

## **ITEM 2. MANAGEMENT’S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS**

*The following discussion is intended to assist in the understanding of trends and significant changes in our results of operations and the financial condition of Epsilon Energy Ltd. and its subsidiaries for the periods presented. The following discussion and analysis should be read in conjunction with our unaudited consolidated financial statements and notes thereto presented in this report, including the unaudited condensed consolidated financial statements as of June 30, 2025 and 2024 together with accompanying notes, as well as our audited consolidated financial statements and notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2024. The following discussion contains “forward-looking statements” that reflect our future plans, estimates, beliefs, and expected performance. Actual results and the timing of events may differ materially from those contained in these forward-looking statements due to a number of factors. See “Part II. Item 1A. Risk Factors” and “Forward-Looking Statements.”*

### **Overview**

Epsilon Energy Ltd. (the “Company”) is a North American onshore focused independent natural gas and oil company engaged in the acquisition, development, gathering and production of natural gas and oil reserves. Our primary areas of operations are the Marcellus shale section of the Appalachian basin in Pennsylvania, the Permian Basin in Texas and New Mexico, the NW Anadarko Basin in Oklahoma, and the Western Canadian Sedimentary Basin in Alberta, Canada.

At June 30, 2025 we held leasehold rights to 24,316 net acres. We have natural gas production from our non-operated wells in Pennsylvania, and oil, natural gas liquids, and natural gas production from our non-operated wells in Texas, New Mexico, Oklahoma, and Alberta, Canada.

At December 31, 2024 our total estimated net proved reserves were 69,401 MMcf of natural gas, 876,808 Bbls of NGLs, and 1,572,465 Bbls of oil and condensate.

In Pennsylvania, the Company owns a 35% interest in the 45-mile Auburn Gas Gathering System (“Auburn GGS”) which is operated by a subsidiary of Williams Partners, LP.

Our common shares trade on the NASDAQ Global Market under the ticker symbol “EPSN.”

### **Business Strategy**

We are committed to disciplined capital allocation including shareholder returns in the form of dividends and share buybacks. We plan to maintain a strong balance sheet and liquidity position to allow us to opportunistically invest in both our existing project areas and potential new projects.

Historically, our investments have been focused on our position in the Marcellus unconventional reservoir in Pennsylvania (“PA”). Our PA assets are supported by our 35% ownership in the Auburn GGS and we have a substantial remaining drillable location inventory within our existing leaseholds.

More recently, our investments have been focused in the Permian Basin in Texas and the Western Canadian Sedimentary Basin in Alberta, Canada.

On February 26, 2024, Epsilon acquired a 25% interest in three producing wells and 3,620 gross undeveloped acres in Ector County, Texas from a private operator. The Company participated in the drilling and completion of 2 gross (0.5 net) wells during 2024 which were put on production in May 2024 and July 2024. Together with the transaction completed in 2023, the Company holds a 25% working interest in 16,592 gross acres and 7 producing wells in Texas. Total capital expenditures (net to Epsilon) through June 30, 2025 in the project (including undeveloped leasehold) are \$40 million.

On April 11, 2024, Epsilon acquired a 50% working interest in 14,243 gross undeveloped acres in Alberta, Canada. The Company participated in the drilling and completion of 2 gross (0.5 net) wells. One well was put on production in September 2024. One well was deemed non-commercial. Total capital expenditures (net to Epsilon) through June 30, 2025 in the project (including undeveloped leasehold) are \$3.5 million (pre-impairment).

In October 2024, Epsilon formed a joint venture with a private operator covering approximately 130,000 gross acres in Garrington and Harmattan areas in Alberta, Canada. The Company provided a \$7 million drilling carry in favor of the operator in exchange for a 25% working interest in the leasehold. To date, the Company participated in the drilling and completion of 2 gross (0.5 net) wells. Total capital expenditures (net to Epsilon) through June 30, 2025 are \$8.9 million (pre-impairment).

We continue to evaluate new opportunities in numerous onshore North American basins.

