MANAGEMENT’S DISCUSSION AND ANALYSIS
For the year ended December 31, 2025

This management’s discussion and analysis of financial condition and results of operations (“MD&A”) of Obsidian Energy Ltd. (“Obsidian Energy”, the “Company”, “we”, “us”, “our”) should be read in conjunction with the Company's audited consolidated financial statements ("audited consolidated Financial Statements") for the year ended December 31, 2025. The date of this MD&A is February 18, 2026. All dollar amounts contained in this MD&A are expressed in millions of Canadian dollars unless noted otherwise.

For additional information, including Obsidian Energy’s audited consolidated Financial Statements and Annual Information Form, please go to the Company’s website at www.obsidianenergy.com, in Canada to the SEDAR+ website at www.sedarplus.ca or in the United States to the EDGAR website at www.sec.gov.

Throughout this MD&A and in other materials disclosed by the Company, we adhere to generally accepted accounting principles ("GAAP"), however the Company also employs certain non-GAAP measures to analyze financial performance, financial position, and cash flow, including funds flow from operations, netback, sales, gross revenues, net operating costs, net debt and free cash flow. Additionally, other financial measures are also used to analyze performance. These non-GAAP and other financial measures do not have any standardized meaning prescribed by International Financial Reporting Standards (“IFRS”) as issued by the International Accounting Standards Board and therefore may not be comparable to similar measures provided by other issuers. 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) and cash flow from operating activities, as indicators of our performance.

This MD&A also contains oil and natural gas information and forward-looking statements. Please see the Company's disclosure under the headings "Non-GAAP and Other Financial Measures", "Oil and Natural Gas Information", and "Forward-Looking Statements" included at the end of this MD&A.

Annual Financial Summary

	Year ended December 31		
(millions, except per share amounts)	**2025**	2024	2023
Production revenues	**$ 599.8**	$ 817.5	$ 720.6
Cash flow from operating activities	**239.8**	361.9	352.7
Basic per share (1)	**3.45**	4.76	4.36
Diluted per share (1)	**3.34**	4.57	4.19
Funds flow from operations (2)	**272.1**	432.0	377.6
Basic per share (3)	**3.92**	5.69	4.67
Diluted per share (3)	**3.79**	5.46	4.49
Net income (loss)	**35.2**	(202.6)	108.0
Basic per share	**0.51**	(2.67)	1.33
Diluted per share	**0.49**	(2.67)	1.28
Capital expenditures	**298.9**	343.1	292.5
Property acquisitions (dispositions), net (4)	**(208.0)**	83.4	0.6
Debt (5)	**184.0**	339.2	224.9
Total Assets	**$ 1,854.8**	$ 2,114.6	$ 2,250.4

(1) Supplementary financial measure. See "Non-GAAP and Other Financial Measures".
(2) Non-GAAP financial measure. See "Non-GAAP and Other Financial Measures".
(3) Non-GAAP ratio. See "Non-GAAP and Other Financial Measures".
(4) Excludes the InPlay Shares (as defined below) that were ultimately sold in August 2025 for $91.4 million. See "Pembina Disposition" for details.
(5) Includes drawings under the Company's syndicated credit facility and senior unsecured notes.

In the second quarter of 2025, the Company closed the disposition of our operated Pembina assets (the "Pembina Disposition") to InPlay Oil Corp ("InPlay"). Refer to the "Pembina Disposition" section below for further details. As a result of the Pembina Disposition, our production levels decreased compared to 2024, which resulted in lower production revenues, cash flow from operating activities and funds flow from operations. Commodity prices were also lower in 2025 compared to 2024, which also led to decreases in those figures.

In 2025, our capital program was focused on development and further delineation in Peace River and Willesden Green, including in the emerging Belly River formation. Additionally, we continued to advance our waterflood initiatives in Peace River, as we brought on-line two pilots in the area in late 2025.

In 2025, the Company's net income benefited from the Company's positive operating results and lower depletion and depreciation expense following the disposition of our operated Pembina assets partially offset by lower oil prices.

Quarterly Financial Summary
(millions, except per share and production amounts) (unaudited)

Three months ended	**Dec. 31 2025**	Sep. 30 2025	Jun. 30 2025	Mar. 31 2025	Dec. 31 2024	Sep. 30 2024	Jun. 30 2024	Mar. 31 2024
Production revenues	**$ 123.8**	$ 128.7	$ 136.3	$ 211.0	$ 213.6	$ 218.2	$ 208.4	$ 177.3
Cash flow from operating activities	**42.6**	45.4	55.2	96.7	115.0	110.3	77.9	58.7
Basic per share (1)	**0.63**	0.68	0.79	1.32	1.55	1.45	1.02	0.76
Diluted per share (1)	**0.62**	0.66	0.75	1.27	1.49	1.40	0.98	0.73
Funds flow from operations (2)	**56.6**	49.7	65.8	100.1	107.7	124.7	115.2	84.4
Basic per share (3)	**0.84**	0.74	0.94	1.36	1.45	1.64	1.51	1.09
Diluted per share (3)	**0.82**	0.72	0.90	1.31	1.39	1.58	1.44	1.05
Net income (loss)	**(12.3)**	16.8	15.3	15.4	(284.8)	33.2	37.1	11.9
Basic per share	**(0.18)**	0.25	0.22	0.21	(3.83)	0.44	0.48	0.15
Diluted per share	**$ (0.18)**	$ 0.24	$ 0.21	$ 0.20	$ (3.83)	$ 0.42	$ 0.46	$ 0.15
Production								
Light oil (bbl/d)	**5,443**	4,979	6,314	12,727	13,271	13,722	13,782	13,079
Heavy oil (bbl/d)	**12,782**	12,586	12,041	10,887	11,621	10,624	7,026	6,748
NGLs (bbl/d)	**2,037**	1,955	2,189	3,072	3,176	3,148	3,193	2,783
Natural gas (mmcf/d)	**46**	47	50	70	72	73	71	70
Total (boe/d)(4)	**27,971**	27,316	28,943	38,416	40,119	39,714	35,773	34,238

(1) Supplementary financial measure. See "Non-GAAP and Other Financial Measures".
(2) Non-GAAP financial measure. See "Non-GAAP and Other Financial Measures".
(3) Non-GAAP ratio. See "Non-GAAP and Other Financial Measures".
(4) Disclosure of production on a per boe basis in this MD&A consists of the constituent product types and their respective quantities. See also "Supplemental Production Disclosure" and "Oil and Natural Gas Information".

Cash flow from Operating Activities, Funds Flow from Operations and Free Cash Flow

	Year ended December 31	
(millions, except per share amounts)	**2025**	2024
Cash flow from operating activities	**$ 239.8**	$ 361.9
Change in non-cash working capital	**(30.6)**	35.7
Decommissioning expenditures	**28.8**	23.9
Equity forward contracts	**28.7**	-
Onerous office lease settlements	**0.7**	9.0
Deferred financing costs	**(1.7)**	(2.3)
Restructuring	**1.0**	-
Transaction costs	**5.4**	1.4
Other expenses	**-**	2.4
Funds flow from operations [(1)]	**272.1**	432.0
Capital expenditures	**(298.9)**	(343.1)
Decommissioning expenditures	**(28.8)**	(23.9)
Free Cash Flow [(1)]	**$ (55.6)**	$ 65.0
Per share – funds flow from operations [(2)]		
Basic per share	**$ 3.92**	$ 5.69
Diluted per share	**$ 3.79**	$ 5.46

(1) Non-GAAP financial measure. See "Non-GAAP and Other Financial Measures".
(2) Non-GAAP ratio. See "Non-GAAP and Other Financial Measures".

Cash flow from operating activities and funds flow from operations both decreased in 2025 compared to 2024 primarily due to lower production revenues, as a result of lower production volumes due to the disposition of our operated Pembina assets at the start of Q2 2025 and lower oil prices.

Pembina Disposition

On April 7, 2025, the Company closed the Pembina Disposition to InPlay of our operated Pembina (Cardium) assets (the "Pembina Assets"). Total consideration for the transaction included approximately $208 million of cash (inclusive of final closing adjustments), 9,139,784 common shares of InPlay, after giving effect to InPlay's consolidation of its common shares on a one for six basis effective April 14, 2025, ("InPlay Shares") and a $14.7 million value associated with acquiring InPlay's 34.6 percent interest in the Willesden Green Cardium Unit #2 property. The transaction included all the Company's assets in Pembina, with the exception of our non-operated interest in Pembina Cardium Unit #11 which we retained. The transaction had an effective date of December 1, 2024. As part of the transaction, InPlay assumed all assets and liabilities associated with the Pembina Assets, including the Company's decommissioning liabilities.

In August 2025, the Company closed the sale of all of our InPlay Shares to a third party, for proceeds of $91.4 million, resulting in a $15.2 million gain.

This transaction further strengthened our balance sheet while reducing our decommissioning liabilities by over 50 percent, with the cash proceeds from the transaction used to initially pay down outstanding debt on our syndicated credit facility at closing and subsequently used to accelerate our share buyback program.

Business Strategy

Upon close of the Pembina Disposition, the Company has a more balanced portfolio of heavy and light oil assets. In Peace River over the past two years we have more than doubled our production in the area through a focused development program. With a significant land base of greater than 700 net sections, we expect to continue to grow our Clearwater and Bluesky production through further development and delineation of existing and new fields in the area. Additionally, in 2025, we progressed on our enhanced oil recovery strategy through our waterflood initiatives and are encouraged by our results to-date. We plan to expand our efforts in the area in 2026 and beyond.

With a now more focused light oil asset base, we also expect to be able to grow our light oil assets through ongoing development. The Company began development in the Belly River formation in 2025 and has plans for future development in the formation given the strong results we have achieved and the expanded infrastructure that was recently completed in Open Creek. The pace and level of future development and growth in both our heavy and light oil assets will be subject to the macro-economic environment (commodity prices and service costs) as we look to generate acceptable returns and maintain the Company's financial strength.

