Management's Discussion and Analysis
For the three and six months ended June 30, 2025 and 2024
Dated August 13, 2025

BUSINESS DESCRIPTION AND READER GUIDANCE

Condor Energies Inc. ("Condor" or the "Company") is an internationally focused energy transition company incorporated on October 20, 2006 that is uniquely positioned on the doorstep of European and Asian markets with three distinct first-mover energy security initiatives: increasing natural gas and condensate production from its eight gas fields in Uzbekistan; an ongoing project to construct and operate Central Asia's first LNG 'lower carbon fuel' diesel substitution facility in Kazakhstan; and a separate initiative to develop and produce critical minerals from brines in Kazakhstan. Condor has built a strong foundation for reserves, production and cashflow growth while also striving to minimize its environmental footprint.

Condor is a publicly traded company listed on the Toronto Stock Exchange under the symbol "CDR". Additional information relating to the Company, including its Annual Information Form for the year ended December 31, 2024, is available on SEDAR+ at: www.sedarplus.ca.

The Company's Management's Discussion and Analysis ("MD&A") which follows should be read in conjunction with the Company's unaudited interim condensed consolidated financial statements for the three and six months ended June 30, 2025 and 2024 (the "Financial Statements"), and the audited consolidated financial statements and associated MD&A for the years ended December 31, 2024 and 2023. The Financial Statements have been prepared in accordance with International Accounting Standard 34, *Interim Financial Reporting*, under IFRS Accounting Standards ("IFRS") as issued by the International Accounting Standards Board. This MD&A is dated August 13, 2025, the date that the Condor Board of Directors approved the Financial Statements and this MD&A.

All financial amounts are in Canadian dollars, unless otherwise stated.

OVERALL PERFORMANCE

HIGHLIGHTS

- Production in Uzbekistan for the second quarter of 2025 averaged 10,258 boe/d comprised of 10,004 boe/d (60,027 Mcf/d) of natural gas and 254 bopd of condensate.
- Uzbekistan natural gas and condensate sales for the second quarter of 2025 was $19.29 million.
- Rigging up operations are underway to commence a multi-well drilling program by early September 2025.
- Detailed engineering for the design and installation of field compression is ongoing, which is intended to mitigate increasing sales gas pipeline pressures that have started impacting production rates.
- On April 15, 2025, the Company secured its third natural gas allocation in Kazakhstan to be used for LNG production

- On May 6, 2025, the Company purchased a modular LNG facility (the "First LNG Facility") capable of producing 48,000 gallons (80 MT) of LNG per day with LNG production planned to commence in the second quarter of 2026.

- On August 12, 2025, the Company executed a USD $5.0 million-dollar bridge loan facility (the "Bridge Loan") for the First LNG Facility which is on schedule to produce Kazakhstan's first LNG in the second quarter of 2026.

Production in Uzbekistan

The Company operates under a production enhancement services contract with JSC Uzbekneftegaz in Uzbekistan to increase the production, recovery and overall system efficiency from an integrated cluster of eight conventional natural gas-condensate fields (the "PEC Project"). Production for the second quarter of 2025 averaged 10,258 boe/d comprised of 10,004 boe/d (60,027 Mcf/d) of natural gas and 254 bopd of condensate. Production rates in the second quarter of 2025 were partially restricted due to unplanned downstream infrastructure maintenance and plant upsets at non-Company operated facilities that increased the sales gas pipeline pressure which curtailed production. Also, recent workovers were more focused on modern data collection to enhance geologic and reservoir modelling in preparation for the upcoming drilling campaign instead of production gains. More than 50 workover operations have been performed since the Company assumed operations in March 2024, which has proven to be a very capital efficient method to mitigate the natural production decline rate of 20 percent per year and has grown production rates and recoveries. However, material near term production growth initiatives are now expected to come from executing a multi-well drilling program and the design and installation of field compression to help mitigate increasing sales gas pipeline pressures.

Rigging up operations are underway to commence a multi-well drilling program in early September 2025. The first well will be drilled vertically to penetrate and evaluate the currently producing carbonate reservoir sections as well as the deeper, under-exploited stacked clastic reservoirs before reaching its total depth at the top of the basement rock formations, where potential exists for a fractured reservoir play. The stacked clastic reservoirs hold exciting upside potential throughout the region as indicated by previously drilled deep wells that have consistently observed strong gas shows from this interval.

Data from the first vertical well will play a critical role in optimizing the subsequent horizontal well target intervals. Two horizontal wells are expected to be drilled in the fourth quarter of 2025 and will utilize Western MWD and LWD technologies and personnel to geo-steer the drill bit within the mapped porous intervals to drill lateral distances of up to 1,500 meters initially. The horizontal wells will be oriented to intersect open, natural fractures and will be completed as open holes, stimulated using a proprietary acid blend assisted by nitrogen. This integration of 'surgical geo-steering' over long lateral distances to maximize reservoir contact will be the first ever application within Uzbekistan. Based on analogous Western Canadian reservoirs, an internally developed 'type curve' for these horizontal wells has indicated that initial production rates are expected to be within a range of 13 MMscf/day to 20 MMscf/day per well, although actual results may differ due to geological or operational conditions as described below in the Business Risks and Forward-Looking Statements sections. The Company currently plans to drill up to eleven new wells in 2026.

The Company continues to mature and expand its well prospect inventory by interpreting and integrating 1,462 km^2 of recently reprocessed 3D seismic data and 142 km^2 of 3D seismic inversion attributes. These efforts have already identified eight targets that can be classified as either large, undrilled attic accumulations of gas or undrilled exploratory structures near the Company's producing gas fields. Based on successful initial drilling results, the Company plans to contract a second drilling rig to further accelerate overall gas production.

Detailed engineering for the design and installation of field compression is ongoing with the intent of mitigating the increasing sales gas pipeline pressures that have started curtailing production rates. Field compression is expected to be installed in 2026 and should provide material production gains. Based on internal calculations, existing production could increase by 25 to 55 percent due to field compression, although actual results may differ as described below in the Business Risks and Forward-Looking Statements sections. More details will be provided once the detailed engineering study is completed.

In the fourth quarter of 2024, the Company commissioned Uzbekistan's first in-field flowline water separation system which separates water from the gas streams at the field gathering network rather than at the production facility. This reduces pipeline flow pressure and allows the reservoir to flow at higher rates due to reduced back pressure. Four additional separation units have since been installed and commissioned through May 2025.

LNG in Kazakhstan

Condor is constructing Kazakhstan's first LNG facilities to produce, distribute, and sell LNG to offset industrial diesel usage in the country. LNG applications include rail locomotives, long-haul truck fleets, marine vessels, mining equipment, municipal bus fleets, and other heavy equipment and machinery with high-horsepower engines. These applications have all successfully used LNG fuel in other countries.

In May 2025, the Company purchased the First LNG Facility for its Saryozek plant site, capable of producing 48,000 gallons (80 MT) of LNG per day. Construction of the First LNG Facility is ongoing, and fabrication works are on-schedule to be completed by the end of the fourth quarter of 2025. The First LNG Facility and supporting equipment will then be shipped to Saryozek, Kazakhstan for assembly and commissioning with LNG production expected in the second quarter of 2026. The Company is finalizing LNG off-taker agreements and advancing several additional third party financing solutions for the First LNG Facility.

As of June 30, 2025, the Company has incurred CAD $2.9 million of costs for the First LNG Facility including $2.2 million of property, plant and equipment and $0.7 million for the third natural gas allocation. The estimated additional costs to complete the First LNG Facility construction and commissioning is USD $24.4 million (CAD $33.3 million) including various ancillary equipment, feed gas hookup and piping, power generation, electrical infrastructure, and distribution equipment including storage tanks, LNG loading facilities and rolling stock.

In April 2025, the Company secured its third natural gas allocation that will provide LNG feed gas for the First LNG Facility. Two additional 48,000 gallon per day modular LNG facilities are planned for the First LNG Facility site to fully utilize the third natural gas allocation.

Condor's modular LNG facilities will be instrumental to supplying a stable, economic and more environmentally friendly fuel source for the Transcaspian International Transport Route ("TITR") expansion, which is currently the shortest, fastest and most geopolitically secure transit corridor for moving freight between Asia and Europe. The Government of Kazakhstan and Kazakhstan's national railroad are making significant investments in TITR infrastructure, including expanding the rail network, constructing a new dry port at the Kazakhstan – China border, and increasing the container-handling capacities at various Caspian Sea ports. Based on the Company's three natural gas allocations of 21,798 m3/hour, 29,110 m3/hour and 20,500 m3/hour, respectively, the total LNG fuel produced will have an energy-equivalent volume of 1.5 million litres of diesel daily, while also reducing CO_2 emissions by 390,000 MT per year, which is equivalent to removing 85,000 cars from the road annually. See "Forward Looking Statements" in this MD&A for further discussion on the risks and uncertainties related to the natural gas allocations and the Company's LNG initiatives.

