

March 30, 2026

PRESIDENT'S MESSAGE

North 40 Resources Ltd. is pleased to report its operating and financial results for the three months and the year ended December 31, 2025. Fourth quarter and full year highlights include:

- Annual average production rate of 7,251 boe/day (58% oil and liquids).
- Total annual operating revenue of \$63.8 mm.
- Realized Q4 2025 average quarterly production of 7,001 boe/day (55% oil and liquids).
- Executed a \$ 87.3 million capital program in 2025, investing in thirteen horizontal wells and one disposal well at the Michichi battery.
- Working capital deficiency of \$13.2 million at year-end with \$10.3 million drawn bank debt.
- Booked proved plus probable reserves of 18.4 mmmboe, a 14% increase over the same period 2024; realized a F&D cost of \$13.20 per boe.
- Closed the purchase of a high working interest property focused on our Sheerness prospect region, which included significant operated pipeline infrastructure and acquired and the remaining working interest in the Rowley 04-09 gas plant and gathering system.
- Completed the water disposal facility at the Michichi 2-13 battery, which continues to serve North 40 trucked in produced water, Michichi 2-13 battery produced water and recently third party trucked in produced water.
- Completed the transition of operatorship of the Seiu Lake gas processing plant to North 40 on November 1, 2025.

2025 Activity

In 2025, North 40 drilled a total of fourteen wells, comprised of ten horizontal Ellerslie oil wells at Michichi/Aerial, three horizontal Ellerslie oil wells at Wayne and one disposal well at the Michichi 2-13 battery.

In total twelve reactivations and three recompletion operations on the acquired Aerial property were completed and brought on production in 2025.

Concurrent with the transition of operatorship at the Seiu Lake and the Rowley 04-09 gas processing plants, North 40 commenced trucking natural gas liquids recovered at the North 40 Rowley 04-09 gas plant to the operated North 40 Seiu Lake gas fractionation facility.

First Quarter 2026

In Q1 2026 North 40 drilled a total of four wells which included one two-mile development horizontal Ellerslie oil well at Wayne, two horizontal appraisal Ellerslie oil wells at Aerial and an exploration horizontal Ellerslie well at Michichi North. The Aerial and Michichi North prospects are both located in the greater Sheerness area.

The Wayne well and the Aerial wells are completed and on production. Both Aerial wells encountered excellent reservoir similar to the Wayne pool.

The fourth well, an exploratory test at Michichi North, was abandoned after reaching total depth. While drilling the well North 40 encountered excellent Ellerslie reservoir. However, shortly after reaching total depth, the well encountered a drill pipe failure in the build section of the horizontal. Subsequent fishing attempts were unsuccessful. The decision was then made to abandon the well. North 40 is currently reviewing the possibility of redrilling this location later in 2026.

On the acquired Aerial property, North 40 conducted two recompletions and one reactivation operation which met expectations.

Acquisition and Funding

On January 13, 2026, North 40 closed the purchase of a high working interest property in our Sheerness prospect region for \$ 3.0 million dollars, subject to customary adjustments.

To fund this infrastructure acquisition, North 40 sold a royalty interest and infrastructure production payment to known third parties.

In this acquisition, North 40 acquired the remaining infrastructure required to consolidate our infrastructure in the Sheerness prospect region and has commenced a reroute project in the field to consolidate and deliver North 40's natural gas production from the prospect region to the Rowley 04-09 gas plant.

The reroute construction project commenced in the field mid-January 2026 and the first stage of the reroute is expected to be complete by mid-April 2026. The final stage of the reroute will be complete by the beginning of May. When the reroute is complete, natural gas production at the 04-09 gas plant will increase from 2.8 MMcf/day to 12 MMcf/day. Natural gas liquids recovered at the Rowley 04-09 gas plant will continue to be trucked to our Seiu Lake fractionation facility.

Non-Cash Impairment and Exploration Expense

Pursuant to IFRS, at December 31, 2025, indicators of impairment were identified. Accordingly, an impairment test was performed and North 40 recorded a \$62.2 million non-cash impairment of property, plant and equipment at year-end 2025. The impairment is primarily a result of lower forecast WTI commodity pricing and elevated gas-oil ratios in some delineation wells.

North 40 has also recognized exploration expense of \$12.1 million resulting mainly from freehold undeveloped land expiries.

Despite this, North 40 is encouraged by how the company is positioned, with a robust producing reserve base and integrated infrastructure that enhances long-term economics.

Outlook

Effective March 31, 2026, North 40 will shut in seventeen gas wells comprising approximately 950 boe/day processed at third party facilities due to low natural gas pricing.

For the balance of the year, we expect to drill 10 wells, a combination of development and appraisal drilling.

More than twenty-five reactivations and recompletions opportunities have been identified on the acquired properties and are now being programmed.

The Board of Directors has approved a 2026 capital budget of \$69 million dollars, net of third-party funding proceeds.

Current North 40 production is approximately 7,200 boe/day with oil and liquids representing 52% of production.

North 40 remains focused on disciplined capital allocation and maximizing value within the company's delineated pool of assets. With expanded infrastructure, an improved geological model, and a strong inventory of development opportunities, the company is well positioned for sustainable growth.

As always, we appreciate and thank you for your support. Please contact me or Kim Schoenroth with any questions or comments you may have.

Sincerely,

NORTH 40 RESOURCES LTD.

Don W. Robson
President & CEO

NORTH 40

RESOURCES LTD.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following analysis was prepared as at March 30, 2026 and should be read in conjunction with North 40 Resources Ltd.'s ("North 40" or "the Company") audited financial statements for the years ended December 31, 2025 and December 31, 2024, together with the accompanying notes, which have been prepared in accordance with IFRS Accounting Standards as issued by International Accounting Standards Board ("IFRS" or "GAAP").

Basis of Presentation – The reporting and the measurement currency is the Canadian dollar. For the purposes of calculating unit costs, natural gas is converted to a barrel of oil equivalent ("boe") using six thousand cubic feet of natural gas equal to one barrel of oil unless otherwise stated.

Forward-Looking Statements – Certain information set forth in this document, including management's assessment of North 40's future plans for capital expenditures and expectations for production rates, prices and operating results, contains forward-looking statements. By their nature, forward-looking statements are subject to numerous risks and uncertainties, some of which are beyond North 40's control, including the impact of general economic conditions, industry conditions, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other industry participants, the lack of availability of qualified personnel or management, stock market volatility and ability to access sufficient capital from internal and external sources. Readers are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. North 40's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements.

