

SATURN OIL & GAS INC.

Q2 2025 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 June 30, 2025 and for the three and six months ended June 30, 2025 and 2024. This MD&A is dated and based on information available as at July 30, 2025 and should be read in conjunction with the Company's unaudited condensed consolidated interim financial statements ("financial statements") and the notes thereto as at June 30, 2025 and for the three and six months ended June 30, 2025 and 2024. Additional information relating to Saturn, including Saturn's Annual Information Form for the year ended December 31, 2024, 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 51-112 - *Non-GAAP and Other Financial Measures* ("NI 51-112") 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.

Q2 2025 HIGHLIGHTS

- Achieved quarterly average production of 40,417 boe/d, compared to 30,127 boe/d in the second quarter of 2024 reflecting production contributions from the South Saskatchewan Acquisition (as defined below), which closed on June 14, 2024, and new well production from the Company's 2H 2024 and 1H 2025 drilling programs;
- Recognized petroleum and natural gas sales of \$236.7 million, up from \$208.9 million in the second quarter of 2024;
- Generated quarterly adjusted EBITDA⁽¹⁾ of \$131.7 million, compared to \$106.0 million in the second quarter of 2024;
- Achieved quarterly adjusted funds flow⁽¹⁾ of \$108.9 million or \$0.56/share, up from \$88.6 million or \$0.52/share, in the second quarter of 2024;
- Invested \$15.8 million in capital expenditures⁽¹⁾ during the second quarter of 2025, consisting primarily of turnaround and facilities spending commensurate with spring break-up;
- Generated free funds flow⁽¹⁾ of \$93.0 million, up from \$66.1 million in the second quarter of 2024;
- Exited the second quarter of 2025 with \$694.8 million of net debt⁽¹⁾, equating to a net debt to annualized quarterly adjusted funds flow⁽¹⁾ of 1.6x; and
- Repurchased 1,998,180 shares for cancellation under the Company's Normal Course Issuer Bid ("NCIB") at a weighted average price of \$1.65 per share for a total cost of \$3.3 million.

⁽¹⁾ See Non-GAAP and Other Financial Measures

FINANCIAL AND OPERATING HIGHLIGHTS

(\$000s, except per share amounts)	Three months ended			Six months ended	
	June 30, 2025	March 31, 2025	June 30, 2024	June 30, 2025	June 30, 2024
FINANCIAL HIGHLIGHTS					
Petroleum and natural gas sales	236,712	278,081	208,853	514,793	377,072
Cash flow from operating activities	89,865	165,372	50,545	255,237	120,767
Operating netback, net of derivatives ⁽¹⁾	131,833	157,567	109,359	289,400	201,070
Adjusted EBITDA ⁽¹⁾	131,712	153,185	106,034	284,897	194,187
Adjusted funds flow ⁽¹⁾	108,854	131,121	88,643	239,975	156,821
per share - Basic ⁽¹⁾	0.56	0.66	0.52	1.22	0.99
- Diluted ⁽¹⁾	0.53	0.65	0.51	1.16	0.95
Free funds flow ⁽¹⁾	93,012	57,826	66,094	150,838	100,306
per share - Basic ⁽¹⁾	0.48	0.29	0.39	0.77	0.63
- Diluted ⁽¹⁾	0.45	0.29	0.38	0.73	0.61
Net income (loss)	95,054	37,819	41,805	132,873	(21,177)
per share - Basic	0.49	0.19	0.25	0.67	(0.13)
- Diluted	0.46	0.19	0.24	0.64	(0.13)
Acquisitions, net of cash acquired	5,132	-	543,145	5,132	543,145
Proceeds from dispositions	-	-	(25,708)	-	(25,708)
Capital expenditures ⁽¹⁾	15,842	73,295	22,549	89,137	56,515
Total assets	2,103,571	2,188,307	2,024,432	2,103,571	2,024,432
Net debt ⁽¹⁾ , end of period	694,835	813,893	792,193	694,835	792,193
Shareholders' equity	929,573	837,958	737,064	929,573	737,064
Common shares outstanding, end of period	194,809	196,212	204,041	194,809	204,041
Weighted average, basic	195,644	198,113	169,267	196,872	158,780
Weighted average, diluted	206,040	202,727	174,723	207,268	164,215
OPERATING HIGHLIGHTS					
Average production volumes					
Crude oil (bbls/d)	30,150	31,142	21,010	30,643	19,996
NGLs (bbls/d)	3,310	3,318	2,673	3,314	2,509
Natural gas (mcf/d)	41,740	43,319	38,664	42,526	34,540
Total boe/d	40,417	41,680	30,127	41,045	28,262
% Oil and NGLs	83%	83%	79%	83%	80%
Average realized prices					
Crude oil (\$/bbl)	79.72	90.48	101.54	85.15	95.41
NGLs (\$/bbl)	40.24	52.95	44.33	46.57	44.29
Natural gas (\$/mcf)	1.80	2.48	1.37	2.14	1.84
Processing expenses (\$/boe)	(0.26)	(0.26)	(0.33)	(0.26)	(0.38)
Petroleum and natural gas sales (\$/boe)	64.36	74.13	76.18	69.29	73.31
Operating netback (\$/boe)					
Petroleum and natural gas sales	64.36	74.13	76.18	69.29	73.31
Royalties	(7.68)	(9.04)	(9.48)	(8.36)	(9.17)
Net operating expenses ⁽¹⁾	(18.28)	(19.58)	(18.12)	(18.93)	(18.91)
Transportation expenses	(1.65)	(1.56)	(1.47)	(1.60)	(1.40)
Operating netback ⁽¹⁾	36.75	43.95	47.11	40.40	43.83
Realized loss on derivatives	(0.91)	(1.96)	(7.21)	(1.44)	(4.74)
Operating netback, net of derivatives ⁽¹⁾	35.84	41.99	39.90	38.96	39.09

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

ACQUISITIONS AND DISPOSITIONS

For the three months ended June 30, 2025, the Company executed a corporate acquisition in the Southeast Saskatchewan business unit for approximately \$5.0 million. The acquisition resulted in an increase in PP&E of approximately \$7.6 million and the assumption of \$2.6 million in decommissioning liabilities.

Brazeau Acquisition

On October 1, 2024, the Company acquired certain oil and gas properties in the Brazeau area of Alberta. During the three months ended June 30, 2025, final adjustments to the purchase price of \$0.1 million were paid resulting in total cash consideration of \$20.6 million.