USD $5.0 Million Bridge Loan Financing

On August 12, 2025, the Company, through its subsidiary, entered a USD $5.0 million-dollar Bridge Loan for the First LNG Facility which is on schedule to produce Kazakhstan's first LNG in the second quarter of 2026. The Bridge Loan was provided by EurAsia Resource Value SE, an existing significant shareholder of the Company, and provides funding to continue purchasing long lead equipment for the First LNG Facility while third party project financing is being finalized. The Bridge Loan is unsecured, bears interest at 9.0% per annum, has no equity components or conversion features, has no financial covenants, requires no repayment of principal or interest payments until maturity, permits early repayment with no penalties or limitations, and matures on the earlier of March 30, 2026 and ten business days following the receipt of project financing for the First LNG Facility. The Bridge Loan's use of proceeds is for capital expenditures and general and administrative costs related to the construction and implementation of the First LNG Facility.

Critical Minerals Licenses in Kazakhstan

The Company holds a 100% working interest in two contiguous critical minerals mining licenses which provide subsurface exploration rights for solid minerals, including lithium and copper, for respective six-year terms. The 37,300- hectare Sayakbay license was awarded in July 2023 and the nearby 6,800-hectare Kolkuduk license was awarded in February 2025.

A prior well drilled in the Kolkuduk license territory for hydrocarbon exploration encountered and tested brine deposits with lithium concentrations of up to 130 milligrams per litre as reported by the Ministry of Geology of the Republic of Kazakhstan. A 1,000-meter column of tested and untested brine reservoir has been identified from historical wireline log and core data. At Sayakbay, a prior legacy well drilled for hydrocarbon exploration encountered and tested brine deposits with lithium concentrations of 67 milligrams per litre in Carboniferous-aged intervals as reported by the Ministry of Geology of the Republic of Kazakhstan. A 670-meter column of tested and untested brine reservoir has been identified from historical wireline log and core data. Other critical minerals identified at the Kolkuduk and Sayakbay licenses include rubidium, strontium and cesium.

The Company is not treating these historical estimates as current mineral resources or mineral reserves as additional drilling and testing is necessary, and a qualified person has not done sufficient work to classify the historical estimates as current mineral resources or mineral reserves. It is uncertain if further drilling will result in either area being delineated as a mineral resource or reserve. The historical lithium concentration estimates should not be relied upon as indicative of the actual lithium concentration or the likelihood that the Company will be able to achieve similar production results.

The initial development plan for Sayakbay includes drilling and testing two wells to verify deliverability rates, confirming the lateral extension and concentrations of lithium in the tested and untested intervals, conducting preliminary engineering for the production facilities, and preparing a mineral resource or mineral reserves report compliant with National Instrument 43-101 Standards of Disclosure for Mineral Projects. Drilling at Sayakbay is not expected to commence until 2027 and the estimated costs for the initial development plan are USD $6.7 million (CAD $9.1 million). The initial development plan for the Kolkuduk license acquired in February 2025 has not as yet been determined.

RESULTS OF OPERATIONS

Production – Uzbekistan

Total Production	Three months ended June 30, 2025	Three months ended June 30, 2024	Change Volume
Natural gas (Mcf)	5,462,413	5,372,044	90,369
Natural gas (boe)	910,402	895,341	15,061
Condensate (barrels)	23,143	19,395	3,748
Total (boe)	933,545	914,736	18,809

Total Production	Six months ended June 30, 2025	Four months ended June 30, 2024*	Change Volume
Natural gas (Mcf)	11,304,929	7,399,949	3,904,980
Natural gas (boe)	1,884,155	1,233,325	650,830
Condensate (barrels)	55,586	27,585	28,001
Total (boe)	1,939,741	1,260,910	678,831

Daily Production	Three months ended June 30, 2025	Three months ended June 30, 2024	Change %
Natural gas (Mcf/d)	60,027	59,033	1.7%
Natural gas (boe/d)	10,004	9,839	1.7%
Condensate (bopd)	254	213	19.2%
Total (boe/d)	10,258	10,052	2.0%

Daily Production	Six months ended June 30, 2025	Four months ended June 30, 2024*	Change %
Natural gas (Mcf/d)	62,458	60,655	3.0%
Natural gas (boe/d)	10,410	10,109	3.0%
Condensate (bopd)	307	226	35.8%
Total (boe/d)	10,717	10,335	3.7%

** Production commenced on March 1, 2024. Production volumes and daily calculations stated in Mcf/d, boe/d and bopd for year-to-date 2024 are for four months (122 days).*

The Company operates under a production enhancement services contract with JSC Uzbekneftegaz in Uzbekistan to increase the production, ultimate recovery and overall system efficiency from an integrated cluster of eight conventional natural gas-condensate fields (the "PEC Project"). Production for the second quarter of 2025 averaged 10,258 boe/d comprised of 10,004 boe/d (60,027 Mcf/d) of natural gas and 254 bopd of condensate, which is a 2.0% increase from average production of 10,052 boe/d for the second quarter of 2024. Since assuming operations in March 2024, the Company has flattened the natural production decline rates, which previously exceeded twenty percent annually.

Non-Controlling Interest in PEC Project

The Company recognizes 100% of the production volumes, sales volumes, sales revenues, royalties and expenses related to the PEC Project in Uzbekistan and then allocates 49% of the comprehensive income (loss) attributable to the non-controlling interest holder. This is consistent with the accounting and disclosure in the Financial Statements. Accordingly, the production volumes, sales volumes, sales revenues, royalties, expenses and netbacks disclosed in this MD&A related to the PEC Project are 100% of the amounts attributable to the PEC Project, of which 51% are attributable to the Company.

Production – Türkiye

Natural gas production in Türkiye was 673 Mcf or an average of 7 Mcf/d for the three months ended June 30, 2025 compared to 8,419 Mcf or an average of 92 Mcf/d for the same period in 2024, and was 1,527 Mcf or an average of 8 Mcf/d for the six months ended June 30, 2025 compared to 21,395 Mcf or an average of 118 Mcf/d for the same period in 2024. The production decline is due mainly to the continuing natural decline of the maturing Poyraz Ridge field which has been producing for eight years with water production and natural pressure declines impeding gas production rates, along with the neighbouring Destan field being temporarily suspended in August 2024.

Operating Netback for Uzbekistan

Operating netback for Natural Gas [1,2]	Natural Gas			
	Three months ended June 30		Six months ended June 30	
	2025	2024 [4]	2025	2024 [4,5]
Sales ($000's)	17,875	17,420	37,857	23,985
Royalties ($000's)	(2,465)	(2,395)	(5,214)	(3,299)
Production costs ($000's)	(8,289)	(7,394)	(16,981)	(9,682)
Transportation and selling ($000's)	(624)	(619)	(1,314)	(847)
Operating netback ($000's)[1,2]	6,497	7,012	14,348	10,157
Sales volume (Mcf)	5,066,697	4,994,363	10,529,010	6,883,152
Sales ($/Mcf)	3.53	3.49	3.60	3.48
Royalties ($/Mcf)	(0.49)	(0.48)	(0.50)	(0.48)
Production costs ($/Mcf)	(1.64)	(1.48)	(1.61)	(1.41)
Transportation and selling ($/Mcf)	(0.12)	(0.12)	(0.13)	(0.12)
Operating netback ($/Mcf)[1,2]	1.28	1.41	1.36	1.47

Operating netback for Condensate [1,2]	**Condensate**			
	Three months ended June 30		**Six months ended June 30**	
	2025	**2024 [4]**	**2025**	**2024 [4,5]**
Sales ($000's)	1,410	1,534	3,690	2,181
Royalties ($000's)	(203)	(221)	(532)	(314)
Production costs ($000's)	(171)	(141)	(386)	(178)
Transportation and selling ($000's)	(9)	(7)	(21)	(10)
Operating netback ($000's)[1,2]	1,027	1,165	2,751	1,679
Sales volume (bbl)	23,041	19,778	55,358	27,965
Sales ($/bbl)	61.19	77.56	66.66	77.99
Royalties ($/bbl)	(8.81)	(11.17)	(9.61)	(11.22)
Production costs ($/bbl)	(7.42)	(7.13)	(6.97)	(6.36)
Transportation and selling ($/bbl)	(0.39)	(0.35)	(0.38)	(0.36)
Operating netback ($/bbl)[1,2]	44.57	58.91	49.70	60.05

Operating netback reconciliation Uzbekistan segmented information For the three months ended June 30, 2025 [1,2,3]	**Natural Gas**	**Condensate**	**Total**
Sales ($000's)	17,875	1,410	19,285
Royalties ($000's)	(2,465)	(203)	(2,668)
Production costs ($000's)	(8,289)	(171)	(8,460)
Transportation and selling ($000's)	(624)	(9)	(633)
Operating netback ($000's)[1]	6,497	1,027	7,524

Operating netback reconciliation Uzbekistan segmented information For the three months ended June 30, 2024 [1,2,3,4]	**Natural Gas**	**Condensate**	**Total**
Sales ($000's)	17,420	1,534	18,954
Royalties ($000's)	(2,395)	(221)	(2,616)
Production costs ($000's)	(7,394)	(141)	(7,535)
Transportation and selling ($000's)	(619)	(7)	(626)
Operating netback ($000's)[1]	7,012	1,165	8,177

Operating netback reconciliation Uzbekistan segmented information For the six months ended June 30, 2025 [1,2,3]	**Natural Gas**	**Condensate**	**Total**
Sales ($000's)	37,857	3,690	41,547
Royalties ($000's)	(5,214)	(532)	(5,746)
Production costs ($000's)	(16,981)	(386)	(17,367)
Transportation and selling ($000's)	(1,314)	(21)	(1,335)
Operating netback ($000's)[1]	14,348	2,751	17,099

Operating netback reconciliation Uzbekistan segmented information For the six months ended June 30, 2024 [1,2,3,4,5]	**Natural Gas**	**Condensate**	**Total**
Sales ($000's)	23,985	2,181	26,166
Royalties ($000's)	(3,299)	(314)	(3,613)
Production costs ($000's)	(9,682)	(178)	(9,860)
Transportation and selling ($000's)	(847)	(10)	(857)
Operating netback ($000's)[1]	10,157	1,679	11,836

1 Operating netback is a non-GAAP measure and is a term with no standardized meaning as prescribed by GAAP and may not be comparable with similar measures presented by other issuers. See "Non-GAAP Financial Measures" in this MD&A. The calculation of operating netback is aligned with the definition found in the Canadian Oil and Gas Evaluation Handbook.