Non-IFRS Measurements – Within Management's Discussion and Analysis, references are made to terms commonly used in the oil and gas industry. This document contains "funds flow from operations" which is a non-IFRS financial measure. This document also contains the terms "operating netback", "working capital surplus (deficiency)", and capital expenditures which are non-IFRS financial measures. These non-IFRS terms do not have any standardized meaning prescribed by IFRS and therefore it may not be comparable with the calculation of similar measures for other entities.

Funds flow from operations

Management uses funds flow from operations to evaluate performance. Funds flow from operations as presented is not intended to represent operating cash flow or operating profits for the period nor should it be viewed as an alternative to cash flow from operating activities. Funds flow from operations per share is calculated based on the weighted average number of shares outstanding consistent with the calculation of net income or loss per share. Total boe is calculated by multiplying the daily production by the number of days in the period.

The following table reconciles funds flow from operations to cash provided by operating activities, which is the most directly comparable measure calculated in accordance with IFRS.

(thousands)	Three months ended		Year ended	
	December 31		December 31	
	2025	2024	2025	2024
Cash provided by operating activities	\$11,152	\$12,811	\$59,468	\$46,568
Plus: Decommissioning expenditures	-	-	-	78
Plus: (Less): Net change in non-cash working capital	(1,663)	1,901	(4,443)	5,372
Funds flow from operations	\$9,489	\$14,712	\$55,025	\$52,018

Operating netback

Management uses operating netbacks as a profitability measure relative to current commodity prices. Operating netback is calculated as the weighted average sales price of all its commodities less royalties, operating and transportation expenses. There are no IFRS measures that are reasonably comparable to operating netbacks.

Working capital surplus (deficiency)

Working capital surplus (deficiency) is the total of current assets less current liabilities. This measure is used to assess efficiency, liquidity and general financial strength of the Company.

<i>(thousands)</i>	<i>Year ended</i>	
	<i>December 31</i>	
	<i>2025</i>	<i>2024</i>
<i>Cash</i>	\$ -	\$ 5,710
<i>Accounts Receivable</i>	11,086	13,261
<i>Current income taxes</i>	-	959
<i>Prepays and Deposits</i>	957	839
<i>Current Assets</i>	<u>\$12,043</u>	<u>\$20,769</u>
<i>Accounts payable and accrued liabilities</i>	\$14,190	\$29,134
<i>Current income taxes</i>	237	-
<i>Decommissioning obligations</i>	435	-
<i>Bank debt</i>	10,339	-
<i>Current Liabilities</i>	<u>\$25,201</u>	<u>\$29,134</u>
<i>Working capital deficiency</i>	<u>\$13,158</u>	<u>\$ 8,365</u>

Capital Expenditures

Capital expenditures are the sum of exploration and evaluation and property, plant and equipment, and acquisition expenditures disclosed in the Statements of Cash Flows.

<i>(thousands)</i>	<i>Three months ended</i>		<i>Year ended</i>	
	<i>December 31</i>		<i>December 31</i>	
	<i>2025</i>	<i>2024</i>	<i>2025</i>	<i>2024</i>
<i>Exploration and evaluation expenditures</i>	\$ 1,131	\$ 172	\$ 7,330	\$10,744
<i>Property, plant and equipment expenditures</i>	3,236	27,675	52,118	57,681
<i>Acquisitions</i>	15,430	-	27,822	-
<i>Capital expenditures</i>	<u>\$19,797</u>	<u>\$27,847</u>	<u>\$87,270</u>	<u>\$68,425</u>

<i>(thousands, except per unit amounts and where indicated)</i>	Three Months Ended		Year Ended	
	December 31		December 31	
	2025	2024	2025	2024
FINANCIAL				
Petroleum and natural gas revenue	\$26,669	\$30,591	\$122,973	\$109,105
Funds flow from operations ⁽¹⁾	\$9,489	\$14,712	\$55,025	\$52,018
Per share – basic	\$0.12	\$0.19	\$0.71	\$0.68
Per share – diluted	\$0.11	\$0.18	\$0.66	\$0.63
Net income (loss)	\$(53,680)	\$3,494	\$(54,994)	\$7,402
Per share – basic	\$(0.69)	\$0.05	\$(0.71)	\$0.10
Per share – diluted	\$(0.69)	\$0.04	\$(0.71)	\$0.09
Capital expenditures (before dispositions) ⁽²⁾	19,797	\$27,847	87,270	\$68,425
Working capital deficiency ⁽³⁾ at end of period	\$13,158	\$8,365	\$13,158	\$8,365
Common shares outstanding at end of period	77,773	76,624	77,773	76,624
OPERATING				
Sales volumes				
Oil and liquids (bbls/day)	3,821	3,809	4,189	3,370
Natural gas (mcf/day)	19,079	12,498	18,375	10,679
Total (boe per day) ⁽⁴⁾	7,001	5,892	7,251	5,150
% Oil and liquids	55	65	58	65
Commodity prices realized (before pipeline tariffs)				
Oil and liquids (\$/bbl)	67.19	85.33	76.30	86.89
Natural gas (\$/mcf)	2.58	1.73	1.89	1.72
Total (\$/boe)	43.70	58.84	48.85	60.43
Operating netback ⁽⁵⁾ (\$/boe)	19.66	30.12	24.10	30.14
Funds from operations netback (\$/boe) ⁽¹⁾	14.73	27.14	20.79	27.60
Net wells drilled	-	4.0	14.0	14.0
Net acres of land at end of period	288,609	265,397	288,609	265,397

⁽¹⁾ Funds flow from operations and funds flow from operations netback does not have a standardized meaning prescribed by IFRS. See Non-IFRS Measurements section of the MD&A.

⁽²⁾ Capital expenditures does not have a standardized meaning prescribed by IFRS. See Non-IFRS Measurements section of the MD&A.

⁽³⁾ Working capital surplus (deficiency) does not have a standardized measure prescribed by IFRS. See Non-IFRS Measurements section of the MD&A. Working capital deficiency at December 31, 2025, includes nil cash (\$5.7 million at December 31, 2024).