### **Three and six months ended June 30, 2025 Highlights**

#### ***Operational Highlights***

##### *Marcellus Shale – Pennsylvania*

- During the three months ended June 30, 2025, Epsilon's realized natural gas price was \$2.53 per Mcf, a 76% increase over the three months ended June 30, 2024. During the six months ended June 30, 2025, Epsilon's realized natural gas price was \$3.22 per Mcf, a 99% increase over the six months ended June 30, 2024.
- During the three months ended June 30, 2025, Epsilon's net revenue interest natural gas production was 2.7 Bcf, a 107% increase over the three months ended June 30, 2024. During the six months ended June 30, 2025, Epsilon's net revenue interest natural gas production was 5.3 Bcf, an 86% increase over the six months ended June 30, 2024.
- Gathered and delivered 11.2 Bcf gross (3.9 net to Epsilon's interest) during the three months ended June 30, 2025, or 123 MMcf/d through the Auburn Gas Gathering System. Gathered and delivered 22.8 Bcf gross (8.0 net to Epsilon's interest) during the six months ended June 30, 2025, or 126 MMcf/d through the Auburn Gas Gathering System.

##### *Permian Basin – Texas and New Mexico*

- During the three months ended June 30, 2025, Epsilon's realized price for all Permian Basin production was \$51.79 per Boe (88% liquids), a 4% decrease over the three months ended June 30, 2024. During the six months ended June 30, 2025, Epsilon's realized price for all Permian Basin production was \$53.46 per Boe (87% liquids), a 0.02% decrease over the six months ended June 30, 2024.
- Total net revenue interest production for the three months ended June 30, 2025, which included oil, natural gas liquids, and natural gas, was 42.9 Mboe compared to 65.9 Mboe during the same period in 2024, an 35% decrease. Total net revenue interest production for the six months ended June 30, 2025, which included oil, natural gas liquids, and natural gas, was 104.9 Mboe compared to 118.2 Mboe during the same period in 2024, an 11% decrease.
- At June 30, 2025, the Company had 1 gross (.25 net) well drilled and awaiting completion in Texas.

##### *Anadarko, NW Stack Trend – Oklahoma*

- During the three months ended June 30, 2025, Epsilon's realized price for all Oklahoma production was \$4.40 per Mcfe (60% natural gas), a 3% increase from the three months ended June 30, 2024. During the six months ended June 30, 2025, Epsilon's realized price for all Oklahoma production was \$4.85 per Mcfe (60% natural gas), a 10% increase from the six months ended June 30, 2024.
- Total net revenue interest production for the three months ended June 30, 2025 included natural gas, oil and other liquids and was 0.09 Bcfe, a 22% decrease from the same period in 2024. Total net revenue interest production for the six months ended June 30, 2025 included natural gas, oil and other liquids and was 0.2 Bcfe, a 10% decrease from the same period in 2024.

*Western Canadian Sedimentary Basin—Alberta, Canada*

- During the three months ended June 30, 2025, Epsilon's realized price for all Canada production was \$42.23 per Boe (75% liquids). During the six months ended June 30, 2025, Epsilon's realized price for all Canada production was \$43.48 per Boe (78% liquids). The Company had no Canada production in 2024.
- Total net revenue interest production for the three months ended June 30, 2025, which included oil, natural gas liquids, and natural gas, was 11.3 Mboe. Total net revenue interest production for the six months ended June 30, 2025, which included oil, natural gas liquids, and natural gas, was 13.1 Mboe.

***Non-GAAP Financial Measures—Adjusted EBITDA***

Epsilon defines Adjusted EBITDA as earnings before (1) net interest expense, (2) taxes, (3) depreciation, depletion, amortization and accretion expense, (4) impairments of natural gas and oil properties, (5) non-cash stock compensation expense, (6) gain or loss on sale of assets, (7) gain or loss on derivative contracts net of cash received or paid on settlement, and (8) net other income(expense). Adjusted EBITDA is not a measure of financial performance as determined under U.S. GAAP and should not be considered in isolation from or as a substitute for net income or cash flow measures prepared in accordance with U.S. GAAP or as a measure of profitability or liquidity.

Additionally, Adjusted EBITDA may not be comparable to other similarly titled measures of other companies. Epsilon has included Adjusted EBITDA as a supplemental disclosure because its management believes that Adjusted EBITDA provides useful information regarding its ability to service debt and to fund capital expenditures. It further provides investors a helpful measure for comparing operating performance on a normalized or recurring basis with the performance of other companies, without giving effect to certain non-cash expenses and other items. This provides management, investors and analysts with comparative information for evaluating the Company in relation to other natural gas and oil companies providing corresponding non-U.S. GAAP financial measures or that have different financing and capital structures or tax rates. These non-U.S. GAAP financial measures should be considered in addition to, but not as a substitute for, measures for financial performance prepared in accordance with U.S. GAAP.