2 Amounts and per unit measures are only presented for the Uzbekistan segment.

3 Reconciliation to the respective financial statement amount for each netback component for the Uzbekistan segment.

4 See "Royalties" in this MD&A which describes an immaterial adjustment made to royalties expense for the three and six months ended June 30, 2024

5 Production commenced on March 1, 2024. Production volumes, sales and expenses for year-to-date 2024 are for four months (122 days).

Sales

For the three months ended June 30	**2025**	**2024**	**Change**
Natural gas ($000's)			
Uzbekistan	17,875	17,420	455
Türkiye	7	97	(90)
	17,882	17,517	365
Condensate ($000's)			
Uzbekistan	1,410	1,534	(124)
Türkiye	-	-	-
	1,410	1.534	(124)

For the six months ended June 30	2025	2024	Change
Natural gas ($000's)			
Uzbekistan	37,857	23,985	13,872
Türkiye	15	259	(244)
	37,872	24,244	13,628
Condensate ($000's)			
Uzbekistan	3,690	2,181	1,509
Türkiye	-	-	-
	3,690	2,181	1,509

Natural gas sales in Uzbekistan increased slightly to $17.88 million on 5,066,697 Mcf or $3.53 per Mcf for the three months ended June 30, 2025 compared to $17.42 million on 4,994,363 Mcf or $3.49 per Mcf for the same period in 2024. Natural gas sales increased to $37.88 million on 10,529,010 Mcf or $3.60 per Mcf for the six months ended June 30, 2025 compared to $23.99 million on 6,883,152 Mcf or $3.48 per Mcf for the period from March 1, 2024 to June 30, 2024 due primarily to the increased sales volumes from six months production in 2025 as compared to four months in 2024.

Condensate sales in Uzbekistan decreased to $1.41 million on 23,041 barrels or $61.19 per barrel for the three months ended June 30, 2025 compared to $1.53 million on 19,778 barrels or $77.56 per barrel for the same period in 2024 primarily due to lower condensate sales prices in the second quarter of 2025. Condensate sales increased to $3.69 million on 55,358 barrels or $66.66 per barrel for the six months ended June 30, 2025 compared to $2.18 million on 27,965 barrels or $77.99 per barrel for the period from March 1, 2024 to June 30, 2024 despite the lower sales prices in 2025 and due primarily to increased sales volumes from six months production in 2025 as compared to four months in 2024.

Natural gas sales in Türkiye decreased to $0.01 million on 531 Mcf for the three months ended June 30, 2025 from $0.10 million on 7,321 Mcf for the same period in 2024, and decreased to $0.02 million on 1,181 Mcf for the six months ended June 30, 2025 from $0.26 million on 19,078 Mcf for the same period in 2024, due mainly to lower production volumes in 2025. Excluding the respective inflation adjustment impact on gas sales for each period, realized gas prices increased to $13.52 per Mcf for the three months ended June 30, 2025 from $13.26 per Mcf for the same period in 2024, and decreased to $12.74 per Mcf for the six months ended June 30, 2025 from $13.58 for the same period in 2024. There were no condensate sales in Türkiye for the six months ended June 30, 2025 and 2024.

Marketing

In Uzbekistan, natural gas is collected by gathering lines into two in-field facilities for initial processing to remove water and condensate and then transported by pipeline to a nearby third-party facility for further processing and onward transport by pipeline to the designated delivery point. Natural gas sales are domestic sales at local market prices. A portion of the associated condensate is separated from the natural gas at the two in-field facilities, and the remainder is separated and processed at the third-party facility. Condensate is sold to the buyer directly at each of the three facilities and the buyer is responsible for all onward transportation costs. Condensate sales prices are based upon Brent crude (a global benchmark for pricing crude oil) less a discount for processing, transportation and marketing.

In Türkiye, natural gas sales are domestic sales via pipeline at Turkish Lira denominated prices published monthly by the state-owned pipeline transportation company BOTAS Petroleum Pipeline Corporation ("BOTAS"). The benchmark for Condor's gas sales is BOTAS Level 2 wholesale tariffs less a marketing differential. Natural gas from the neighbouring Destan gas field is produced, compressed and trucked to the Company's owned and operated Poyraz Ridge gas plant and is marketed along with Poyraz Ridge gas production which is directly tied into the gas plant. Associated condensate is compressed and trucked to a near-by facility for blending, storage and onward sales at prices based on the nearest accessible global free market and determined by a formula provided for under the Petroleum Market Law and published monthly in Turkish Lira by the Turkish Petroleum Corporation, the Turkish national oil company.

Royalties

Royalties and production entitlements in Uzbekistan increased slightly to $2.67 million for the three months ended June 30, 2025 compared to $2.62 million for the same period in 2024 due to higher production volumes in the current period, and were $5.75 million for the six months ended June 30, 2025 compared to $3.61 million for the period from March 1, 2024 to June 30, 2024 due primarily to the increased sales volumes from six months production in 2025 as compared to four months in 2024.

In accordance with the terms of the PEC Project, certain of the Company's payment obligations for royalty expenses are deferred. These liabilities are initially recognized at fair value by discounting the expected future payments at the Company's estimated incremental borrowing rate of 16% and are subsequently accreted over the deferral period to the principal amount on the due date with a corresponding non-cash accretion charge recognized in finance expense.

An immaterial adjustment has been made to these royalty expenses and non-cash finance income in the interim condensed consolidated statements of income and cash flows for the three and six months ended June 30, 2024. Previously, the difference between the fair value of the payment obligations and the undiscounted value of these royalty expenses was recorded as non-cash finance income upon recognition. The Company should have recorded these royalty expenses at the discounted amount and non-cash finance income should not be recognized. The impact of this immaterial adjustment to the three months ended March 31, 2025 is also described below.

The adjustment for the three months ended June 30, 2024 is $0.9 million and the impact on the statements of income (loss) and comprehensive income (loss) is to reduce finance income from $0.9 million to less than $0.1 million and royalty expenses from $3.5 million to $2.6 million with a corresponding adjustment to total revenue from $15.5 million to $16.4 million. The impact on the operating activities section of the statements of cash flows is to reduce non-cash finance income from $0.9 million to $Nil and reduce the change in other long-term liabilities from $1.6 million to $0.7 million.

The adjustment for the six months ended June 30, 2024 is $1.2 million and the impact on the statements of income (loss) and comprehensive income (loss) is to reduce finance income from $1.3 million to $0.1 million and royalty expenses from $4.8 million to $3.6 million with a corresponding adjustment to total revenue from $21.6 million to $22.8 million. The impact on the operating activities section of the statements of cash flows is to reduce non-cash finance income from $1.2 million to $Nil and reduce the change in other long-term liabilities from $2.2 million to $1.0 million.

The adjustment for the three months ended March 31, 2025 is $1.0 million and the impact on the statements of income (loss) and comprehensive income (loss) is to reduce finance income from $1.1 million to $0.1 million and royalty expenses from $4.1 million to $3.1 million with a corresponding adjustment to total revenue from $18.2 million to $19.2 million. The impact on the operating activities section of the statements of cash flows is to reduce non-cash finance income from $1.0 million to $Nil and reduce the change in other long-term liabilities from $1.9 million to $0.9 million.

Excluding the respective discounting impact on certain royalty expenses for each period, the Company is subject to a total royalty and production entitlement rate of 20% on the natural gas and condensate produced under the PEC project based on realized sales prices less certain adjustments for processing and transportation costs. The total royalty and production entitlement rate under the PEC Project including the discounting impact for the three and six months ended June 30, 2025 is 13.8% for both periods (2024 – 13.8% for both periods).

In Türkiye, the Company is subject to a 12.5% royalty rate on natural gas and condensate sales. Royalties in Türkiye were less than $0.01 million for the three months ended June 30, 2025 compared to $0.01 million for the same period in 2024, and were less than $0.01 million for the six months ended June 30, 2025 compared to $0.03 million for the same period in 2024, due primarily to lower natural gas production and realized sales prices in 2025.