⁽⁴⁾ Boe conversion is 6:1

⁽⁵⁾ Operating netback does not have a standardized meaning prescribed by IFRS. See Non-IFRS Measurements section of the MD&A.

PRODUCTION

	Three Months Ended		Year Ended	
	December 31		December 31	
	2025	2024	2025	2024
Oil (bbls per day)	3,213	3,425	3,604	3,049
Liquids (bbls per day)	608	384	585	321
Natural gas (mcf per day)	19,079	12,498	18,375	10,679
BOE per day	7,001	5,892	7,251	5,150

Average production in Q4 2025 was 7,001 boe per day, consisting of 55% oil and liquids, compared to 5,892 boe per day with 65% oil and liquids in Q4 2024. For the year ended December 31, 2025, production averaged 7,251 boe per day (58% oil and liquids) versus 5,150 boe per day (65% oil and liquids) in 2024. These increases were driven by new wells brought on production during 2025, reactivations and recompletions of non-producing wells acquired in Q1 2025, and additional volumes from assets acquired in Q4 2025.

Two wells were brought on production in Q4 2025—one in Wayne and one in Sheerness. All thirteen wells drilled in 2025 were placed on production within the year. In addition, one water disposal well was drilled in Sheerness, bringing total well count to fourteen.

In comparison, seven wells were brought on production in Q4 2024, including three in Sheerness and two each in Wayne and Drumheller. The Wayne and Drumheller wells came on stream late in the quarter. Sheerness wells were temporarily restricted due to gas-flaring limitations but produced without restriction beginning in late January 2025 after pipeline completion. Thirteen wells were brought on production in 2024.

Oil and liquids production averaged 3,821 bbls per day in Q4 2025, similar to 3,809 bbls per day in Q4 2024. Higher liquids volumes, tied to increased natural gas production, offset a slight decline in oil-only volumes. On a full-year basis, oil and liquids production averaged 4,189 bbls per day in 2025, a 24% increase over 3,370 bbls per day in 2024.

Natural gas production increased 53% in Q4 2025 and 72% for the full year compared to 2024. These increases reflect production from new wells in the Sheerness area and volumes added through acquisitions.

OPERATING NETBACKS

(\$ per BOE)	Three Months Ended December 31		Year Ended December 31	
	2025	2024	2025	2024
Revenue ⁽¹⁾	\$41.40	\$56.43	\$46.47	\$57.89
Royalties	(8.02)	(11.30)	(9.27)	(12.25)
Operating expenses	(11.83)	(12.70)	(11.05)	(13.15)
Transportation expenses	(1.89)	(2.31)	(2.05)	(2.35)
Operating netback ⁽²⁾	\$19.66	\$30.12	\$24.10	\$30.14

⁽¹⁾ Includes pipeline tariff amount of \$2.30 and \$2.39 per boe for the three months and year ended December 31, 2025, and \$2.41 and \$2.55 per boe in the comparable periods of 2024 respectively.

⁽²⁾ Operating netback does not have a standardized meaning prescribed by IFRS. See Non-IFRS Measurements section of the MD&A.

Operating netbacks were lower in Q4 2025 and for the full year 2025 compared to the same periods in 2024, primarily due to lower realized oil prices and a higher weighting of natural gas production to total production, partially offset by higher realized natural gas prices and lower royalties, operating costs, and transportation expenses.

COMMODITY PRICES

(\$ per bbl, before pipeline tariffs)	Three Months Ended December 31		Year Ended December 31	
	2025	2024	2025	2024
WTI (US\$/bbl)	\$59.14	\$70.32	\$64.81	\$75.76
MSW benchmark price ⁽¹⁾	\$76.57	\$94.95	\$85.63	\$97.60
WCS benchmark price ⁽²⁾	\$66.87	\$80.75	\$75.06	\$83.56
Realized crude oil price	\$72.47	\$89.11	\$81.44	\$90.46

⁽¹⁾ Mixed sweet blend (MSW) is the benchmark conventionally produced light sweet crude for Western Canada. It is often referenced as Edmonton Par Crude.

⁽²⁾ Western Canadian Select (WCS) is a Hardisty based blend of conventional and oil sands production. WCS is a heavy sour blend of crude oil.

North 40's realized crude oil price reflects 27° API and differentials are typically close to the average of the MSW and WCS benchmark differentials.

North 40's realized crude oil price decreased 19% to \$72.47 per bbl in Q4 2025 from \$89.11 per bbl, in Q4 2024 primarily reflecting a 16% decline in WTI benchmark prices and wider light-sweet differentials, partially offset by improved heavy differentials. The WCS differential narrowed to average US\$11.20 per barrel in Q4 2025 compared to US\$12.57 per barrel in Q4 2024. The MSW differential widened to average US\$4.25 per barrel in Q4 2025 compared to US\$2.42 per barrel in Q4 2024.

North 40's realized crude oil price decreased 10% in 2025 to \$81.44 per barrel from \$90.46 per barrel realized in 2024 largely due to lower WTI benchmark prices, partly offset by a weaker Canadian dollar and narrower Canadian stream differentials. The WCS differential narrowed to average US\$11.13 per barrel in 2025 compared to US\$14.83 per barrel in 2024. The MSW differential also narrowed to average US\$3.57 per barrel in 2025 compared to US\$4.51 per barrel in 2024.

Benchmark WTI prices softened in 2025 amid macroeconomic uncertainty, trade policy volatility, global supply growth and elevated inventories, and OPEC+'s decision to accelerate its planned reintroduction of voluntary production cuts. WCS differentials improved materially with the May 2024 successful start up of the TMX (Trans Mountain) pipeline expansion.

(\$ per mcf, before pipeline tariffs)	Three Months Ended December 31		Year Ended December 31	
	2025	2024	2025	2024
AECO Daily (5A) index	\$2.23	\$1.46	\$1.68	\$1.48
Realized natural gas price	\$2.58	\$1.73	\$1.89	\$1.72

North 40's natural gas production is sold at the AECO daily 5A index and realizes a slightly better price than the index due to its higher-than-standard heat content. North 40's realized price increased 49% to \$2.58 per mcf in Q4 2025 from \$1.73 per mcf in Q4 2024 and increased 10% to \$1.89 per mcf for 2025 from \$1.72 per mcf in 2024.

