secured Overnight Financing Rate plus a margin and standby fee based on the Company’s Net Debt to Consolidated EBITDA Ratio as defined in the Credit Agreement, currently between 2.50% to 3.50% and 0.88%, respectively.

There were no letters of credit outstanding under the Credit Facility.

Unsecured Letter of Credit Facility

The Company has a \$20.0 million unsecured demand letter of credit facility (the “LC Facility”) with a Canadian bank. Saturn’s obligations under the LC Facility are supported by a performance security guarantee (“PSG”) from Export Development Canada. At March 31, 2026, \$11.0 million was drawn under the LC Facility (December 31, 2025 – \$10.8 million). The PSG is subject to annual renewal with the next scheduled renewal date of June 30, 2026.

Liquidity

(\$000s)	March 31, 2026	December 31, 2025
Credit Facility ⁽¹⁾	135,654	115,467
Adjusted working capital (deficit) surplus ⁽²⁾	4,196	(2,966)
Total Liquidity	139,850	112,501

(1) Represents \$14.3 million drawn on the \$150.0 million Credit Facility (December 31, 2025 - \$34.5 million).

(2) Adjusted working capital is calculated as cash, accounts receivable, deposits and prepaids net of accounts payable.

The Company relies on a combination of internal profitability measured by adjusted funds flow, undrawn balance on its Credit Facility, debt financing and equity issuances to fund its capital requirements and provide liquidity. To the extent possible, Saturn has attempted to mitigate certain risks by entering into financial derivative commodity and foreign exchange contracts to reduce the financial impact of downward commodity price movements on a portion of the Company’s anticipated production and the financial impact of Canadian dollar weakness upon settlement of the Company’s US denominated debt. Future liquidity depends primarily on profitability and the ability to access debt and equity markets. All principal repayments on the Senior Notes that are due within twelve months are presented as current liabilities on the balance sheet with the remainder classified as non-current. The Company believes that the capital structure of the Company coupled with the projected adjusted funds flow will satisfy continuing operations.

Net Debt, Enterprise Value and Leverage

Management considers net debt a key measure in assessing the Company's liquidity. Saturn's net debt totaled \$724.8 million as at March 31, 2026 compared to \$761.5 million as at December 31, 2025. The Company's net debt to annualized quarterly adjusted funds flow was 1.7x as at March 31, 2026.

(\$000s)	March 31, 2026	December 31, 2025
Net debt ⁽¹⁾	724,763	761,476
Total market capitalization ⁽²⁾	1,130,318	447,324
Enterprise value ⁽¹⁾	1,855,081	1,208,800
Net debt as a percentage of enterprise value	39%	63%
Annualized quarterly adjusted funds flow ⁽¹⁾	428,912	482,788
Net debt to annualized quarterly adjusted funds flow ⁽¹⁾	1.7x	1.6x

(1) See "Non-GAAP and Other Financial Measures".

(2) Calculated as 179,986,761 Common shares outstanding as of March 31, 2026 multiplied by the TSX closing share price of \$6.28 per share on the last day of trading of the period.

Off-balance Sheet Transactions

The Company is not party to any material arrangements that would be excluded from the balance sheets other than disclosed in the "Commitments and Contractual Obligations" section of this MD&A.

SHARE CAPITAL

The Company is authorized to issue an unlimited number of common shares without par value.

On August 25, 2025, the TSX approved the renewal of the Company's NCIB. Pursuant to the NCIB, the Company may purchase for cancellation, from time to time, as it considers advisable, up to a maximum of 12,078,583 common shares between August 27, 2025 and August 26, 2026.

For the three months ended March 31, 2026, the Company repurchased 3,673,180 common shares under its NCIB at a weighted average price of \$3.29 per share for a cost of \$12.1 million. Subsequent to March 31, 2026, the Company repurchased an additional 559,000 common shares at a weighted average price of \$6.03 per share for a cost of \$3.4 million.

For the year ended December 31, 2025, the Company repurchased 12,841,768 shares under its NCIB at a weighted average price of \$2.33 per share for a cost of \$30.6 million.

On June 5, 2025, the Company initiated a substantial issuer bid ("SIB"). Pursuant to the SIB, the Company offered to purchase up to 7,000,000 common shares from holders of the Company's common shares for cancellation at a purchase price of \$2.15 per common share between June 11, 2025 and July 16, 2025, for an aggregate purchase price not exceeding \$15.1 million. The SIB expired on July 16, 2025 with 1,608,182 common shares being tendered and taken up under the SIB for an aggregate purchase price of \$3.5 million plus \$0.1 million in fees and taxes.

As at the date of this MD&A, March 31, 2026 and December 31, 2025, the following common shares are outstanding and/or remain issuable upon exercise of the underlying securities.