Production costs

Production costs to produce natural gas in Uzbekistan were $8.29 million or $1.64 per Mcf for the three months ended June 30, 2025 compared to $7.39 million or $1.48 per Mcf for the same period in 2024, and were $16.98 million or $1.61 per Mcf for the six months ended June 30, 2025 compared to $9.68 million or $1.41 per Mcf for the period from March 1, 2024 to June 30, 2024. Production costs to produce condensate in Uzbekistan were $0.17 million or $7.42 per boe for the three months ended June 30, 2025 compared to $0.14 million or $7.13 per boe for the same period in 2024, and were $0.39 million or $6.97 per boe for the six months ended June 30, 2025 compared to $0.18 million or $6.36 per boe for the period from March 1, 2024 to June 30, 2024. Overall production costs increased in total and per unit due primarily to increased sales volumes from six months production in 2025 as compared to four months in 2024, additional personnel to manage the eight gas fields and in-field facilities, and increased vehicle and equipment rental and maintenance costs. Production costs in Uzbekistan comprise mainly facility, processing, compression, personnel, vehicle, equipment rental, safety and maintenance costs.

Total production costs in Türkiye were $0.13 million for the three months ended June 30, 2025 compared to $0.17 million for the same period in 2024, and were $0.27 million for the six months ended June 30, 2025 compared to $0.34 million for the same period in 204, primarily due to lower sales volumes. Production costs are primarily fixed in nature and are comprised mainly of field personnel, fuel, utilities, chemicals, water disposal, safety and maintenance costs.

Transportation and selling

Transportation and selling costs in Uzbekistan for natural gas were $0.62 million or $0.12 per Mcf for the three months ended June 30, 2025 compared to $0.62 million or $0.12 per Mcf for the three months ended June 30, 2024, and were $1.31 million or $0.13 per Mcf for the six months ended June 30, 2025 compared to $0.85 million or $0.12 per Mcf for the six months ended June 30, 2024. Transportation and selling costs for condensate were $0.01 million or $0.39 per boe for the three months ended June 30, 2025 compared to $0.01 million or $0.35 per boe for the three months ended June 30, 2024, and were $0.02 million or $0.38 per boe for the six months ended June 30, 2025 compared to $0.01 million or $0.36 per boe for the six months ended June 30, 2024. These costs are comprised of pipeline costs to deliver natural gas and associated condensate to the processing facilities and to deliver natural gas onwards to the designated sales delivery point and are primarily fixed on a per unit basis.

Transportation and selling costs in Türkiye on natural gas sales decreased to less than $0.01 million or $0.70 per Mcf for the three months ended June 30, 2025 compared to $0.08 million or $10.40 per Mcf for the same period in 2024, and were less than $0.01 million or $0.73 per Mcf for the six months ended June 30, 2025 compared to $0.14 million or $7.22 per Mcf for the same period in 2024. Transportation and selling expenses for natural gas sales are comprised of pipeline transmission fees and compressed natural gas trucking costs on Destan sales and for condensate sales are comprised of trucking, blending, storage and loading costs. These costs were higher in 2024 due mainly to the higher proportion of sales from Destan which requires additional trucking costs.

General and administrative

General and administrative expenses, comprised mainly of personnel, professional services, office, and travel costs, increased to $2.0 million for the three months ended June 30, 2025 from $1.39 million for the same period in 2024, and increased to $4.49 million for the six months ended June 30, 2025 from $3.49 million for the same period in 2024, primarily due to higher personnel, consultants, professional services, travel and office costs related to the Uzbekistan project and higher costs in 2025 related to other new business initiatives.

Depletion and depreciation

Depletion and depreciation increased to $3.17 million for the three months ended June 30, 2025 from $0.49 million for the same period in 2024, and increased to $6.45 million for the six months ended June 30, 2025 from $0.74 million for the same period in 2024, primarily due to increased depletion in Uzbekistan resulting from higher production volumes in 2025 and a higher per unit depletion charge commencing in the fourth quarter of 2024 based on the Company's reserve report as of December 31, 2024. Changes in decommissioning costs in Türkiye and Kazakhstan relating to oil and gas properties with no net book value are recognized immediately as depletion and depreciation expense and amounted to $0.49 million and $0.62 million for the three and six months ended June 30, 2025, respectively (2024 – $0.28 million and $0.46 million, respectively).

Stock based compensation

Stock based compensation expenses increased to $0.34 million for the three months ended June 30, 2025 from $0.22 million for the same period in 2024, and increased to $1.03 million for the six months ended June 30, 2025 from $0.34 million for the same period in 2024. The expense is recognized on a graded basis and fluctuates based on the fair value of stock options determined at the date of grant, the timing of the grants, vesting periods and estimated forfeiture rates.

Finance income

Finance income increased to $0.12 million for the three months ended June 30, 2025 from $0.05 million for the same period in 2024, and increased to $0.22 million for the six months ended June 30, 2025 from $0.09 million for the same period in 2024. Finance income is related to interest income earned on cash and cash equivalents and other long-term assets. See "Royalties" in this MD&A which describes an immaterial adjustment made to non-cash finance income for the three and six months ended June 30, 2024.

Finance expense

Finance expense increased to $0.97 million and $1.94 million for the three and six months ended June 30, 2025, respectively, from $0.77 million and $1.21 million for the comparable periods in 2024. The non-cash accretion expense on certain PEC Project payment obligations for royalty expenses for the three and six months ended June 30, 2025 was $0.16 million and $0.28 million, respectively (2024 – $0.02 million for both periods). See "Royalties" in this MD&A which describes this arrangement and an immaterial adjustment made to certain royalty expenses and non-cash finance income for the three and six months ended June 30, 2024. The total undiscounted cash outflows required to settle these obligations are $9.06 million and are due between March 2029 and June 2030.

Effective interest expense on the Loan Facility and Debentures was $0.58 million and $1.17 million for the three and six months ended June 30, 2025, respectively (2024 – $0.60 million and $0.99 million, respectively), and accretion of provisions was $0.15 million and $0.31 million for the three and six months ended June 30, 2025, respectively (2024 – $0.14 million and $0.20 million, respectively).

The Company had no risk management contracts that would be affected by interest rates in place during the six months ended June 30, 2025 or the year ended December 31, 2024.

Foreign currency exchange gains and losses

The foreign exchange gain for the three and six months ended June 30, 2025 amounted to $0.61 million and $0.63 million, respectively, compared to losses of $0.04 million and $0.16 million for the comparable periods in 2024, due primarily to the USD denominated Loan Facility and Debentures, partially offset by USD cash and cash equivalents held by the Company. The Company is exposed to significant foreign currency risk as the Company's natural gas and condensate sales and a substantial portion of foreign activities are transacted in or referenced to foreign currencies, a portion of the Company's cash and cash equivalents are held in USD and the Company's Loan Facility and Debentures are denominated in USD. Natural gas and condensate sales in Uzbekistan are domestic sales at local market prices, and natural gas sales in Türkiye are denominated in TRL.

The Company had no forward exchange rate contracts in place during the six months ended June 30, 2025 or the year ended December 31, 2024.

Unrealized gain (loss) on embedded derivative:

The conversion feature in the Debentures is accounted for as an embedded derivative liability and its fair value will be estimated at each reporting period date with changes in fair value recognized in earnings as an unrealized gain or loss. The Company recognized an unrealized gain on embedded derivative of $0.05 million for the three months ended June 30, 2025 (2024 – unrealized loss of $0.57 million), and an unrealized gain of $0.32 million for the six months ended June 30, 2025 (2024 – unrealized loss of $0.57 million).

Other expense

On April 15, 2025, the Company acquired the rights to a natural gas allocation in Kazakhstan for USD $0.48 million (CAD $0.66 million) to provide LNG feed gas for the First LNG Facility. The natural gas allocation does not meet the recognition criteria for an asset and was expensed during the three and six months ended June 30, 2025.

The other expense of $1.9 million for both the three and six months ended June 30, 2024 relates to the Termination and Settlement Agreement recorded to other long-term liabilities.

Net monetary gain (loss)

The Company recognized a net monetary loss of $Nil for the three months ended June 30, 2025 (2024 – gain of $0.01 million) and a net monetary loss of $0.01 million for the six months ended June 30, 2025 (2024 – gain of less than $0.01 million) due to an increase in the Turkish inflation rate of approximately 17% (2024 – 25%) since January 1, 2025.

Income taxes

Income tax expense for the three and six months ended June 30, 2025 is comprised of current income tax expense of $0.39 million and $1.75 million, respectively (2024 – $1.16 million and $1.64 million, respectively) and deferred income tax expense (recovery) of $0.13 million and ($0.48) million, respectively (2024 – $Nil for both periods) related to Uzbekistan, where the tax rate is 15% of estimated taxable income. The Company has not recognized the tax benefits associated with the operating activities of other business segments.

Net income

Net income for the three months ended June 30, 2025 decreased to $0.53 million compared to $1.56 million for the same period in 2024, primarily due to general and administrative and depletion and depreciation expenses, partially offset by increased sales volumes and revenues and lower other expense. Net income for the six months ended June 30, 2025 increased to $2.15 million compared to $1.65 million for the same period in 2024 primarily due to the increased sales volumes and revenues from six months of production in 2025 as compared to four months in 2024 and lower other expense, partially offset by increased production, general and administrative, depletion and depreciation expenses.

