



Obsidian Energy Announces Third Quarter 2025 Results

- *Active H2 2025 capital program in Peace River and successful drilling of the first Belly River well in Crimson*
- *Average production of 27,316 boe per day resulting in funds flow from operations of \$49.7 million (\$0.74 per share basic) including a \$5.5 million mark-to-market impact on share-based compensation*
- *Increased H2 2025 production guidance to 27,800 - 28,300 boe/d on strong results from our development program*
- *Commencement of a pre-paid equity forward program to hedge our outstanding share-based incentive plan awards*

CALGARY, October 30, 2025 - OBSIDIAN ENERGY LTD. (TSX / NYSE American – OBE) (“**Obsidian Energy**”, the “**Company**”, “**we**”, “**us**” or “**our**”) is pleased to report our operating and financial results for the third quarter of 2025.

	Three months ended September 30		Nine months ended September 30	
	2025	2024	2025	2024
FINANCIAL				
<i>(millions, except per share amounts)</i>				
Cash flow from operating activities	\$ 45.4	\$ 110.3	\$ 197.3	\$ 246.9
Basic per share (\$/share) ¹	0.68	1.45	2.81	3.23
Diluted per share (\$/share) ¹	0.66	1.40	2.74	3.10
Funds flow from operations ²	49.7	124.7	215.6	324.3
Basic per share (\$/share) ³	0.74	1.64	3.07	4.24
Diluted per share (\$/share) ³	0.72	1.58	2.99	4.07
Net income	16.8	33.2	47.5	82.2
Basic per share (\$/share)	0.25	0.44	0.68	1.07
Diluted per share (\$/share)	0.24	0.42	0.66	1.03
Capital expenditures	65.3	85.5	233.9	259.0
Property acquisitions (dispositions), net	0.3	-	(210.6)	84.9
Decommissioning expenditures	7.9	6.3	18.5	20.4
Long-term debt	145.4	342.1	145.4	342.1
Net debt ²	\$ 219.3	\$ 413.6	\$ 219.3	\$ 413.6
OPERATIONS				
Daily Production				
Light oil (bbl/d)	4,979	13,722	7,978	13,528
Heavy oil (bbl/d)	12,586	10,624	11,844	8,142
NGL (bbl/d)	1,955	3,148	2,401	3,043
Natural gas (mmcf/d)	47	73	56	71
Total production ⁴ (boe/d)	27,316	39,714	31,518	36,587
Average sales price (before hedging) ¹				
Light oil (\$/bbl)	\$ 86.67	\$ 100.09	\$ 94.56	\$ 100.94
Heavy oil (\$/bbl)	67.93	73.73	66.35	71.78
NGL (\$/bbl)	36.44	48.92	44.53	49.38
Natural gas (\$/mcf)	\$ 0.91	\$ 0.86	\$ 1.77	\$ 1.51

Netback (\$/boe)					
Sales price	\$	51.26	\$	59.77	\$ 55.39 \$ 60.34
Risk management gain (loss)		(0.33)		2.16	0.02 1.56
Net sales price		50.93		61.93	55.41 61.90
Royalties		(6.56)		(7.77)	(7.06) (7.73)
Transportation		(4.46)		(4.19)	(4.63) (4.10)
Net operating costs ³		(15.01)		(13.74)	(14.84) (13.82)
Netback ³ (\$/boe)	\$	24.90	\$	36.23	\$ 28.88 \$ 36.25

(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) Please refer to the 'Oil and Gas Information Advisory' section below for information regarding the term "boe".