The table below sets forth a reconciliation of net income to Adjusted EBITDA for the three and six months ended June 30, 2025 and 2024, which is the most directly comparable measure of financial performance calculated under U.S. GAAP and should be reviewed carefully.

	<b>Three months ended June 30,</b>		<b>Six months ended June 30,</b>	
	<b>2025</b>	<b>2024</b>	<b>2025</b>	<b>2024</b>
<b>Net income</b>	\$ 1,551,461	\$ 815,660	\$ 5,567,495	\$ 2,322,556
Add Back:				
Interest expense (income), net	2,659	(100,184)	(429)	(357,696)
Income tax expense	1,837,687	459,016	3,507,881	513,066
Depreciation, depletion, amortization, and accretion	3,201,654	2,048,403	6,677,511	4,428,829
Impairment expense	2,670,000	—	2,676,669	—
Stock based compensation expense	385,838	313,589	771,676	635,158
(Gain) loss on derivative contracts net of cash received or paid on settlement	(2,267,203)	367,148	(1,220,076)	956,159
Foreign currency translation loss	14,021	—	24,310	570
<b>Adjusted EBITDA</b>	<b>\$ 7,396,117</b>	<b>\$ 3,903,632</b>	<b>\$ 18,005,037</b>	<b>\$ 8,498,642</b>

## Results of Operations

### Net Operating Revenues

For the six months ended June 30, 2025 revenues increased \$12.5 million, or 82%, to \$27.8 million from \$15.3 million during the same period of 2024.

Revenue and volume statistics for the three and six months ended June 30, 2025 and 2024 were as follows:

	Three months ended June 30,		Six months ended June 30,	
	2025	2024	2025	2024
<b>Revenues</b>				
Pennsylvania				
Natural gas revenue	\$ 6,702,131	\$ 1,843,548	\$ 17,030,025	\$ 4,601,656
Volume (MMcf)	2,653	1,285	5,290	2,841
Avg. Price (\$/Mcf)	\$ 2.53	\$ 1.44	\$ 3.22	\$ 1.62
Gathering system revenue (net of elimination)	\$ 1,845,005	\$ 1,444,448	\$ 3,737,355	\$ 3,380,146
<b>Total PA Revenues</b>	<b>\$ 8,547,136</b>	<b>\$ 3,287,996</b>	<b>\$ 20,767,380</b>	<b>\$ 7,981,802</b>
Permian Basin				
Natural gas revenue	\$ 17,189	\$ (2,757)	\$ 95,528	\$ 38,821
Volume (MMcf)	30	58	80	101
Avg. Price (\$/Mcf)	\$ 0.56	\$ (0.05)	\$ 1.19	\$ 0.38
Natural gas liquids revenue	\$ 41,837	\$ 281,770	\$ 326,798	\$ 541,684
Volume (MBOE)	3.2	14.5	15.3	26.0
Avg. Price (\$/Bbl)	\$ 13.06	\$ 19.38	\$ 21.36	\$ 20.85
Oil and condensate revenue	\$ 2,163,481	\$ 3,266,693	\$ 5,182,976	\$ 5,753,206
Volume (MBbl)	34.6	41.7	76.2	75.4
Avg. Price (\$/Bbl)	\$ 62.47	\$ 78.35	\$ 68.06	\$ 76.35
<b>Total Permian Basin Revenues</b>	<b>\$ 2,222,507</b>	<b>\$ 3,545,706</b>	<b>\$ 5,605,302</b>	<b>\$ 6,333,711</b>
Oklahoma				
Natural gas revenue	\$ 166,635	\$ 120,439	\$ 373,975	\$ 283,732
Volume (MMcf)	52	65	105	131
Avg. Price (\$/Mcf)	\$ 3.20	\$ 1.86	\$ 3.57	\$ 2.17
Natural gas liquids revenue	\$ 79,789	\$ 106,653	\$ 182,078	\$ 219,723
Volume (MBOE)	3.7	4.7	7.4	9.3
Avg. Price (\$/Bbl)	\$ 21.61	\$ 22.78	\$ 24.64	\$ 23.52
Oil and condensate revenue	\$ 133,446	\$ 247,024	\$ 291,383	\$ 475,593
Volume (MBbl)	2.0	3.1	4.3	6.1
Avg. Price (\$/Bbl)	\$ 66.00	\$ 79.66	\$ 68.29	\$ 78.38
<b>Total OK Revenues</b>	<b>\$ 379,870</b>	<b>\$ 474,116</b>	<b>\$ 847,436</b>	<b>\$ 979,048</b>
Canada				
Natural gas revenue	\$ 24,389	\$ —	\$ 24,389	\$ —
Volume (MMcf)	17	—	17	—
Avg. Price (\$/Mcf)	\$ 1.44	\$ —	\$ 1.44	\$ —
Natural gas liquids revenue	\$ 23,394	\$ —	\$ 23,394	\$ —
Volume (MBOE)	0.9	—	0.9	—
Avg. Price (\$/Bbl)	\$ 24.91	\$ —	\$ 24.91	\$ —
Oil and condensate revenue	\$ 427,437	\$ —	\$ 519,972	\$ —
Volume (MBbl)	7.5	—	9.3	—
Avg. Price (\$/Bbl)	\$ 57.11	\$ —	\$ 55.98	\$ —
<b>Total Canada Revenues</b>	<b>\$ 475,220</b>	<b>\$ —</b>	<b>\$ 567,755</b>	<b>\$ —</b>
<b>Total Revenues</b>	<b>\$ 11,624,733</b>	<b>\$ 7,307,818</b>	<b>\$ 27,787,873</b>	<b>\$ 15,294,561</b>