In 2023, we began our return of capital initiative through our share buyback program under our normal course issuer bid ("NCIB"). This program has further enhanced shareholder returns, specifically through a focus on per share growth. Purchases under the NCIB are subject to having $65 million of liquidity and otherwise complying with the terms of our current credit facilities. We re-purchased and cancelled a total of approximately 17.2 million common shares (approximately 21 percent of our then outstanding shares) for total consideration of $143.9 million since the inception of the NCIB in 2023. We renewed our NCIB program in March 2025 and by the end of August 2025, the Company had re-purchased and cancelled the maximum number of shares allowed under our current program of 7,144,408 shares. In 2026, we are also in the process of renewing our NCIB, which should be in place in early March.

The Company continued with our environmental remediation efforts in 2025 with a focus on abandoning and reclaiming inactive fields.

Business Environment

The following table outlines quarterly averages for benchmark prices and Obsidian Energy's realized prices for the previous eight quarters.

	Q4 2025	Q3 2025	Q2 2025	Q1 2025	Q4 2024	Q3 2024	Q2 2024	Q1 2024
Benchmark prices								
WTI oil ($US/bbl)	**$ 59.14**	$ 64.93	$ 63.74	$ 71.42	$ 70.27	$ 75.09	$ 80.57	$ 76.96
Edm mixed sweet par price (CAD$/bbl)	**76.30**	86.57	84.04	95.00	94.39	97.60	105.41	92.21
Western Canada Select (CAD$/bbl)	**66.65**	75.28	73.89	84.04	80.67	83.80	91.82	77.80
NYMEX Henry Hub ($US/mmbtu)	**3.55**	3.07	3.44	3.65	2.79	2.16	1.89	2.24
AECO 5A Index (CAD$/mcf)	**2.23**	0.60	1.69	2.17	1.48	0.69	1.18	2.50
Foreign exchange rate (US/CAD)	**1.39**	1.38	1.38	1.43	1.40	1.37	1.37	1.35
Benchmark differentials								
WTI - Edm Light Sweet ($US/bbl)	**(4.25)**	(2.20)	(2.84)	(4.98)	(2.42)	(3.35)	(3.63)	(8.65)
WTI - Western Canadian Select Heavy ($US/bbl)	**(11.19)**	(10.38)	(10.20)	(12.65)	(12.54)	(13.51)	(13.55)	(19.33)
Average sales price (1) (2)								
Light oil (CAD$/bbl)	**75.30**	86.67	91.09	99.46	96.95	100.09	107.61	94.82
Heavy oil (CAD$/bbl)	**59.10**	67.93	61.27	70.14	67.70	73.73	79.73	60.39
NGLs (CAD$/bbl)	**35.33**	36.44	39.42	53.49	44.27	48.92	48.92	50.43
Total liquids (CAD$/bbl)	**61.07**	69.56	68.11	82.21	78.88	84.04	91.64	79.08
Natural gas (CAD$/mcf)	**$ 2.38**	$ 0.91	$ 2.00	$ 2.18	$ 1.53	$ 0.86	$ 1.33	$ 2.38

(1) Excludes the impact of realized hedging gains or losses.
(2) Supplementary financial measures. See "Non-GAAP and Other Financial Measures".

Oil

In 2025, WTI oil prices averaged US$64.81 per bbl compared to US$75.72 per bbl in 2024. Despite some temporary increases as a result of geopolitical concerns, prices weakened throughout 2025 with Q1 2025 averaging US$71.42 per bbl compared to US$59.14 per bbl in Q4 2025. The weakness in WTI oil pricing was mainly due to OPEC+ increasing their output leading to concerns regarding oversupply versus demand projections.

In 2025, differentials were narrow as a result of the increased capacity from the Trans Mountain ("TMX") pipeline expansion. Despite brief periods of weakness due to concerns over US imposed tariffs, the MSW differential tightened to an average of US$3.57 per bbl in 2025, compared to US$4.51 per bbl in 2024 and the WCS differential narrowed to an average of US$11.11 per bbl in 2025, compared to US$14.73 per bbl in 2024.

The Company currently has the following oil hedging contracts in place on a weighted average basis:

Type	Volume (bbls/d)	Remaining Term		Price ($/bbl)
WTI Swap	6,127	January 2026	CAD$	84.12
WTI Swap	13,298	February 2026	US$	62.47
WTI Swap	12,800	March 2026	US$	64.13
WTI Swap	8,000	April 2026	US$	64.29
WTI Swap	2,000	May 2026	US$	63.70

Natural Gas

In 2025, both NYMEX and AECO prices remained low for the majority of the year. There were some improvements, particularly in Q4, as demand strengthened and additional LNG projects came into service. In 2025 NYMEX averaged US$3.43 per mmbtu, compared to US$2.27 per mmbtu in 2024 and AECO 5A prices increased to $1.68 per mcf in 2025, compared to $1.46 per mcf in 2024.

The Company currently has the following natural gas hedging contracts in place on a weighted average basis:

Type	Volume (mcf/d)	Remaining Term		Price ($/mcf)
AECO Swap	26,540	January 2026 - March 2026	$	3.30
AECO Swap	35,377	April 2026 - October 2026		2.68
AECO Swap	1,896	November 2026 - March 2027	$	3.73

Prepaid Equity Forward Contracts

In Q3 2025, the Company began entering into prepaid equity forward contracts in respect of our common shares to mitigate the equity price risk associated with our share-based compensation plans. Given the value of our share-based compensation plans fluctuates based on the Company's share price on the Toronto Stock Exchange ("TSX") at each period end date, entering into equity forward contracts will help reduce the volatility in our funds flow from operations. The Company currently has the following contracts in place on a weighted average basis:

Type	Share Volume	Remaining Term [1]		Price (C$)
Equity Forward Contract	720,000	September 2028	$	8.89
Equity Forward Contract	1,300,000	October 2028		8.72
Equity Forward Contract	550,000	November 2028		8.43
Equity Forward Contract	715,000	December 2028		8.31
Equity Forward Contract	450,000	January 2029		8.76
Equity Forward Contract	555,000	February 2029	$	10.10

(1) The Company can settle the contract, or a portion of the contract, at any time.

Foreign Exchange Forward Contracts

Subsequent to December 31, 2025, the Company began entering into foreign exchange forward contracts to mitigate the risk of changes in the $US/$CAD exchange rate on oil sales that reference $US benchmark prices and commodity hedging contracts that are settled in $US. The Company currently has the following contracts in place on a weighted average basis:

Type	Notional Amount ($millions)	Remaining Term		Price (C$)
FX forward contract	2.5	January 2026	$	1.3840
FX forward contract	19.0	February 2026		1.3719
FX forward contract	16.0	March 2026		1.3686
FX forward contract	13.5	April 2026	$	1.3650

RESULTS OF OPERATIONS

Average Sales Prices (1)

	Year ended December 31		
	2025	2024	% change
Light oil (per bbl)	**$ 90.96**	$ 99.95	(9)
Heavy oil (per bbl)	**64.41**	70.46	(9)
NGL (per bbl)	**42.49**	48.05	(12)
Total liquids (per bbl)	**71.05**	83.30	(15)
Realized risk management gain (loss) (per bbl)	**(0.08)**	0.20	N/A
Total liquids, net (per bbl)	**70.97**	83.50	(15)
Natural gas (per mcf)	**1.90**	1.52	25
Realized risk management gain (per mcf)	**0.40**	0.75	(47)
Natural gas net (per mcf)	**2.30**	2.27	1
Weighted average (per boe)	**53.73**	59.70	(10)
Realized risk management gain (per boe)	**0.65**	1.58	(59)
Weighted average net (per boe)	**$ 54.38**	$ 61.28	(11)

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

Performance Indicators

Obsidian Energy monitors performance based on the following three key focus areas using several qualitative and quantitative factors:

- Values – Execution of our field, health, safety, environmental and regulatory programs and our focus on operational excellence;
- Delivery – Key performance metrics include a low cost structure as compared to our industry peers and a focus on free cash flow generation; and
- Sustainability – Management of the Company's asset portfolio, financial stewardship and the goal of sustaining production and reserves and long-term competitive return on investment for our shareholders.

Values

At Obsidian Energy, the health, safety and wellness of our employees, contractors and stakeholders living within our areas of operation is paramount. Safety policies, procedures and programs developed by Obsidian Energy shall meet or exceed legislative requirements and all injuries and serious incidents are reported and investigated accordingly. Additionally, the Company is committed to mitigating the environmental impacts of our operations which includes our programs focusing on stakeholder communication, impact mitigation, resource conservation and site abandonment and reclamation. Throughout our operations, Obsidian Energy requires a high standard of professional conduct and supports a culture that ensures all individuals act with integrity and respect. These principles form the operational standards for the Company.

Delivery

In 2025, the Company continued to emphasize operational execution, focus on cost reduction initiatives and monitor our operations and development plans given volatility in commodity markets. The Company had guidance for the second half of 2025 ("H2 2025"), given the Pembina Disposition was closed in Q2 2025. All operational guidance metrics are outlined below:

- The Company's average H2 2025 production of 27,644 boe per day compared to our H2 2025 production guidance of 27,800 to 28,300 boe per day. Cold weather and significant snowfall in Peace River impacted operations in late 2025;
- Capital expenditures of $130.3 million in H2 2025 were above our H2 2025 guidance of $120.0 million to $125.0 million as the Company added incremental injector wells to our program in late 2025 to further advance our waterflood initiatives in Peace River. Additionally, we were able to accelerate a portion of our planned 2026 development program into 2025 given our development program was ahead of schedule;
- Decommissioning expenditures of $18.2 million in H2 2025 were higher than our H2 2025 guidance of $14.0 - 15.0 million. We will be able to apply the increased spending to reduce our 2026 spending obligation as mandated by the Alberta Energy Regulator;
- Net operating costs of $15.10 per boe, were higher than our H2 2025 guidance of $14.35 - $14.60 per boe mainly due to the cold weather and resultant higher repair and maintenance costs in Peace River in late 2025; and
- General & Administration ("G&A") costs per boe were $1.97 in H2 2025, which was within our H2 2025 guidance range of $1.95 - $2.05 per boe.