PRESIDENTS MESSAGE

"Coming out of spring break-up, we had an active third quarter focused on rebuilding our production profile post the closing of our Pembina disposition during the second quarter", commented Stephen Loukas, Obsidian Energy's President and CEO. "The execution of our second half development program is ahead of schedule, while our development volumes have exceeded our expectations. In Peace River we reached a record 7-day average of ~15,000 boe/d in September. At Willesden Green, we began our program in August drilling our first Belly River well at Crimson. The results from this initial well are very encouraging, with an IP25 of 538 boe/d (76% oil), validating an additional fairway in the emerging Belly River play. As a result of sustained success in our second half development program, we have narrowed our guidance range by increasing the lower end target. Our second half production range is now 27,800 to 28,300 boe/d and we anticipate being in the upper end of guidance. Additionally, water injection began at our Bluesky and Clearwater pilots and we intend to implement this recovery method on a broader scale in the area. We currently plan to accelerate the drilling of two new water injector wells in Dawson during the fourth quarter, which will result in a slight increase to our second half 2025 capital program."

Mr. Loukas continued, "During the third quarter we disposed of the InPlay Oil Corp. shares we received as partial consideration in our Pembina disposition for \$91.4 million. These proceeds were applied against our credit facility, further strengthening our financial position and providing us with significant financial flexibility during this period of elevated volatility in commodity markets. The Board has opted to take advantage of our balance sheet strength by authorizing the execution of a pre-paid equity forward program to hedge the Company's outstanding share-based incentive plan exposure. Lastly, our concern about short-term oil prices was reflected in our already tempered second half capital program announced in July and we increased our hedged volumes through the balance of the year with approximately two-thirds of our fourth quarter WTI exposure hedged via swaps at ~C\$90 per barrel. We will continue to monitor market conditions and consistent with our prior actions are prepared to make further adjustments to our capital program(s), including increasing it when appropriate to do so."

THIRD QUARTER 2025 CORPORATE HIGHLIGHTS

- **Funds Flow from Operations** – The Company generated funds flow from operations ("FFO") of \$49.7 million (\$0.74 per share basic) compared to \$124.7 million (\$1.64 per share basic) in the third quarter of 2024. FFO declined in 2025 as a result of lower production volumes due to the disposition of our Pembina assets in April 2025, as well as a plant turnaround at the PCU#11 Pembina field during the quarter, lower oil prices and the mark-to-market impact of our previously issued share-based compensation awards. Our active share buyback program under our normal course issuer bid ("NCIB") partially mitigated the lower FFO on a per share basis.

- Share-based compensation charges increased during the third quarter primarily due to the Company's share price increase and the resulting mark-to-market impact (September 30, 2025 - \$9.07 per share vs. June 30, 2025 - \$7.58 per share) which reduced FFO by \$5.5 million. None of these awards settled during the third quarter and did not impact our available cash. In September, the Company began making purchases under a prepaid equity forward program, which will also be marked-to-market, to reduce the exposure of our share based compensation plans to future share price changes.
- **Capital Development** – Third quarter capital expenditures totaled \$65.3 million (2024 – \$85.5 million) while decommissioning expenditures were \$7.9 million (2024 – \$6.3 million). We progressed through our second half capital program with multiple rigs running in Peace River while commencing our development program within the Belly River formation in Willesden Green.
- **InPlay Share Disposition** – In August 2025, we disposed of the Company's common share position in InPlay Oil Corp. ("InPlay") that we received as part of the consideration on the disposition of our Pembina assets. The Company received proceeds of \$91.4 million from the sale which resulted in a gain of \$15.2 million that was recorded within net income. The proceeds from this sale were applied against debt and to accelerate share buybacks.
- **Net Debt** – Net debt levels were \$219.3 million at September 30, 2025, compared to \$411.7 million at December 31, 2024. The cash proceeds associated with the sale of our Pembina assets in April 2025 and the subsequent sale of our InPlay share position in August 2025 were applied against bank debt which led to significantly lower net debt.
 - In August 2025, the Company completed a partial redemption on \$30.0 million of our senior unsecured notes, resulting in \$80.8 million of senior notes currently outstanding. The pay down of these notes will result in future interest savings.
- **Share Buyback Program** – The Company had an active buyback program during the third quarter of 2025 and repurchased and cancelled approximately 1.1 million shares under the Company's NCIB for \$8.7 million (at an average price of \$7.99 per share). By the end of August 2025, the Company had repurchased and cancelled 7.1 million shares since the renewal of our NCIB in March 2025, which is the maximum number allowed under the plan. The Company expects to renew our NCIB in March 2026.
- **Net Operating Costs** – Net operating costs of \$15.01 per boe in the third quarter of 2025 compared to \$13.74 per boe in 2024. Net operating costs were impacted by increased trucking costs and higher processing fees due to expanded operations in our Peace River area compared to 2024. We anticipate operating costs per boe to decrease going forward as additional water disposal capabilities are expected to reduce trucking expenses in Peace River.
- **General and administrative ("G&A") Costs** – G&A costs were \$1.95 per boe in the third quarter of 2025 compared to \$1.37 per boe in 2024. G&A costs increased on a per boe basis given our lower production levels as a result of the Pembina asset disposition that closed in April 2025.
- **Net Income** – Net income for the third quarter of 2025 was \$16.8 million (\$0.25 per share basic) versus \$33.2 million (\$0.44 per share basic) in 2024. Net income was impacted by lower production from our Pembina asset disposition earlier in the year and lower commodity prices, which led to lower revenues.