South Saskatchewan Acquisition

On June 14, 2024, the Company acquired certain oil and gas properties in southern Saskatchewan (the “South Saskatchewan Acquisition”) for total cash consideration of \$534.2 million. The South Saskatchewan Acquisition comprised of two distinct asset packages including Battrum area assets located in Southwest Saskatchewan and Flat Lake area assets located in Southeast Saskatchewan. The South Saskatchewan Acquisition was accounted for as a business combination using the acquisition method of accounting, whereby the assets acquired and liabilities assumed are recorded at the estimated fair value on the acquisition date.

Swan Hills Disposition

On June 4, 2024, the Company disposed of its non-core Deer Mountain property in North Alberta (the “Swan Hills Disposition”) for cash consideration of \$25.7 million with a carrying value of \$25.6 million resulting in a gain of \$0.1 million.

Adonai Resources II Corp

On May 6, 2024, the Company completed the acquisition of Adonai Resources II Corp. (the “Adonai Acquisition”) for total cash consideration of \$8.3 million. The Company applied the optional IFRS 3 concentration test which resulted in acquisition being accounted for as an asset acquisition recorded at cost.

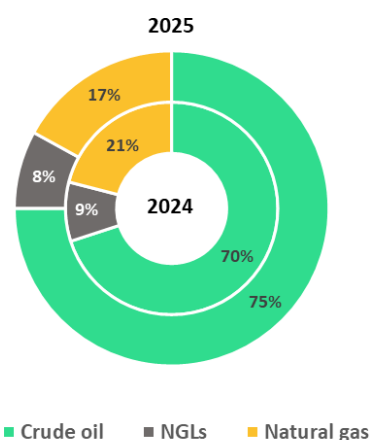
PRODUCTION

	June 30, 2025	Three months ended		June 30, 2025	Six months ended
		March 31, 2025	June 30, 2024		June 30, 2024
Crude oil (bbls/d) ⁽¹⁾	30,150	31,142	21,010	30,643	19,996
NGLs (bbls/d)	3,310	3,318	2,673	3,314	2,509
Natural gas (mcf/d) ⁽¹⁾	41,740	43,319	38,664	42,526	34,540
Total boe/d ⁽²⁾	40,417	41,680	30,127	41,045	28,262
Oil and liquids %	83%	83%	79%	83%	80%

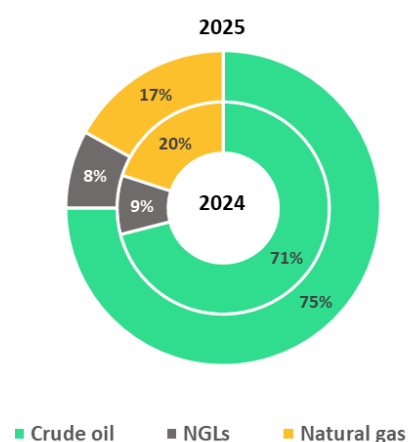
(1) "Crude oil" refers to light and medium crude oil and heavy crude oil combined. "Natural gas" refers to conventional natural gas. For further breakdown of crude oil and natural gas production volumes, refer to the "Product Type Information" section of this MD&A.

(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.

Production by Volume
Three Months Ended June 30,



Production by Volume
Six Months Ended June 30,



Production volumes increased to 40,417 boe/d for the three months ended June 30, 2025 from 30,127 boe/d in the comparative quarter of 2024. The increase is attributed to production contribution from the South Saskatchewan Acquisition and new well production additions from a successful second half 2024 and first half 2025 development capital program, which more than offset natural well declines.

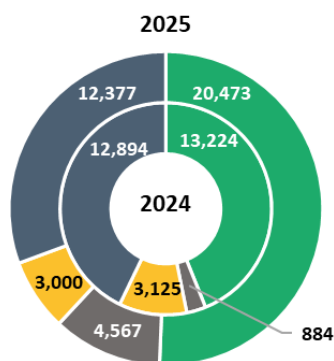
Production volumes decreased by 1,263 boe/d during the three months ended June 30, 2025 compared to the three months ended March 31, 2025, due to natural declines on account of limited new well development activity during spring break-up, in addition to increased facility downtime to complete turnarounds and routine annual maintenance.

The following table summarizes Saturn's average production by business unit for the three and six months ended June 30, 2025 and 2024:

	Three months ended June 30, 2025				Three months ended June 30, 2024			
	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	17,544	1,628	7,805	20,473	11,650	877	4,181	13,224
Southwest Saskatchewan	4,539	1	160	4,567	878	-	38	884
West Central Saskatchewan	2,823	33	863	3,000	3,014	19	550	3,125
Central Alberta	5,244	1,648	32,912	12,377	5,468	1,777	33,895	12,894
Total boe/d	30,150	3,310	41,740	40,417	21,010	2,673	38,664	30,127

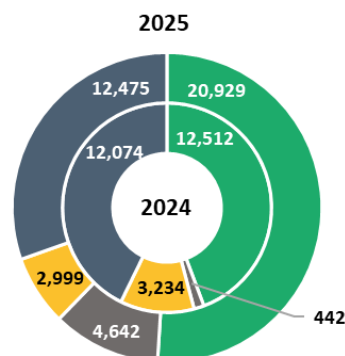
	Six months ended June 30, 2025				Six months ended June 30, 2024			
	Crude oil (bbls/d)	NGLs (bbls/d)	Natural gas (mcf/d)	Total (boe/d)	Crude oil (bbls/d)	NGLs (bbls/d)	Natural gas (mcf/d)	Total (boe/d)
Southeast Saskatchewan	18,025	1,607	7,781	20,929	10,962	833	4,299	12,512
Southwest Saskatchewan	4,611	1	177	4,642	439	-	19	442
West Central Saskatchewan	2,831	29	834	2,999	3,117	28	533	3,234
Central Alberta	5,176	1,677	33,734	12,475	5,478	1,648	29,689	12,074
Total boe/d	30,643	3,314	42,526	41,045	19,996	2,509	34,540	28,262

Production by Area
Three Months Ended June 30,



■ S.E. Saskatchewan ■ S.W. Saskatchewan
■ West Central Saskatchewan ■ Central Alberta

Production by Area
Six Months Ended June 30,



■ S.E. Saskatchewan ■ S.W. Saskatchewan
■ West Central Saskatchewan ■ Central Alberta

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 June 30, 2025, Southeast Saskatchewan produced 20,473 boe/d, an increase of 55% from 13,224 boe/d in the prior year comparative period. The increase is attributed to 5,792 boe/d of incremental production contributed from the Flat Lake assets acquired as part of the South Saskatchewan Acquisition that closed on June 14, 2024, in addition to new well production from our second half 2024 and first half 2025 capital programs. For the six months ended June 30, 2025, Southeast Saskatchewan produced 20,929 boe/d, an increase of 67% from 12,512 boe/d in the 2024 comparative period. The increase is primarily attributed to 6,836 boe/d of production contributed from the Flat Lake assets acquired as part of the South Saskatchewan Acquisition and new well production additions from our second half 2024 and first half 2025 capital programs.