In 2026, we are employing a disciplined approach to our plans given the current volatility in commodity prices, and based on our commodity price forecasts results in a small free cash flow positive budget for the year (prior to any potential share repurchases) while marginally growing production. In Willesden Green, the light oil program is centered on further development in Open Creek, predominately in the Belly River formation, as we benefit from new infrastructure in the area that was constructed in late 2025. In Peace River, our capital program is a combination of primary development in both the Bluesky and Clearwater formations while also progressing waterflood projects in our Dawson and Nampa areas.

Sustainability

In 2025, the Company expanded development and delineation activities in Peace River and increased production while maintaining a steady pace of activity in our light oil assets. Our 2026 development program has begun with two rigs running in Peace River and one rig running in Willesden Green. The Company will continue to monitor commodity prices and geopolitical factors and has the operational flexibility to alter our program quickly in response to the macro environment.

Production

Daily production	Year ended December 31 2025	2024	% change
Light oil (bbl/d)	**7,340**	13,463	(45)
Heavy oil (bbl/d)	**12,080**	9,016	34
NGL (bbl/d)	**2,308**	3,077	(25)
Natural gas (mmcf/d)	**53**	72	(26)
Total production (boe/d)	**30,624**	37,474	(18)

In 2025, production levels decreased compared to 2024 due to the Pembina Disposition which closed at the start of Q2 2025. Production associated with the Pembina Assets averaged approximately 11,000 boe/d in Q1 2025. For 2025, a total of 64 wells (59.1 net) were brought on production.

Average production within the Company's key development areas and within the Company's Legacy asset area was as follows:

Daily production (boe/d) (1)	Year ended December 31 2025	2024	% change
Willesden Green (2)	**16,157**	25,320	(36)
Peace River	**12,927**	9,503	36
Viking	**1,258**	2,322	(46)
Legacy	**282**	329	(14)
Total	**30,624**	37,474	(18)

(1) Refer to "Supplemental Production Disclosure" for details by product type.
(2) Area was previously referred to as Cardium. In 2024 and from January 1 to April 6, 2025 includes production from the Pembina Assets.

Netbacks

(per boe)	Year ended December 31 2025	2024
Netback:		
Sales price (1) (3)	**$ 53.73**	$ 59.70
Risk management gain (2)	**0.65**	1.58
Royalties	**(6.55)**	(7.76)
Transportation	**(4.78)**	(4.22)
Net operating costs (3)	**(14.92)**	(13.85)
Netback (3)	**$ 28.13**	$ 35.45
	(boe/d)	(boe/d)
Production	**30,624**	37,474

(1) Includes the impact of commodities purchased and sold to/from third parties of $0.7 million (2024 – $1.3 million).
(2) Realized risk management gains and losses on commodity contracts.
(3) Non-GAAP ratios. See "Non-GAAP and Other Financial Measures".

The Company's netback per boe decreased in 2025 from 2024 primarily due to lower oil prices which led to lower realized prices. Transportation costs were also higher as a result of our higher production base in Peace River. Net operating costs were higher in 2025 due to increased emulsion trucking costs and processing fees due to our expanded Peace River operations.

(millions)	Year ended December 31 2025	2024
Netback:		
Sales (1) (3)	**$ 600.5**	$ 818.8
Risk management gain (2)	**7.3**	21.6
Royalties	**(73.2)**	(106.5)
Transportation	**(53.4)**	(57.9)
Net operating costs (3)	**(166.7)**	(189.3)
Netback (3)	**$ 314.5**	$ 486.7

(1) Includes the impact of commodities purchased and sold to/from third parties of $0.7 million (2024 – $1.3 million). See "Production Revenues" below for a reconciliation of "Sales" to "Production Revenues".
(2) Realized risk management gains on commodity contracts.
(3) Non-GAAP financial measures. See "Non-GAAP and Other Financial Measures" and see "Expenses - Operating" for reconciliation of net operating costs to operating costs.

Production Revenues

A reconciliation from production revenues to gross revenues is as follows:

(millions)	Year ended December 31 2025	2024
Production revenues	**$ 599.8**	$ 817.5
Sales of commodities purchased from third parties	**4.1**	7.8
Less: Commodities purchased from third parties	**(3.4)**	(6.5)
Sales (1)	**600.5**	818.8
Realized risk management gain (2)	**7.3**	21.6
Gross revenues (1)	**$ 607.8**	$ 840.4

(1) Non-GAAP financial measure. See "Non-GAAP and Other Financial Measures".
(2) Relates to realized risk management gains on commodity contracts.

The Company's production revenues and gross revenues were lower in 2025 compared to 2024, mainly due to lower production volumes as a result of the Pembina Disposition early in Q2 2025, accompanied by lower realized prices and lower realized risk management gains on our commodity contracts.

Change in Gross Revenues (1)

(millions)	
Gross revenues – January 1 – December 31, 2024	$ 840.4
Decrease in liquids production	(150.5)
Decrease in liquids prices	(65.2)
Decrease in natural gas production	(10.1)
Increase in natural gas prices	7.5
Increase in realized oil risk management loss	(2.5)
Decrease in realized natural gas risk management gain	(11.8)
Gross revenues – January 1 – December 31, 2025 (2)	$ 607.8

(1) Non-GAAP financial measure. See "Non-GAAP and Other Financial Measures".
(2) Excludes processing fees and other income.

Royalties

		Year ended December 31		
		2025		2024
Royalties (millions)	**$**	**73.2**	$	106.5
Average royalty rate (1)		**12%**		13%

(1) Excludes effects of risk management activities and other income.

For 2025 absolute royalties and the average royalty rate both decreased from 2024 which was largely attributed to lower production volumes due to the Pembina Disposition in Q2 2025 and lower oil prices.

Expenses

		Year ended December 31		
(millions)		**2025**		2024
Net operating (1)	**$**	**166.7**	$	189.3
Transportation		**53.4**		57.9
Financing		**42.1**		52.2
Share-based compensation	**$**	**11.7**	$	8.2

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

Operating

A reconciliation of operating costs to net operating costs is as follows:

		Year ended December 31		
(millions)		**2025**		2024
Operating costs	**$**	**183.5**	$	208.7
Less processing fees		**(10.1)**		(12.4)
Less road use recoveries		**(6.7)**		(8.6)
Add realized power risk management loss		**-**		1.6
Net operating costs (1)	**$**	**166.7**	$	189.3

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

On an absolute basis, in 2025, both operating and net operating costs were lower than in 2024, mainly due to our lower production base as a result of the Company closing the Pembina Disposition at the start of Q2 2025.

Transportation

The Company continues to utilize multiple sales points in the Peace River area to increase realized prices. New wells drilled in the Peace River area over the past year resulted in higher production and thus higher transportation costs on a per boe basis in 2025 compared to the 2024. On an absolute basis transportation costs are lower in 2025 than in 2024 due to the Pembina Disposition in early Q2 2025.

Financing

Financing expense consists of the following:

		Year ended December 31		
(millions)		**2025**		2024
Interest	**$**	**22.1**	$	31.9
Accretion on decommissioning liability		**12.2**		16.5
Accretion on office lease provision		**-**		0.3
Accretion on discount of senior unsecured notes		**0.4**		0.5
Accretion on lease liabilities		**0.4**		0.6
Loss on repurchased/redeemed senior unsecured notes		**5.3**		0.1
Deferred financing costs		**1.7**		2.3
Financing	**$**	**42.1**	$	52.2

Obsidian Energy's debt structure includes short-term borrowings under our syndicated credit facility and term financing through our senior unsecured notes. Interest charges were lower in 2025 compared to 2024 mainly due to lower drawings on our syndicated credit facility following the Pembina Disposition as the proceeds received from the transaction were used to reduce the amount outstanding under our syndicated credit facility.

The Company has a reserve-based syndicated credit facility which is subject to a semi-annual borrowing base redetermination (typically completed in May and November of each year). The aggregate amount available under the syndicated credit facility is $235.0 million and the revolving period and maturity dates are set at May 31, 2026 and May 31, 2027, respectively. Borrowings under our syndicated credit facility are available by way of either Canadian Overnight Repo Rate Average or the banks' prime lending rate plus applicable margins. Interest rate margins and standby fees on the undrawn amount of the facilities depend on the Company's debt to earnings before interest, taxes, depreciation and amortization ("EBITDA") ratio for the most recent four quarters.

In December 2025, the Company completed a refinancing and issued five-year senior unsecured notes for an aggregate principal amount of $175.0 million (the "2025 Notes"). The 2025 Notes have an interest rate of 8.125 percent and mature on December 3, 2030. The 2025 Notes were issued at par under a trust indenture and are direct senior unsecured obligations of Obsidian Energy ranking equal with all other present and future senior unsecured indebtedness of the Company. The Company used the net proceeds from the 2025 Notes to redeem all of our previous outstanding senior unsecured notes due July 27, 2027 ("2022 Notes") at a price of $1,029.88 per $1,000 principal amount, and to pay down indebtedness under our syndicated credit facility.

Prior to the full redemption of the 2022 Notes, in August 2025, the Company completed a partial redemption of $30.0 million of the 2022 Notes at a price of $1,029.88 per $1,000 principal amount.

At December 31, 2025, letters of credit totaling $2.5 million were outstanding (December 31, 2024 – $4.4 million) that reduce the amount otherwise available to be drawn on our syndicated credit facility.

Share-Based Compensation

Share-based compensation expense relates to options ("Options") to acquire common shares granted under the Company's Stock Option Plan (the "Option Plan"), restricted share units ("RSUs") granted under the Restricted and Performance Share Unit Plan ("RPSU plan"), deferred share units ("DSUs") granted under the Deferred Share Unit Plan ("DSU plan"), performance share units ("PSUs") granted under the RPSU plan and unrealized gains or losses under the equity forward contracts.

Share-based compensation expense consisted of the following:

	Year ended December 31	
(millions)	**2025**	2024
DSUs	**$ 1.0**	$ (0.6)
PSUs	**1.8**	(0.5)
NTIP (1)	**-**	1.1
Equity forward contract loss (2)	**0.6**	-
Liability based incentive plans	**$ 3.4**	$ -
RSUs	**$ 6.2**	$ 6.1
Options	**2.1**	2.1
Equity based incentive plans	**8.3**	8.2
Share-based compensation	**$ 11.7**	$ 8.2

(1) Restricted awards outstanding under the Non-Treasury Incentive Award Plan ("NTIP") were classified as a liability and were settled in cash. There were no outstanding restricted awards under the NTIP at December 31, 2025.
(2) Relates to the equity forward contracts entered into to mitigate the Company's exposure to our share-based compensation plans.