THIRD QUARTER 2025 CAPITAL PROGRAM & HIGHLIGHTS

During the third quarter, the Company advanced our second half capital program at both Peace River and Willesden Green. In Peace River, primary development was focused in the Clearwater at Dawson and Bluesky at Harmon Valley South ("**HVS**"). Enhanced oil recovery initiatives also progressed, as we commenced water injection at both Bluesky and Clearwater waterflood pilots. In Willesden Green, we drilled our first Belly River well in our Crimson field, which was brought on production in early October, and rig-released two additional Belly River wells in Open Creek also earlier in October. Key highlights are as follows:

Peace River

- **Active Development Program** - Rig-released 16 (16.0 net) wells in the area, including 14 (14.0 net) wells in the Dawson Clearwater field, and 2 (2.0 net) wells in the HVS Bluesky field. We experienced significant efficiencies from multi-well, pad drilling which resulted in advancing our execution timeline by one month allowing us to accelerate certain projects into the fourth quarter of 2025.
- **Strong Initial Rates** - Brought on production 14 (14.0 net) wells during the quarter, with initial production rates as follows:
 - 14-07 pad HVS (Bluesky) - 2 (2.0 net) wells with an average IP30 of 385 boe/d (100% oil) per well
 - 04-24 pad Dawson (Clearwater) - 2 (2.0 net) wells with an average IP30 of 316 boe/d (100% oil) per well
 - 13-23 pad Dawson (Clearwater) - 5 (5.0 net) wells with an average IP30 of 258 boe/d (100% oil) per well
 - 09-28 pad Dawson (Clearwater) - 5 (5.0 net) wells with an average IP30 of 214 boe/d (100% oil) per well.
- **Road Infrastructure Project** - During the third quarter we began construction on a major road infrastructure project in the Nampa field. Upon completion, which is expected in the fourth quarter, this infrastructure will provide year-round access to the field supporting future development drilling and the re-activation of approximately 200 bbl/d of previously shut-in Clearwater production.
- **Waterflood Injection** - Two waterflood projects were completed and injection commenced during the third quarter.
 - Two Bluesky wells (2.0 net) were converted to injection at the HVS 09-25 pad Waterflood project.
 - Two single leg injectors (2.0 net) were converted to injection at the 04-24 pad at our Dawson Waterflood pilot. We are planning to expand the Dawson Waterflood project and will drill an additional two (2.0 net) injection wells from the 04-24 pad in the fourth quarter of 2025.

Willesden Green

- **Belly River Focus** - In September, we rig released our first Belly River horizontal well at our 12-21 pad in Crimson which was subsequently brought on production in early October. This well is in the heart of our existing Crimson field and is the first appraisal well in a new Belly River development fairway.
 - 12-21 pad (Belly River) - 1 (1.0 net) well with strong initial rates with an IP25 of 538 boe/d (76% oil).