AECO prices in 2025 were supported by stronger demand including higher exports to the United States and increased feed gas demand associated with the ramp up of operations at LNG Canada.

REVENUE

(\$ thousands)	Three Months Ended December 31		Year Ended December 31	
	2025	2024	2025	2024
Oil and liquids	\$22,776	\$28,972	\$112,612	\$103,608
Natural gas	3,893	1,619	10,361	5,497
Petroleum and natural gas revenue	\$26,669	\$30,591	\$122,973	\$109,105
% Oil and liquids	85	95	92	95

Note: Petroleum and natural gas revenue presented in the Statements of Net Income and Comprehensive Income is net of pipeline tariffs.

Petroleum and natural gas revenue for the three months ended December 31, 2025, totaled \$26.7 million, compared to \$30.6 million in the same period of 2024. The decrease was primarily driven by materially lower crude oil price realizations, partially offset by higher natural gas and liquids production volumes and stronger natural gas pricing.

For the year ended December 31, 2025, revenue increased 13% to \$123.0 million, up from \$109.1 million in 2024. This increase reflects significantly higher oil production volumes and improved realized prices for natural gas, which more than offset the decline in crude oil price realizations year-over-year.

Oil and liquids revenue represented 85% of total revenue in Q4 2025 and decreased 21%, from \$29.0 million in Q4 2024 to \$22.8 million in Q4 2025. Crude oil realizations were 19% lower and oil production volumes were 6% lower in Q4 2025 compared to the same quarter last year. On an annual basis, oil and liquids revenue increased 9% to \$112.6 million, compared with \$103.6 million in 2024. The increase was driven by 24% higher oil production volumes, partially offset by a 10% reduction in crude oil price realizations.

Natural gas revenue increased to \$3.9 million in the fourth quarter of 2025, compared to \$1.6 million in the prior-year quarter. This 240% increase reflects a 49% improvement in realized natural gas prices and a 53% increase in production volumes. Natural gas revenue for 2025 represented 8% of total revenue and increased 89% compared to 2024 due to a 10% increase in price and a 72% increase in production volume.

The Company's revenue continues to be predominantly weighted toward crude oil and liquids. However, natural gas contributed a higher share of revenue in both the quarter and the full year as a result of stronger production and improved pricing.

Oil pipeline tariffs of \$0.8 million and \$4.0 million are included in revenue for the fourth quarter and the year ended December 31, 2025, respectively. This compares to \$0.9 million and \$3.6 million in the same periods of 2024. The custody transfer to the purchaser is at the point the oil is offloaded at the terminal. Gas pipeline tariffs of \$0.6 million and \$2.3 million are also included in revenue for the three months and year ended December 31, 2024, respectively. This compares to \$0.4 million and \$1.2 million in the same periods of 2024. The custody transfer to the purchaser is at the point the natural gas enters the receipt meter.

ROYALTIES

(\$ thousands, except per unit amounts)	Three Months Ended December 31		Year Ended December 31	
	2025	2024	2025	2024
Freehold, gross overriding and other royalties	\$3,316	\$4,293	\$15,269	\$15,205
Crown royalties	1,294	1,151	6,264	4,799
Freehold mineral tax	555	684	3,002	3,075
Total royalties	\$5,165	\$6,128	\$24,535	\$23,079
Per BOE	\$8.02	\$11.30	\$9.27	\$12.25
% of Revenue before pipeline tariffs	18%	19%	19%	20%

Royalties will fluctuate with commodity prices and production rates and are determined primarily by the terms of the mineral rights owner agreements and the Alberta provincial government royalty regime.

Royalties for the three months and year ended December 31, 2025, were influenced primarily by lower realized oil prices and higher production volumes relative to the prior year.

Royalties on a boe basis decreased to \$8.02 and \$9.27 per boe in Q4 2025 and 2025 respectively compared to \$11.30 and \$12.25 per boe in the comparable periods of 2024. These decreases were primarily attributed to lower realized oil prices. On an absolute basis, royalties decreased to \$5.2 million in Q4 2025 compared to \$6.1 million in Q4 2024. Royalties were \$24.5 million for 2025 compared to \$23.1 million in 2024 commensurate with the increase in production volumes.

Royalties as a percentage of revenue were 18% and 19% in the fourth quarters of 2025 and 2024 respectively. Royalties as a percentage of revenue decreased to 19% for the year ended December 31, 2025, compared to 20% for the same period in 2024.

OPERATING AND TRANSPORTATION

<i>(thousands, except per unit amounts)</i>	Three Months Ended December 31		Year Ended December 31	
	2025	2024	2025	2024
Operating expenses	\$7,592	\$6,883	\$29,217	\$24,784
Per BOE	\$11.83	\$12.70	\$11.05	\$13.15
Transportation expenses	\$1,220	\$1,254	\$5,431	\$4,424
Per BOE	\$1.89	\$2.31	\$2.05	\$2.35

Operating expenses averaged \$11.83 per boe (\$7.6 million) in the fourth quarter of 2025 compared to \$12.70 per boe (\$6.9 million) in the same period of 2024. The increase in total operating costs was primarily due to higher well workover activity and increased contract operating expenses resulting from the expansion of the Company's operated asset base late in the year.

For the year ended December 31, 2025, operating expenses averaged \$11.05 per boe (\$29.2 million) compared to \$13.15 per boe (\$24.8 million) in 2024. The year-over-year increase in absolute operating costs was mainly driven by higher electricity costs at newly operated facilities, along with higher property taxes, contract labour, and lease rentals associated with the Company's larger asset base in 2025.

Despite higher total operating costs for both the quarter and full year, per-unit operating expenses decreased relative to 2024, driven by higher production volumes in 2025, which allowed fixed operating costs to be spread over a larger production base.

Transportation costs, which are clean oil trucking expenses, averaged \$1.89 (\$1.2 million) and \$2.05 (\$5.4 million) per boe in the fourth quarter and the year ended December 31, 2025, respectively compared to \$2.31 (\$1.3 million) and \$2.35 (\$4.4 million) per boe in the same periods of 2024. The cost is incurred on oil production only.

North 40's crude oil production may be sold in different sales streams in Alberta which may vary month to month depending on the netback at those different streams. As a result, there will be fluctuations in crude oil differentials and transportation costs as the Company seeks out the highest netback opportunity.