Non-controlling interest ("NCI"):

A third-party NCI shareholder holds 49% of the shares of Condor Natural Gas B.V. ("CNG"), the sole shareholder of the Company's subsidiary which is conducting the production enhancement services under the PEC Project in Uzbekistan. The NCI is allocated 49% of the comprehensive income of CNG commencing March 1, 2024.

A third-party NCI shareholder holds 10% of the shares of Condor LNG Ltd. ("CLNG"), the sole shareholder of three Kazakhstan subsidiaries which are developing liquefied natural gas facilities in Kazakhstan. The NCI is allocated 10% of the comprehensive loss of CLNG commencing April 24, 2024.

NON-GAAP FINANCIAL MEASURES

The Company refers to "operating netback" in this MD&A, a term with no standardized meaning as prescribed by GAAP and which may not be comparable with similar measures presented by other issuers. This additional information should not be considered in isolation or as a substitute for measures prepared in accordance with GAAP. Operating netback is calculated as sales less royalties, production costs and transportation and selling costs on a dollar basis and divided by the sales volume for the period on a per Mcf basis for natural gas and per boe basis for condensate. The reconciliation of this non-GAAP measure is presented in the "Operating Netback" section of this MD&A. This non-GAAP measure is commonly used in the oil and gas industry to assist in measuring operating performance against prior periods on a comparable basis and has been presented to provide an additional measure to analyze the Company's sales on a per unit basis and the Company's ability to generate funds.

LIQUIDITY AND CAPITAL RESOURCES

The Company commenced production enhancement services under the PEC Project in Uzbekistan in March 2024 and is responsible for all capital expenditures and operating costs of the project. In June 2024, the Company initiated a multi-well workover campaign for the eight gas fields and intends to continue and expand the ongoing workover program in 2025 comprised of installing various artificial lift equipment, perforating previously non-depleted and bypassed pay zones, performing downhole stimulation treatments, and isolating identified water intervals. The Company is planning to commence a multi-well drilling program in September 2025 and detailed engineering for the design and installation of field compression is ongoing and is expected to be installed in 2026.

The Company has an LNG initiative in Kazakhstan and is seeking to produce and deliver LNG to displace diesel fuel usage in Central Asia.

The Sayakbay exploration license in Kazakhstan contains contractual work commitments of $0.2 million per annum during the first three years and $0.3 million per annum during the final three years of the six-year term. The Kolkuduk exploration license in Kazakhstan contains contractual work commitments of approximately $0.05 million per annum during the first three years and $0.1 million per annum during the final three years of the six-year term. The contractual work commitments may be amended from time to time in accordance with planned exploration activities proposed by the Company and approved by the Government of Kazakhstan and additional contractual work commitment amounts could be significant.

These initiatives will require the Company to use a combination of cash on hand, increase cashflows from operating activities, securing funding from debt or equity financing, disposing of assets or making other arrangements. There is no assurance that the Company will be successful with these initiatives and the outcome of these matters is uncertain.

The Company has long term borrowings which include: i) a term loan facility ("Loan Facility") which is unsecured, non-revolving, bears interest at 9.0% per annum paid quarterly, and with various quarterly principal payments due until maturity on September 30, 2026; and ii) convertible debentures (the "Debentures") convertible into 2,950,336 common shares which are unsecured, bear interest at 9.0% per annum paid semi-annually, and with the principal due on the maturity date of March 21, 2027 unless converted into common shares.

As at June 30, 2025, the Company had a deficit of $5.12 million (December 31, 2024 – $3.89 million). For the three and six months ended June 30, 2025, the Company reported net income of $0.53 million and $2.15 million, respectively (2024 – $1.56 million and $1.65 million, respectively) and cash from (used in) operating activities of ($11.22) million and $3.64 million, respectively (2024 – $2.21 million and ($0.23) million, respectively). The Company's working capital balance has decreased from $25.98 million as at December 31, 2024 to $13.96 million as at June 30, 2025.

COMMITMENTS AND CONTINGENT LIABILITIES

The Company has capital commitments for the LNG facility in Kazakhstan of USD $4.9 million (CAD $6.69 million), and the payments are due in a combination of time and milestone-based instalments until the LNG facility is commissioned, which is expected to be in Q2 2026.

The Company has a 100% interest in and operates the Poyraz Ridge and Destan operating licenses and gas fields in Türkiye. In March 2025, the competent authority in Türkiye extended the Poyraz Ridge license until June 2035 and the Destan license until June 2030. There are no work commitments related to the Poyraz Ridge or Destan licenses.

The Sayakbay exploration license in Kazakhstan contains contractual work commitments of $0.2 million per annum during the first three years and $0.3 million per annum during the final three years of the six-year term. The Kolkuduk exploration license in Kazakhstan contains contractual work commitments of approximately $0.05 million per annum during the first three years and $0.1 million per annum during the final three years of the six-year term. The contractual work commitments may be amended from time to time in accordance with planned exploration activities proposed by the Company and approved by the Government of Kazakhstan and additional contractual work commitment amounts could be significant.

FINANCIAL RISK MANAGEMENT

Credit risk

Credit risk arises from the possibility that a counterparty to which the Company provides goods or services is unable or unwilling to fulfil their contractual obligations. The maximum exposure to credit risk at year end is as follows:

Carrying amounts as at ($000's)	**June 30, 2025**	**December 31, 2024**
Cash and cash equivalents	12,243	27,841
Trade and other receivables	27,124	17,617
Other long term assets	267	279
	39,634	45,737

The Company limits its exposure to credit risk on cash and cash equivalents and bank deposits by depositing and investing in banks with investment grade credit ratings.

Credit risk on trade receivables is related mainly to natural gas marketers, and the risk of financial loss if a customer, partner or counterparty to a financial instrument fails to meet its contractual obligations. During the six months ended June 30, 2025 and 2024, sales of natural gas were sold to one customer in each of Uzbekistan and Turkiye, and sales of condensate were sold to one customer in Uzbekistan and therefore all sales transactions are subject to concentration risk. As at June 30, 2025, these three customers represented 99% of outstanding trade and other receivables (December 31, 2024 – 99%). Of the $27.1 million trade and other receivables balance as of June 30, 2025, $27.0 million was collected subsequent to June 30, 2025.

Credit risk is mitigated by management's policies and practices. Natural gas and condensate produced in Uzbekistan are supplied to the domestic market through sales agreements with national companies of Uzbekistan. For natural gas sales in Türkiye, the Company holds a bank guarantee provided by the buyer of its natural gas amounting to two month's estimated gas sales as security on gas sales receivables.

Liquidity risk and capital management

Liquidity risk is the risk the Company will encounter difficulty in meeting financial obligations and commitments and repaying liabilities as they fall due. The Company's objective is to ensure, as far as possible, that it will have sufficient liquidity to meet its obligations when due. The Company requires liquidity mainly to satisfy financial obligations and operating requirements related to activities in Uzbekistan, Kazakhstan and Türkiye. The Company looks to manage liquidity by adjusting its capital structure by issuing new equity or debt, disposing of assets and making adjustments to its capital expenditure program to the extent the capital expenditures are not committed.

Managing the Company's obligations will require using a combination of cash on hand, funds from operating activities, securing funding from debt or equity financing, disposing of assets or making other arrangements. While the Company believes it has sufficient resources to manage these obligations for the next year, there is no assurance over the longer term that the Company will be successful with these initiatives and the outcome of these matters is uncertain.

As at June 30, 2025, the Company had a deficit of $5.12 million (December 31, 2024 – $3.89 million). For the three and six months ended June 30, 2025, the Company reported net income of $0.53 million and $2.15 million, respectively (2024 – $1.56 million and $1.65 million, respectively) and cash from (used in) operating activities of ($11.22) million and $3.64 million, respectively (2024 – $2.21 million and ($0.23) million, respectively). The Company's working capital balance has decreased from $25.98 million as at December 31, 2024 to $13.96 million as at June 30, 2025.

To manage capital expenditures and operating cashflows, annual budgets are prepared, monitored regularly and updated as required. The Company also utilizes authorizations for expenditures to manage capital spending.

The cash flows presented in the tables below are the contractual undiscounted cash flows and accordingly certain amounts differ from the amounts included in the consolidated statements of financial position. The Company's undiscounted contractual obligations are as follows:

($000's)	Less than 1 year	Greater than 1 year	Total
As at June 30, 2025			
Accounts payable and accrued liabilities	14,837	-	14,837
Lease liabilities	312	438	750
Loan facility	2,745	3,963	6,708
Convertible debentures	160	6,508	6,668
Other long-term liabilities	682	10,214	10,896
As at December 31, 2024			
Accounts payable and accrued liabilities	9,844	-	9,844
Lease liabilities	282	480	762
Loan facility	2,182	5,936	8,118
Convertible debentures	171	6,864	7,035
Other long-term liabilities	719	7,467	8,186

Market risk

Market risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market prices and their impact on the future performance of the business. Market risk is comprised of three types of market price changes: foreign currency exchange rates, interest rates and commodity prices. Derivative instruments may be used to reduce exposure to these risks.