Additionally, in October we rig-released two Belly River wells in Open Creek which follow up on our successful 2024 Belly River drill. We anticipate these wells to be on production during the fourth quarter.

- **Mannville Development** - We drilled 1 (1.0 net) well in the Mannville formation in September. We experienced positive flow results through the test phase, prior to the well being shut-in for equip and tie-in work. The well will be placed back on production in the fourth quarter timed to optimize for seasonal gas prices.
- **Open Creek Infrastructure Project** - During the third quarter, we made significant progress on our Open Creek infrastructure project which will connect this under-exploited field into our regional infrastructure system. We anticipate completing this project by the end 2025 allowing further development of our Belly River and Cardium plays at Open Creek.

WELLS RIG RELEASED AND ON PRODUCTION 2025

	Q1-Q3 Gross (Net) Wells		Rig Released Gross (Net) Wells	
	Rig Released	On Production	Q4E	2025E
DEVELOPMENT WELLS				
<i>Heavy Oil Assets</i>				
Peace River (Bluesky)	14 (12.4)	16 (14.4)	-	14 (12.4)
Peace River (Clearwater)	21 (21.0)	19 (19.0)	4 (4.0)	25 (25.0)
<i>Light Oil Assets</i>				
Willesden Green (Cardium)	-	-	4 (4.0)	4 (4.0)
Willesden Green (Belly River)	1 (1.0)	-	2 (2.0)	3 (3.0)
Willesden Green (Mannville)	1 (1.0)	-	-	1 (1.0)
Pembina (Cardium) ¹	4 (4.0)	4 (4.0)	-	4 (4.0)
	41 (39.4)	39 (37.4)	10 (10.0)	51 (49.4)
EXPLORATION/APPRaisal WELLS				
Peace River (Bluesky)	3 (3.0)	3 (3.0)	-	3 (4.0)
Peace River (Clearwater)	4 (4.0)	4 (4.0)	-	4 (4.0)
	7 (7.0)	7 (7.0)	-	7 (7.0)
TOTAL OPERATED WELLS²	48 (46.4)³	46 (44.4)⁴	10 (10.0)⁵	58 (56.4)

- (1) Capital expenditures for the Pembina wells were paid for by InPlay as they were included in the interim closing adjustments of the Pembina disposition.
- (2) In addition, Obsidian Energy participated in the rig release of six non-operated (2.7 net) wells in the first nine months of 2025 and anticipates participating in six (2.7) non-operated wells in the fourth quarter of 2025.
- (3) The number of wells also excludes the two (2.0 net) Peace River single leg injector wells.
- (4) Three (3.0 net) wells rig released in 2024 were placed on production in the first quarter of 2025; they are included in the total.
- (5) We anticipate drilling an additional two (2.0) injectors in Q4 which are not included in the total.

UPDATED 2025 GUIDANCE

Supported by recent success in our development program we are increasing the lower end of our second half 2025 production guidance to 27,800 - 28,300 boe/d. With continued operational momentum, we anticipate being in the upper-end of this range.

In addition to strong production rates, better than expected program efficiencies have allowed us to accelerate certain projects into late 2025, which includes drilling two (2.0 net) incremental injector wells at our Dawson waterflood project. Combining this with a larger capital program at our non-operated PCU#11 asset we are updating our capital expenditure guidance range to \$120 to \$125 million.

Driven by the previously mentioned increased trucking costs and higher processing fees in Peace River, third quarter operating costs were higher than expected. With higher costs incurred to date we are increasing our second half 2025 operating cost guidance to \$14.35 to \$14.60 per boe. Improved water handling costs over the remainder of the year are expected to result in lower costs moving forward.