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 June 30, 2025, Southwest Saskatchewan produced 4,567 boe/d compared to 884 boe/d in the prior year comparative period. For the six months ended June 30, 2025, Southwest Saskatchewan produced 4,642 boe/d compared to 442 boe/d in the 2024

comparative period. The Battrum assets were acquired on June 14, 2024 as part of the South Saskatchewan Acquisition. As a result, the significant increase in production for both the three and six months ended June 30, 2025 is attributed to there being only 17 days of production contribution from these assets in the prior year comparative periods.

West Central Saskatchewan

The core producing properties in West Central Saskatchewan consist of our Viking assets, which produced 3,000 boe/d for the three months ended June 30, 2025, compared to 3,125 boe/d in the prior year comparative period. For the six months ended June 30, 2025, West Central Saskatchewan produced 2,999 boe/d, a decrease of 7% from 3,234 boe/d in the comparative 2024 period. The decrease is attributed to natural declines exceeding new well production on account of reduced development capital directed towards the West Central Saskatchewan business unit during the first half of 2025.

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 June 30, 2025, Central Alberta produced 12,377 boe/d, a decrease of 4% from 12,894 boe/d in the prior year comparative period. The decrease is attributed to the Swan Hills Disposition completed on June 4, 2024, combined with unplanned third party natural gas facility downtime in Brazeau during the second quarter of 2025. For the six months ended June 30, 2025, Central Alberta produced 12,475 boe/d, an increase of 3% from 12,074 boe/d in the 2024 comparative period. The increase is attributed to new well production additions in Kaybob during the second half of 2024 and in the Cardium during the first half of 2025, which more than offset the impact of natural declines and the Swan Hills Disposition.

BENCHMARK AND REALIZED PRICES

	Three months ended			Six months ended	
	June 30, 2025	March 31, 2025	June 30, 2024	June 30, 2025	June 30, 2024
Average benchmark prices					
WTI (US\$/bbl) ⁽¹⁾	63.71	71.42	80.55	67.55	78.76
Exchange rate (US\$/CA\$)	1.37	1.44	1.37	1.41	1.36
WTI (CA\$/bbl)	88.16	102.49	110.22	95.29	107.02
MSW (\$/bbl) ⁽²⁾	84.22	95.34	105.25	89.75	98.71
Midale (\$/bbl) ⁽³⁾	82.10	92.39	103.44	87.22	95.10
LSB (\$/bbl) ⁽⁴⁾	82.84	93.62	104.26	88.20	96.93
Fosterton (\$/bbl) ⁽⁵⁾	75.00	85.42	92.66	80.18	86.80
WCS (\$/bbl) ⁽⁶⁾	73.93	84.30	91.61	79.09	84.69
AECO (\$/mcf) ⁽⁷⁾	1.69	2.16	1.18	1.92	1.84
Average differentials					
MSW (US\$/bbl) ⁽²⁾	(2.83)	(4.98)	(3.63)	(3.90)	(6.14)
WCS (US\$/bbl) ⁽⁶⁾	(10.26)	(12.68)	(13.60)	(11.47)	(16.46)
LSB (\$/bbl) ⁽⁴⁾	(5.32)	(8.88)	(5.96)	(7.09)	(10.10)
Average realized prices					
Crude oil (\$/bbl)	79.72	90.48	101.54	85.15	95.41
NGLs (\$/bbl)	40.24	52.95	44.33	46.57	44.29
Natural gas (\$/mcf)	1.80	2.48	1.37	2.14	1.84
Processing expenses (\$/boe)	(0.26)	(0.26)	(0.33)	(0.26)	(0.38)
Petroleum and natural gas sales (\$/boe)	64.36	74.13	76.18	69.29	73.31

(1) West Texas Intermediate ("WTI")

(2) Mixed Sweet Blend ("MSW") Par at Edmonton

(3) Midale Par at Cromer

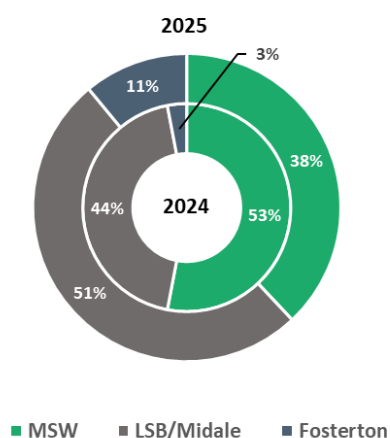
(4) Light Sour Blend ("LSB") Par at Cromer

(5) Fosterton Par at Regina

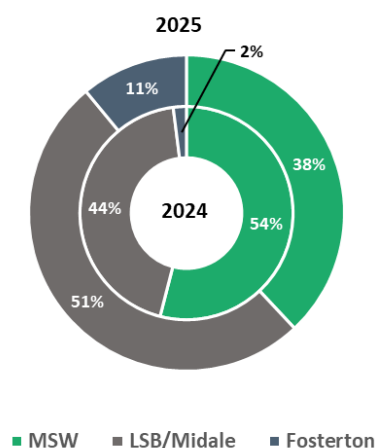
(6) Western Canadian Select ("WCS") at Hardisty

(7) Alberta Energy Company ("AECO") 5A Daily Index Price for natural gas

Crude Oil Sales by Index
Three Months Ended June 30,



Crude Oil Sales by Index
Six Months Ended June 30,



For the three and six months ended June 30, 2025, the Company realized an average combined price for petroleum and natural gas sales of \$64.36 per boe and \$69.29 per boe versus \$76.18 per boe and \$73.31 per boe in the comparative 2024 period.

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.

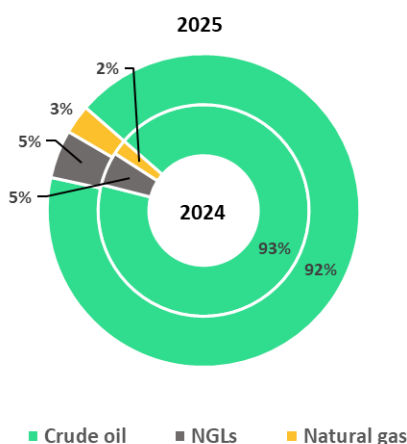
The Company's average realized oil price for the three months ended June 30, 2025 was \$79.72 per bbl, a 21% decrease from \$101.54 per bbl in the prior year comparative period. The Company's average realized oil price for the six months ended June 30, 2025 was \$85.15 per bbl, an 11% decrease from \$95.41 per bbl in the comparative 2024 period. The decrease in realized pricing is consistent with the decrease in US\$WTI crude oil benchmark price, offset somewhat by the impact of a weaker Canadian dollar on crude oil sales denominated in US dollars and narrower Canadian crude oil differentials. The Company's average realized oil price decreased 12% during the three months ended June 30, 2025 compared to the three months ended March 31, 2025 due primarily to a decrease in the US\$WTI benchmark price and the strengthening of the Canadian dollar.