Foreign currency exchange risk

The Company is exposed to significant foreign currency risk as the Company's natural gas and condensate sales and a substantial portion of foreign activities are transacted in or referenced to foreign currencies, a portion of the Company's cash and cash equivalents are held in USD and the Company's Loan Facility and Debentures are denominated in USD. Natural gas and condensate sales in Uzbekistan are domestic sales at local market prices and natural gas sales in Türkiye are denominated in TRL. In general, an increase in the value of the Canadian dollar as compared to the USD or the TRL will reduce the prices received by the Company for its natural gas and condensate sales. The Company had no forward exchange rate contracts in place during the six months ended June 30, 2025 or the year ended December 31, 2024.

During the six months ended June 30, 2025, the CAD appreciated from 1.44 per 1.00 USD to 1.36, the KZT appreciated from 523.5 per 1.00 USD to 520.4, and the TRL depreciated from 35.2 per 1.00 USD to 39.7, which led to a foreign exchange gain of $0.63 million (2024 – loss of ($0.16) million) related mainly to the USD denominated Loan Facility and Debentures, partially offset by USD cash and cash equivalents held by the Company.

During the six months ended June 30, 2025, the CAD appreciated from 1.44 per 1.00 USD to 1.36, the KZT depreciated from 363.9 per 1.00 CAD to 381.0, and the TRL depreciated from 24.4 per 1.00 CAD to 29.1, resulting in a $1.12 million translation loss adjustment through equity (2024 – gain of $0.13 million).

Interest rate risk

Interest rate risk is the risk that the value of the financial instrument or future cash flows associated with the financial instrument will fluctuate as a result of changes in market interest rates. The Company's Loan Facility and Debentures both bear fixed-rate interest at 9.0% per annum to be paid quarterly in arrears and their value is exposed to interest rate risk from changes in market interest rates. The Company had no risk management contracts that would be affected by interest rates in place during the six months ended June 30, 2025 or the year ended December 31, 2024.

Commodity price risk

Commodity price risk is the risk that the fair value of future cash flows will fluctuate as a result of changes in commodity prices. The Company is exposed to changes in commodity prices inherent in the oil and natural gas industry. Commodity prices for oil and natural gas are impacted by economic events and factors which are beyond the Company's control. Fluctuations in petroleum and natural gas prices may have a significant effect on the Company's results of operations and cash flows from operating activities, and may also affect the value of the oil and gas properties, the level of spending for exploration and development and the Company's ability to raise capital. The Company had no derivative commodity price contracts in place during the six months ended June 30, 2025 or the year ended December 31, 2024.

Natural gas sales in Uzbekistan are domestic sales at local market prices. Condensate sales prices in Uzbekistan are based on Brent less a discount for processing, transportation and marketing.

Natural gas sales in Türkiye are domestic sales via pipeline at prices published monthly by the state owned pipeline transportation company BOTAS. The benchmark for Condor's gas sales in Türkiye is BOTAS Level 2 wholesale tariffs less a marketing differential.

HEALTH RISK MANAGEMENT

Condor has offices, activities and operations in various areas in Canada, Uzbekistan, Türkiye and Kazakhstan. Company personnel are stationed and work and travel to and from these locations as required. Such personnel are exposed from time to time to concentrated groups of people at various locations both within and outside the Company's direct control, for varying lengths of time. Any personnel or visitors that become infected with a serious illness that has the potential to spread rapidly throughout the organization could place the personnel and the operations of the Company at risk.

Although the Company takes precautions and follows industrial hygiene and occupational health guidelines, there can be no assurance that an infectious illnesses will not negatively impact Condor's personnel or its operations and may in the future result in fluctuating demand for oil and gas, volatile oil and gas prices and the implementation of various travel restrictions which constrain or prohibit international travel and limit or forbid movement within the individual countries of operation.

Condor's future operations could be materially impacted by these factors, as well as related emergency measures including, but not limited to: travel restrictions including shelter in place orders, curfews and lockdowns which may impact the timing and ability of Company personnel, suppliers and contractors to travel internationally or domestically and to access or deliver services, goods and equipment to the fields of operation; the risk of shutting-in or reducing production due to travel restrictions, Government orders, crew illnesses and the availability of goods, works and essential services for the fields of operations; the potential for gas pipeline or sales market interruptions; the risk of changes to foreign currency controls, availability of foreign currencies, availability of hard currency, and currency controls or banking restrictions which restrict or prevent the repatriation of funds from or to foreign jurisdiction in which the Company operates; the timing and ability to meet financial and other reporting deadlines; potential decreased interest in and ability to conclude farm-in transactions, potential decreased ability to raise additional capital to fund current operations and new business projects; and the inherent increased risk of information technology failures and cyber-attacks.

OUTSTANDING SHARE DATA

Common shares

As at June 30, 2025, there were 67,495,117 common shares of the Company outstanding and as of the date of this MD&A, there were 67,973,783 common shares of the Company outstanding.

Convertible securities

As at June 30, 2025, the Company has outstanding 6,424,566 stock options with a weighted average exercise price of $0.93 per common share. As of the date of this MD&A, the Company has outstanding 5,987,900 stock options with a weighted average exercise price of $0.97per common share.

As of June 30, 2025 and the date of this MD&A, the Company has outstanding 2,754,497 common share purchase warrants of which:

- 255,000 warrants at an exercise price of $0.48 per common share and expire on June 30, 2026;
- 2,278,334 warrants at an exercise price of $0.48 per common share and expire on July 14, 2026; and
- 221,163 warrants at an exercise price of $2.20 per common share and expire on December 9, 2026.

As at June 30, 2025 and the date of this MD&A, the Company has outstanding Debentures convertible into 2,950,336 common shares at a conversion price of US$1.61676 per common share.

Reduction of share capital

On June 20, 2024, Condor's shareholders resolved by special resolution that the Company's share capital be reduced, without payment of or reduction to the Company's stated capital or paid-up capital, by the amount of the deficit as of December 31, 2023 of $219.39 million.

Dividends

The Company has not paid or declared any dividends since the date of incorporation, nor are any contemplated in the foreseeable future.

OFF-BALANCE SHEET ARRANGEMENTS

The Company did not have any off-balance sheet arrangements as at June 30, 2025.

QUARTERLY INFORMATION

The following table sets forth selected financial information of the Company for the eight most recently completed quarters to June 30, 2025:

For the quarter ended (000's except per share amounts)	**Q2 2025**	**Q1 2025**	**Q4 2024**	**Q3 2024**	**Q2 2024**	**Q1 2024**	**Q4 2023**	**Q3 2023**
Sales	19,292	22,270	20,982	19,208	19,063	7,373	51	169
Net income (loss) (1)	527	1,624	(1,318)	3,157	1,563	91	(7,615)	(852)
Net income (loss) attributable to common shareholders (2)	(1,149)	(85)	(3,303)	578	50	(1,397)	(7,615)	(852)
Net income (loss) per share (3)	(0.02)	(0.00)	(0.06)	0.01	0.00	(0.02)	(0.13)	(0.02)

1 The net income (loss) in all periods has been impacted by, among other things, production and sales volumes, commodity prices, operating costs, exploration and evaluation ("E&E") assets impairment, depletion and depreciation, PP&E impairment expense, net monetary gain (loss) from hyper-inflation accounting in Türkiye, finance expenses from the Loan Facility and Debentures, unrealized loss on embedded derivative, other expense and foreign exchange gains and losses in the respective periods. The net income (loss) amounts include specific significant period items of: $3.3 million E&E impairment and $1.2 million impairment expense in Q4 2023; and significant changes in revenues and expenses from Q1 2024 onwards related to the Company commencing production enhancement activities under the PEC Project in Uzbekistan on March 1, 2024, as described in the relevant sections above in this MD&A.

2 Net income (loss) attributable to common shareholders is presented after the allocation of net income (loss) attributable to non-controlling interests, as described in the relevant section above in this MD&A. See "Non-controlling interests ("NCI")" in this MD&A which describes the two NCIs.

3 Per share amounts are basic and diluted and attributable to common shareholders. The Company treats the common shares as either dilutive or anti-dilutive based on net income (loss). If the common shares are anti-dilutive at this level, they are treated as anti-dilutive for all other per share calculations.

CRITICAL ACCOUNTING ESTIMATES AND JUDGEMENTS

The timely preparation of financial statements requires management to make use of judgments, estimates and assumptions when transactions affecting the current accounting period cannot be finalized until future periods. These estimates will affect assets, liabilities and the disclosure of assets and liabilities at the date of the financial statements, as well as revenues and expenses during the reporting periods. Such estimates are based on informed judgments made by management. Actual results could differ from those estimates as future confirming events occur. Significant assumptions and estimates about the future and other sources of estimation uncertainty that management has made at the financial position reporting date that could result in a material adjustment to the carrying amount of assets and liabilities, in the event that actual results differ from assumptions made, are outlined below.