Our updated second half 2025 guidance assumes commodity prices of US\$60.00/bbl WTI, US\$4.00/bbl MSW differential, US\$11.50/bbl WCS differential, and \$2.75/GJ AECO natural gas for the remainder of the year. Based on these assumptions and our hedges in place, we anticipate FFO of approximately \$114 million for the second half of 2025 with a net debt to annualized FFO ratio of approximately 1.0 times.

Updated second half guidance is presented below:

		Previous H2 2025E Guidance	Updated H2 2025E Guidance
Production ¹	boe/d	27,100 – 28,300	27,800 – 28,300
% Oil and NGLs	%	72	72
Capital expenditures ²	\$ millions	110 – 120	120 – 125
Decommissioning expenditures	\$ millions	13 – 15	14 – 15
Net operating costs ³	\$/boe	13.45 – 14.35	14.35 – 14.60
General & administrative	\$/boe	2.00 – 2.10	1.95 – 2.05
Based on midpoint of above guidance			
FFO ³	\$ millions	113	114
FFO/share ^{2,3}	\$/share	1.67	1.70
FCF ³	\$ millions	(16)	(23)
FCF/share ^{2,3}	\$/share	(0.24)	(0.34)
Net debt ³	\$ millions	213	235
Net debt to annualized FFO ³	times	0.9	1.0
Pricing assumptions²			
WTI	US\$/bbl	65.00	60.00
Foreign Exchange Rate	CAD/USD	1.36	1.40
MSW Differential	US\$/bbl	3.50	4.00
WCS Differential	US\$/bbl	11.50	11.50
AECO	\$/GJ	2.50	2.75
Asset level information, based on midpoint of above guidance			
Heavy Oil			
Average production	boe/d	13,500	13,900
Capital expenditures ²	\$ millions	62	64
Net operating costs ³	\$/boe	17.40	18.10
Netback ³	\$/boe	26.92	27.80
Net operating income ³	\$ millions	67	70
Asset level FCF	\$ millions	5	6
Light Oil			
Average production	boe/d	14,200	14,150
Capital expenditures ²	\$ millions	52	58
Net operating costs ³	\$/boe	10.60	10.35
Netback ³	\$/boe	26.90	23.65
Net operating income ³	\$ millions	70	60
Asset level FCF	\$ millions	18	2

(1) Refer to 'Supplemental Production Disclosure' below for details of production by product types.

(2) Refer to "Budget Assumptions Information" below for further details.

(3) See "Non-GAAP and Other Financial Measures" section below for further details.

Estimated sensitivities to selected key assumptions on FFO for the second half of 2025 are as follows:

Guidance Sensitivity Table

Variable	Range	Change in H2 2025E FFO (\$ millions)
WTI (US\$/bbl)	+/- \$1.00/bbl	0.7
Foreign Exchange Rate (CAD/USD)	+/- \$0.01	0.2
MSW light oil differential (US\$/bbl)	+/- \$1.00/bbl	0.2
WCS heavy oil differential (US\$/bbl)	+/- \$1.00/bbl	0.3
AECO (\$/GJ)	+/- \$0.25/GJ	0.3

HEDGING UPDATE

The Company has been actively hedging in response to the volatile commodity markets to preserve cash flow.

Additionally, in September 2025, the Company began entering into prepaid equity forward contracts on our shares to help mitigate the equity price risk associated with our share-based compensation plans. During the third quarter of 2025, the Company purchased prepaid equity forward contracts on 820,000 shares at an average price of \$8.92 per share and subsequently increased our position in October.