At December 31, 2025, the Company's share price closed at $8.42 per share which was higher than the $8.36 per share on December 31, 2024. As the share price was higher, this resulted in an increase in our share-based compensation in 2025 compared to 2024. The change in share price at the balance sheet date results in a mark-to-market valuation which is used to calculate the DSU and PSU future obligations.

To mitigate the exposure to fluctuations in our share price, in the third quarter of 2025, the Company began entering into equity forward contracts and the mark-to-market valuation on these contracts is also included in share-based compensation. The unrealized loss on the equity forward contract at December 31, 2025 was based on an average valuation of $8.62 per share compared to the fair value of $8.42 per share.

General and Administrative Expenses

	Year ended December 31	
(millions, except per boe amounts)	**2025**	2024
Gross	**$ 40.4**	$ 40.8
Per boe (1)	**3.62**	2.97
Net (2)	**20.6**	20.5
Per boe (1)	**$ 1.84**	$ 1.50

(1) Supplementary financial measure. See "Non-GAAP and Other Financial Measures".
(2) Net G&A includes the impact of overhead recoveries and capitalized G&A.

On an absolute basis, G&A was similar in 2025 compared to 2024 as staff costs were relatively consistent year-over-year. On a per boe basis, the impact of the Pembina Disposition in Q2 2025 led to higher costs in 2025 compared to 2024.

Depletion, Depreciation and Impairment

	Year ended December 31	
(millions)	**2025**	2024
Depletion and depreciation ("D&D")	**$ 180.0**	$ 247.1
PP&E Impairment	**$ 23.2**	$ 415.3

The Company's D&D expense decreased in 2025 compared to 2024, due to the Pembina Assets being classified as assets held for sale and no longer being depleted in 2025.

The Company classified the Pembina Assets as held for sale at the end of 2024 prior to the close of the Pembina Disposition in April 2025. The Pembina Assets were recorded at the lesser of fair value less costs to sell and their carrying amount, resulting in a non-cash, before tax, impairment loss of $30.0 million (2024 - $395.4 million), primarily due to the decrease in value of the InPlay Shares from year-end 2024 to closing. The impairment was recorded within depletion, depreciation and impairment on the Consolidated Statements of Income (Loss).

Additionally, in 2025, we recorded a $6.8 million net impairment reversal (2024 - $19.9 million net impairment) in our Legacy cash generating unit ("CGU") due to a reduction in the decommissioning liability in the area. The Legacy CGU has no recoverable amount, as such changes in our decommissioning liability are expensed or recovered as applicable each period.

Taxes

	Year ended December 31	
(millions)	**2025**	2024
Deferred income tax expense (recovery)	**$ 11.8**	$ (62.5)

The deferred tax expense in 2025 was due to the Company's net income and resultant reduction of our deferred income tax asset. In 2024, the Company recorded a deferred tax recovery of $62.5 million due to the Company's net loss as a result of recognizing a $415.3 million non-cash impairment and resultant increase of our deferred income tax asset.

Tax Pools

	As at December 31	
(millions)	**2025**	2024
Non-capital losses	**$ 1,155.9**	$ 1,665.1
Undepreciated capital cost (UCC)	**453.6**	316.1
Canadian development expense (CDE)	**548.8**	319.6
Canadian exploration expense (CEE)	**6.0**	0.2
Canadian oil and gas property expense (COGPE)	**-**	85.0
Other	**50.0**	52.3
Total	**$ 2,214.3**	$ 2,438.3

Net Income (loss)

	Year ended December 31	
(millions, except per share amounts)	**2025**	2024
Net income (loss)	**$ 35.2**	$ (202.6)
Basic per share	**0.51**	(2.67)
Diluted per share	**$ 0.49**	$ (2.67)

In 2025, net income was the result of the Company's positive operating results combined with the Pembina Disposition which led to lower depletion and depreciation expense. Additionally, the Company recorded a $15.2 million gain in Other Income as a result of selling all of our InPlay Shares in Q3 2025. This was partially offset by the Company's lower production revenues due to the lower oil price environment and lower production volumes following the closing of the Pembina Disposition.

In 2024, the net loss was primarily due to non-cash, PP&E impairment charges as a result of classifying our Pembina Assets as held for sale. This was partially offset by the Company's higher production accompanied by positive operating results, along with realized risk management gains on our commodity contracts.

Capital Expenditures

(millions)		Year ended December 31 **2025**		2024
Drilling and completions	**$**	**188.9**	$	240.8
Well equipping and facilities		**95.3**		101.0
Land and geological/geophysical		**13.2**		0.5
Corporate		**1.5**		0.8
Capital expenditures	**$**	**298.9**	$	343.1
Property acquisitions (dispositions), net		**(208.0)**		83.4
Total	**$**	**90.9**	$	426.5

In 2025, our capital program was focused on development and further delineation in Peace River and Willesden Green, including in the emerging Belly River formation. Additionally, we continued to advance our waterflood initiatives in Peace River, as we brought on-line two pilots in the area in late 2025. Overall, capital expenditures were lower in 2025 compared to 2024 as we moderated capital spending in H2 2025 in response to lower commodity prices. During the year 64 (59.1 net) wells were brought on production, including operated and non-operated activities, of which 50 (48.4 net) wells were in Peace River and 4 (4.0 net) wells were in Willesden Green. Also, an additional 6 (2.7) non-operated wells in PCU#11 were brought on-line during the year.

Drilling

	Year ended December 31			
	2025		2024	
(number of wells)	**Gross**	**Net**	Gross	Net
Oil	**70**	**62**	73	65
Gas	**1**	**1**	4	1
Injectors, stratigraphic and service	**4**	**4**	7	6
Total	**75**	**67**	84	72

The Company drilled 63 (61.4 net) operated wells, including injector wells, during 2025. In addition, the Company had a non-operated working interest in 12 (5.4 net) wells that were drilled by various partners during the year.

Environmental and Climate Change

The oil and natural gas industry has a number of environmental risks and hazards and is subject to regulation by all levels of government. Environmental legislation includes, but is not limited to, operational controls, site rehabilitation requirements and restrictions on emissions of various substances produced in association with oil and natural gas operations. Compliance with such legislation is expected to require additional expenditures and a failure to comply may result in fines and penalties which could, in the aggregate and under certain assumptions, become material.

Obsidian Energy monitors our operations for environmental impacts and allocates capital to reclamation and other activities to mitigate the impact on the areas in which the Company operates. The Company follows the Alberta Energy Regulator guidance under Directive 088 where a minimum amount of spending is required to abandon inactive sites.

Liquidity and Capital Resources

Net Debt

Net debt is the total of long-term debt and working capital deficiency as follows:

		As at December 31		
(millions)		**2025**		2024
Long-term debt				
Syndicated credit facility	**$**	**9.0**	$	225.0
Senior unsecured notes (8.125%, maturing December 3, 2030)		**175.0**		-
Senior unsecured notes (11.95%, maturing July 27, 2027)		**-**		114.2
Unamortized discount of senior unsecured notes		**-**		(1.1)
Deferred financing costs		**(4.1)**		(2.7)
Total		**179.9**		335.4
Working capital deficiency				
Accounts receivable		**(56.1)**		(88.0)
Prepaid expenses and other		**(11.0)**		(12.0)
Bank overdraft		**0.4**		0.5
Accounts payable and accrued liabilities		**155.0**		175.8
Total		**88.3**		76.3
Net debt (1)	**$**	**268.2**	$	411.7

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

Net debt decreased compared to December 31, 2024, primarily as a result of lower drawings under our syndicated credit facility. The Company applied the cash proceeds received as part of the Pembina Disposition in April 2025 as well as the proceeds received upon the sale of all of our InPlay Shares in August 2025 to our syndicated credit facility which led to the reduction.

Liquidity

The Company has a reserve-based syndicated credit facility with a borrowing limit of $235.0 million and senior unsecured notes totaling $175.0 million at December 31, 2025, due in December 2030. For further details on the Company's debt instruments please refer to the "Financing" section of this MD&A.

The Company actively manages our debt portfolio and considers opportunities to reduce or diversify our debt capital structure. In December 2025, we refinanced our existing senior unsecured notes, which provided additional term to our debt structure and additional proceeds, which we used to largely pay down our syndicated credit facility and increase the overall liquidity of the Company. Management contemplates both operating and financial risks and takes action as appropriate to limit the Company's exposure to certain risks. Management maintains close relationships with the Company's lenders and agents to monitor credit market developments. These actions and plans aim to increase the likelihood of maintaining the Company's financial flexibility and an appropriate capital program, supporting the Company's ongoing operations and ability to execute longer-term business strategies.

Investment in InPlay

In April 2025, the Company closed the Pembina Disposition. As part of the consideration, the Company received 9,139,784 InPlay Shares. InPlay paid a cash dividend of $0.09 per common share per month, resulting in the Company receiving $3.3 million in 2025. The dividend income received from InPlay was recorded within Other Income.

Subsequently in August 2025, the Company sold all of our InPlay Shares for total proceeds of $91.4 million and recorded a $15.2 million gain on the sale within Other Income.

Financial Instruments

Obsidian Energy had the following financial instruments outstanding as at December 31, 2025. Fair values are determined using external counterparty information, which is compared to observable market data. The Company limits our credit risk by executing counterparty risk procedures which include transacting only with institutions within our syndicated credit facility or companies with high credit ratings, and by obtaining financial security in certain circumstances.