PETROLEUM AND NATURAL GAS SALES

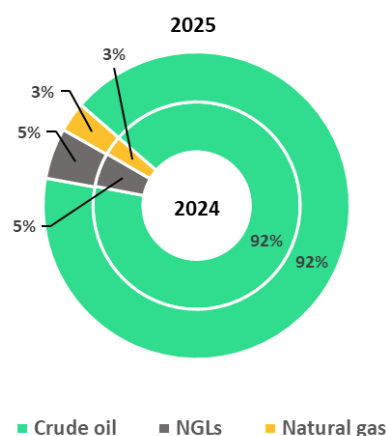
(\$000s)	Three months ended			Six months ended	
	June 30, 2025	March 31, 2025	June 30, 2024	June 30, 2025	June 30, 2024
Crude oil	218,712	253,587	194,132	472,299	347,233
NGLs	12,121	15,812	10,785	27,934	20,224
Natural gas	6,831	9,651	4,828	16,482	11,579
Gross petroleum and natural gas sales ⁽¹⁾	237,664	279,050	209,745	516,715	379,036
Less: Processing expenses	(952)	(969)	(892)	(1,922)	(1,964)
Petroleum and natural gas sales	236,712	278,081	208,853	514,793	377,072

(1) See Non-GAAP and Other Financial Measures

**Petroleum and Natural Gas Sales
Three Months Ended June 30,**



**Petroleum and Natural Gas Sales
Six Months Ended June 30,**



Gross petroleum and natural gas sales increased for the three and six months ended June 30, 2025 compared to the prior year, due to increased volumes associated with the South Saskatchewan Acquisition and new well development, partially offset by lower average realized commodity prices. Gross petroleum and natural gas sales decreased for the three months ended June 30, 2025 compared to the three months ended March 31, 2025 due to the decrease in volumes and lower average realized prices. 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)	June 30, 2025	Three months ended		June 30, 2025	Six months ended June 30, 2024
		March 31, 2025	June 30, 2024		
Royalties	28,239	33,893	26,002	62,132	47,191
% of gross petroleum and natural gas sales ⁽¹⁾	11.9%	12.1%	12.4%	12.0%	12.5%
\$ per boe	7.68	9.04	9.48	8.36	9.17

(1) See Non-GAAP and Other Financial Measures

Royalties increased for the three and six months ended June 30, 2025 compared to prior year, on a total basis, consistent with higher petroleum and natural gas sales. Royalties as a percentage of gross petroleum and natural gas sales decreased for the three and six months ended June 30, 2025 compared to prior year, due to the impact of royalty incentives on newer wells in Alberta. Royalties decreased for the three months ended June 30, 2025 compared to the three months ended March 31, 2025 due to the decrease in petroleum and natural gas sales. 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)	June 30, 2025	Three months ended		June 30, 2025	Six months ended June 30, 2024
		March 31, 2025	June 30, 2024		
Operating expenses	71,062	76,982	52,923	148,044	103,955
Less: processing income	(3,836)	(3,541)	(3,231)	(7,377)	(6,700)
Net operating expenses ⁽¹⁾	67,226	73,441	49,692	140,667	97,255
\$ per boe ⁽¹⁾	18.28	19.58	18.12	18.93	18.91

(1) See Non-GAAP and Other Financial Measures

Net operating expenses increased for the three and six months ended June 30, 2025 compared to prior year, due to higher variable costs associated with expanded field activity following the South Saskatchewan Acquisition. Net operating expenses per boe increased for the three and six months ended June 30, 2025 compared to prior year, due to higher relative costs per boe associated with the South Saskatchewan Acquisition. Net operating expenses decreased for the three months ended June 30, 2025 compared to the three months ended March 31, 2025 as field activity moderated during the second quarter due to challenging conditions associated with spring break-up.

TRANSPORTATION EXPENSES

(\$000s, except per boe amounts)	June 30, 2025	Three months ended		June 30, 2025	Six months ended	
		March 31, 2025	June 30, 2024		June 30, 2024	June 30, 2024
Transportation expenses	6,077	5,845	4,035	11,922	7,190	
\$ per boe	1.65	1.56	1.47	1.60	1.40	

Transportation expenses increased for the three and six months ended June 30, 2025 compared to prior year, on a total basis, due to the increase in pipeline tariffs and clean oil trucking costs associated with increased crude oil production volumes. Transportation expenses increased for the three months ended June 30, 2025 compared to the three months ended March 31, 2025 due to increased oil tariff rates in Southeast Saskatchewan as a result of the annual rate setting process. 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)	June 30, 2025	Three months ended		June 30, 2025	Six months ended	
		March 31, 2025	June 30, 2024		June 30, 2024	June 30, 2024
Realized loss on derivatives	(3,337)	(7,335)	(19,765)	(10,672)	(24,366)	
Unrealized gain (loss) on derivatives	64,082	1,688	11,398	65,770	(91,840)	
Realized loss on derivatives \$ per boe	(0.91)	(1.96)	(7.21)	(1.44)	(4.74)	

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 June 30, 2025 are described in the "Market Risk" section below. Realized losses occur on commodity hedge contracts when market prices for crude oil or natural gas settle at levels above those set in the Company's derivative contracts. Realized losses occur on differential hedge contracts when crude oil differentials settle at levels below those set in the Company's derivative contracts.

For the three and six months ended June 30, 2025, the Company realized a loss on its financial commodity contracts of \$3.3 million and \$10.7 million respectively, compared to a loss of \$19.8 million and \$24.4 million in the prior year periods. The decreased realized loss on derivatives reflects the decrease in market prices from those in the comparative 2024 periods. The realized loss on derivatives decreased \$4.0 million during the three months ended June 30, 2025 compared to the three months ended March 31, 2025, due to the decrease in the US\$WTI benchmark crude oil price.

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 June 30, 2025, the outstanding financial commodity contracts had a net asset value of \$22.6 million (December 31, 2024 - \$43.2 million liability).

GENERAL AND ADMINISTRATIVE EXPENSES

(\$000s, except per boe amounts)	June 30, 2025	Three months ended		Six months ended	
		March 31, 2025	June 30, 2024	June 30, 2025	June 30, 2024
General and administrative expenses	5,214	5,995	3,248	11,209	6,773
\$ per boe	1.42	1.60	1.18	1.51	1.32

General and administrative (“G&A”) expenses increased for the three and six months ended June 30, 2025, due to higher personnel and office related costs as a result of the Company’s growth following the South Saskatchewan Acquisition. G&A expenses decreased for the three months ended June 30, 2025 compared to the three months ended March 31, 2025, due to lower direct personnel costs associated with reduced employer statutory payments.