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

Type	Volume (bbls/d)	Remaining Term	Price (\$/bbl)
Oil			
WTI Swap	12,000	October 2025	\$ 90.11
WTI Swap	11,250	November 2025	89.99
WTI Swap	9,250	December 2025	89.61
WCS Differential Swap	6,000	October 2025 - December 2025	\$ (19.30)

Type	Volume (mcf/d)	Remaining Term	Price (\$/mcf)
Natural Gas			
AECO Swap	25,118	October 2025	\$ 2.24
AECO Swap	24,171	November 2025 - March 2026	3.31
AECO Swap	27,488	April 2026 - October 2026	2.80
AECO Collar	1,896	October 2025	\$ 2.11 - 2.64

Type	Share Volume	Remaining Term	Price (C\$)
Equity			
Equity Forward Contract	720,000	September 2028	\$ 8.89
Equity Forward Contract	1,200,000	October 2028	\$ 8.78

UPDATED CORPORATE PRESENTATION

For further information on these and other matters, Obsidian Energy will post an updated corporate presentation on our website, www.obsidianenergy.com, in due course.

ADDITIONAL READER ADVISORIES

SUPPLEMENTAL PRODUCTION DISCLOSURE

Outlined below is expected average production by product based on the midpoint of our second half 2025 guidance estimates.

<i>Based on midpoint of guidance</i>		Previous H2 2025E Guidance	Updated H2 2025E Guidance
Heavy Oil	bbl/d	12,700	13,000
Light Oil	bbl/d	5,400	5,300
NGLs	bbl/d	1,960	1,950
Natural gas	mmcf/d	45.8	46.8
Total Production	boe/d	27,700	28,050

BUDGET ASSUMPTIONS INFORMATION

Capital Expenditures

- Asset level capital does not include \$1 million in corporate capital.

Commodity Pricing

- Updated second half capital guidance pricing assumptions include risk management (hedging) adjustments as of October 29, 2025. WTI, Foreign Exchange and AECO price assumptions for second half 2025 are forecasted for November to December 2025. MSW and WCS differential assumptions for the second half 2025 are forecasted for December 2025.
- Previous second half 2025 pricing assumptions include risk management (hedging) adjustments as of July 9, 2025. WTI, Foreign Exchange and AECO price assumptions for second half 2025 are forecasted for July to December 2025. MSW and WCS differential assumptions for the second half 2025 are forecasted for August to December 2025.

Per Share Calculations

- Updated second half 2025 guidance per share calculations are based on an estimated 67.1 million weighted average shares outstanding for the six months ended December 31, 2025.
- Previous second half 2025 guidance per share calculations are based on an estimated 67.7 million weighted average shares outstanding for the six months ended December 31, 2025.

OIL AND GAS INFORMATION ADVISORY

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 crude 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 crude 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.

TEST RESULTS AND INITIAL PRODUCTION RATES

Test results and initial production rates disclosed herein, particularly those short in duration, may not necessarily be indicative of long-term performance or of ultimate recovery. Readers are cautioned that short-term rates should not be relied upon as indicators of future performance of these wells and therefore should not be relied upon for investment or other purposes. A pressure transient analysis or well-test interpretation has not been carried out and thus certain of the test results provided herein should be considered preliminary until such analysis or interpretation has been completed.

NON-GAAP AND OTHER FINANCIAL MEASURES

Throughout this news release 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 and cash flow from operating activities as indicators of our performance. The interim consolidated financial statements and MD&A as at and for three and nine months ended September 30, 2025, will be available in due course on the Company's website at www.obsidianenergy.com and under our SEDAR+ profile at www.sedarplus.ca and EDGAR profile at www.sec.gov. The disclosure under the section '*Non-GAAP and Other Financial Measures*' in the MD&A is incorporated by reference into this news release.

Non-GAAP Financial Measures

The following measures are non-GAAP financial measures: FFO; net debt; net operating costs; netback; and free cash flow ("**FCF**"). These non-GAAP financial measures are not standardized financial measures under IFRS and might not be comparable to similar financial measures disclosed by other issuers. See the disclosure under the section '*Non-GAAP and Other Financial Measures*' in our MD&A for the three and nine months ended September 30, 2025, for an explanation of the composition of these measures, how these measures provide useful information to an investor, and the additional purposes, if any, for which management uses these measures.

For a reconciliation of FFO to cash flow from operating activities, being our nearest measure prescribed by IFRS, see '*Non-GAAP Measures Reconciliations*' below.