(000s) Number of securities	May 6, 2026	March 31, 2026	December 31, 2025
Common shares outstanding	180,253	179,987	184,084
Performance warrants	7,000	7,000	7,000
Restricted share units	7,277	8,699	8,772
Stock options	455	455	589
Deferred share units	554	423	423
Performance share units	843	1,245	1,245
Fully diluted shares outstanding	196,382	197,809	202,113

COMMITMENTS AND CONTRACTUAL OBLIGATIONS

The Company has the following contractual obligations and commitments as at May 6, 2026:

(\$000s)	Less than 1 year	1-3 years	3-5 years	Greater than 5 years	Total
Senior Notes ⁽¹⁾	90,604	181,207	453,017	-	724,828
Credit Facility	-	20,250	-	-	20,250
Interest payments ⁽²⁾	72,230	118,715	22,611	-	213,556
Lease liabilities ⁽³⁾	5,661	8,872	4,342	158	19,033
Gas processing contracts	13,256	23,166	20,708	39,691	96,821
	181,751	352,210	500,678	39,849	1,074,488

- (1) Represents the remaining principal amount of US\$520.0 million owing on the Company's Senior Notes converted at the period end exchange rate of 1.3939. Excludes unamortized debt issue costs.
- (2) The Senior Notes bear interest at 9.625% per annum, payable semi-annually in arrears, have mandatory prepayments of 10% per annum, payable quarterly.
- (3) Represents the remaining undiscounted minimum lease payments on the Company's lease liabilities, excluding gas processing contracts subject to IFRS 16 *Leases*

RISKS AND UNCERTAINTIES

Factors beyond Saturn's control may determine whether any oil and gas reserves the Company discovers are economically viable to be developed. The determination of whether petroleum and natural gas deposits are economic is affected by numerous factors beyond Saturn's control. These factors include market fluctuations for oil and gas; the costs of access and surface rights; and government regulations governing prices, taxes, royalties, land tenure, land use, importing and exporting of resources and environmental protection.

Land reclamation requirements for exploration and development properties may be burdensome. Although variable depending on location and the governing authority, land reclamation requirements are generally imposed on companies in extractive industries such as oil and gas or mining in order to minimize long-term effects of land disturbance. Reclamation may include requirements to control dispersion of potentially deleterious effluents and reasonably re-establish pre-disturbance landforms and vegetation. In order to carry out reclamation obligations imposed on the Company in connection with ongoing exploration and development, Saturn must allocate financial resources that might otherwise be spent on further exploration and development programs.

Liquidity Risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they are due. While the Company is exposed to liquidity risk, that risk is actively managed through strategies such as prudent capital spending, an active commodity risk management program; shown in the "Market Risk" section below, and by continuously monitoring forecast and actual cash flows from operating, financing and investing activities. Management believes it will have sufficient funding to meet foreseeable liquidity requirements.

Credit Risk

Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligations that arise principally from the Company's accounts receivable from oil and natural gas marketers and joint operators in the oil and gas industry. Receivables from oil and natural gas marketers are normally collected on the 25th day of the month following production.

The Company's policy to mitigate credit risk going forward is to maintain marketing relationships with large, established and reputable purchasers that are considered to be creditworthy. The Company attempts to mitigate the risk from joint venture receivables by obtaining partner approval of significant capital and operating expenditures prior to expenditure and in certain circumstances may require cash deposits in advance of incurring financial obligations on behalf of joint venture partners. Joint venture receivables are from partners in the petroleum and natural gas industry who are subject to the risks and conditions of the industry. Significant changes in industry conditions and risks that negatively impact partners' ability to generate cash flow will increase the risk of not collecting receivables. The Company does not request letters of credit in its

favour from joint venture partners; however, the Company has the ability to withhold production from joint operating partners in the event of non-payment or is able to register security on the assets of joint operating partners.

Counterparties to financial instruments expose the Company to credit losses in the event of non-performance. Counterparties for derivative instrument transactions are limited to investment grade counterparties.

Currency Risk

Currency risk is the risk that the fair value of future cash flows will fluctuate as a result of changes in foreign exchange rates. All of the Company's petroleum and natural gas sales are conducted in Canada and are denominated in Canadian dollars. Canadian commodity prices are influenced by fluctuations in the Canada to US dollar exchange rate. Prices for oil are determined in global markets and generally denominated in US dollars. The Company is exposed to currency risk in relation to its US dollar denominated financial derivatives and Senior Notes. A ten percent change in the US dollar would have resulted in a \$74.9 million change to net income (loss) before tax (December 31, 2025 – \$73.3 million) assuming all other variables remain constant. The exposure of realized price fluctuations of the US dollar and Canadian dollar exchange rate, serves as a natural hedge to US dollar denominated financial derivatives.

The Company is exposed to currency risk in relation to its US dollar denominated Senior Notes. To mitigate its exposure to changes in the Canadian to US dollar exchange rate, the Company has entered into foreign exchange contracts with respect to its US denominated interest and principal repayments.

The Company had the following outstanding foreign exchange contracts as at May 6, 2026:

Period	Forward Rate Contracts- USD/CAD		
	Notional Amount (\$000s, US\$)	Rate	Contract Type
Q2 2026	43,500	1.3484	Average rate currency swap
Q3 2026	17,100	1.3484	Average rate currency swap
Q4 2026	41,900	1.3484	Average rate currency swap
Q1 2027	17,100	1.3484	Average rate currency swap
Q2 2027	23,300	1.3484	Average rate currency swap

Price Risk

The Company is exposed to price risk related to commodity and equity prices. Equity price risk is the potential adverse impact on the Company's earnings due to movements in individual equity prices or general movements in the level of the stock market. Commodity price risk is the potential adverse impact on earnings and economic value due to commodity price movements and volatility. The Company's commodity price risk is also impacted by its derivative contracts. The ability of the Company to explore its resource properties and future profitability of the Company are directly related to the market price of commodities. Prices for oil are impacted not only by the relationship between the Canadian and United States dollars but also worldwide economic events that influence supply and demand.

Market Risk

Saturn manages the risks associated with changes in commodity prices by entering into a variety of risk management commodity contracts classified as financial derivatives. The realized and unrealized gains and losses are recognized on the statement of income and comprehensive income net of option premiums. The Company assesses the effects of movement in commodity prices on income before tax. A ten percent increase or decrease in commodity prices would have resulted in a \$65.0 million change to unrealized gains or (losses) on risk management contracts and net income (loss) before tax assuming all other variables remain constant.