Upstream natural gas revenue for the six months ended June 30, 2025 increased by \$12.6 million, or 256%, over the same period in 2024. An increase of \$8.7 million was due to higher natural gas prices and an increase of \$3.9 million was a result of previously delayed turn in line wells coming online in Pennsylvania and the end of operator-elected well

shut-ins in Pennsylvania. Upstream natural gas revenue for the three months ended June 30, 2025 increased by \$5.0 million, or 252%, over the same period in 2024. An increase of \$3.1 million was due to higher natural gas prices and an increase of \$1.9 million was a result of previously delayed turn in line wells coming online in Pennsylvania and the end of operator-elected well shut-ins in Pennsylvania.

Upstream natural gas liquids revenue for the six months ended June 30, 2025 decreased by \$0.2 million, or 30%, over the same period in 2024. This decrease was mostly due to lower volumes in the Permian Basin as a result of processing disruptions at the Goldsmith plant in Texas in the second quarter. Upstream natural gas liquids revenue for the three months ended June 30, 2025 decreased by \$0.2 million, or 63%, over the same period in 2024. This decrease was mostly due to lower volumes in the Permian Basin as a result of the aforementioned processing disruption.

Upstream oil and condensate revenue for the six months ended June 30, 2025 decreased by \$0.2 million, or 4% over the same period in 2024. An increase of \$0.6 million was due to additional sales volumes from new wells drilled and acquired in the Permian Basin and Canada partially offset by a decrease of \$0.9 million due to lower prices. Upstream oil and condensate revenue for the three months ended June 30, 2025 decreased by \$0.8 million, or 22% over the same period in 2024. A decrease of \$0.05 million was due to constant sales volumes and a decrease of \$0.75 million was due to lower prices.

Gathering system revenue for the six months ended June 30, 2025 increased by \$0.4 million, or 11%, compared with the same period in 2024 as a result of crossflow gas being displaced with Anchor Shipper gas which is charged a higher gathering fee. Gathering system revenue for the three months ended June 30, 2025 increased by \$0.4 million, or 28%, compared with the same period in 2024 due to higher volumes and a higher percentage of Anchor Shipper gas. Revenues derived from transporting and compressing our production, which have been eliminated from gathering system revenues amounted to \$0.5 million and \$1.1 million, respectively, for the three and six months ended June 30, 2025, and \$0.3 million and \$0.6 million, respectively, for the three and six months ended June 30, 2024.

### ***Operating Costs***

The following table presents total cost and cost per unit of production (Mcf), including ad valorem, severance, and production taxes for the three and six months ended June 30, 2025 and 2024:

	<u>Three months ended June 30,</u>		<u>Six months ended June 30,</u>	
	<u>2025</u>	<u>2024</u>	<u>2025</u>	<u>2024</u>
Lease operating costs (net of elimination)	\$ 2,462,785	\$ 1,649,867	\$ 5,218,683	\$ 3,418,329
Gathering system operating costs	613,795	649,967	1,166,446	1,202,537
	<b><u>\$ 3,076,580</u></b>	<b><u>\$ 2,299,834</u></b>	<b><u>\$ 6,385,129</u></b>	<b><u>\$ 4,620,866</u></b>
Upstream operating costs—Total \$/Mcf	0.80	0.92	\$ 0.85	\$ 0.91
Gathering system operating costs \$/Mcf	0.15	0.20	\$ 0.14	\$ 0.14

Operating costs include the effects of elimination entries to remove the gathering fees paid to Epsilon's ownership in the gathering system.