DEPLETION, DEPRECIATION AND AMORTIZATION

(\$000s, except per boe amounts)	June 30, 2025	Three months ended		Six months ended	
		March 31, 2025	June 30, 2024	June 30, 2025	June 30, 2024
Depletion, depreciation and amortization	72,640	74,098	48,150	146,738	90,379
\$ per boe	19.75	19.75	17.56	19.75	17.57

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 declining balance method for its corporate administrative assets.

DD&A expense increased for the three and six months ended June 30, 2025 compared to prior year, due to an increase in the carrying value of PP&E attributed to the South Saskatchewan Acquisition and associated increase in production volumes. The increase in DD&A on a per boe basis for the three and six months ended June 30, 2025 compared to prior year, reflects a higher relative increase in the depletable base compared to reserve value as a result of the South Saskatchewan Acquisition.

SHARE BASED PAYMENTS

(\$000s, except per boe amounts)	June 30, 2025	Three months ended		Six months ended	
		March 31, 2025	June 30, 2024	June 30, 2025	June 30, 2024
Share based payments	3,165	2,035	2,888	5,200	5,140
\$ per boe	0.86	0.54	1.05	0.70	1.00

The Company has an omnibus Long Term Incentive Plan (“LTIP”), 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 increased for the three and six months ended June 30, 2025 compared to prior year, due to annual grants of RSUs, PSUs and DSUs to directors, officers and employees in 2025. Share based payments expense increased for the three months ended June 30, 2025 compared to the three months ended March 31, 2025 due to additional grants during the second quarter of 2025.

FINANCING EXPENSES

(\$000s)	June 30, 2025	Three months ended		Six months ended	
		March 31, 2025	June 30, 2024	June 30, 2025	June 30, 2024
Interest expense, cash	21,274	22,662	17,787	43,936	38,192
Interest income	(476)	(598)	(396)	(1,074)	(826)
Amortization of original issue discount and debt issue costs	781	784	690	1,565	1,364
Accretion, debt instruments	-	-	9	-	22
Accretion, leases	1,881	1,918	556	3,799	905
Accretion, decommissioning obligations	3,813	3,925	3,329	7,738	6,815
Financing expenses	27,273	28,691	21,975	55,964	46,472

Financing expenses increased for the three and six months ended June 30, 2025 compared to prior year, due primarily to higher debt service costs related to the Company's Senior Notes (as defined below) denominated in US dollars, which replaced the Company's Senior Term Loan during the second quarter of 2024. Additionally, the increase in financing expenses is due to increased accretion on leases attributed to a third party gas handling agreement entered into during the third quarter of 2024, which qualified for lease recognition and increased accretion on decommissioning obligations attributed to decommissioning obligations added as part of the South Saskatchewan Acquisition. Financing expenses decreased for the three months ended June 30, 2025 compared to the three months ended March 31, 2025 due to lower cash interest expense on the Company's Senior Notes associated with a reduced principal balance following accelerated debt repayments made during the second quarter of 2025.

GAIN ON REPAYMENT OF SENIOR NOTES

For the six months ended June 30, 2025, the Company made additional principal repayments by purchasing US\$16.3 million of Senior Notes in the open market at a discount to par value for \$19.8 million, resulting in a \$2.8 million realized gain on repayment.

LOSS ON DEBT EXTINGUISHMENT

On June 14, 2024, the Company early retired its Senior Term Loan with a principal amount outstanding of \$364.7 million and associated early retirement fees of \$27.4 million paid to the lender. In addition, \$4.3 million of non-cash original issue discount and debt issue costs were accelerated and expensed in profit or loss.

DEFERRED TAXES

For the three and six months ended June 30, 2025, the Company recognized deferred tax expense of \$23.1 million and \$36.0 million respectively, compared to a deferred tax recoveries of \$1.4 million and \$21.1 million in the comparative 2024 period. The deferred tax expense relates to the non-cash change in the Company's deferred tax liabilities, resulting from the utilization of non-capital losses in the period.

FINANCIAL RESULTS OF OPERATIONS

(\$000s, except per boe amounts)	Three months ended			Six months ended	
	June 30, 2025	March 31, 2025	June 30, 2024	June 30, 2025	June 30, 2024
Cash flow from operating activities	89,865	165,372	50,545	255,237	120,767
per share - Basic	0.46	0.83	0.30	1.30	0.76
- Diluted	0.44	0.82	0.29	1.23	0.74
Adjusted funds flow ⁽¹⁾	108,854	131,121	88,643	239,975	156,821
per share - Basic ⁽¹⁾	0.56	0.66	0.52	1.22	0.99
- Diluted ⁽¹⁾	0.53	0.65	0.51	1.16	0.95
Free funds flow ⁽¹⁾	93,012	57,826	66,094	150,838	100,306
per share - Basic ⁽¹⁾	0.48	0.29	0.39	0.77	0.63
- Diluted ⁽¹⁾	0.45	0.29	0.38	0.73	0.61
Net income (loss)	95,054	37,819	41,805	132,873	(21,177)
per share - Basic	0.49	0.19	0.25	0.67	(0.13)
- Diluted	0.46	0.19	0.24	0.64	(0.13)

(1) See Non-GAAP and Other Financial Measures

Adjusted funds flow increased for the three and six months ended June 30, 2025 compared to prior year, primarily due to increased petroleum and natural gas sales, decreased realized loss on derivatives and increased realized foreign exchange gain, offset in part by increased royalties, increased net operating expense and increased transportation expense.

Adjusted funds flow decreased during the three months ended June 30, 2025 compared to the three months ended March 31, 2025 due to decreased petroleum and natural gas sales and increased transportation expenses, offset in part by decreased realized loss on derivatives, increased realized foreign exchange gain, decreased royalties and decreased net operating expenses.

For the three months ended June 30, 2025, the Company recorded net income of \$95.1 million compared to net income of \$41.8 million during the three months ended June 30, 2024. The increase in net income for the three months ended June 30, 2025 was primarily due to increased adjusted funds flow, increased unrealized gain on derivatives, an unrealized foreign exchange gain on Saturn's U.S. denominated Senior Notes and the absence of a loss on debt extinguishment related to the early retirement of Saturn's Senior Term Loan in the prior year, partially offset by increased DD&A and absence of the gain recognized on the South Saskatchewan Acquisition in the prior year.