The Company had the following outstanding derivative commodity contracts as at May 6, 2026:

Period	WTI Collars		WTI Swaps				NGL Propane Swaps	
	Volume bbls/d	Price ⁽¹⁾ CA\$/bbl	Volume bbls/d	Price ⁽¹⁾ US\$/bbl	Volume bbls/d	Price ⁽¹⁾ CA\$/bbl	Volume bbls/d	Price ⁽¹⁾ US\$/bbl
Q2 2026	13,500	77.93-99.94	6,048	72.21	4,320	85.47	500	0.75
Q3 2026	10,500	76.40-98.90	1,000	79.90	4,649	83.51	500	0.75
Q4 2026	10,000	77.50-100.04	500	80.35	4,463	83.47	500	0.75
Q1 2027	5,500	78.91-101.58	2,500	78.10	-	-	500	0.75
Q2 2027	3,500	79.43-97.40	-	-	-	-	-	-

(1) Weighted average prices for the period.

Period	MSW Differential		WCS Differential	
	Volume bbls/d	Price ⁽¹⁾ US\$/bbl	Volume bbls/d	Price ⁽¹⁾ US\$/bbl
Q2 2026	17,500	(3.39)	2,000	(13.05)
Q3 2026	18,500	(2.93)	2,000	(14.00)
Q4 2026	12,000	(4.18)	2,000	(15.08)

(1) Weighted average prices for the period.

Period	Natural Gas Swaps				Natural Gas Collars	
	Volume GJ/d	Price ⁽¹⁾ CA\$/GJ	Volume GJ/d	Price ⁽²⁾ CA\$/GJ	Volume GJ/d	Price ⁽¹⁾ CA\$/GJ
Q2 2026	15,000	2.69	10,550	Index	-	-
Q3 2026	15,000	2.69	10,550	Index	-	-
Q4 2026	21,630	3.03	3,555	Index	3,315	3.20-3.70
Q1 2027	15,000	3.40	-	-	5,000	3.20-3.70
Q2 2027	5,000	2.70	-	-	-	-
Q3 2027	5,000	2.70	-	-	-	-
Q4 2027	1,685	2.70	-	-	-	-

(1) Weighted average prices for the period.

(2) Physically settled derivative contracts based off US natural gas index prices (Malin index minus US\$1.98/GJ minus AECO 5A) and (NW Rocky index minus US\$1.99/GJ minus AECO 5A).

General Risks

Petroleum and natural gas exploration and production can involve environmental risks such as litigation, physical and regulatory risks. Physical risks include pollution of the environment, climate change and destruction of natural habitat, as well as safety risks such as personal injury. The Company works hard to identify the potential environmental impacts of its new projects in the planning stage and during operations. The Company conducts its operations with high standards in order to protect the environment, its employees and consultants, and the general public. Saturn maintains current insurance coverage for comprehensive and general liability as well as limited pollution liability. The amount and terms of this insurance are reviewed on an ongoing basis and adjusted as necessary to reflect current corporate requirements, as well as industry standards and government regulations. Without such insurance, and if the Company becomes subject to environmental liabilities, the payment of such liabilities could reduce or eliminate its available funds or could exceed the funds the Company has available and result in financial distress.

Climate Change Risks

Climate change may have actual or perceived adverse impacts on the Company's operations, business, and financial results, including an increase in the frequency of extreme climatic conditions. Weather and climate affect demand for crude oil and natural gas, and therefore, the predictability of weather and climate affects the Company's ability to accurately forecast supply and demand. In addition, the Company's operations, including exploration, production and construction operations, and the operations of major customers, suppliers and service providers, can be affected by acute and chronic physical climate risks, such as floods, forest fires, earthquakes, hurricanes, landslides, and other extreme weather events, natural disasters or long-term shifts in weather patterns. This may result in cessation or diminishment or production, delay of exploration and development activities or delay in executing the Company's capital expenditure plans, which may require

the Company to adopt increased or additional mitigation requirements. Growing concerns over climate change have also led to an increase in climate and environment-centric disputes and litigation in various jurisdictions, including at a federal and provincial level, alleging various claims and registering complaints, including that energy producers contribute to climate change, that such entities are not reasonably managing business risks associated with climate change, and that such entities have not adequately disclosed business risks of climate change. The outcome and ramifications of any such litigation is uncertain and may materially impact the Company's business, financial condition or results of operations. The Company may also be subject to negative or damaging publicity associated with such matters, which may adversely affect the public sentiment and the Company's reputation, regardless of whether the Company is ultimately found responsible for claims alleged. The Company may be required to incur significant expenses or devote significant resources in defense against any such litigation.