GENERAL AND ADMINISTRATIVE

<i>(thousands, except per unit amounts)</i>	Three Months Ended December 31		Year Ended December 31	
	2025	2024	2025	2024
Gross G&A	\$2,778	\$1,563	\$7,452	\$4,708
Capitalized G&A and overhead recoveries	(304)	(150)	(588)	(411)
Net G&A	\$2,474	\$1,413	\$6,864	\$4,297
Per BOE	\$3.84	\$2.61	\$2.59	\$2.28

Net general and administrative ("G&A") expenses were \$2.5 million and \$6.9 million for the fourth quarter, and the year ended December 31, of 2025 respectively compared to \$1.4 million and \$4.3 million in the comparable periods of 2024.

The increase in G&A quarter-over-quarter is mostly attributable to an increase in staffing levels and consulting related to ongoing operations and higher professional fees, specifically legal and land consulting fees, related to asset transactions that closed in 2025 and early 2026. The increase in net G&A in 2025 compared to 2024 are due to the same factors for the quarterly increase as well as payments made in relation to the departure of the Company's former Vice President Exploration in Q2 2025.

On a boe basis, net G&A was \$3.84 and \$2.59 per boe in Q4 and for the year ended December 31, 2025, respectively compared to \$2.61 and \$2.28 per boe in same periods of 2024. The increase in the per boe cost for both Q4 2025 compared to Q4 2024 and 2025 compared to 2024 is due to the impact of higher costs partially offset by the impact of higher production volume.

Capitalized G&A relates to a portion of the Company's engineering compensation for 2024 and for the first nine months of 2025. Beginning in Q4 2025, the Company amended its capitalization and overhead recovery policy to industry standard practices. As a result of asset transactions that closed in 2025, the Company's operations include partners in many wells and infrastructure. Overhead and capital recoveries charged to and by partners are governed by contractual agreements. North 40 has applied the industry standard practice to all its operations.

SHARE BASED COMPENSATION

<i>(thousands, except per unit amounts)</i>	Three Months Ended December 31		Year Ended December 31	
	2025	2024	2025	2024
Share based compensation	\$495	\$279	\$936	\$1,145
Capitalized share-based compensation	-	(27)	(53)	(111)
	\$495	\$252	\$883	\$1,034
Per BOE	\$0.77	\$0.46	\$0.33	\$0.55

Share based compensation expense is related to the issuance of Class B and C shares and the grants of options on Class B and C shares to directors, officers, employees, and consultants.

In November 2025, the Board of Directors extended the expiry of certain Class B and Class C shares and options to September 2029 from September 2026. The term extension is a modification under IFRS and requires an update to the calculation of share-based compensation expense.

Incremental value of \$0.4 million was determined for the vested Class B shares and options. This incremental value was recognized in Q4 2025.

Incremental value of \$0.6 million was determined for the Class C shares and options and will be recognized over the estimated remaining expected term of 2.0 years for the Class C shares and options. The Company recognized \$27,000 as share based compensation expense in the fourth quarter and for the year ended December 31, 2025, respectively related to this Class C incremental value.

Detailed information regarding the Class B and Class C shares and options have been disclosed in Note 12 of the financial statements.

DEPLETION AND DEPRECIATION

<i>(thousands, except per unit amounts)</i>	Three Months Ended December 31		Year Ended December 31	
	2025	2024	2025	2024
Depletion and depreciation	\$12,037	\$9,883	\$47,120	\$36,275
Per BOE	\$18.69	\$18.23	\$17.81	\$19.25

The Company recognized depletion and depreciation expense ("D&D") of \$12.0 million (\$18.69 per boe) and \$47.1 million (\$17.81 per boe) for the quarter and the year ended December 31, 2025, respectively compared to \$9.9 million (\$18.23 per boe) and \$36.3 million (\$19.25 per BOE) in the same periods of 2024.

D&D expense is calculated using the unit-of-production method based on proved plus probable reserves, taking into account estimated future development costs necessary to bring those reserves into production. In 2025, the Company had its reserves evaluated by McDaniel & Associates Consultants Ltd. and Q4 2025 D&D expense was based on the external evaluation of proved and probable reserves. The D&D expense in 2024 and for the first three quarters of 2025 was based on an internal evaluation of proved and probable reserves.

D&D expense increased by 21% in the fourth quarter of 2025 (\$12.0 million) compared to Q4 2024 (\$9.9 million) largely due to higher production volume and a slightly higher per unit rate. The 30% increase in depletion expense for year ended December 31, 2025 (\$47.1 million) compared to 2024 (\$36.3 million) is largely due to higher production volume partially offset by a lower rate.

The D&D expense recognized was comprised primarily of depletion expenses with minor amounts relating to depreciation of office assets, right of use assets and field vehicles.

D&D per boe will differ from period to period depending on the amount and type of capital spending, the amount of reserves added, and production volume.

EXPLORATION EXPENSE

<i>(thousands, except per unit amounts)</i>	Three months ended December 31		Year ended December 31	
	2025	2024	2025	2024
Exploration expense	\$4,383	\$46	\$12,144	\$4,970
Per BOE	\$6.80	\$0.08	\$4.59	\$2.64

North 40 recognized exploration expense of \$4.4 million (\$6.80 per boe) in Q4 2025 and \$12.1 million (\$4.59 per boe) for the year ended December 31, 2025. Q4 expense primarily reflects undeveloped freehold land expiries predominantly at Wintering Hills and Drumheller. Annual exploration expense for 2025 reflects undeveloped freehold land expiries at Matziwin South (\$4.1 million), Drumheller (\$3.1 million), Wintering Hills (\$2.0 million) and Wayne (\$1.6 million) as well as costs related to drilling two test wells in prior years.

North 40 recognized exploration expense of \$0.1 million (\$0.08 per boe) in Q4 2024 and \$5.0 million (\$2.64 per boe) for the year ended December 31, 2024, related to an unsuccessful test well at Tide Lake drilled in the first quarter and undeveloped land expiries. Undeveloped freehold land expiries in 2024 were predominantly in the Princess area.