For a reconciliation of net debt to long-term debt, being our nearest measure prescribed by IFRS, see '*Non-GAAP Measures Reconciliations*' below.

For a reconciliation of net operating costs to operating costs, being our nearest measure prescribed by IFRS, see '*Non-GAAP Measures Reconciliations*' below.

For a reconciliation of netback to sales price, being our nearest measure prescribed by IFRS, see '*Non-GAAP Measures Reconciliations*' below.

For a reconciliation of FCF to cash flow from operating activities, being our nearest measure prescribed by IFRS, see '*Non-GAAP Measures Reconciliations*' below.

Non-GAAP Ratios

The following measures are non-GAAP ratios: FFO (basic per share (\$/share) and diluted per share (\$/share)), which use FFO as a component; net operating costs (\$/boe), which uses net operating costs as a component; netback (\$/boe), which uses netback as a component; and net debt to FFO, which uses net debt and FFO as components. These non-GAAP ratios are not standardized financial measures under IFRS and might not be comparable to similar financial measures disclosed by other issuers. See the disclosure under the section 'Non-GAAP and Other Financial Measures' in our MD&A in our MD&A for three and nine months ended September 30, 2025, for an explanation of the composition of these non-GAAP ratios, how these non-GAAP ratios provide useful information to an investor, and the additional purposes, if any, for which management uses these non-GAAP ratios.

Supplementary Financial Measures

The following measures are supplementary financial measures: average sales price; cash flow from operating activities (basic per share and diluted per share); and G&A costs (\$/boe). See the disclosure under the section 'Non-GAAP and Other Financial Measures' in our MD&A for the three and nine months ended September 30, 2025, for an explanation of the composition of these measures.

Non-GAAP Measures Reconciliations

Cash Flow from Operating Activities, FFO and FCF

(millions, except per share amounts)	Three months ended September 30		Nine months ended September 30	
	2025	2024	2025	2024
Cash flow from operating activities	\$ 45.4	\$ 110.3	\$ 197.3	\$ 246.9
Change in non-cash working capital	(11.6)	6.1	(13.1)	49.2
Decommissioning expenditures	7.9	6.3	18.5	20.4
Equity forward contracts	7.4	-	7.4	-
Onerous office lease settlements	-	2.2	0.7	6.7
Deferred financing costs	(0.4)	(0.6)	(1.4)	(1.8)
Restructuring charges	0.1	-	0.9	-
Transaction costs	0.9	-	5.3	1.4
Other expenses	-	0.4	-	1.5
FFO	49.7	124.7	215.6	324.3
Capital expenditures	(65.3)	(85.5)	(233.9)	(259.0)
Decommissioning expenditures	(7.9)	(6.3)	(18.5)	(20.4)
Free Cash Flow	\$ (23.5)	\$ 32.9	\$ (36.8)	\$ 44.9

Netback to Sales Price

(millions)	Three months ended September 30		Nine months ended September 30	
	2025	2024	2025	2024
Sales price	\$ 128.8	\$ 218.5	\$ 476.6	\$ 605.0
Risk management gain (loss)	(0.8)	7.8	0.2	15.6
Net sales price	128.0	226.3	476.8	620.6
Royalties	(16.5)	(28.4)	(60.8)	(77.5)
Transportation	(11.2)	(15.3)	(39.8)	(41.1)
Net operating costs	(37.7)	(49.8)	(127.7)	(138.1)
Netback	\$ 62.6	\$ 132.8	\$ 248.5	\$ 363.9

Net Operating Costs to Operating Costs

(millions)	Three months ended September 30		Nine months ended September 30	
	2025	2024	2025	2024
Operating costs	\$ 41.3	\$ 54.3	\$ 140.0	\$ 152.7
Less processing fees	(1.7)	(2.7)	(7.1)	(9.5)
Less road use recoveries	(1.9)	(2.3)	(5.2)	(6.1)
Add realized power risk management loss	-	0.5	-	1.0
Net operating costs	\$ 37.7	\$ 49.8	\$ 127.7	\$ 138.1