SUMMARY OF QUARTERLY RESULTS

	2026	2025				2024		
(\$000s, except per boe amounts)	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Financial:								
Petroleum and natural gas sales	270,237	233,554	235,344	236,712	278,081	268,845	262,379	208,853
Cash flow from operations	113,246	76,065	126,097	89,865	165,372	91,157	100,013	50,545
Adjusted funds flow ⁽¹⁾	107,228	120,697	103,282	108,854	131,121	129,205	94,065	88,643
Basic (\$/share) ⁽¹⁾	0.59	0.64	0.54	0.56	0.66	0.64	0.46	0.52
Diluted (\$/share) ⁽¹⁾	0.59	0.61	0.51	0.53	0.65	0.63	0.45	0.51
Net income (loss)	(97,324)	31,230	3,466	95,054	37,819	(26,318)	101,601	41,805
Basic (\$/share)	(0.53)	0.17	0.02	0.49	0.19	(0.13)	0.50	0.25
Diluted (\$/share)	(0.53)	0.16	0.02	0.46	0.19	(0.13)	0.49	0.24
Acquisitions	(1,713)	23,469	65,212	5,132	-	26,011	(4,749)	543,145
Dispositions	(3,503)	-	-	-	-	576	-	(25,708)
Capital expenditures ⁽¹⁾	44,750	64,764	87,339	15,842	73,295	105,420	84,381	22,549
Total assets	2,174,597	2,190,825	2,214,611	2,103,571	2,188,307	2,161,578	2,155,632	2,024,432
Common shares outstanding (000s)	179,987	184,084	190,020	194,809	196,212	199,555	203,103	204,041
Operational:								
Average daily production								
Crude oil (bbls/d)	30,844	31,287	29,152	30,150	31,142	30,449	28,994	21,010
NGLs (bbls/d)	3,938	4,052	4,180	3,310	3,318	3,381	3,407	2,673
Natural gas (mcf/d)	50,004	49,906	46,860	41,740	43,319	43,328	39,885	38,664
Total (boe/d)	43,116	43,657	41,142	40,417	41,680	41,051	39,049	30,127

(1) See "Non-GAAP and Other Financial Measures".

In the first quarter of 2026, the Company achieved adjusted funds flow of \$107.2 million driven by quarterly production of 43,116 boe/d and an operating netback, net of derivatives of \$34.21 per boe. The Company invested \$44.8 million in capital expenditures, drilling 23 wells (18.7 net) with the remainder of spending primarily directed towards facilities and land expenditures. The Company disposed of non-core assets in Central Alberta for net proceeds of \$3.5 million. The Company repurchased 3,673,180 common shares for cancellation under its NCIB at a weighted average price of \$3.29 per share for a cost of \$12.1 million. The Company made principal repayments of \$22.6 million (US\$16.3 million) on the Senior Notes and ended the quarter with net debt of \$724.8 million. Changes in quarterly sales, pricing, production, net income, cash flow from operations, adjusted funds flow and capital expenditures are all discussed in the previous sections of this MD&A.

In the fourth quarter of 2025, the Company achieved adjusted funds flow of \$120.7 million driven by quarterly production of 43,657 boe/d and an operating netback, net of derivatives of \$34.01 per boe. The Company invested \$64.8 million in capital expenditures, drilling 30 wells (22.1 net) with the remainder of spending primarily directed towards facilities and closed a corporate acquisition for \$22.7 million. The Company repurchased 4,789,900 common shares for cancellation under its NCIB at a weighted average price of \$2.58 per share for a cost of \$12.3 million. The Company made principal repayments of \$22.3 million (US\$16.3 million) on the Senior Notes and ended the quarter with net debt of \$761.5 million

In the third quarter of 2025, the Company achieved adjusted funds flow of \$103.3 million driven by quarterly production of 41,142 boe/d and an operating netback, net of derivatives of \$33.97 per boe. The Company invested \$87.3 million in capital expenditures, drilling 29 wells (24.7 net) with the remainder of spending primarily directed towards land purchases and closed an asset acquisition for \$65.3 million. The Company repurchased 3,260,164 common shares for cancellation under its NCIB at a weighted average price of \$2.61 per share for a cost of \$8.5 million and purchased 1,608,182 common shares for cancellation under its SIB at a purchase price of \$2.15 per share for an aggregate purchase price of \$3.5 million. The Company made principal repayments of \$22.6 million (US\$16.3 million) on the Senior Notes and ended the quarter with net debt of \$782.5 million.

In the second quarter of 2025, the Company achieved adjusted funds flow of \$108.9 million driven by quarterly production of 40,417 boe/d and an operating netback, net of derivatives of \$35.84 per boe. The Company invested \$15.8 million in capital expenditures, drilling one well (0.2 net) with the remainder of spending primarily directed towards facilities and land acquisitions and closed a corporate acquisition for \$5.2 million. The Company repurchased 1,998,180 common shares for cancellation under its NCIB at a weighted average price of \$1.65 per share for a cost of \$3.3 million. The Company made principal repayments of \$42.0 million (US\$32.5 million) on the Senior Notes and ended the quarter with net debt of \$694.8 million.

In the first quarter of 2025, the Company achieved record adjusted funds flow of \$131.1 million driven by record quarterly production of 41,680 boe/d and an operating netback, net of derivatives of \$41.99 per boe. The Company invested \$73.3 million in capital expenditures, drilling 33 wells (24.4 net). The Company repurchased 2,793,524 common shares for cancellation under its NCIB at a weighted average price of \$2.08 per share for a cost of \$5.8 million. The Company made principal repayments of \$23.2 million (US\$16.3 million) on the Senior Notes and ended the quarter with net debt of \$813.9 million.

In the fourth quarter of 2024, the Company closed the Brazeau Acquisition for \$20.5 million. The Company achieved adjusted funds flow of \$129.2 million driven by quarterly production of 41,051 boe/d and an operating netback, net of derivatives of \$40.41 per boe. The Company invested a record \$105.4 million in capital expenditures, drilling 33 wells (26.2 net). The Company repurchased 3,385,052 common shares for cancellation under its NCIB at a weighted average price of \$2.21 per share for a cost of \$7.5 million. The Company made principal repayments of \$23.4 million (US\$16.3 million) on the Senior Notes and ended the quarter with net debt of \$860.2 million.