Commodity contracts

	Notional Volume (mcf/d)	Remaining Term	Price (C$/mcf)	Fair value (millions)
Natural Gas				
AECO Swap	26,540	January 2026 - March 2026	$ 3.30	$ 1.0
AECO Swap	29,384	April 2026 - October 2026	2.81	2.5
AECO Swap	1,896	November 2026 - March 2027	$ 3.73	$ 0.1
Total natural gas				**$ 3.6**
Total				**$ 3.6**

The components of risk management within Income on the Consolidated Statements of Income (Loss) are as follows:

(millions)	Year ended December 31 2025	2024
Realized		
Settlement of oil contracts gain (loss)	**$ (0.6)**	$ 1.9
Settlement of natural gas contracts gain	**7.9**	19.7
Total realized risk management gain	**$ 7.3**	$ 21.6
Unrealized		
Oil contracts gain (loss)	**$ (3.3)**	$ 3.3
Natural gas contracts loss	**(0.2)**	(8.5)
Total unrealized risk management loss	**(3.5)**	(5.2)
Risk management gain	**$ 3.8**	$ 16.4

Prepaid Equity Forward Contracts

Obsidian Energy is exposed to equity price risk on our common share price in relation to our share-based compensation plans. Given the value of our share-based compensation plans fluctuates based on the Company's common share price on the TSX at each period end date, beginning in Q3 2025, the Company began mitigating this exposure by entering into equity forward contracts. Unrealized and realized gains/losses on our equity forward contracts for the period are recorded through share-based compensation.

	Share Volume	Remaining Term (1)	Price (C$)	Fair value (millions)
Equity				
Equity Forward Contract	720,000	September 2028	$ 8.89	$ 6.1
Equity Forward Contract	1,300,000	October 2028	8.72	10.9
Equity Forward Contract	550,000	November 2028	8.43	4.6
Equity Forward Contract	715,000	December 2028	8.31	6.0
Equity Forward Contract	55,000	January 2029	$ 8.44	$ 0.5
Total				**$ 28.1**

(1) The Company can settle the contract, or a portion of the contract, at any time.

Refer to the Business Environment section above for a full list of hedges currently outstanding including contracts that were entered into subsequent to December 31, 2025.

Based on commodity prices and equity contracts in place at December 31, 2025, the Company notes the following sensitivities:

- a $0.10 change in the price per mcf of natural gas would change pre-tax unrealized risk management by $0.9 million; and
- a 10 per cent change in our share price would change pre-tax unrealized risk management by $2.9 million.

Sensitivity Analysis

Estimated sensitivities to selected key assumptions on funds flow from operations for the 12 months subsequent to the date of this MD&A, including risk management contracts entered into to date, are based on forecasted results.

		Impact on funds flow from operations (1)	
Change of:	Change	$ millions	$/share
WTI - Price per barrel of liquids	WTI US$1.00	8.9	0.13
WCS - Price per barrel of liquids	WCS US$1.00	5.4	0.08
Liquids production	1,000 bbl/day	19.6	0.29
Price per mcf of natural gas	AECO $0.10	0.6	0.01
Natural gas production	1 mmcf/day	0.7	0.01
Effective interest rate	1%	0.2	-
Exchange rate ($US per $CAD)	$ 0.01	4.0	0.06

(1) Non-GAAP financial measure or non-GAAP ratio. See “Non-GAAP and Other Financial Measures”.

Contractual Obligations and Commitments

Obsidian Energy is committed to certain payments over the next five calendar years and thereafter as follows:

	2026	2027	2028	2029	2030	Thereafter	Total
Long-term debt (1)	**$ -**	$ 9.0	$ -	$ -	$ 175.0	$ -	$ 184.0
Transportation	**16.9**	14.5	12.0	12.1	5.7	-	61.2
Interest obligations	**14.7**	14.4	14.2	14.2	14.2	-	71.7
Lease liability	**3.3**	2.9	2.1	1.5	1.5	18.5	29.8
Decommissioning liability (2)	**8.9**	12.2	11.5	10.9	10.3	53.4	107.2
Total	**$ 43.8**	$ 53.0	$ 39.8	$ 38.7	$ 206.7	$ 71.9	$ 453.9

(1) The 2027 figure includes our syndicated credit facility which has a term-out date of May 2027. The 2030 figure includes our senior unsecured notes due in December 2030. Refer to the Financing section above for further details. Historically, the Company has successfully renewed its syndicated credit facility.
(2) These amounts represent the inflated, discounted future reclamation and abandonment costs that are expected to be incurred over the life of the Company's properties.

At December 31, 2025, the Company had an aggregate of $175.0 million in senior unsecured notes maturing in December 2030. Also, the revolving period of our syndicated credit facility is May 31, 2026, with a term out period to May 31, 2027. In the future, if the Company is unsuccessful in renewing or replacing the syndicated credit facility or obtaining alternate funding for some or all of the maturing amounts of the senior unsecured notes, it is possible that we could be required to seek other sources of financing, including other forms of debt or equity arrangements if available. Please see the Financing section of this MD&A for further details regarding our outstanding debt instruments.

The Company is involved in various litigation and claims in the normal course of business and records provisions for claims as required.

Equity Instruments

Common shares issued:	
As at December 31, 2025	67,274,326
Issuance under stock option and restricted and performance share unit plans	32,625
As at February 18, 2026	67,306,951
Options outstanding:	
As at December 31, 2025	1,978,228
Exercised	(29,980)
Forfeited	(8,130)
As at February 18, 2026	1,940,118
RSUs outstanding:	
As at December 31, 2025	1,417,152
Granted	13,670
Vested	(5,761)
Forfeited	(10,289)
As at February 18, 2026	1,414,772

Fourth Quarter Highlights

Key financial and operational results for the fourth quarter were as follows:

	Three months ended December 31		
	2025	2024	% change
Financial (millions, except per share or per boe amounts)			
Production revenues	**$ 123.8**	$ 213.6	(42)
Cash flow from operating activities	**42.6**	115.0	(63)
Basic per share [1]	**0.63**	1.55	(59)
Diluted per share [1]	**0.62**	1.49	(59)
Funds flow from operations [2]	**56.6**	107.7	(47)
Basic per share [3]	**0.84**	1.45	(42)
Diluted per share [3]	**0.82**	1.39	(41)
Net loss	**(12.3)**	(284.8)	N/A
Basic per share	**(0.18)**	(3.83)	N/A
Diluted per share	**(0.18)**	(3.83)	N/A
Capital expenditures	**65.0**	84.1	(23)
Decommissioning expenditures	**10.3**	3.5	194
G&A per boe [1]	**$ 1.98**	$ 1.39	43
Operations			
Daily production			
Light oil (bbl/d)	**5,443**	13,271	(59)
Heavy oil (bbl/d)	**12,782**	11,621	10
NGLs (bbl/d)	**2,037**	3,176	(36)
Natural gas (mmcf/d)	**46**	72	(36)
Total production (boe/d)	**27,971**	40,119	(30)
Average sales price [1] [4]			
Light oil (CAD$/bbl)	**$ 75.30**	$ 96.95	(22)
Heavy oil (CAD$/bbl)	**59.10**	67.70	(13)
NGLs (CAD$/bbl)	**35.33**	44.27	(20)
Total liquids (CAD$/bbl)	**61.07**	78.88	(23)
Natural gas (CAD$/mcf)	**$ 2.38**	$ 1.53	56
Netback per boe			
Sales price	**$ 48.17**	$ 57.94	(17)
Realized risk management gain	**2.75**	1.62	70
Royalties	**(4.81)**	(7.85)	(39)
Transportation	**(5.28)**	(4.55)	16
Net operating costs [3]	**(15.19)**	(13.91)	9
Netback [3]	**$ 25.64**	$ 33.25	(23)

(1) Supplementary financial measure. See Non-GAAP and Other Financial Measures".
(2) Non-GAAP financial measure. See "Non-GAAP and Other Financial Measures".
(3) Non-GAAP ratio. See "Non-GAAP and Other Financial Measures".
(4) Excludes the impact of realized hedging gains or losses.

Financial

In Q4 2025, production revenues and funds flow from operations decreased from Q4 2024 as a result of lower realized oil prices and lower production volumes due to the Pembina Disposition in Q2 2025.

The net loss in Q4 2025 was primarily due to lower realized oil prices.

Operations

Capital expenditure activities continued across our Peace River and Willesden Green assets with the drilling of 5 (5.0 net) producing wells and 2 (2.0 net) injector wells in Peace River, and 6 (6.0 net) producing wells in Willesden Green, including 2 (2.0 net) wells in the Belly River formation. The Company continued to advance waterflood initiatives in the Peace River area and brought two pilots on-line.

Production in Q4 2025 decreased from the comparable period in 2024 as a result of the Pembina Disposition in Q2 2025. In December 2025, operations were impacted by extreme cold weather and significant snow in Peace River restricting our ability to truck production to sales points. Average production within the Company's key development areas was as follows:

	Three months ended December 31		
Daily production (boe/d) [1]	**2025**	2024	% change
Willesden Green	**12,968**	25,621	(49)
Peace River	**13,741**	12,280	12
Viking	**1,025**	1,905	(46)
Legacy	**237**	313	(24)
Total	**27,971**	40,119	(30)

(1) Refer to "Supplemental Production Disclosure" for details by product type.

Netbacks

Netbacks decreased from Q4 2024 mainly due to lower oil prices and higher transportation costs associated with a larger Peace River production base. Net operating costs were higher in Q4 2025 than in Q4 2024 due to increased emulsion trucking costs and processing fees due to our expanded Peace River operations. Late in the fourth quarter of 2025, our Peace River operations were negatively impacted by extreme cold weather and significant snowfall which resulted in higher repair & maintenance activity.

WTI prices decreased in Q4 2025, settling at US$57.87 per barrel in December which was the lowest monthly average of 2025. Concerns over a surplus of supply in the market and continued discussions on tariffs were the main drivers in the decline. For Q4 2025, WTI averaged US$59.14 per barrel.

In Q4 2025, WCS differentials continued to be narrow due to the added export capacity from the TMX pipeline expansion. In Q4 2025, the WCS differential averaged US$11.19 per bbl while the MSW differential averaged US$4.25 per bbl.

In Alberta, AECO 5A prices for Q4 2025 averaged $2.23 per mcf, up from $0.60 per mcf in Q3 2025. AECO prices closed the year higher, with increased demand and additional LNG takeaway coming online.