Upstream operating costs consist of lease operating expenses necessary to extract natural gas and oil, including gathering and treating the natural gas and oil to ready it for sale. For the six months ended June 30, 2025 these costs increased by \$1.8 million, or 53%, over the same period in 2024. The increase is primarily due to higher volumes. For the three months ended June 30, 2025 these costs increased by \$0.8 million, or 49%, over the same period in 2024. The increase is primarily due to higher volumes.

Gathering system operating costs consist primarily of rental payments for the natural gas fueled compression units and overhead fees due to the system's operator. For the three and six months ended June 30, 2025, gathering system operating costs were constant compared to the same period in 2024.

### *Depletion, Depreciation, Amortization and Accretion (“DD&A”)*

	<u>Three months ended June 30,</u>		<u>Six months ended June 30,</u>	
	<u>2025</u>	<u>2024</u>	<u>2025</u>	<u>2024</u>
<b>Depletion, depreciation, amortization and accretion</b>	<b>\$ 3,201,654</b>	<b>\$ 2,048,403</b>	<b>\$ 6,677,511</b>	<b>\$ 4,428,829</b>

Natural gas and oil and gathering system assets are depleted and depreciated using the units of production method aggregating properties on a field basis. For leasehold acquisition costs and the cost to acquire proved and unproved properties, the reserve base used to calculate depreciation and depletion is total proved reserves. For natural gas and oil development and gathering system costs, the reserve base used to calculate depletion and depreciation is proved developed reserves.

Depreciation expense includes amounts pertaining to our office furniture and fixtures, leasehold improvements, computer hardware. Depreciation is calculated using the straight-line method over the estimated useful lives of the assets, ranging from 3 to 7 years. Also included in depreciation expense is an amount pertaining to buildings owned by the Company. Depreciation for the buildings is calculated using the straight-line method over an estimated useful life of 30 years.

Accretion expense is related to the asset retirement costs.

DD&A expense for the three and six months ended June 30, 2025 increased by \$1.2 million, or 56%, and \$2.2 million, or 51%, respectively, from the same period in 2024. This increase was a result of higher produced volumes in Pennsylvania and the Permian Basin.

### *Impairment*

	<u>Three months ended June 30,</u>		<u>Six months ended June 30,</u>	
	<u>2025</u>	<u>2024</u>	<u>2025</u>	<u>2024</u>
<b>Impairment</b>	<b>\$ 2,670,000</b>	<b>\$ —</b>	<b>\$ 2,676,669</b>	<b>\$ —</b>

We perform a quantitative impairment test whenever events or changes in circumstances indicate that an asset group's carrying amount may not be recoverable, over proved properties using the market forward prices, timing, methods and other assumptions consistent with historical periods. When indicators of impairment are present, GAAP requires that the Company first compare expected future undiscounted cash flows by asset group to their respective carrying values. If the carrying amount exceeds the estimated undiscounted future cash flows, a reduction of the carrying amount of the natural gas properties to their estimated fair value is required. Additionally, GAAP requires that if an exploratory well is determined not to have found proved reserves, the costs incurred, net of any salvage value, should be charged to expense.

For the three and six months ended June 30, 2025, the Company recorded an impairment of \$2.7 million for two wells drilled in Alberta, Canada. The impairment was a result of a decrease in estimated reserves due to early production coming in below expectations, cost overruns and lower forward commodity prices. For the three and six months ended June 30, 2024, there was no impairment.

### *General and Administrative (“G&A”)*

	<u>Three months ended June 30,</u>		<u>Six months ended June 30,</u>	
	<u>2025</u>	<u>2024</u>	<u>2025</u>	<u>2024</u>
<b>General and administrative</b>	<b>\$ 1,847,716</b>	<b>\$ 1,791,804</b>	<b>\$ 4,051,972</b>	<b>\$ 3,672,396</b>

G&A expenses consist of general corporate expenses such as compensation, legal, accounting and professional fees, consulting services, travel and other related corporate costs such as restricted stock granted.

G&A expenses for the six months ended June 30, 2025 increased by \$0.4 million, or 10% from the same period in 2024. This was primarily due to higher compensation expenses. G&A expenses for the three months ended June 30, 2025 was constant from the same period in 2024.