In the third quarter of 2024, the Company achieved adjusted funds flow of \$94.1 million driven by quarterly production of 39,049 boe/d in the first full quarter following the South Saskatchewan Acquisition. The Company invested \$84.4 million in capital expenditures, drilling 48 wells (41.2 net). The Company received TSX approval for the commencement of the NCIB and repurchased 1,095,236 common shares for cancellation at a weighted average price of \$2.50 per share for a cost of \$2.7 million. The Company's initial principal repayment of US\$16.3 million was made on the Senior Notes and ended the quarter with net debt of \$779.0 million.

In the second quarter of 2024, the Company closed the Adonai Acquisition for \$8.3 million, closed the South Saskatchewan Acquisition for cash consideration of \$534.8 million and closed the non-core Swan Hills Disposition for net cash proceeds of \$25.7 million. Concurrent with the acquisitions, the Company completed a refinancing issuing US\$650 in Senior Notes, closed a \$100.0 million equity financing and extinguished its Senior Term Loan. The Company realized adjusted funds flow of \$88.6 million and invested \$22.5 million in capital expenditures. The Company generated quarterly petroleum and natural gas sales of \$208.9 million, driven primarily by record average production of 30,127 boe/d.

STANDARDS ISSUED BUT NOT YET EFFECTIVE

In April 2024, the IASB issued IFRS 18 *Presentation and Disclosure in Financial Statements* ("IFRS 18") which replaces IAS 1 *Presentation of Financial Statements* effective for annual reporting periods beginning on or after January 1, 2027 and is required to be adopted retrospectively with early adoption permitted. The standard introduces a defined structure to the Statement of Net Income and Comprehensive Income with related specific disclosure requirements. The Company is assessing the impact of IFRS 18 on its consolidated financial statements.

INTERNAL CONTROLS OVER FINANCIAL REPORTING ("ICFR")

ICFR is a set of processes designed to provide reasonable assurance that all assets are safeguarded, transactions are appropriately authorized, and facilitate the preparation of relevant, reliable, and timely information. Because of its inherent limitations, ICFR may not prevent or detect misstatements. Management has designed and assessed the effectiveness of

Saturn's ICFR as defined in Canada by National Instrument 52-109 *Certification of Disclosure in Issuers' Annual and Interim Filings* ("NI 52-109"). The assessment was based on the framework in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. NI 52-109 requires that Saturn disclose in its MD&A any material weaknesses relating to design existing at the end of the period in Saturn's ICFR and/or any changes in Saturn's ICFR that occurred during the period that have materially affected, or are reasonably likely to materially affect, Saturn's ICFR. Management confirms there were no changes in Saturn's ICFR during the period ended March 31, 2026 that materially affected, or are reasonably likely to materially affect, the Company's ICFR.

USE OF ESTIMATES

The Company makes estimates and assumptions about the future that affect the reported amounts of assets and liabilities. Estimates and judgments are continually evaluated based on historical experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances. In the future, actual experience may differ from these estimates and assumptions.

The effect of a change in an accounting estimate is recognized prospectively by including it in profit or loss in the period of the change, if the change affects that period only, or in the period of the change and future periods, if the change affects both.

Significant assumptions about the future and other sources of estimation uncertainty that management has made at the balance sheets date, that could result in a material adjustment to the carrying amounts of assets and liabilities, in the event that actual results differ from assumptions made relate to, but are not limited to, the following:

- The recoverability of accounts receivable, which is included in the consolidated balance sheets;
- The determination of the fair value of stock options and warrants using stock pricing models requires the input of highly subjective assumptions, including the expected price volatility. Changes in the subjective input assumptions could materially affect the fair value estimate; therefore, the existing models do not necessarily provide a reliable single measure of the fair value of the Company's outstanding stock based compensation;
- Fair values of petroleum and natural gas properties, depletion and depreciation expense and amounts used in impairment calculations are based on estimates of proved and probable oil and gas reserves are based upon a number of significant assumptions, such as forecasted production volumes, forecasted oil and gas commodity prices, forecasted operating costs, forecasted royalty costs and forecasted future development costs. By their nature, estimates of proved and probable oil and gas reserves and the related future cash flows are subject to measurement uncertainty, and the impact of differences between actual and estimated amounts on the consolidated financial statements of future periods could be material;
- Amounts recorded for asset retirement obligation liabilities including estimates around timing and amount of expenditures required to settle liabilities and the credit-adjusted risk-free discount rate used;
- Financial derivative commodity and foreign exchange contracts are valued using valuation techniques with market observable inputs. The most frequently applied valuation techniques include Black-Scholes valuation model and forward pricing and swap models. The models incorporate various inputs including the credit quality of counterparties, forecast benchmark commodity prices, and foreign exchange;
- The determination of the estimated acquisition-date fair value of oil and gas properties involves significant estimates, including proved and probable oil and gas reserves and discount rates. The estimate of proved and probable reserves includes significant assumptions related to forecasted oil and gas commodity prices, forecasted production volumes, forecasted operating costs, forecasted royalty costs and forecasted future development costs. Changes in the assumptions or estimates used in determining the estimated acquisition date fair value of the acquired assets and liabilities could impact the allocation of the purchase price between assets and liabilities recorded on the balance sheets and revenue and expenses recorded on the statement of comprehensive income; and
- The determination of income tax liabilities includes estimates around future utilization of tax pools. All tax filings are subject to audit and potential reassessment after the lapse of considerable time.