Non-GAAP financial measure reconciliations – Q4

A reconciliation from production revenues to sales and gross revenues for the fourth quarter is as follows:

(millions)		Three months ended December 31 2025		2024
Production revenues	**$**	**123.8**	$	213.6
Sales of commodities purchased from third parties		**0.4**		1.2
Less: Commodities purchased from third parties		**(0.3)**		(1.0)
Sales [1]		**123.9**		213.8
Realized risk management gain [2]		**7.1**		6.0
Gross revenues [1]	**$**	**131.0**	$	219.8

(1) Non-GAAP financial measure. See "Non-GAAP and Other Financial Measures".
(2) Relates to realized risk management gains on commodity contracts.

A reconciliation of operating costs to net operating costs for the fourth quarter are as follows:

(millions)		Three months ended December 31 2025		2024
Operating costs	**$**	**43.5**	$	56.0
Less processing fees		**(3.0)**		(2.9)
Less road use recoveries		**(1.5)**		(2.5)
Add realized power risk management loss		**-**		0.6
Net operating costs [1]	**$**	**39.0**	$	51.2

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

A reconciliation of sales to netback for the fourth quarter on an absolute dollar basis are as follows:

(millions)		Three months ended December 31 2025		2024
Netback:				
Sales [1] [3]	**$**	**123.9**	$	213.8
Risk management gain [2]		**7.1**		6.0
Royalties		**(12.4)**		(29.0)
Transportation		**(13.6)**		(16.8)
Net operating costs [3]		**(39.0)**		(51.2)
Netback [3]	**$**	**66.0**	$	122.8

(1) Includes the impact of commodities purchased and sold to/from third parties of $0.1 million (2024 – $0.2 million).
(2) Realized risk management gains and losses on commodity contracts.
(3) Non-GAAP financial measures. See "Non-GAAP and Other Financial Measures".

Supplemental Production Disclosure

Outlined below is production by product type for each area and in total for the periods indicated:

	Three months ended December 31		Year ended December 31	
Daily production (boe/d)	**2025**	2024	**2025**	2024
Willesden Green [(1)]				
Light oil (bbl/d)	**4,949**	12,108	**6,666**	11,919
Heavy oil (bbl/d)	**-**	63	**24**	61
NGLs (bbl/d)	**1,955**	3,081	**2,227**	2,978
Natural gas (mmcf/d)	**36**	62	**43**	62
Total production (boe/d)	**12,968**	25,621	**16,157**	25,320
Peace River				
Light oil (bbl/d)	**-**	-	**3**	-
Heavy oil (bbl/d)	**12,672**	11,423	**11,948**	8,821
NGLs (bbl/d)	**20**	9	**16**	11
Natural gas (mmcf/d)	**6**	5	**6**	4
Total production (boe/d)	**13,741**	12,280	**12,927**	9,503
Viking				
Light oil (bbl/d)	**438**	1,088	**611**	1,477
Heavy oil (bbl/d)	**91**	99	**83**	95
NGLs (bbl/d)	**37**	63	**41**	64
Natural gas (mmcf/d)	**3**	4	**3**	4
Total production (boe/d)	**1,025**	1,905	**1,258**	2,322
Legacy				
Light oil (bbl/d)	**56**	75	**60**	67
Heavy oil (bbl/d)	**19**	36	**25**	39
NGLs (bbl/d)	**25**	23	**24**	24
Natural gas (mmcf/d)	**1**	1	**1**	2
Total production (boe/d)	**237**	313	**282**	329
Total				
Light oil (bbl/d)	**5,443**	13,271	**7,340**	13,463
Heavy oil (bbl/d)	**12,782**	11,621	**12,080**	9,016
NGLs (bbl/d)	**2,037**	3,176	**2,308**	3,077
Natural gas (mmcf/d)	**46**	72	**53**	72
Total production (boe/d)	**27,971**	40,119	**30,624**	37,474

(1) Area was previously referred to as Cardium. On April 7, 2025, the Company closed the Pembina Disposition. Production associated with the Pembina Assets averaged approximately 11,000 boe/d in Q1 2025.

Reconciliation of Cash flow from operating activities to Funds flow from operations

Three months ended	**Dec. 31 2025**	Sep. 30 2025	Jun. 30 2025	Mar. 31 2025	Dec. 31 2024	Sep. 30 2024	Jun. 30 2024	Mar. 31 2024
Cash flow from operating activities	**$ 42.6**	$ 45.4	$ 55.2	$ 96.7	$ 115.0	$ 110.3	$ 77.9	$ 58.7
Change in non-cash working capital	**(17.5)**	(11.6)	4.3	(5.8)	(13.5)	6.1	29.7	13.4
Decommissioning expenditures	**10.3**	7.9	4.0	6.6	3.5	6.3	4.0	10.1
Equity forward contracts	**21.3**	7.4	-	-	-	-	-	-
Onerous office lease settlements	**-**	-	-	0.7	2.3	2.2	2.2	2.3
Deferred financing costs	**(0.3)**	(0.4)	(0.6)	(0.4)	(0.5)	(0.6)	(0.6)	(0.6)
Restructuring	**0.1**	0.1	0.7	0.1	-	-	-	-
Transaction costs	**0.1**	0.9	2.2	2.2	-	-	1.4	-
Other expenses	**-**	-	-	-	0.9	0.4	0.6	0.5
Funds flow from operations	**$ 56.6**	$ 49.7	$ 65.8	$ 100.1	$ 107.7	$ 124.7	$ 115.2	$ 84.4

Evaluation of Disclosure Controls and Procedures

The Company's disclosure controls and procedures are designed to provide reasonable assurance that information required to be disclosed by the Company in our annual filings, interim filings or other reports filed or submitted by us under securities legislation is recorded, processed, summarized and reported within the time periods specified in such securities legislation. They include controls and procedures designed to ensure that information required to be disclosed by the Company in our annual filings, interim filings or other reports that we file or submit under applicable securities legislation is accumulated and communicated to the Company's management, including our President and Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

An internal evaluation was carried out by management under the supervision and with the participation of the Company's President and Chief Executive Officer and Chief Financial Officer of the effectiveness of Obsidian Energy's disclosure controls and procedures as defined in Rule 13a-15 under the US Securities Exchange Act of 1934 (the "Exchange Act") and as defined in Canada by National Instrument 52-109 – *Certification of Disclosure in Issuers' Annual and Interim Filings* ("NI 52-109") as at December 31, 2025. Based on that evaluation, the President and Chief Executive Officer and the Chief Financial Officer concluded that as at December 31, 2025 the disclosure controls and procedures were effective.

Management's Report on Internal Control over Financial Reporting

Internal control over financial reporting ("ICFR") is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. Obsidian Energy's management, including our President and Chief Executive Officer and Chief Financial Officer, is responsible for establishing and maintaining adequate ICFR, as such term is defined in Rule 13a-15 under the Exchange Act and as defined in Canada by NI 52-109. A material weakness in the Company's ICFR exists if a deficiency, or a combination of deficiencies, in our ICFR is such that there is a reasonable possibility that a material misstatement of our annual financial statements or interim financial reports will not be prevented or detected on a timely basis.

An internal evaluation was carried out by management under the supervision and with the participation of the Company's President and Chief Executive Officer and Chief Financial Officer of the effectiveness of the Company's ICFR as at December 31, 2025. The assessment was based on the framework in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on that evaluation, the President and Chief Executive Officer and the Chief Financial Officer concluded that as at December 31, 2025 the Company's ICFR was effective.

The effectiveness of the Company's ICFR as at December 31, 2025, has been audited by KPMG LLP, independent registered public accounting firm, as stated in their attestation report which appears with the audited financial statements.

Changes in Internal Control Over Financial Reporting

Obsidian Energy's senior management has evaluated whether there were any changes in the Company's ICFR that occurred during the period beginning on October 1, 2025 and ending on December 31, 2025 that have materially affected, or are reasonably likely to materially affect, the Company's ICFR. No changes to the Company's ICFR were made during the quarter.

Off-Balance-Sheet Financing

Obsidian Energy has off-balance-sheet financing arrangements consisting of operating leases. The operating lease payments are summarized in the Contractual Obligations and Commitments section.

Critical Accounting Estimates

Obsidian Energy's material accounting policies are detailed in Note 3 to our audited consolidated Financial Statements. In the determination of financial results, Obsidian Energy must make certain critical accounting estimates as follows:

Decommissioning Liability

The decommissioning liability is the present value of the Company's future statutory, contractual, legal or constructive obligations to retire long-lived assets including wells, facilities and pipelines. The liability is recorded on the balance sheet with a corresponding increase to the carrying amount of the related asset. The recorded liability increases over time to its future liability amount through accretion charges to income. Revisions to the estimated amount or timing of the obligations are reflected as increases or decreases to the recorded decommissioning liability. Actual decommissioning expenditures are charged to the liability to the extent of the then-recorded liability. Amounts capitalized to the related assets are amortized to income consistent with the depletion or depreciation of the underlying asset. Note 8 to Obsidian Energy's audited consolidated Financial Statements details the impact of these accounting standards.

Deferred Tax

Deferred taxes are recorded based on the liability method of accounting whereby temporary differences are calculated assuming financial assets and liabilities will be settled at their carrying amount. Deferred taxes are computed on temporary differences using substantively enacted income tax rates expected to apply when future income tax assets and liabilities are realized or settled.

A deferred income tax asset is recognized to the extent that it is probable that future taxable income will be available against which the deductible temporary differences can be utilized. Deferred income tax assets are reviewed at each reporting date and are not recognized until such time that it is probable that the related tax benefit will be realized.

Depletion and Impairments

Costs of developing oil and natural gas reserves are capitalized and depleted against associated oil and natural gas production using the unit-of-production method based on the estimated proved plus probable reserves with forecast commodity pricing.

All the Company's reserves were evaluated by GLJ Ltd., an independent, qualified reserve evaluation engineering firm. Obsidian Energy's reserves are determined in compliance with National Instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities*. The evaluation of oil and natural gas reserves is, by its nature, based on complex extrapolations and models as well as other significant engineering, reservoir, capital, pricing and cost assumptions. Reserve estimates are a key component in the calculation of depletion and are an important component in determining the recoverable amount in impairment tests. The determination of the recoverable amount involves estimating the higher of an asset's fair value less costs to sell or its value-in-use, the latter of which is based on its discounted future cash flows using an applicable discount rate. To the extent that the recoverable amount, which could be based in part on its reserves, is less than the carrying amount of property, plant and equipment, a write-down against income is recorded.