For the six months ended June 30, 2025, the Company recorded net income of \$132.9 million compared to a net loss of \$21.2 million during the six months ended June 30, 2024. The increase in net income for the six months ended June 30, 2025 was primarily due to increased adjusted funds flow, an unrealized gain on derivatives compared to an unrealized loss in the prior year, an unrealized foreign exchange gain on Saturn's U.S. denominated Senior Notes and the absence of a loss on debt extinguishment related to the early retirement of Saturn's Senior Term Loan in the prior year, partially offset by increased DD&A and absence of the gain recognized on the South Saskatchewan Acquisition in the prior year.

The increase in net income for the three months ended June 30, 2025 compared to the three months ended March 31, 2025 is primarily due to an increased unrealized gain on derivative contracts, increased unrealized foreign exchange gain on the Company's US denominated Senior Notes, decreased DD&A and decreased debt service costs from accelerated repayments made on Saturn's U.S. denominated Senior Notes during the second quarter, partially offset by decreased adjusted funds flow.

CAPITAL EXPENDITURES

(\$000s)	Three months ended			Six months ended	
	June 30, 2025	March 31, 2025	June 30, 2024	June 30, 2025	June 30, 2024
Drilling and Completions	4,348	54,041	14,320	58,389	37,839
Facilities	6,372	15,940	3,881	22,312	9,604
Land and lease	1,844	424	1,594	2,268	2,961
Seismic	(17)	1,368	30	1,351	385
F&D expenditures⁽¹⁾	12,547	71,773	19,825	84,320	50,789
Capitalized G&A and other	3,295	1,522	2,724	4,817	5,726
Capital expenditures	15,842	73,295	22,549	89,137	56,515
Capitalized G&A and other	(3,295)	(1,522)	(2,724)	(4,817)	(5,726)
Corporate acquisition, net of cash acquired	5,031	-	8,319	5,031	8,319
Property acquisitions	101	-	534,826	101	534,826
Property disposition	-	-	(25,708)	-	(25,708)
FD&A expenditures⁽¹⁾	17,679	71,773	537,262	89,452	568,226

(1) See Non-GAAP and Other Financial Measures

Capital expenditures decreased for the three months ended June 30, 2025, compared to the second quarter of 2024, due to reduced drilling and completions activity attributed to the deferral of our second half 2025 capital program to later in the third quarter given current market conditions.

Capital expenditures increased for the six months ended June 30, 2025, compared to prior year, due to an increased drilling program and increased facility infrastructure development of Saturn's expanded asset base resulting from the South Saskatchewan Acquisition. The Company's first half 2025 operated drilling program was heavily focused on development of acquired locations in Southeast Saskatchewan. Facility expenditures during the first six months of 2025 included continued investment in our waterflood projects.

Capital expenditures decreased during the three months ended June 30, 2025 compared to the three months ended March 31, 2025 due to a curtailed drilling program on account of spring break-up. Facilities spending also decreased from the prior quarter, consisting primarily of battery turnarounds and other planned maintenance programs.

During the three months ended June 30, 2025, the Company drilled one gross (0.2 net) well in Southeast Saskatchewan compared to seven gross (6.0 net) wells in the prior year comparative period: six in Southeast Saskatchewan; and one in West Central Saskatchewan.

During the six months ended June 30, 2025, the Company drilled 34 gross (24.6 net) wells: 27 in Southeast Saskatchewan; five in West Central Saskatchewan; one in Southwest Saskatchewan; and one in Central Alberta compared to 16 gross (14.3 net) wells in the prior year comparative period: twelve in Southeast Saskatchewan; three in Central Alberta; and one in West Central Saskatchewan.

	Three months ended June 30,				Six months ended June 30,			
	2025		2024		2025		2024	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Wells drilled	1	0.2	7	6.0	34	24.6	16	14.3

CAPITAL RESOURCES AND LIQUIDITY

Senior Notes

The Company has US\$568.8 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. As at June 30, 2025, the principal balance on the Senior Notes was \$775.9 million (US\$568.8 million). 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%.

We 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

At June 30, 2025, 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 agreement governing the Credit Facility includes an additional \$100 million accordion feature allowing for the expansion up to \$250 million in total, subject to certain conditions. The Credit Facility is committed on a revolving basis until June 14, 2026, 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 November 30, 2025.

As at June 30, 2025, 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 ("CORRA"), or Secured Overnight Financing Rate ("SOFR") 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.

As at the date of this MD&A, the Company had no amounts drawn nor any of 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 June 30, 2025, \$8.7 million was drawn under the LC Facility (December 31, 2024 – \$7.9 million). The PSG is subject to annual renewal with the next scheduled renewal date of June 30, 2026.

Liquidity

(\$000s)	June 30, 2025	December 31, 2024
Credit Facility ⁽¹⁾	150,000	150,000
LC Facility ⁽²⁾	11,300	12,100
Adjusted working capital surplus ⁽³⁾	68,596	14,433
Total Liquidity	229,896	176,533

(1) Represents \$nil drawn on the \$150.0 million Credit Facility.

(2) Represents \$8.7 million drawn on the \$20.0 million LC Facility (December 31, 2024 - \$7.9 million).

(3) 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. 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 Saturn's 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 \$694.8 million as at June 30, 2025 compared to \$860.2 million as at December 31, 2024. The Company's net debt to annualized quarterly adjusted funds flow was 1.6x at June 30, 2025.

(\$000s)	June 30, 2025	December 31, 2024
Net debt ⁽¹⁾	694,835	860,155
Total market capitalization ⁽²⁾	411,047	431,039
Enterprise value ⁽¹⁾	1,105,882	1,291,194
Net debt as a percentage of enterprise value	63%	67%
Annualized quarterly adjusted funds flow ⁽¹⁾	435,416	516,820
Net debt to annualized quarterly adjusted funds flow ⁽¹⁾	1.6x	1.7x

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

(2) Calculated as 194,809,345 Common Shares outstanding as of June 30, 2025 multiplied by the TSX closing share price 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 section of this MD&A.

SHARE CAPITAL

The Company is authorized to issue an unlimited number of Common Shares without par value.

On August 23, 2024, the TSX approved the commencement of the Company's NCIB. Pursuant to the NCIB, the Company will purchase for cancellation, from time to time, as it considers advisable, up to a maximum of 11,306,825 Common Shares between August 27, 2024 and August 26, 2025.

For the six months ended June 30, 2025, the Company repurchased 4,791,704 Common Shares under its NCIB at a weighted average price of \$1.90 per share for a total cost of \$9.1 million. Subsequent to June 30, 2025, the Company repurchased an additional 368,256 Common Shares at a weighted average price of \$2.26 per share for a total cost of \$0.8 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. Subsequent to June 30, 2025, the SIB expired with 1,608,182 common shares being tendered and taken up under the SIB for an aggregate purchase price of \$3.5 million.