NON-GAAP AND OTHER FINANCIAL MEASURES

Throughout this MD&A and in other materials disclosed by the Company, Saturn employs certain measures to analyze financial performance, financial position, and cash flow. These non-GAAP and other financial measures do not have any standardized meaning prescribed under IFRS and therefore may not be comparable to similar measures presented by other entities. The non-GAAP and other financial measures should not be considered to be more meaningful than GAAP measures which are determined in accordance with IFRS, such as net income (loss), cash flow from operating activities, and cash flow used in investing activities, as indicators of Saturn's performance.

Non-GAAP Financial Measures and Ratios

NI 52-112 defines a non-GAAP financial measure as a financial measure that: (i) depicts the historical or expected future financial performance, financial position or cash flow of an entity, (ii) with respect to its composition, excludes an amount that is included in, or includes an amount that is excluded from, the composition of the most directly comparable financial measure disclosed in the primary financial statements of the entity, (iii) is not disclosed in the financial statements of the entity, and (iv) not a ratio, fraction, percentage or similar representation. NI 52-112 defines a non-GAAP ratio as a financial ratio that: (i) is in the form of a ratio, fraction, percentage or similar representation, (ii) has a non-GAAP financial measure as one or more of its components, and (iii) is not disclosed in the financial statements of the entity. The Company has presented the following non-GAAP financial measures and ratios within this MD&A.

Capital Expenditures

Saturn uses capital expenditures to monitor its capital investments relative to those budgeted by the Company on an annual basis. Saturn's capital budget excludes acquisition and disposition activities as well as the accounting impact of any accrual changes or payments under certain lease arrangements. The most directly comparable GAAP measure for capital expenditures is cash flow used in investing activities. The following table reconciles capital expenditures and capital expenditures, net A&D to the nearest GAAP measure, cash flow used in investing activities.

(\$000s)	Three months ended		
	March 31, 2026	December 31, 2025	March 31, 2025
Cash flow used in investing activities	54,473	104,906	99,520
Change in non-cash working capital	(14,939)	(16,673)	(26,225)
Capital expenditures, net A&D	39,534	88,233	73,295
Acquisitions, net of cash acquired	1,713	(23,469)	-
Proceeds from disposition	3,503	-	-
Capital expenditures	44,750	64,764	73,295

F&D and FD&A Expenditures

Saturn uses F&D and FD&A expenditures as a basis to monitor its capital efficiency. The Company's F&D expenditures are calculated by removing certain capitalized overhead costs from capital expenditures. The Company's FD&A expenditures are calculated by adding A&D to FD&A expenditures. Both measures calculate the capital cost outlay associated with the Company's exploration and development activities for the purposes of finding, developing and, when desired, acquiring its reserves.

Adjusted Funds Flow per Share

Adjusted funds flow per share is a non-GAAP ratio by management to better analyze the Company's performance against prior periods on a more comparable basis. Adjusted funds flow per share is calculated as adjusted funds flow from operations divided by weighted average shares outstanding during the applicable period on a basic or diluted basis.

Free Funds Flow and Free Funds Flow per Share

Saturn uses free funds flow as an indicator of the efficiency and liquidity of its business, measuring its funds after capital investment available to manage debt levels, pursue acquisitions and gauge optionality to pay dividends and/or and return capital to shareholders through activities such as share repurchases. Saturn calculates free funds flow as adjusted funds flow in the period less capital expenditures. By removing the impact of current period capital expenditures from adjusted funds flow, management monitors its free funds flow to inform its capital allocation decisions. Free funds flow is also presented on a per share basis as a non-GAAP financial ratio. The following table reconciles adjusted funds flow to free funds flow.

(\$000s)	Three months ended		
	March 31, 2026	December 31, 2025	March 31, 2025
Adjusted funds flow	107,228	120,697	131,121
Capital expenditures	(44,750)	(64,764)	(73,295)
Free funds flow	62,478	55,933	57,826

Gross Petroleum and Natural Gas Sales

Gross petroleum and natural gas sales is calculated by adding crude oil, natural gas and NGLs revenue, before deducting certain gas processing expenses in arriving at petroleum and natural gas revenue as required under IFRS 15 *Revenue from Contracts with Customers*. These processing expenses associated with the processing of natural gas and NGLs revenue are a result of the Company transferring custody of the product at the terminal inlet, and therefore receiving net prices. This metric is used by management to quantify and analyze the realized price received before required processing deductions, against benchmark prices. The calculation of the Company's gross petroleum and natural gas sales is shown within the "Petroleum and Natural Gas Sales" section within this MD&A.

Royalties as a Percentage of Gross Petroleum and Natural Gas Sales

Royalties as a percentage of gross petroleum and natural gas sales is calculated as royalties divided by gross petroleum and natural gas sales. This metric is used by management to quantify the Company's royalty costs as they relate to revenue before deducting certain processing expenses and to better analyze how royalty rates change over time and compare to prior periods.

Net Operating Expenses

Net operating expense is calculated by deducting processing income primarily generated by processing third party production at processing facilities where the Company has an ownership interest, from operating expenses presented on the Statement of income (loss). Where the Company has excess capacity at one of its facilities, it will process third-party volumes to reduce the cost of ownership in the facility. The Company's primary business activities are not that of a midstream entity whose activities are focused on earning processing and other infrastructure-based revenues, and as such third-party processing revenue is netted against operating expenses in this MD&A. This metric is used by management to evaluate the Company's net operating expenses on a unit of production basis. Net operating expense per boe is a non-GAAP financial ratio and is calculated as net operating expense divided by total barrels of oil equivalent produced over a specific period of time. The calculation of the Company's net operating expenses is shown within the "Net Operating Expenses" section within this MD&A.