Financial Instruments

Financial instruments included in the balance sheets consist of accounts receivable, fair values of derivative financial instruments, current liabilities and long-term debt. The fair values of these financial instruments approximate their carrying amounts due to the short-term maturity of the instruments, the mark-to-market values recorded for the financial instruments and the market rate of interest applicable to the bank debt.

Obsidian Energy's revenues from the sale of oil, natural gas liquids and natural gas are directly impacted by changes to the underlying commodity prices. To manage our planned capital program to within funds flows from operations, financial instruments including swaps and collars may be utilized from time to time.

Substantially all the Company's accounts receivable are with customers in the oil and natural gas industry and are subject to normal industry credit risk. Obsidian Energy may, from time to time, use various types of financial instruments to reduce its exposure to fluctuating oil and natural gas prices, electricity costs, exchange rates and interest rates. The use of these financial instruments exposes us to credit risks associated with the possible non-performance of counterparties to the derivative contracts. The Company limits this risk by executing counterparty risk procedures which include transacting only with financial institutions who are members of its credit facility or those with high credit ratings as well as obtaining security in certain circumstances.

Non-GAAP and Other Financial Measures

Throughout this MD&A and in other materials disclosed by the Company, we employ 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 by IFRS and therefore may not be comparable to similar measures provided by other issuers. 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) and cash flow from operating activities, as indicators of our performance.

Non-GAAP Financial Measures

"Free cash flow" is funds flow from operations less both capital and decommissioning expenditures and the Company believes it is a useful measure to determine and indicate the funding available to Obsidian Energy for investing and financing activities, including the repayment of debt, reallocation to existing areas of operation, deployment into new ventures and return of capital to shareholders. See "Cash flow from Operating Activities, Funds Flow from Operations and Free Cash Flow" above for a reconciliation of free cash flow to cash flow from operating activities, being our nearest measure prescribed by IFRS.

"Funds flow from operations" is cash flow from operating activities before changes in non-cash working capital, decommissioning expenditures, equity forward contracts, onerous office lease settlements, the effects of financing related transactions from foreign exchange contracts and debt repayments, restructuring, transaction costs and certain other revenues and expenses and is representative of cash related to our underlying operations. Funds flow from operations is used to assess the Company's ability to fund our planned capital programs. See "Cash flow from Operating Activities, Funds Flow from Operations and Free Cash Flow" and "Reconciliation of Cash flow from operating activities to Funds flow from operations" above for reconciliations of funds flow from operations to cash flow from operating activities, being our nearest measure prescribed by IFRS.

"Gross revenues" are production revenues including realized risk management gains and losses on commodity contracts and adjusted for commodities purchased from third parties and sales of commodities purchased from third parties and is used to assess the cash realizations on commodity sales. See "Results of Operations – Production Revenues" and "Fourth Quarter Highlights – Non-GAAP financial measure reconciliations – Q4" above for a reconciliation of gross revenues to production revenues, being our nearest measure prescribed by IFRS.

"Sales" are production revenues plus sales of commodities purchased from third parties less commodities purchased from third parties and is used to assess the cash realizations on commodity sales before realized risk management gains and losses. See "Results of Operations – Production Revenues" and "Fourth Quarter Highlights

– Non-GAAP financial measure reconciliations – Q4" above for a reconciliation of gross revenues and sales to production revenues, being our nearest measure prescribed by IFRS.

“Net debt” is the total of long-term debt and working capital deficiency and is used by the Company to assess our liquidity. See “Liquidity and Capital Resources – Net Debt” above for a reconciliation of net debt to long-term debt, being our nearest measure prescribed by IFRS.

“Net operating costs” are calculated by deducting processing income, road use recoveries and realized gains and losses on power risk management contracts from operating costs and is used to assess the Company’s cost position. Processing fees are primarily generated by processing third party volumes at the Company’s facilities. In situations where the Company has excess capacity at a facility, it may agree with third parties to process their volumes to reduce the cost of operating/owning the facility. Road use recoveries are a cost recovery for the Company as we operate and maintain roads that are also used by third parties. Realized gains and losses on power risk management contracts occur upon settlement of our contracts. See “Results of Operations – Expenses – Operating” and "Fourth Quarter Highlights - Non-GAAP financial measure reconciliations - Q4" above for a reconciliation of net operating costs to operating costs, being our nearest measure prescribed by IFRS.

“Netback” is production revenues plus sales of commodities purchased from third parties less commodities purchased from third parties (sales), less royalties, net operating costs, transportation expenses and realized risk management gains and losses, and is used in capital allocation decisions and to economically rank projects. See "Results of Operations – Netbacks" and "Fourth Quarter Highlights – Non-GAAP financial measure reconciliations – Q4" above for a reconciliation of netbacks to sales and "Results of Operations – Production Revenues" and "Fourth Quarter Highlights – Non-GAAP financial measure reconciliations – Q4" above for a reconciliation of sales to production revenues, being our nearest measure prescribed by IFRS.

Non-GAAP Ratios

“Funds flow from operations – basic per share” is comprised of funds flow from operations divided by basic weighted average common shares outstanding. Funds flow from operations is a non-GAAP financial measure. See “Cash flow from Operating Activities, Funds Flow from Operations and Free Cash Flow” and “Reconciliation of Cash flow from operating activities to Funds flow from operations” above.

“Funds flow from operations – diluted per share” is comprised of funds flow from operations divided by diluted weighted average common shares outstanding. Funds flow from operations is a non-GAAP financial measure. See “Cash flow from Operating Activities, Funds Flow from Operations and Free Cash Flow” and “Reconciliation of Cash flow from operating activities to Funds flow from operations” above.

“Net operating costs per bbl”, “Net operating costs per mcf” and “Net operating costs per boe” are net operating costs divided by weighted average daily production on a per bbl, per mcf or per boe basis, as applicable. Net operating costs is a non-GAAP financial measure. See “Results of Operations – Expenses – Operating" and "Fourth Quarter Highlights - Non-GAAP financial measure reconciliations - Q4"above.

“Netback per bbl”, “Netback per mcf” and “Netback per boe” are netbacks divided by weighted average daily production on a per bbl, per mcf or per boe basis, as applicable. Management believes that netback per boe is a key industry performance measure of operational efficiency and provides investors with information that is also commonly presented by other oil and natural gas producers. Netback is a non-GAAP financial measure. See “Results of Operations – Netbacks” and "Fourth Quarter Highlights – Non-GAAP financial measure reconciliations – Q4" above.

"Sales per boe" is sales divided by weighted average daily production on a per boe basis. Sales is a non-GAAP financial measure. See “Results of Operations – Production Revenues" and "Fourth Quarter Highlights -Non-GAAP financial measure reconciliations - Q4" above.

Supplementary Financial Measures

Average sales prices for light oil, heavy oil, NGLs, total liquids and natural gas are supplementary financial measures calculated by dividing each of these components of production revenues by their respective production volumes for the periods.

“Cash flow from operating activities – basic per share” is comprised of cash flow from operating activities, as determined in accordance with IFRS, divided by basic weighted average common shares outstanding.

“Cash flow from operating activities – diluted per share" is comprised of cash flow from operating activities, as determined in accordance with IFRS, divided by diluted weighted average common shares outstanding.

"G&A gross – per boe" is comprised of general and administrative expenses on a gross basis, as determined in accordance with IFRS, divided by boe for the period.

"G&A net – per boe" is comprised of general and administrative expenses on a net basis, as determined in accordance with IFRS, divided by boe for the period.

Oil and Natural Gas Information

Barrels of oil equivalent ("boe") may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one barrel of oil 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 based on the current price of oil as compared to natural gas is significantly different from the energy equivalency conversion ratio of 6:1, utilizing a conversion on a 6:1 basis is misleading as an indication of value.

Abbreviations

Oil		Natural Gas	
bbl	barrel or barrels	mcf	thousand cubic feet
bbl/d	barrels per day	mcf/d	thousand cubic feet per day
boe	barrel of oil equivalent	mmcf	million cubic feet
boe/d	barrels of oil equivalent per day	mmcf/d	million cubic feet per day
MSW	Mixed Sweet Blend	mmbtu	Million British thermal unit
WTI	West Texas Intermediate	AECO	Alberta benchmark price for natural gas
WCS	Western Canadian Select	NGL	natural gas liquids
		LNG	liquefied natural gas
		NYMEX	New York Mercantile Exchange price for natural gas

References to Q1, Q2, Q3 and Q4 are to the three-month periods ended March 31, June 30, September 30 and December 31, respectively.

Forward-Looking Statements

Certain statements contained in this document constitute forward-looking statements or information (collectively "forward-looking statements") within the meaning of the "safe harbour" provisions of applicable securities legislation. In particular, this document contains forward-looking statements pertaining to, without limitation, the following: that following the Pembina Disposition the Company has a more balanced portfolio of heavy and light oil assets; expectations that the Company will grow its Clearwater and Bluesky production through further development and delineation of existing and new fields in the area; the Company's plans to expand its efforts in the Peace River area in 2026 and beyond; the Company's expectations to grow its light oil assets through ongoing development; the Company's plans for future development in the Belly River formation; that the pace and level of future development and growth in both our heavy and light oil assets will be subject to macro-economic environment and the Company's intention to generate acceptable returns and maintain our financial strength; our expectations regarding our NCIB; the factors the Company monitors performance based on; that the safety policies, procedures and programs developed by the Company shall meet or exceed legislative requirements and that all injuries and serious incidents are reported and investigated accordingly; that the Company is committed to mitigating the environmental impacts of our operations which includes our programs focusing on stakeholder communication, impact mitigation, resource conservation and site abandonment and reclamation; that we are employing a disciplined approach to our plans given the current volatility in commodity prices, and based on our commodity price forecasts results in a small free cash flow positive budget for the year (prior to any potential share repurchases) while marginally growing production; our intention to progress waterflood projects in both the Dawson and Nampa areas; expectations that the Company will continue to monitor commodity prices and have the operational flexibility to alter its program quickly in response to commodity prices; expectations in connection with the Company's compliance with environmental and safety legislation; expectations that the Company will monitor its operations for environmental impacts and allocate capital to reclamation and other activities to mitigate the impact on the areas in which it operates; how we plan to manage our debt portfolio; all information disclosed under "Sensitivity Analysis"; our future payment obligations as disclosed under "Contractual Obligations and Commitments", and in particular the amount of our decommissioning liability; that management contemplates both operating and financial risks and takes action as appropriate to limit the Company's exposure to certain risks and that management maintains close relationships with the Company's lenders and agents to monitor credit market developments, and these actions and plans aim to increase the likelihood of maintaining the Company's financial flexibility and capital program.