- Impairment testing: estimates include volumes of recoverable reserves and resources, forward natural gas and condensate prices, future operating, royalty, and capital costs, production profiles, discount rates, and consequently fair values of properties. A downward revision in the reserve estimates or future forecast prices or an upward revision to future capital costs could result in an asset impairment which would reduce future earnings and the associated net book value of assets;
- Depletion: estimates include the amount of reserve volumes and future development capital. A downward revision in the reserve estimates or an upward revision to future capital may result in increased depletion and a reduction in net book value of assets if such a revision results in an accounting impairment. Depletion is charged on a unit-of-production basis over the Proved plus Probable reserves for each cash generating unit and a revision in the productive capacity of the assets may result in increased depletion and a reduced net book value of assets;
- E&E expenditures: costs associated with acquiring oil and gas licenses and exploratory drilling are accumulated as E&E assets pending determination of technical feasibility and commercial viability. Establishment of technical feasibility and commercial viability is subject to judgment and involves management's review of project economics, resource quantities, expected production techniques, production costs and required capital expenditures to develop and extract the underlying resources. Management uses the establishment of commercial reserves within the exploration area as the basis for determining technical feasibility and commercial viability. Upon determination of commercial reserves, E&E assets attributable to those reserves are tested for impairment and reclassified from E&E assets to a separate category within property, plant and equipment referred to as oil and gas properties;
- Identification of Impairment Indicators - E&E assets: the Company assesses its E&E assets to determine whether any indication of impairment exists at the end of each reporting period. Significant judgment is required in determining whether indicators of impairment exist, including factors and considerations such as the remaining period for which the Company has the right to explore, whether expenditures on further exploration and evaluation of properties are budgeted, whether commercially viable quantities of mineral resources have been discovered or whether data exists to suggest the carrying amount is unlikely to be recovered;
- Decommissioning provisions: estimates include the amount and expected timing of asset retirements, discount and inflation rates and future cashflows. As a result of the long-term nature of the Company's operations, these estimates may change over time which may result in a change in the decommissioning provision and corresponding asset value, and impact future earnings (loss) as a result of changes in accretion and depletion expense;
- Convertible debentures: The conversion feature associated with the US dollar denominated convertible debentures has been identified as a derivative financial liability. Derivative financial liabilities are recorded upon recognition and subsequently at each period-end date at fair value, with changes in fair value being recognized in earnings. The fair value estimate involves assumptions regarding the probability a forced conversion will occur, the expected life of the Debentures, dividend yields, risk-free interest rates, and volatility of the Company's common shares. The fair value is measured using the Black-Scholes option pricing model, and using an alternate pricing model could produce different results;

- Stock based compensation: estimates include determining appropriate share price volatility, expected lives, forfeiture rates and risk-free rates. The expense is measured using the Black-Scholes option pricing model, and using an alternate pricing model could produce different results;
- Going concern: estimates include the ability to fund operations by generating positive cashflows from operations, securing funding from additional debt or equity financing, disposing of assets or making other arrangements;
- Income taxes: tax interpretations, regulations and legislation in the various jurisdictions in which the Company and its subsidiaries operate are subject to change and interpretation. As such, income taxes are subject to measurement uncertainty. Deferred tax assets are assessed by management at the end of the reporting period to determine the likelihood that they will be realized from future taxable earnings. Changes in the estimate of future taxable income and the recovery of deductible temporary differences may result in the recognition of a deferred tax asset on the statement of financial position and an increase in earnings at the time when the tax recovery is recorded; and
- As part of its capital management process, the Company prepares budgets and forecasts, which are used by management and the Board of Directors to direct and monitor the strategy and ongoing operations and liquidity of the Company. Budgets and forecasts are subject to significant judgement and estimates relating to activity levels, future cashflows and the timing thereof and other factors which may or may not be within the control of the Company (see "Liquidity and Capital Resources").

FUTURE ACCOUNTING PRONOUNCEMENTS

IFRS 18 "Presentation and Disclosure in Financial Statements": On April 9, 2024, the International Accounting Standards Board ("IASB") issued IFRS 18, which will replace International Accounting Standard 1, "Presentation of Financial Statements". IFRS 18 will establish a revised structure for the Consolidated Statements of Income and Comprehensive Income and improve comparability across entities and reporting periods. IFRS 18 is effective for annual periods beginning on or after January 1, 2027. The standard is to be applied retrospectively, with certain transition provisions. The Company is currently evaluating the impact of adopting IFRS 18 on the Consolidated Financial Statements.

Amendments to IFRS 9 "Financial Instruments" and IFRS 7 "Financial Instruments: Disclosures": On May 30, 2024, the IASB issued targeted amendments to IFRS 9 and IFRS 7 which include new requirements for financial institutions and corporate entities to clarify the date of recognition and derecognition of some financial assets and liabilities, with a new exception for some financial liabilities settled through an electronic cash transfer system. These new requirements will apply from January 1, 2026, with early application permitted. The Company is currently evaluating the impact of adopting IFRS 18 on the Consolidated Financial Statements.

INTERNAL CONTROLS OVER FINANCIAL REPORTING

The Company's President and Chief Executive Officer and Vice President, Finance and Chief Financial Officer have designed, or caused to be designed under their supervision, disclosure controls and procedures ("DC&P") and internal controls over financial reporting ("ICFR") as defined in *National Instrument 52-109 Certification of Disclosure in Issuer's Annual and Interim Filings* in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Financial Statements for external purposes in accordance with IFRS Accounting Standards.

During the three months ended June 30, 2025, there have been no changes to the Company's ICFR that have materially or are reasonably likely to materially affect the ICFR. Because of their inherent limitations, DC&P and ICFR may not prevent or detect misstatements, errors or fraud. Control systems, no matter how well conceived or operated, can provide only reasonable, not absolute assurance that the objectives of the control systems are met.

BUSINESS RISKS

In the normal course of business, the Company is exposed to a variety of risks and uncertainties. In addition to the risks associated with liquidity and capital resources, critical accounting estimates, financial instruments, credit risk and market risk described in this MD&A, the Company is exposed to various operational, technical, financial and regulatory risks and uncertainties, many of which are beyond its control and may significantly affect future results. Operations may be unsuccessful or delayed as a result of competition for services, supplies and equipment, mechanical and technical difficulties, the ability to attract and retain employees and contractors on a cost-effective basis, commodity and marketing risk and seasonality. The Company is exposed to considerable risks and uncertainties including, but not limited to:

- The timing and ability to find natural gas, condensate and critical mineral reserves on an economical basis;
- uncertainties related to estimating the initial production rate of the type curve horizontal wells;
- uncertainties related to estimating the increased production rates for installing field compression;
- uncertainties related to estimating the Company's reserves;
- financial risks including access to debt or equity markets on acceptable terms;
- technical problems which could lead to unsuccessful wells, well blowouts and environmental damage;
- obtaining regulatory approvals on a timely basis or at all;
- third party related operational risks including the ability to obtain access to wells, access to third party processing facilities, and access to pipelines, railways and other transportation infrastructure;
- obtaining qualified personnel, parts, equipment and service providers in a timely and cost-efficient manner;
- fluctuations in commodity prices, interest rates and foreign currency exchange rates;
- adverse factors including climate, geographical and weather conditions and natural disasters;
- risks associated with human resources management including labor disputes;

- timing of future debt and other obligations;
- potential for prior year tax re-assessments not aligned with previously filed and assessed periods;
- regulatory legislation and policies, including the fulfillment of contractual minimum work programs, the compliance with which may require significant expenditures and non-compliance with which may result in fines, penalties, production restrictions, suspensions or revocations of contracts;
- changes to taxation policies, laws and interpretations thereof;
- political risks inherent with international activities and doing business in foreign jurisdictions;
- medical and health risks inherent with international activities and doing business in foreign countries including travel bans or travel restrictions;
- obtaining comprehensive and appropriate insurance coverage at reasonable rates;
- obtaining approval for extensions to development periods;
- obtaining approval for extensions to exploration periods, and, upon commercial discovery, negotiating and signing development contracts;
- negative public or community response to natural gas, condensate and critical minerals exploration, development and production and related environmental impacts could adversely affect Condor's business and the price of its securities; and
- information technology and system risks including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, data privacy and destruction or interruption of the Company's information technology.

Please see the Company's Annual Information Form, filed on SEDAR+ at www.sedarplus.ca for further discussion on these risks.

GEOPOLITICAL INSTABILITY

On February 24, 2022, Russia began a military operation in Ukraine and the UN General Assembly overwhelmingly condemned the invasion and has called for Russia to immediately and completely withdraw its troops. The United States, the European Union, the United Kingdom, Canada, Australia, Japan, Switzerland, and other countries have imposed new financial and trade sanctions against Russia, including prohibitions or restrictions from doing business anywhere in the world with listed Russian individuals or companies. To-date these events have not impacted the Company's ability to carry on business, there have been no significant delays or direct security issues affecting the Company's operations, offices or personnel, and the enacted sanctions have not affected the Company's operations. The outcome of these events is uncertain at this time and may impact the peace and stability of the region and the world and could affect the global economy including regions and markets in which the Company operates. Any subsequent commodity supply shortages or volatile commodity prices could have adverse impacts on the world economy and the Company's business. If these events continue, re-occur or escalate, they could have a material adverse effect on Condor's business, financial condition or results of operations.