As at the date of this MD&A, June 30, 2025 and December 31, 2024, the following Common Shares are outstanding and/or remain issuable upon exercise of the underlying securities.

(000s) Number of securities	July 30, 2025	June 30, 2025	December 31, 2024
Common Shares outstanding	192,833	194,809	199,555
Warrants	-	-	6,871
Performance warrants	7,000	7,000	7,000
Restricted share units	8,742	8,764	4,088
Stock options	614	614	718
Deferred share units	387	387	-
Performance share units	1,245	1,245	622
Fully diluted shares outstanding	210,821	212,819	218,854

COMMITMENTS AND CONTRACTUAL OBLIGATIONS

The Company has the following contractual obligations and commitments as at July 30, 2025:

(\$000s)	Less than 1 year	1-3 years	3-5 years	Greater than 5 years	Total
Senior Notes ⁽¹⁾	88,680	177,359	509,906	-	775,945
Interest payments ⁽²⁾	76,279	126,894	50,615	-	253,788
Lease liabilities ⁽³⁾	6,231	8,512	5,581	-	20,324
Gas processing contracts	12,725	23,619	21,151	47,457	104,952
	183,915	336,384	587,253	47,457	1,155,009

- (1) Represents the remaining principal amount owing of US\$568.8 million on the Company's Senior Notes converted at the period end exchange rate of 1.3643
- (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

RISKS AND UNCERTAINTIES

Factors beyond Saturn's control may determine whether any oil and gas reserves the Company discovers are sufficiently economic 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 favor 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 \$77.9 million change to net income (loss) before tax (December 31, 2024 – \$89.4 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 July 30, 2025:

Period	Forward Rate Contracts- USD/CAD		
	Notional Amount (\$000s, US\$)	Rate	Contract Type
Q3 2025	17,100	1.33935	Average rate currency swap
Q4 2025	45,000	1.33935	Average rate currency swap
Q1 2026	17,100	1.33935	Average rate currency swap
Q2 2026	43,500	1.33935	Average rate currency swap
Q3 2026	17,100	1.33935	Average rate currency swap
Q4 2026	41,900	1.33935	Average rate currency swap
Q1 2027	17,100	1.33935	Average rate currency swap
Q2 2027	23,300	1.33935	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 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 \$44.2 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 financial derivative commodity contracts as at July 30, 2025:

Period	WTI Collars				WTI Swaps				WTI Puts	
	Volume bbls/d	Price ⁽¹⁾⁽²⁾ US\$/bbl	Volume bbls/d	Price ⁽¹⁾⁽²⁾ CA/bbl	Volume bbls/d	Price ⁽¹⁾ US\$/bbl	Volume bbls/d	Price ⁽¹⁾ CA\$/bbl	Volume bbls/d	Price ⁽¹⁾⁽²⁾ CA\$/bbl
Q3 2025	6,729	67.23-84.37	5,000	100.00-110.00	2,753	69.05	4,923	89.10	2,500	100.00
Q4 2025	1,684	65.00-68.10	5,000	100.00-110.00	2,637	68.99	4,674	89.05	-	-
Q1 2026	1,080	65.00-68.10	-	-	3,077	67.21	4,481	85.46	-	-
Q2 2026	-	-	-	-	4,028	67.30	4,320	85.47	-	-
Q3 2026	-	-	-	-	-	-	4,649	83.51	-	-
Q4 2026	-	-	-	-	-	-	4,463	83.47	-	-

(1) Weighted average prices for the period.

(2) For the reporting periods Q3 2025 to Q4 2025, the Company has a weighted average option premium of US\$3.41/bbl.

Period	MSW Differential		WCS Differential		Natural Gas Swaps				NGL Propane Swaps	
	Volume bbls/d	Price ⁽¹⁾ US\$/bbl	Volume bbls/d	Price ⁽¹⁾ US\$/bbl	Volume GJ/d	Price ⁽¹⁾ CA\$/GJ	Volume GJ/d	Price ⁽²⁾ CA\$/GJ	Volume bbls/d	Price ⁽¹⁾ US\$/bbl
Q3 2025	19,500	(3.41)	4,000	(12.91)	15,000	2.49	10,550	Index	375	49% WTI
Q4 2025	9,000	(4.61)	4,000	(13.95)	11,685	2.62	10,550	Index	375	49% WTI
Q1 2026	5,000	(4.60)	2,000	(14.25)	10,000	2.73	10,550	Index	375	49% WTI
Q2 2026	5,000	(4.10)	2,000	(13.05)	15,000	2.69	10,550	Index	-	-
Q3 2026	-	-	-	-	15,000	2.69	10,550	Index	-	-
Q4 2026	-	-	-	-	18,315	2.95	3,555	Index	-	-
Q1 2027	-	-	-	-	10,000	3.35	-	-	-	-

(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).

During the three months ended June 30, 2025, the Company terminated certain 2026 and 2027 WTI swap contracts with an average price of CA\$81.35/bbl for \$2.3 million.

General Risks

Petroleum and natural gas exploration and production can involve environmental risks such as litigation, physical and regulatory risks. Physical risks include the 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

Saturn's exploration and production infrastructure and other operations and activities emit greenhouse gases ("GHG") which may require the Company to comply with federal and/or provincial GHG 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 change measures that are ultimately put in place to prevent climate change or mitigate the effects. The direct or indirect costs of compliance with GHG-related regulations may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. Some of Saturn's significant facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage GHG emissions. In addition, climate change has been linked to long-term shifts in climate patterns and extreme weather conditions both of which pose the risk of causing operational difficulties.

SUMMARY OF QUARTERLY RESULTS

	2025		2024				2023	
	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
(\$000s, except per boe amounts)								
Financial:								
Petroleum and natural gas sales	236,712	278,081	268,845	262,379	208,853	168,219	185,384	201,066
Cash flow from operations	89,865	165,372	91,157	100,013	50,545	70,222	75,380	70,466
Adjusted funds flow ⁽¹⁾	108,854	131,121	129,205	94,065	88,643	68,178	80,247	76,477
Basic (\$/share) ⁽¹⁾	0.56	0.66	0.64	0.46	0.52	0.46	0.58	0.55
Diluted (\$/share) ⁽¹⁾	0.53	0.65	0.63	0.45	0.51	0.45	0.56	0.54
Net income (loss)	95,054	37,819	(26,318)	101,601	41,805	(62,982)	131,456	(111,156)
Basic (\$/share)	0.49	0.19	(0.13)	0.50	0.25	(0.42)	0.94	(0.80)
Diluted (\$/share)	0.46	0.19	(0.13)	0.49	0.24	(0.42)	0.92	(0.80)
Acquisitions	5,132	-	26,011	(4,749)	543,145	-	-	-
Dispositions	-	-	576	-	(25,708)	-	-	-
Capital expenditures ⁽¹⁾	15,842	73,295	105,420	84,381	22,549	33,966	57,175	35,271
Total assets	2,103,571	2,188,307	2,161,578	2,155,632	2,024,432	1,326,721	1,335,216	1,376,271
Common shares outstanding (000s)	194,809	196,212	199,555	203,103	204,041	161,206	139,313	139,313
Operational:								
Average daily production								
Crude oil (bbls/d)	30,150	31,142	30,449	28,994	21,010	18,981	19,407	19,132
NGLs (bbls/d)	3,310	3,318	3,381	3,407	2,673	2,344	2,533	2,287
Natural gas (mcf/d)	41,740	43,319	43,328	39,885	38,664	30,416	29,704	29,077
Total (boe/d)	40,417	41,680	41,051	39,049	30,127	26,394	26,891	26,265