With respect to forward-looking statements contained in this document, the Company has made assumptions regarding, among other things: the duration and impact of tariffs that are currently in effect on goods exported from or imported into Canada, and that other than the tariffs that are currently in effect, neither the U.S. nor Canada (i) increases the rate or scope of such tariffs, reenacts tariffs that are currently suspended, or imposes new tariffs, on the import of goods from one country to the other, including on oil and natural gas, and/or (ii) imposes any other form of tax, restriction or prohibition on the import or export of products from one country to the other, including on oil and natural gas; that the Company does not dispose of or acquire material producing properties or royalties or other interests therein (except as disclosed herein); that regional and/or global health related events will not have any adverse impact on energy demand and commodity prices in the future; global energy policies going forward, including the continued ability and willingness of members of OPEC and other nations to agree on and adhere to production quotas from time to time; our ability to execute our plans as described herein and in our other disclosure documents and the impact that the successful execution of such plans will have on our Company and our stakeholders, including our ability to return capital to shareholders and/or further reduce debt levels; future capital expenditure and decommissioning expenditure levels; expectations and assumptions concerning applicable laws and regulations, including with respect to environmental, safety and tax matters; future operating costs and G&A costs and the impact of inflation thereon; future oil, natural gas liquids and natural gas prices and differentials between light, medium and heavy oil prices and Canadian, WTI and world oil and natural gas prices; future hedging activities; future oil, natural gas liquids and natural gas production levels; future exchange rates, interest rates and inflation rates; future debt levels; our ability to execute our capital programs as planned without significant adverse impacts from various factors beyond our control, including extreme weather events such as wild fires, droughts and flooding, infrastructure access (including the potential for blockades or other activism) and delays in obtaining regulatory approvals and third party consents; the ability of the Company's contractual counterparties to perform their contractual obligations; our ability to obtain equipment in a timely manner to carry out development activities and the costs thereof; our ability to market our oil and natural gas successfully to current and new customers; our ability to obtain financing on acceptable terms, including our ability (if necessary) to extend the revolving period and term out period of our credit facility, our ability to maintain the existing borrowing base under our credit facility, our ability (if necessary) to replace our syndicated bank facility and our ability (if necessary) to finance the repayment of our senior unsecured notes on maturity or pursuant to the terms of the underlying agreement; the accuracy of our estimated reserve volumes; and our ability to add production and reserves through our development and exploitation activities.

The future acquisition by the Company of the Company's common shares pursuant to its share buyback program (including through its NCIB), if any, and the level thereof is uncertain. Any decision to acquire common shares of the Company pursuant to the share buyback program will be subject to the discretion of the board of directors of the Company and may depend on a variety of factors, including, without limitation, the Company's business performance, financial condition, financial requirements, growth plans, expected capital requirements and other conditions existing at such future time including, without limitation, contractual restrictions and satisfaction of the solvency tests imposed on the Company under applicable corporate law. There can be no assurance of the number of common shares of the Company that the Company will acquire pursuant to its share buyback program, if any, in the future.

Although the Company believes that the expectations reflected in the forward-looking statements contained in this document, and the assumptions on which such forward-looking statements are made, are reasonable, there can be no assurance that such expectations will prove to be correct. Readers are cautioned not to place undue reliance on forward-looking statements included in this document, as there can be no assurance that the plans, intentions or expectations upon which the forward-looking statements are based will occur. By their nature, forward-looking statements involve numerous assumptions, known and unknown risks and uncertainties that contribute to the possibility that the forward-looking statements contained herein will not be correct, which may cause our actual performance and financial results in future periods to differ materially from any estimates or projections of future performance or results expressed or implied by such forward-looking statements. These risks and uncertainties include, among other things: the risk that (i) the tariffs that are currently in effect on goods exported from or imported into Canada continue in effect for an extended period of time, the tariffs that have been threatened are implemented, the tariffs that are currently suspended are reactivated, the rate or scope of tariffs are increased, or new tariffs are imposed, including on oil and natural gas, (ii) the U.S. and/or Canada imposes any other form of tax, restriction or prohibition on the import or export of products from one country to the other, including on oil and natural gas, and (iii) the tariffs imposed or threatened to be imposed by the U.S. on other countries and retaliatory tariffs imposed or threatened to be imposed by other countries on the U.S., will trigger a broader global trade war which could have a material adverse effect on the Canadian, U.S. and global economies, and by extension the Canadian oil and natural gas industry and the Company, including by decreasing demand for (and the price of) oil and natural gas, disrupting supply chains, increasing costs, causing volatility in global financial markets, and limiting access to financing; the possibility that we change our budgets (including our capital expenditure budgets) in response to internal and external factors, including those described herein; the possibility that the Company will not be able to continue to successfully execute our business plans and strategies in part or in full, and the possibility that some or all of the benefits that the Company anticipates will accrue to our Company and our stakeholders as a result of the successful execution of such plans and strategies do not materialize (such as our inability to return capital to shareholders and/or reduce our debt levels to the extent anticipated or at all); the impact on energy demand and commodity prices of regional and/or global health related events, and the responses of governments and the public thereto, including the risk of energy demand destruction; the risk that there is another significant decrease in the valuation of oil and natural gas companies and their securities and in confidence in the oil and natural gas industry generally, whether caused by regional and/or global health related events, the worldwide transition towards less reliance on fossil fuels and/or other factors; the risk that the financial capacity of the Company's contractual counterparties is adversely affected and potentially their ability to perform their contractual obligations; the possibility that the revolving period and/or term out period of our credit facility and the maturity date of our senior unsecured notes is not extended (if necessary), that the borrowing base under our credit facility is reduced, that the Company is unable to renew or refinance our credit facilities on acceptable terms or at all and/or finance the repayment of our senior unsecured notes when they mature on acceptable terms or at all and/or obtain new debt and/or equity financing to replace our credit facilities and/or senior unsecured notes or to fund other activities; the possibility that we are forced to shut-in production, whether due to commodity prices decreasing, extreme weather events such as wild fires, inability to access our properties due to blockades or other activism, or other factors; the risk that OPEC and other nations fail to agree on and/or adhere to production quotas from time to time that are sufficient to balance supply and demand fundamentals for oil; general economic and political conditions in Canada, the U.S. and globally, and in particular, the effect that those conditions have on commodity prices and our access to capital; industry conditions, including fluctuations in the price of oil, natural gas liquids and natural gas, price differentials for oil and natural gas produced in Canada as compared to other markets, and transportation restrictions, including pipeline and railway capacity constraints; fluctuations in foreign exchange, including the impact of the Canadian/U.S. dollar exchange rate on our revenues and expenses; fluctuations in interest rates, including the effects of interest rates on our borrowing costs and on economic activity, and including the risk that elevated interest rates cause or contribute to the onset of a recession; the risk that our costs increase due to inflation, supply chain disruptions, scarcity of labour and/or other factors, adversely affecting our profitability; unanticipated operating events or environmental events that can reduce production or cause production to be shut-in or delayed (including extreme cold during winter months, wild fires, flooding and droughts (which could limit our access to the water we require for our operations)); the risk that wars and other armed conflicts adversely affect world economies and the demand for oil and natural gas, including the ongoing war between Russian and Ukraine and/or hostilities in the Middle East and Venezuela; the possibility that fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to fossil fuels, government mandates requiring the sale of electric vehicles and/or electrification of the power grid, and technological advances in fuel economy and renewable energy generation systems could permanently reduce the demand for oil and natural gas and/or permanently impair the Company's ability to obtain financing and/or insurance on acceptable terms or at all, and the possibility that some or all of these risks are heightened as a result of the response of governments, financial institutions and consumers to regional and/or global health related events and/or the influence of public opinion and/or special interest groups; the risk that the Company may not grow its Clearwater and Bluesky production or establish new fields as anticipated; the risk that the Company's decommissioning liabilities may be greater than anticipated; and the other factors described under "Risk Factors" in our Annual Information Form and described in our public filings, available in Canada at www.sedarplus.ca and in the United States at www.sec.gov. Readers are cautioned that this list of risk factors should not be construed as exhaustive.

The forward-looking statements contained in this document speak only as of the date of this document. Except as expressly required by applicable securities laws, the Company does not undertake any obligation to publicly update any forward-looking statements. The forward-looking statements contained in this document are expressly qualified by this cautionary statement.

This document contains future-oriented financial information and financial outlook information (collectively, "FOFI") including all information disclosed under "Sensitivity Analysis" which are subject to the same assumptions, risk factors, limitations, and qualifications as set forth in the above paragraphs. The actual results of operations of the Company and the resulting financial results will likely vary from the amounts set forth herein and such variation may be material. The Company and its management believe that the FOFI has been prepared on a reasonable basis, reflecting management's best estimates and judgments. However, because this information is subjective and subject to numerous risks, it should not be relied on as necessarily indicative of future results. Except as required by applicable securities laws, the Company undertakes no obligation to update such FOFI. FOFI contained in this press release was made as of the date of this press release and was provided for the purpose of providing further information about the Company's anticipated future business operations. Readers are cautioned that the FOFI contained in this press release should not be used for purposes other than for which it is disclosed herein.

Additional Information

Additional information relating to Obsidian Energy, including Obsidian Energy’s Annual Information Form, is available on the Company’s website at www.obsidianenergy.com, on SEDAR+ at www.sedarplus.ca and on EDGAR at www.sec.gov.