Net Debt to Long-Term Debt

(millions)	As at September 30	
	2025	2024
Long-term debt		
Syndicated credit facility	\$ 67.0	\$ 189.5
Senior unsecured notes	80.8	114.2
Term loan	-	42.5
Unamortized discount of senior unsecured notes	(0.6)	(1.2)
Deferred financing costs	(1.8)	(2.9)
Total	145.4	342.1
Working capital deficiency		
Cash	(1.0)	(0.9)
Accounts receivable	(60.9)	(87.8)
Prepaid expenses and other	(13.4)	(17.3)
Accounts payable and accrued liabilities	149.2	177.5
Total	73.9	71.5
Net debt	\$ 219.3	\$ 413.6

ABBREVIATIONS

Oil		Natural Gas	
bbl	barrel or barrels	AECO	Alberta benchmark price for natural gas
bbl/d	barrels per day	GJ	gigajoule
boe	barrel of oil equivalent	mcf	thousand cubic feet
	barrels of oil equivalent per		
boe/d	day	mcf/d	thousand cubic feet per day
MSW	Mixed Sweet Blend	mmcf/d	million cubic feet per day
WTI	West Texas Intermediate		
WCS	Western Canadian Select		

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. Forward-looking statements are typically identified by words such as “anticipate”, “continue”, “estimate”, “expect”, “forecast”, “budget”, “may”, “will”, “project”, “could”, “plan”, “intend”, “should”, “believe”, “outlook”, “objective”, “aim”, “potential”, “target” and similar words suggesting future events or future performance. In addition, statements relating to “reserves” or “resources” are deemed to be forward-looking statements as they involve the implied assessment, based on certain

estimates and assumptions, that the reserves and resources described exist in the quantities predicted or estimated and can be profitably produced in the future. In particular, this document contains forward-looking statements pertaining to, without limitation, the following: our development plans for the second half of 2025, including our waterflood projects, timing and locations; our expectations for interest payments in the future; that we plan to renew the NCIB in 2026; our expectations for operating costs per boe and trucking requirements in the future; our expectations for well on-production and rig release dates and road completion; our expected timing for our Open Creek Infrastructure project; our updated corporate guidance for production, capital and decommissioning expenditures, net operating costs, G&A costs, FFO, FFO/share, FCF, FCF/share, net debt and net debt to annualized FFO; our updated asset level guidance for production, capital, net operating costs, netback, net operating income, and asset level FCF; our guidance sensitivities; our hedges; our update guidance by product; the timing of our updated corporate presentation; and that we will file our interim consolidated financial statements and MD&A on our website, SEDAR+ and EDGAR in due course.

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, flooding and drought, 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, that 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 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 that the amount of energy demand destruction and/or the length of the decreased demand exceeds our expectations; 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 unable to complete one or more repurchase offers pursuant to our Notes when otherwise required to do so; 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; the possibility that fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to hydrocarbons, 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 a regional and/or global health related event and/or the influence of public opinion and/or special interest groups.

Additional information on these and other factors that could affect Obsidian Energy, or its operations or financial results, are included in the Company's Annual Information Form (see '*Risk Factors*' and '*Forward-Looking Statements*' therein) which may be accessed through the SEDAR+ website (www.sedarplus.ca), EDGAR website (www.sec.gov) or Obsidian Energy's [website](#). Readers are cautioned that this list of risk factors should not be construed as exhaustive.

Unless otherwise specified, 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, we do not undertake any obligation to publicly update or revise any forward-looking statements. The forward-looking statements contained in this document are expressly qualified by this cautionary statement.

Obsidian Energy shares are listed on both the Toronto Stock Exchange in Canada and the NYSE American in the United States under the symbol "OBE".

All figures are in Canadian dollars unless otherwise stated.

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