### ***Interest Income***

	<u>Three months ended June 30,</u>		<u>Six months ended June 30,</u>	
	<u>2025</u>	<u>2024</u>	<u>2025</u>	<u>2024</u>
<b>Interest income</b>	<b>\$ 17,247</b>	<b>\$ 108,943</b>	<b>\$ 32,546</b>	<b>\$ 375,215</b>

Interest income for the three and six months ended June 30, 2025 decreased by \$0.1 million, or 84%, and \$0.3 million, or 91%, respectively, from the same period in 2024. This was primarily due to a reduction in the balance of cash and short term investments.

### ***Interest Expense***

	<u>Three months ended June 30,</u>		<u>Six months ended June 30,</u>	
	<u>2025</u>	<u>2024</u>	<u>2025</u>	<u>2024</u>
<b>Interest expense</b>	<b>\$ 19,906</b>	<b>\$ 8,759</b>	<b>\$ 32,117</b>	<b>\$ 17,519</b>

Interest expense is related to the fees paid on the revolving credit facility.

Interest expense during the three and six months ended June 30, 2025 and 2024 was relatively flat.

### ***Gain (Loss) on Derivative Contracts***

	<u>Three months ended June 30,</u>		<u>Six months ended June 30,</u>	
	<u>2025</u>	<u>2024</u>	<u>2025</u>	<u>2024</u>
<b>Gain (Loss) on derivative contracts</b>	<b>\$ 2,573,863</b>	<b>\$ (94,891)</b>	<b>\$ 1,111,693</b>	<b>\$ (195,617)</b>

For the six months ended June 30, 2025, Epsilon had NYMEX HH Natural Gas futures swaps, Tennessee Gas Pipeline Zone 4 basis swaps, NYMEX HH options, and crude oil NYMEX WTI CMA swaps derivative contracts for the purpose of hedging a portion of its physical natural gas and oil sales revenue. The amounts recorded represent the fair value changes on our derivative instruments during the year.

During the three months ended June 30, 2025, we received net cash settlements of \$306,660. During the six months ended June 30, 2025, we paid net cash settlements of \$108,383. During the three and six months ended June 30, 2024, we received net cash settlements of \$272,257 and \$760,542, respectively.

For the three and six months ended June 30, 2025, realized gains on derivative contracts increased by \$2.7 million and \$1.3 million, respectively. This increase was primarily the result of a significant decrease in Henry Hub natural gas prices during the quarter.

## **Capital Resources and Liquidity**

### ***Cash Flow***

The primary source of cash for Epsilon during the three and six months ended June 30, 2025 and 2024 was funds generated from operations. The primary uses of cash for the three and six months ended June 30, 2025 were the development of upstream properties and the distribution of dividends. The primary uses of cash for the three months ended

June 30, 2024 were the development of upstream properties, investment in U.S. Treasury Bills, the repurchase of shares of common stock, and the distribution of dividends.

At June 30, 2025, we had a working capital surplus of \$9.1 million, an increase of \$1.9 million from the \$7.2 million surplus at December 31, 2024. The Company anticipates its current cash balance, available borrowings, and cash flows from operations to be sufficient to meet its cash requirements for at least the next twelve months.

#### *Six months ended June 30, 2025 compared to 2024*

During the six months ended June 30, 2025, \$16.9 million was provided by the Company's operating activities, compared to \$9.1 million during the same period in 2024, representing an 87% increase. The increase was primarily due to higher produced volumes and realized prices in Pennsylvania.

The Company used \$10.7 million and \$9.5 million of cash for investing activities during the six months ended June 30, 2025 and 2024, respectively. During the six months ended June 30, 2025, the Company had net investments of \$10.7 million primarily in well costs and leasehold in Pennsylvania, Texas, and Canada. During the six months ended June 30, 2024, the Company had net investments of \$28.6 million in leasehold and well costs in Pennsylvania and Texas offset by net proceeds of \$19.1 million in U.S. Treasury Bills.

The Company used \$2.8 million and \$3.9 million of cash for financing activities during the six months ended June 30, 2025 and 2024, respectively. During the six months ended June 30, 2025, this was spent on dividend payments. During the six months ended June 30, 2024, this was spent on dividend payments and the repurchase of shares of common stock.