BARRELS OF OIL EQUIVALENT ADVISORY

References herein to barrels of oil equivalent ("boe") are derived by converting gas to oil in the ratio of six thousand standard cubic feet ("Mcf") of gas to one barrel of oil based on an energy conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6 Mcf to 1 barrel, utilizing a conversion ratio at 6 Mcf to 1 barrel may be misleading as an indication of value, particularly if used in isolation.

FORWARD-LOOKING STATEMENTS

Certain statements in this MD&A constitute forward-looking information under applicable securities legislation. Such statements are generally identifiable by the terminology used, such as "expect", "plan", "estimate", "may", "will", "should", "could", "would", "ongoing", "project", "expect", "predict", "intend", "seek", "future", "forecast", "continue", "capable", "schedule", "prepare", upcoming" or other similar wording. Forward-looking information in this MD&A includes, but is not limited to, information concerning: the timing and ability of the Company to execute growth and sustainability strategies including the financing for these activities; the timing and ability to complete rigging up and commence a multi-well drilling program; the timing and ability to design and install field compression; the timing and ability to penetrate and evaluate the carbonate reservoir sections and the deeper stacked clastic reservoirs and reach the planned depth at the top of the basement rock formations; the timing and ability of the structure to contain a potential fractured reservoir play; the timing and ability for the stacked clastic reservoirs to hold upside potential in the region; the timing and ability for the data from the first vertical well to optimize the subsequent horizontal well target intervals; the timing and ability to drill two horizontal wells in the fourth quarter of 2025; the timing and ability to utilize western MWD and LWD technologies and personnel to geo-steer the drill bit within the mapped porous intervals to drill lateral distances of up to 1,500 meters; the timing and ability to intersect open, natural fractures; the timing and ability to complete the horizontal wells as open holes and stimulate using acid and nitrogen; the accuracy of the internally developed 'type curve' for the horizontal wells to predicted initial production rates and actual results may differ significantly; the timing and ability to add a second drilling rig in 2026; the timing and ability to drill up to eleven new wells in 2026; the timing and ability to interpret and integrate recently reprocessed 3D seismic and 3D seismic inversion attributes; the and ability to contract a second drilling rig the timing and ability of the in-field flowline water separation system to separate water from the gas streams at the field gathering network, reduce pipeline flow pressure and lead to higher reservoir flow rates; the timing and ability to conduct detailed engineering for field compression; the timing and ability of the field compression to help mitigate increasing trunkline pressures; the timing and ability of the field compression to increase production; the accuracy of the internal calculations to predict production increases due to field compression and actual results may differ significantly; the timing and ability to receive and utilize the natural gas allocations as feed gas for the planned modular LNG production facilities; the Company's expectations in respect of the future uses of LNG; the timing and ability to acquire, transport and construct modular LNG production facilities; the timing and ability to obtain funding for the construction of modular LNG production facilities; the timing and ability to commission the First LNG Facility during the second quarter of 2026; the estimated costs to complete the First LNG Facility construction and commissioning; the timing and ability to liquefy natural gas to produce LNG; the timing and ability to confirm LNG volume commitments with potential end-users; the timing and ability of the First LNG Facility to produce 48,000 gallons of LNG per day; the timing and ability of the Company to construct two additional modular LNG facilities capable of producing 48,000 gallons of LNG per day at the First LNG Facility site; the timing and ability to finalize LNG off-taker agreements for the First LNG Facility; the timing and ability to complete fabrication works with respect to the First Facility; the timing and ability to receive the Bridge Loan funds; the timing and ability to purchase and receive long lead equipment; the potential for the Sayakbay and Kolkuduk license to contain commercial deposits; the timing and ability of the Company to fund, permit and complete planned activities at Sayakbay including drilling two wells and conducting preliminary engineering for the production facilities; the estimated costs of the initial development plan for Sayakbay; the timing and ability of the third natural gas allocation to be used for LNG production; the timing and ability to optimize the planned method for direct lithium extraction; the timing and ability of the Company to generate a report in compliance with National Instrument 43-101 Standards of Disclosure for Mineral Projects; the timing and ability to commence exploration mining activities to evaluate the potential for commercial lithium brine deposits; the accuracy of the projections and timing with respect to natural gas and condensate production; expected markets, prices and costs for future natural gas and condensate sales; the timing and ability of the Company to obtain various approvals and conduct its planned exploration and development activities; the timing and ability to access natural gas pipelines; the timing and ability to access domestic and export sales markets; the accuracy of the anticipated capital expenditures; forecasted capital and operating budgets and cashflows; anticipated working capital; sources and availability of financing for potential budgeting shortfalls; the timing and ability to obtain future funding on favourable terms, if at all; the potential for additional contractual work commitments to be significant; the ability to satisfy and fund the contractual work commitments; projections relating to the adequacy of the Company's provision for taxes; the expected reporting impacts of adopting amendments to IFRS accounting policies; and treatment under governmental regulatory regimes and tax laws.

This MD&A also includes forward-looking information regarding health risk management including, but not limited to: travel restrictions including shelter in place orders, curfews and lockdowns which may impact the timing and ability of Company personnel, suppliers and contractors to travel internationally, travel domestically and to access or deliver services, goods and equipment to the fields of operation; the risk of shutting in or reducing production due to travel restrictions, Government orders, crew illness, and the availability of goods, works and essential services for the fields of operations; decreases in the demand for oil and gas; decreases in the prices of natural gas, condensate and crude oil; potential for gas pipeline or sales market interruptions; the risk of changes to foreign currency controls, availability of foreign currencies, availability of hard currency, and currency controls or banking restrictions which restrict or prevent the repatriation of funds from or to foreign jurisdiction in which the Company operates; the Company's financial condition, results of operations and cash flows; access to capital and borrowings to fund operations and new business projects on terms acceptable to the Company; the timing and ability to meet financial and other reporting deadlines; and the inherent increased risk of information technology failures and cyber-attacks.

By its very nature, such forward-looking information requires Condor to make assumptions that may not materialize or that may not be accurate including, but not limited to, the assumptions that: the Company will be able to secure necessary drilling rigs, support services, and off-taker agreements in a timely manner; the engineering design and final investment decisions for additional LNG facilities will proceed as planned; the Government of Kazakhstan will continue to invest in infrastructure supporting the TITR expansion; the Company's additional drilling and testing will be successful in verifying deliverability rates and confirming mineral concentrations; the Company will be able to fund its initiatives through a combination of cash on hand, increased cashflows, debt or equity financing, asset sales, or other arrangements; the Company will be able to manage liquidity and capital expenditures through budgeting and authorizations for expenditures; the Company will be able to manage health, safety, and operational risks through existing precautions and guidelines; the Company will be able to adapt to changing trade policies, tariffs, and restrictions; and the Company will be able to manage the impact of geopolitical instability and sanctions.

Forward-looking information is subject to both known and unknown risks and uncertainties and other factors, which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such information. Such risks and uncertainties include, but are not limited to: regulatory changes including changes to environmental regulations; the timing of regulatory approvals; the risk that actual minimum work programs will exceed the initially estimated amounts; the results of exploration and development drilling and related activities; the risk that prior lithium testing results may not be indicative of future testing results or actual results; the risk of imprecision of reserves estimates and ultimate recovery of reserves; the risk that historical production and testing rates may not be indicative of future production rates, capabilities or ultimate recovery; the risk that the historical composition and quality of oil and gas does not accurately predict its future composition and quality; general economic, market and business conditions; risks relating to the uncertainty related to marketing and transportation; competitive action by other companies; fluctuations in oil and natural gas prices; the effects of weather and climate conditions; fluctuation in interest rates and foreign currency exchange rates; the ability of suppliers to meet commitments; actions by governmental authorities, including increases in taxes, tariffs, levies and fees; decisions or approvals of administrative tribunals and the possibility that government policies or laws may change or the possibility that government approvals may be delayed or withheld; risks associated with oil and gas operations, both domestic and international; and other factors, many of which are beyond the control of Condor.

These risk factors are discussed in greater detail in filings made by Condor with Canadian securities regulatory authorities including the Company's most recent Annual Information Form, which may be accessed through the SEDAR+ website (www.sedarplus.ca).

Readers are cautioned that the foregoing list of factors affecting forward-looking information is not exhaustive. The forward-looking information contained in this MD&A are made as of the date of this MD&A and, except as required by applicable law, Condor does not undertake any obligation to update publicly or to revise any of the included forward-looking information, whether as a result of new information, future events or otherwise. The forward-looking information contained in this MD&A is expressly qualified by this cautionary statement.

ABBREVIATIONS

The following is a summary of abbreviations used in this MD&A:

3-D	Three dimensional
Mcf	Thousands of standard cubic feet
Mcf/d	Thousands of standard cubic feet per day
MMcf	Millions of standard cubic feet
bbl	Barrels of oil
bopd	Barrels of oil per day
boe	Barrels of oil equivalent
boe/d	Barrels of oil equivalent per day
MT	Metric tonnes
CAD	Canadian Dollars
KZT	Kazakhstan Tenge
TRL	Turkish Lira
USD	United States Dollars
LNG	Liquefied natural gas
Türkiye	Republic of Türkiye
Kazakhstan	Republic of Kazakhstan
Uzbekistan	Republic of Uzbekistan
MWD	Measurement while drilling
LWD	Logging while drilling