(1) See Non-GAAP and Other Financial Measures

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 \$5.0 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 total cost of \$3.3 million. The Company made principal repayments of \$42.0 million (US\$32.5 million) on the Senior Notes, reducing net debt to \$694.8 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 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 total cost of \$5.8 million. The Company made principal repayments of \$23.2 million (US\$16.3 million) on the Senior Notes, reducing net debt to \$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 total cost of \$7.5 million. The Company made principal repayments of \$23.4 million (US\$16.3 million) on the Senior Notes, reducing net debt to \$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 total cost of \$2.7 million. The Company's initial principal repayment of US\$16.3 million was made on the Senior Notes, reducing net debt to \$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.

In the first quarter of 2024, the Company achieved adjusted funds flow of \$68.2 million driven by strong production of 26,394 boe/d and an operating netback, net of derivatives of \$38.18 per boe. The Company invested \$34.0 million in capital expenditures, drilling 9 wells (8.3 net). Principal repayments on the Senior Term Loan of \$76.1 million were made resulting in net debt of \$386.4 million. The Company enhanced liquidity with the completion of a bought-deal equity financing, issuing 22,223,000 Common Shares for gross proceeds of \$50.0 million.

In the fourth quarter of 2023, the Company achieved record adjusted funds flow of \$80.2 million driven by record production of 26,891 boe/d and an operating netback, net of derivatives of \$42.17 per boe. The Company invested \$57.2 million in capital expenditures, drilling 19 wells (16.9 net). Principal repayments on the Senior Term Loan of \$50.7 million were made resulting in net debt of \$460.5 million.

In the third quarter of 2023, the Company achieved adjusted funds flow of \$76.5 million driven by production of 26,265 boe/d and an operating netback, net of derivatives of \$43.74 per boe. The Company invested \$35.3 million in capital expenditures, drilling 20 wells (15.7 net). Principal repayments on the Senior Term Loan of \$50.7 million were made resulting in net debt of \$473.8 million.

STANDARDS ISSUED BUT NOT YET EFFECTIVE

In April 2024, the International Accounting Standards Board ("IASB") issued IFRS 18 *Presentation and Disclosure in Financial Statements* 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 June 30, 2025 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, RSUs, PSUs, or 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; and
- 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 (loss).
- 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			Six months ended	
	June 30, 2025	March 31, 2025	June 30, 2024	June 30, 2025	June 30, 2024
Cash flow used in investing activities	67,934	99,520	552,357	167,454	602,049
Change in non-cash working capital	(46,960)	(26,225)	(12,371)	(73,185)	(28,097)
Capital expenditures, net A&D	20,974	73,295	539,986	94,269	573,952
Acquisitions, net of cash acquired	(5,132)	-	(543,145)	(5,132)	(543,145)
Proceeds from disposition	-	-	25,708	-	25,708
Capital expenditures	15,842	73,295	22,549	89,137	56,515

F&D and FD&A Expenditures

Saturn uses finding and development (“F&D”) and finding, development, and acquisition (“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.

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 pershare basis as a non-GAAP financial ratio. The following table reconciles adjusted funds flow to free funds flow.

(\$000s)	Three months ended			Six months ended	
	June 30, 2025	March 31, 2025	June 30, 2024	June 30, 2025	June 30, 2024
Adjusted funds flow	108,854	131,121	88,643	239,975	156,821
Capital expenditures	(15,842)	(73,295)	(22,549)	(89,137)	(56,515)
Free funds flow	93,012	57,826	66,094	150,838	100,306

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.

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. 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 excluded from realized financial 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			Six months ended	
	June 30, 2025	March 31, 2025	June 30, 2024	June 30, 2025	June 30, 2024
Petroleum and natural gas sales	236,712	278,081	208,853	514,793	377,072
Royalties	(28,239)	(33,893)	(26,002)	(62,132)	(47,191)
Net operating expenses	(67,226)	(73,441)	(49,692)	(140,667)	(97,255)
Transportation expenses	(6,077)	(5,845)	(4,035)	(11,922)	(7,190)
Operating netback	135,170	164,902	129,124	300,072	225,436
Realized loss on financial derivatives ⁽¹⁾	(3,337)	(7,335)	(19,765)	(10,672)	(24,366)
Operating netback, net of derivatives	131,833	157,567	109,359	289,400	201,070
(\$ per boe amounts)					
Petroleum and natural gas sales	64.36	74.13	76.18	69.29	73.31
Royalties	(7.68)	(9.04)	(9.48)	(8.36)	(9.17)
Net operating expenses	(18.28)	(19.58)	(18.12)	(18.93)	(18.91)
Transportation expenses	(1.65)	(1.56)	(1.47)	(1.60)	(1.40)
Operating netback	36.75	43.95	47.11	40.40	43.83
Realized loss on financial derivatives	(0.91)	(1.96)	(7.21)	(1.44)	(4.74)
Operating netback, net of derivatives	35.84	41.99	39.90	38.96	39.09

(1) Includes early termination payment on certain WTI oil derivative contracts for the three and six months ended June 30, 2025 of \$2.3 million.

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 three and six months ended June 30, 2025, for additional disclosure on: adjusted working capital, 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:

	2025		2024				2023	
	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Average daily production								
Light & medium crude oil (bbls/d)	26,712	27,697	27,330	24,992	18,346	18,981	19,407	19,132
Heavy crude oil (bbls/d)	3,438	3,445	3,119	4,002	2,664	-	-	-
NGLs (bbls/d)	3,310	3,318	3,381	3,407	2,673	2,344	2,533	2,287
Conventional natural gas (mcf/d)	41,740	43,319	43,328	39,885	38,664	30,416	29,704	29,077
Total (boe/d)	40,417	41,680	41,051	39,049	30,127	26,394	26,891	26,265

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 and Director
Andrew Claugus	Director
Thomas Gutschlag	Director
Ivan Bergerman	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.