IMPAIRMENT

<i>(thousands, except per unit amounts)</i>	Three months ended December 31		Year ended December 31	
	2025	2024	2025	2024
Impairment	\$62,159	\$ -	\$62,159	\$ -
Per BOE	\$96.50	\$ -	\$23.49	\$ -

North 40 has one Cash-Generating Unit (CGU) as of December 31, 2025. At December 31, 2025, indicators of impairment were identified due to a lower commodity price environment and negative technical revisions for crude oil. As a result, an impairment test was performed. The recoverable value was estimated at fair value less costs to sell based on before tax discounted cash flows from proved and probable oil and gas reserves, based on the underlying composition of reserve categories.

At December 31, 2025, it was determined that the carrying value exceeded the estimated recoverable amount and a \$62.2 million impairment was recognized. The before tax discount rate applied in the calculation ranged between 10% and 20% depending on the reserve category.

The results of the impairment tests are sensitive to changes in any of the key significant assumptions including forecasted oil and commodity prices, forecasted production volumes, forecasted operating costs, royalty costs and future development costs which impact the estimate of cash flows from proved and probable oil and gas reserves, in addition to the discount rate, of which changes could increase or decrease the estimated recoverable amount of the CGU and result in additional impairment charges or in the recovery of previously recorded impairment charges. All estimates are subject to uncertainty.

A one percent change in the discount rate or a five percent change in the forward price over the life of the reserves would result in changes in impairment of \$3.8 million and \$20.0 million respectively.

IMPAIRMENT ON DISPOSITION OF ASSETS

<i>(thousands, except per unit amounts)</i>	Three months ended December 31		Year ended December 31	
	2025	2024	2025	2024
Impairment on disposition of assets	\$ -	\$ -	\$4,479	\$ -
Per BOE	\$ -	\$ -	\$2.24	\$ -

North 40 entered into a purchase and sale agreement on June 4, 2025, for the disposition of its non-core Entice assets for \$0.3 million in cash. The transaction closed on July 30, 2025, however given the disposition was determined to be highly probable, the assets were classified as held for sale at June 30, 2025.

North 40 recognized an impairment on disposition of the assets held for sale of \$4.5 million, primarily due to the carrying value of the disposed assets exceeding the consideration received. As part of the transaction, North 40 reduced decommissioning obligations by \$0.2 million associated with the properties sold.

FINANCE EXPENSE

<i>(thousands)</i>	Three Months Ended December 31		Year Ended December 31	
	2025	2024	2025	2024
Accretion of decommissioning obligations	\$203	\$76	\$586	\$271
Interest	194	15	432	43
Banking fees	47	50	286	199
Interest on leased liabilities	5	6	22	24
Total	\$449	\$147	\$1,326	\$537
Per BOE	\$0.70	\$0.27	\$0.50	\$0.29

Finance expense for the three months ended December 31, 2025, was \$0.4 million, compared to \$0.1 million in the same period of 2024. For the year ended December 31, 2025, finance expense totaled \$1.3 million (2024 – \$0.5 million). The increase year-over-year was driven primarily by higher interest costs resulting from increased borrowings under the Company's credit facility to fund the 2025 capital program and higher accretion costs mostly from asset acquisitions in the year.

Banking fees include standby charges and fees associated with the Company's annual credit facility review. These increased in the current year in connection with expanded facility limits.

Finance expense on a per boe basis was \$0.50 for the year ended December 31, 2025 (2024 – \$0.29), reflecting higher total finance costs partially offset by increased production.

Accretion of decommissioning obligations and interest on lease liabilities are non-cash charges.

INCOME TAXES

For the three months ended December 31, 2025, North 40 incurred current income tax expense of \$0.5 million, and \$1.2 million for the year. This compares to \$0.2 million and \$0.5 million, respectively, in 2024.

Although the Company recorded a net loss for the year, current income taxes arose because significant components of the accounting loss, primarily impairment, exploration expenditures and impairment on asset dispositions are not fully deductible in the current year for tax purposes. These items are deductible over time or subject to specific limitations, resulting in a difference between accounting income and taxable income.

Deferred income taxes arise from temporary differences between the accounting carrying values and tax basis of assets and liabilities. The estimate of deferred taxes is based on the current tax status of the Company, enacted legislation, and management's best estimates of future events.

For the three months and year ended December 31, 2025, deferred income tax recoveries of \$16.1 million and \$17.4 million, respectively, were recognized compared to a deferred income tax expense of \$1.0 million and \$2.1 million for the comparable periods in 2024.

The increase in the deferred income tax recovery in 2025 is largely a result of the reduction in carrying amounts of exploration assets and property, plant and equipment from recognition of exploration expense (mainly undeveloped land expiries) and impairment of property, plant and equipment.

The following tax pool balances are estimated at December 31, 2025, and 2024:

<i>(thousands)</i>	Maximum Annual Deduction	2025	2024
Canadian oil and gas property expense (COGPE)	10%	\$3,276	\$5,736
Canadian development expense (CDE)	30%	67,364	58,022
Undepreciated capital cost (UCC)	25%	50,082	51,723
		\$120,722	\$115,481

NET INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)

<i>(thousands)</i>	Three Months Ended December 31		Year Ended December 31	
	2025	2024	2025	2024
Net income (loss) and comprehensive income (loss)	\$(53,680)	\$3,494	\$(54,993)	\$7,402
Per share – basic	\$(0.69)	\$0.05	\$(0.71)	\$0.10
– diluted	\$(0.69)	\$0.04	\$(0.71)	\$0.09

North 40 recognized a net loss and comprehensive loss of \$53.7 million (\$0.69 per basic and diluted share) and \$55.0 million (\$0.71 per basic and diluted share) for the three months and year ended December 31, 2025, respectively and net income and comprehensive income of \$3.5 million (\$0.05 per basic and \$0.04 per diluted share) and \$7.4 million (\$0.10 per basic and \$0.09 per diluted share) for the comparable periods in 2024.

The decrease in net income for the three months December 31, 2025, as compared to the same period in 2024 is primarily due to recognition of impairment of property, plant and equipment, a decrease in petroleum and natural gas revenue, and increases in exploration expense, depletion and depreciation expense, royalties, operating expenses, general and administrative costs, partially offset by an increase in the deferred income tax recovery.