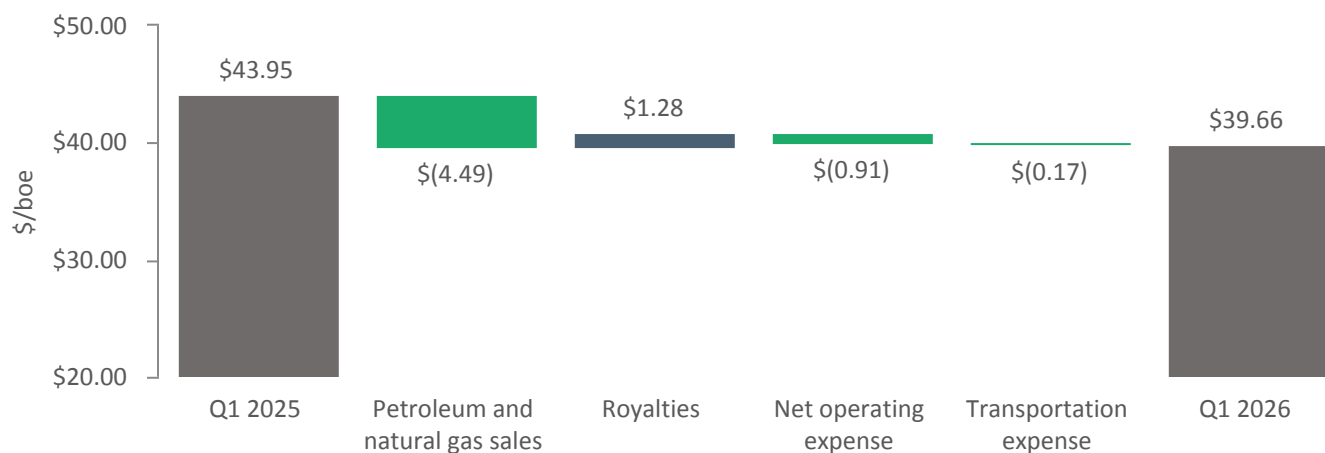
Operating Netback and Operating Netback, Net of Derivatives

The Company's operating netback is determined by deducting royalties, net operating expenses and transportation expenses from petroleum and natural gas sales. The Company's operating netback, net of derivatives is calculated by adding or deducting realized financial derivative commodity contract gains or losses from the operating netback. Derivative

contract termination payments are included in realized derivative commodity contract gains or losses for the purposes of calculating the operating netback. The Company's operating netback and operating netback, net of derivatives are used in operational and capital allocation decisions. Presenting operating netback and operating netback, net of derivatives on a per boe basis is a non-GAAP financial ratio and allows management to better analyze performance against prior periods on a per unit of production basis. The calculation of the Company's operating netbacks and operating netback, net of derivatives are summarized as follows.

(\$000s)	Three months ended		
	March 31, 2026	December 31, 2025	March 31, 2025
Petroleum and natural gas sales	270,237	233,554	278,081
Royalties	(30,095)	(26,710)	(33,893)
Net operating expenses	(79,518)	(77,272)	(73,441)
Transportation expenses	(6,716)	(6,317)	(5,845)
Operating netback	153,908	123,255	164,902
Realized gain (loss) on derivatives	(21,168)	13,345	(7,335)
Operating netback, net of derivatives	132,740	136,600	157,567
(\$ per boe amounts)			
Petroleum and natural gas sales	69.64	58.15	74.13
Royalties	(7.76)	(6.65)	(9.04)
Net operating expenses	(20.49)	(19.24)	(19.58)
Transportation expenses	(1.73)	(1.57)	(1.56)
Operating netback	39.66	30.69	43.95
Realized gain (loss) on derivatives	(5.45)	3.32	(1.96)
Operating netback, net of derivatives	34.21	34.01	41.99

Change in Operating Netback Three months ended March 31



Enterprise value

The Company's enterprise value is calculated as total market capitalization plus net debt. Enterprise value is used to assess the valuation of the Company. Refer to the *Liquidity and Capital Resources* section in this MD&A for further information.

Capital Management Measures

NI 52-112 defines a capital management measure as a financial measure that: (i) is intended to enable an individual to evaluate an entity's objectives, policies and processes for managing the entity's capital; (ii) is not a component of a line item disclosed in the primary financial statements of the entity; (iii) is disclosed in the notes to the financial statements of the entity; and (iv) is not disclosed in the primary financial statements of the entity. Please refer to note 13 "Capital Management" in Saturn's financial statements as at and for the period ended March 31, 2026, for additional disclosure on: adjusted working capital deficit (surplus), net debt, adjusted EBITDA, adjusted funds flow, free funds flow, annualized quarterly adjusted funds flow, and net debt to annualized quarterly adjusted funds flow, each of which are capital management measures used by the Company in this MD&A.

Supplementary Financial Measures

NI 52-112 defines a supplementary financial measure as a financial measure that: (i) is, or is intended to be, disclosed on a periodic basis to depict the historical or expected future financial performance, financial position or cash flow of an entity; (ii) is not disclosed in the financial statements of the entity; (iii) is not a non-GAAP financial measure; and (iv) is not a non-GAAP ratio. The supplementary financial measures used in this MD&A are either a per unit disclosure of a corresponding GAAP measure, or a component of a corresponding GAAP measure, presented in the financial statements. Supplementary financial measures that are disclosed on a per unit basis are calculated by dividing the aggregate GAAP measure (or component thereof) by the applicable unit for the period. Supplementary financial measures that are disclosed on a component basis of a corresponding GAAP measure are a granular representation of a financial statement line item and are determined in accordance with GAAP.