#### ***Credit Agreement***

The Company closed a senior secured reserve based revolving credit facility on June 28, 2023 with Frost Bank as issuing bank and sole lender. The current borrowing base is \$45 million (redetermined as of February 10, 2025), supported by the Company's upstream assets in Pennsylvania and subject to semi-annual redeterminations with a maturity date of June 28, 2027. Interest will be charged at the Daily Simple SOFR rate plus a margin of 3.25%. The facility is secured by the assets of the Company's Epsilon Energy USA subsidiary (Borrower). There are currently no borrowings under the facility.

Under the terms of the facility, the Company must adhere to the following financial covenants:

- Current ratio of 1.0 to 1.0 (current assets / current liabilities)
- Leverage ratio of less than 2.5 to 1.0 (total debt / income adjusted for interest, taxes and non-cash amounts)

Additionally, if the Leverage ratio is greater than 1.0 to 1.0, or the borrowing base utilization is greater than 50%, the Company is required to hedge 50% of the anticipated production from PDP reserves for a rolling 24 month period.

#### ***Repurchase Transactions***

On February 12, 2025, Epsilon's board of directors (the "Board") authorized a new share repurchase program of up to 2,200,876 common shares, representing 10% of the current outstanding common shares of Epsilon, for an aggregate purchase price of not more than US \$13.0 million. The program commenced on February 12, 2025 and ends on February 11, 2026, unless the maximum amount of common shares is purchased before then or the Board approves earlier termination.

The previous share repurchase program commenced on March 19, 2024. During the year ended December 31, 2024, we repurchased 125,000 common shares and spent \$627,500 at an average price of \$5.00 per share (excluding commissions) under the plan. On February 12, 2025, the Board terminated and revoked authority under the program.

During the six months ended June 30, 2025, no shares were repurchased under the new or previous program.

### ***Derivative Transactions***

The Company has entered into hedging arrangements to reduce the impact of commodity price volatility on operations. By reducing the price volatility from a portion of natural gas and crude oil production, the potential effects of changing prices on operating cash flows have been partially mitigated, but not eliminated. While mitigating the negative effects of falling commodity prices, these derivative contracts also limit the benefits we might otherwise receive from increases in commodity prices.

At June 30, 2025, Epsilon's outstanding natural gas and crude oil commodity contracts consisted of the following:

Derivative Type	Volume (MMbtu)	Weighted Average Price (\$/Mmbtu)			Fair Value of Asset June 30, 2025
		Swaps	Ceiling Price	Floor Price	
<b>2025</b>					
Henry Hub Nymex Swap	1,026,000	\$ 3.65	\$ —	\$ —	\$ (144,265)
Tennessee Z4 Basis swap	782,000	\$ —	\$ —	\$ —	\$ 351,769
Henry Hub Nymex Option - Put	122,000	\$ —	\$ —	\$ 4.00	\$ 48,138
Henry Hub Nymex Option - Call	—	\$ —	\$ 6.17	\$ —	\$ (15,996)
<b>2026</b>					
Henry Hub Nymex Swap	1,644,000	\$ 4.24	\$ —	\$ —	\$ 157,504
Henry Hub Nymex Option - Put	623,000	\$ —	\$ —	\$ 4.72	\$ 250,131
Henry Hub Nymex Option - Call	—	\$ —	\$ 4.79	\$ —	\$ (191,398)
<b>2027</b>					
Henry Hub Nymex Option - Put	180,000	\$ —	\$ —	\$ 4.00	\$ 105,184
Henry Hub Nymex Option - Call	—	\$ —	\$ 6.18	\$ —	\$ (92,002)
	<u>4,377,000</u>				<u>\$ 469,065</u>

Derivative Type	Volume (Bbl)	Weighted Average Price (\$/Bbl)	Fair Value June 30, 2025
<b>2025</b>			
Crude Oil NYMEX WTI CMA	39,600	\$ 69.19	\$ 263,462
	<u>39,600</u>		<u>\$ 263,462</u>

### ***Contractual Obligations***

The Company enters into commitments for capital expenditures in advance of the expenditures being made. As of June 30, 2025, the Company has commitments of \$1.9 million for capital expenditures and has undiscounted long term commitments of \$15.7 million for asset retirement obligations.

### **ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK**

Our earnings and cash flow are significantly affected by changes in the market price of commodities. The prices of natural gas and oil can fluctuate widely and are influenced by numerous factors such as demand, production levels, world political and economic events, and the strength of the US dollar relative to other currencies. Should the price of natural gas and oil decline substantially, the value of our assets could fall dramatically, impacting our future operations and exploration and development activities, along with our gas gathering system revenues. In addition, our operations are exposed to market risks in the ordinary course of our business, including interest rate and certain exposure as well as risks relating to changes in the general economic conditions in the United States.