The decrease in net income for the year ended December 31, 2025, as compared to the same period in 2024 is primarily due to recognition of impairment of property, plant and equipment, impairment on disposition of assets and increases in depletion and depreciation, exploration expense, operating expenses and general and administrative expenses partially offset by an increase in petroleum and natural gas revenue and deferred income tax recovery.

CAPITAL EXPENDITURES

Capital expenditures by type and by area for the three months and year ended December 31, 2025, and 2024 were as follows:

<i>(thousands)</i>	Three months ended December 31		Year Ended December 31	
	2025	2024	2025	2024
Acquisitions	\$15,430	\$ -	\$28,076	\$ -
Land and lease rentals ⁽¹⁾	866	174	1,240	1,545
Seismic and geological ⁽²⁾	45	(360)	1,026	2,087
Drilling and completion	2,075	16,133	38,202	40,038
Equipping and tie-ins	934	2,098	13,880	11,245
Facilities	382	9,652	4,499	13,089
Office and other	65	150	347	421
Total capital expenditures	\$19,797	\$27,847	\$87,270	\$68,425

(1) Net of land fund reimbursements

(2) Negative amounts represent prior period adjustments

<i>(thousands)</i>	Three Months Ended December 31		Year Ended December 31	
	2025	2024	2025	2024
Sheerness	\$16,620	\$18,933	\$75,128	\$36,497
Wayne	2,850	7,235	11,423	8,821
Drumheller	135	2,478	-	17,385
Tide Lake ⁽³⁾	20	(280)	60	2,930
Matziwin ⁽³⁾	5	(315)	65	1,832
Other ⁽³⁾	167	(204)	596	960
Total capital expenditures	\$19,797	\$27,847	\$87,270	\$68,425

(3) Negative amounts represent prior period adjustments

Wells drilled by property were as follows:

	Three Months Ended December 31		Year Ended December 31	
	2025	2024	2025	2024
Sheerness	-	-	11	5
Wayne	-	2	3	2
Drumheller	-	2	-	6
Tide Lake	-	-	-	1
Total	-	4	14	14

Quarterly Highlights

Fourth quarter 2025 capital expenditures were \$19.8 million and includes the following activities:

- Acquisition of assets in the Sheerness (Aerial) area which includes certain crude oil and natural gas properties and related infrastructure for \$15.4 million. Also includes the remaining 50% working interest in the Rowley 4-9 natural gas plant,
- Completion of two wells drilled in Q3 2025. One in Wayne and the other at Sheerness (Michichi), and
- Workovers, predominantly in the Wayne area.

Fourth quarter 2024 capital expenditures were \$27.8 million and includes the following activities:

- Drilling, completion, equip and tie-in of four wells, two at Wayne and two at Drumheller which were brought on production late in the quarter,
- Completion of three wells at Sheerness, drilled in Q3 and brought on production in Q4,
- Purchase of a 50% non-operated working interest in the Rowley 4-9 natural gas plant in Sheerness,
- Completion and start-up of an oil battery at Sheerness, and
- Construction of natural gas pipelines commenced to connect the newly constructed 2-13 battery to the newly acquired Rowley 4-9 natural gas plant.

Annual Highlights

Capital expenditures in 2025 were \$87.3 million and predominantly directed to the Sheerness area. The Company drilled 14 wells of which 11 were in Sheerness and 3 in Wayne. One Sheerness well was a water disposal well. Other capital activities included: construction of a water disposal facility at Sheerness (Michichi), commencement of construction of an oil battery at Sheerness (Aerial), completion of a pipeline connecting Sheerness (Michichi) natural gas production to a natural gas plant (50% working interest prior to November 23rd and 100% working interest thereafter), acquisition of a 75% working interest in the Seiu Lake natural gas plant in the Drumheller area, recompletion of three wells and several reactivations on wells acquired in Q1 2025, and routine well workovers. The year also included two property acquisitions as described below.

Capital expenditures in 2024 were \$68.4 million which included the drilling of 14 wells. The majority of the capital was directed in Sheerness where \$36.5 million was spent. At Sheerness five wells have been drilled and brought on production, construction of an oil battery was completed, purchase of a 50% working interest in a natural gas plant closed, a 3D seismic shoot was completed, and construction of a natural gas pipeline to connect the battery to the gas plant commenced. In Drumheller where \$17.4 million has been expended, six wells have been drilled. Two wells were drilled and brought on production in Wayne. Other activities include workovers at several wells, electrification of three Wayne battery sites, as well as equipment purchases for future capital projects.

To fund the Sheerness infrastructure development, the Company sold a royalty interest and an infrastructure volumetric payment on current and future production on certain lands in the Michichi area of Sheerness. Production volumes processed at the infrastructure described are subject to the infrastructure volume payment. Proceeds from the sale were \$15.6 million and is not included in the capital expenditures values disclosed above.

Acquisitions and Funding

In Q1 2025, the Company acquired certain crude oil and natural gas properties with minimal production for \$12.4 million of cash consideration. The properties comprise of approximately 8,300 hectares, developed historically with vertical wells and exhibiting multi-zone potential in Aerial. The property includes a number of inactive and/or suspended wells and facilities. A reactivation and recompletion program began in Q3 2025. To fund this acquisition, the Company sold a royalty interest and an infrastructure volumetric payment on future production. Proceeds from the sale was \$12 million and is not included in the capital expenditure values disclosed above.

In Q4 2025, the Company acquired additional crude oil and natural gas properties and related infrastructure, including the remaining 50% working interest in the Rowley 4-9 natural gas plant, for \$15.4 million of cash consideration. The acquired properties were producing approximately 400 boe per day and include approximately 16,700 net acres of land and a number of inactive or suspended wells and facilities. To fund this acquisition, the Company sold a royalty interest and an infrastructure volumetric payment on future production. Proceeds from the sale was \$15 million and is not included in the capital expenditure values disclosed above.

LAND

North 40's net land holdings per area at December 31, 2025, and 2024 were as follows:

<i>(acres)</i>	December 31, 2025	December 31 2024
Sheerness	183,822	119,160
Drumheller	36,339	55,874
Wayne	10,080	15,951
Tide Lake	24,528	26,427
Matziwin	10,744	24,249
Other	23,096	23,736
Total	288,609	265,397

The increase in land holdings are mainly a result of the acquisition of leases in the Sheerness area partially offset by freehold lease expiries in the Matziwin South (Matziwin), Drumheller, Wintering Hills (Matziwin), and Wayne areas.