Product Type Information

The Company's aggregate average production for the past eight quarters and the references to "crude oil", "NGLs", and "natural gas" reported in this MD&A consist of the following product types, as defined in NI 51-101 and using a conversion ratio of 1 Bbl : 6 Mcf where applicable:

	2026	2025				2024		
	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Average daily production								
Light & medium crude oil (bbls/d)	27,645	27,962	25,825	26,712	27,697	27,330	24,992	18,346
Heavy crude oil (bbls/d)	3,199	3,325	3,327	3,438	3,445	3,119	4,002	2,664
NGLs (bbls/d)	3,938	4,052	4,180	3,310	3,318	3,381	3,407	2,673
Conventional natural gas (mcf/d)	50,004	49,906	46,860	41,740	43,319	43,328	39,885	38,664
Total (boe/d)	43,116	43,657	41,142	40,417	41,680	41,051	39,049	30,127

BOE PRESENTATION

Boe means barrel of oil equivalent. All boe conversions in this MD&A are derived by converting gas to oil at the ratio of six thousand cubic feet ("Mcf") of natural gas to one barrel ("Bbl") of oil. Boe may be misleading, particularly if used in isolation. A Boe conversion rate of 1 Bbl : 6 Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio of oil compared to natural gas based on currently prevailing prices is significantly different than the energy equivalency ratio of 1 Bbl : 6 Mcf, utilizing a conversion ratio of 1 Bbl : 6 Mcf may be misleading as an indication of value.

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL STATEMENTS

The information provided in this report, including the financial statements, is the responsibility of management. In the preparation of these statements, estimates are sometimes necessary in the determination of future values for certain assets or liabilities. Management believes such estimates have been based on careful judgments and have been properly reflected in the financial statements.

DIRECTORS AND EXECUTIVE OFFICERS

As of the date of this report the Company had the following directors and executive officers:

John Jeffrey	Chief Executive Officer and Director
Scott Sanborn	Chief Financial Officer
Justin Kaufmann	Chief Development Officer
Grant MacKenzie	Chief Legal Officer
Ivan Bergerman	Director
Andrew Claugus	Director
Thomas Gutschlag	Director
Lynn A. Peterson	Director
Jim Payne	Director
Christopher Ryan	Director
S. Janet Yang	Director

ADVISORIES AND FORWARD-LOOKING INFORMATION

Certain information in this MD&A, including all statements that are not historical facts, constitutes forward-looking information within the meaning of applicable Canadian securities laws. Such forward-looking information may include, but is not limited to, information which reflect management's expectations regarding the Company's future growth and business plans, the effects of the Company's acquisitions and dispositions on the Company's strategy, land holdings and profitability, the continued availability of adequate financing and funds flow to fund the Company's planned expenditures, results of operations (including, without limitation, future production and capital expenditures), performance (both operational and financial), the impact of hedging on the Company's operations and business prospects (including the timing and development of new reserves and the success of exploration activities) and opportunities, the Company's liquidity needs, including its ability to source its liquidity requirements, the sufficiency of the Company's capital structure and projected adjusted funds flow on its continuing operations, the risks associated with financial instruments and the methods by which the Company manages such risks and the impact of changes to critical accounting estimates and new accounting pronouncements. Often, this information includes words such as "plans", "expects" or "does not expect", "is expected", "budget", "scheduled", "estimates", "forecasts", "intends", "anticipates" or "does not anticipate" or "believes" or variations of such words and phrases or statements that certain actions, events or results "may", "could", "would", "might" or "will" be taken, occur or be achieved.

In making and providing the forward-looking information included in this MD&A the Company's assumptions may include among other things: (i) that there are no material delays in the optimization of operations at the properties; (ii) assumptions about operating costs and expenditures; (iii) assumptions about future production recovery and cash flows; (iv) that there is no unanticipated fluctuation in foreign exchange rates; (v) the ability to replace and expand oil and natural gas reserves through acquisition, development or exploration, and (vi) that there is no material deterioration in general economic conditions. Although management believes that the assumptions made and the expectations represented by such information are reasonable, there can be no assurance that the forward-looking information will prove to be accurate. By its nature, forward-looking information is based on assumptions and involves known and unknown risks, uncertainties and other factors that may cause the Company's actual results, performance or achievements, or results, to be materially different from future results, performance or achievements expressed or implied by such forward-looking information. Such risks, uncertainties and other factors include among other things the following: (i) the risk that additional financing will not be obtained as and when required; (ii) material increases in operating costs; (iii) adverse fluctuations in foreign exchange rates; (iv) commodity price fluctuations; (v) environmental risks and changes in environmental legislation; and (vi) drilling results differing from expectations and plans.

This MD&A (See "*Risks and Uncertainties*") contains information on risks, uncertainties and other factors relating to the forward-looking information. Although the Company has attempted to identify factors that would cause actual actions, events or results to differ materially from those disclosed in the forward-looking information, there may be other factors that cause actual results, performances, achievements or events not to be anticipated, estimated or intended. Also, many of the factors are beyond the Company's control. Accordingly, readers should not place undue reliance on forward-looking information. The Company undertakes no obligation to reissue or update forward looking information as a result of new information or events after the date of this MD&A except as may be required by law. All forward-looking information disclosed in this document is qualified by this cautionary statement.