### ***Gathering System Revenue Risk***

The Auburn Gas Gathering System lies within the Marcellus Basin with historically high levels of recoverable reserves and low cost of production. We believe that a short-term low commodity price environment will not significantly impact the reserves produced and thus the revenue of our gas gathering system.

### ***Interest Rate Risk***

Market risk is estimated as the change in fair value resulting from a hypothetical 100 basis point change in the interest rate on the outstanding balance under our credit agreement. The credit agreement allows us to fix the interest rate.

At June 30, 2025 and 2024, the outstanding principal balance under the credit agreement was nil.

### ***Derivative Contracts***

The Company's financial results and condition depend on the prices received for production. Natural gas, natural gas liquids, and crude oil prices have fluctuated widely and are determined by economic and political factors. Supply and demand factors, including weather, general economic conditions, the ability to transport to other regions, as well as conditions in other regions, impact prices. Epsilon has established a hedging strategy and may manage the risk associated with changes in commodity prices by entering into various derivative financial instrument agreements and physical contracts. Although these commodity price risk management activities could expose Epsilon to losses or gains, entering into these contracts helps to stabilize cash flows and support the Company's capital spending program.

## **ITEM 4. CONTROLS AND PROCEDURES**

### ***Disclosure Controls and Procedures***

As required by Rule 13a-15(b) under the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our chief executive officer and our chief financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this 10-Q. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including our chief executive officer and chief financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Our chief executive officer and chief financial officer have concluded that our current disclosure controls and procedures were effective as of June 30, 2025 at the reasonable assurance level.

### ***Changes in Internal Control over Financial Reporting***

No changes in our internal control over financial reporting occurred during the quarter ended June 30, 2025 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

### ***Inherent Limitations on Effectiveness of Controls***

Internal control over financial reporting cannot provide absolute assurance of achieving financial reporting objectives because of its inherent limitations. Internal control over financial reporting is a process that involves human diligence and compliance and is subject to lapses in judgment and breakdowns resulting from human failures. Internal control over financial reporting can also be circumvented by collusion or improper management override. Because of such limitations, there is a risk that material misstatements may not be prevented or detected on a timely basis by internal control over financial reporting. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that of limitations are known features of the financial reporting process. Therefore, it is possible to design into the process safeguards to reduce, though not eliminate, the risk.

## **PART II OTHER INFORMATION**

### **ITEM 1. LEGAL PROCEEDINGS**

None.

### **ITEM 1A. RISK FACTORS**

There have been no material changes from the risk factors disclosed in Item 1A. Risk Factors of our Annual Report on Form 10-K for the year ended December 31, 2024.

### **ITEM 2. UNREGISTERED SALE OF EQUITY SECURITIES AND USE OF PROCEEDS**

(c) Purchases of Equity Securities by Epsilon Energy Ltd.

For the six months ended June 30, 2025, no shares had been repurchased.

### **ITEM 3. DEFAULTS UPON SENIOR SECURITIES**

Not applicable.

### **ITEM 4. MINE SAFETY DISCLOSURES**

Not applicable.

### **ITEM 5. OTHER INFORMATION**

Not applicable.

## ITEM 6. —EXHIBITS

<b>Exhibit No.</b>	<b>Description of Exhibit</b>
31.1	Sarbanes-Oxley Section 302 certification of Principal Executive Officer.
31.2	Sarbanes-Oxley Section 302 certification of Principal Financial Officer.
32.1	Sarbanes-Oxley Section 906 certification of Principal Executive Officer.
32.2	Sarbanes-Oxley Section 906 certification of Principal Financial Officer.
101.INS	Inline XBRL Instance Document.
101.SCH	Inline XBRL Schema Document.
101.CAL	Inline XBRL Calculation Linkbase Document.
101.DEF	Inline XBRL Definition Linkbase Document.
101.LAB	Inline XBRL Labels Linkbase Document.
101.PRE	Inline XBRL Presentation Linkbase Document.
104	Cover Page Interactive Data File (embedded within the Inline XBRL document)

## SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, as amended, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Epsilon Energy Ltd.  
(Registrant)

Date: August 13, 2025

By: /s/ J. Andrew Williamson

J. Andrew Williamson  
Chief Financial Officer