The land holdings consist of approximately 88% crown and 12% freehold leases at December 31, 2025. Working interest in North 40's land holdings is 84 percent. At December 31, 2024, the land holdings consisted of 72% crown and 28% freehold leases and the working interest in North 40's land holdings was 100 percent.

DECOMMISSIONING OBLIGATIONS

Decommissioning obligations are based on estimated costs and timing to abandon and reclaim ownership interests in oil and natural gas assets. North 40 has recognized a provision for decommissioning obligations of \$30.5 million at December 31, 2025 (\$9.1 million at December 31, 2024).

Estimated abandonment and reclamation costs are based on the directives issued by the Alberta Energy Regulator and management's experience. The decommissioning obligation is measured using the estimated present value of costs to abandon

and reclaim all ownership interests. Estimated timing of cash flows are aligned with reserve life and regulatory expectations. A risk-free rate of 3.55% (3.35% at December 31, 2024) and an inflation rate of 2.00% (2.00% at December 31, 2024) were used to calculate the best estimate of the decommissioning obligation.

The increase of \$21.4 million in the decommissioning obligation at December 31, 2025, compared to December 31, 2024, is largely due to liabilities acquired with 2025 asset acquisitions, adding \$17.0 million. Also contributing to the increase in the decommissioning obligations are new obligations associated with wells drilled and facilities and a decrease in reserve life assumptions partially offset by a decrease in discount rates.

For 2026, the Company plans to spend its mandatory spend requirement of \$0.4 million under the Alberta Energy Regulator's Liability Management Program.

LIQUIDITY AND CAPITAL RESOURCES

At December 31, 2025, the Company had a working capital deficit of \$13.2 million which includes \$10.3 million of bank debt. Activities to date have been largely funded with cash flow from operations, initial equity proceeds, sales of royalty interests and volumetric payments, and bank debt.

At December 31, 2025, the Company had a \$45.0 million revolving demand operating facility with a Canadian chartered bank. The facility bears interest based on the prime rate or Canadian Overnight Repo Rate Average ("CORRA") rates plus a margin. Interest rates applicable to draws and standby fees are based on a pricing margin grid and will change as a result of the ratio of net debt to cash flow as calculated in accordance with the credit facility agreement. Standby fees on undrawn amounts are currently 0.50%. The Company has a letter of credit outstanding for \$0.1 million at December 31, 2025, that reduces the amount otherwise available to be drawn on the operating facility.

The facility includes a financial covenant that requires the "Adjusted Working Capital" ratio (as defined in the credit agreement, with undrawn capacity under the facility included in the definition of current assets) be not less than 1.0 at each fiscal quarter end. The Company was in compliance with this covenant at December 31, 2025. Advances under the facility are secured by a first floating charge debenture and borrowings under the facility may be made by way of prime loans and CORRA loans. The credit facility is subject to periodic review at the lenders' discretion. The next review date has been set for on or before May 31, 2026.

The Company has entered into a Royalty Acquisition Agreement (the "agreement") with an arm's length party (the "party") whereby the party will fund certain crown land purchases incurred by the Company in exchange for a royalty on future production from those crown lands. The term of the agreement is to October 31, 2026. At December 31, 2025, there is \$2.2 million remaining on the funding limit.

RESERVE INFORMATION

North 40 retained McDaniel & Associates Consultants Ltd., a qualified reserves evaluator, to provide an independent evaluation of the Company's Proved and Probable reserves. North 40's statements of reserves data and other oil and gas information have an effective date of December 31, 2025.

The independent reserve report has been prepared in accordance with reserve definitions, standards and procedures contained in the Canadian Oil and Gas Evaluation Handbook (COGE).

The following table summarizes North 40's Company Interest reserves at December 31, 2025:

<i>(Company Interest)</i>	Oil and Liquids (Mbbls)	Natural Gas (MMcf)	Oil Equivalent (Mboe)
Proved developed producing	4,534	24,957	8,693
Proved developed non-producing	135	227	172
Proved undeveloped	2,668	8,668	4,113
Total proved	7,337	33,852	12,979
Probable	3,383	12,122	5,403
Total proved plus probable	10,720	45,974	18,382

The following table summarizes changes in reserves during 2025:

<i>(Mboe)</i>	Proved Producing	Total Proved	Total Probable	Total Proved & Probable
December 31, 2024	7,471	12,191	3,790	15,981
Production – 2025	(2,647)	(2,647)	-	(2,647)
Additions	1,978	3,232	901	4,133
Acquisitions	799	799	190	989
Economic Factors	(248)	(359)	(80)	(439)
Technical revisions	1,340	(238)	603	365
December 31, 2025	8,693	12,979	5,403	18,382

The following table summarizes net reserves values at December 31, 2025:

NET PRESENT VALUES OF FUTURE NET CASH FLOW (BEFORE INCOME TAXES)

<i>(\$ Million)</i>	0%	5%	10%	15%
Proved developed producing	55	95	92	84
Proved developed non-producing	5	4	4	3
Proved undeveloped	31	18	9	3
Total proved	91	117	105	91
Probable	95	64	46	35
Total proved plus probable	186	181	151	126

Abandonment and reclamation costs for; inactive wells with no reserves assigned, for pipelines and infrastructure and for multi-well batteries have been included within the reserve evaluation. These are also included within the decommissioning obligations in the statements of financial position.

Notes:

The following reserve definitions are as set out in National Instrument 51-101 and the Canadian Oil and Gas Evaluation Handbook (COGE):

“**Company Interest**” reserves are the sum of the of Company Gross plus Company Royalty Interest reserves.

“**Company Royalty Interest**” reserves are the net reserves received as a result of a royalty or carried interest.

“**Gross**” means North 40’s interest in operated and non-operated production and reserves before the deduction of royalties.

“**Net**” means North 40’s interest in operated and non-operated production and reserves after deduction of royalty obligations.

“**Reserves**” are the estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on: analysis of drilling, geological, geophysical and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable. Reserves are classified according to the degree of certainty associated with the estimates.

“**Proved Reserves**” are those Reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated Proved Reserves. At least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated Proved Reserves is the targeted level of certainty.

“**Probable Reserves**” are those additional Reserves that are less certain to be recovered than Proved Reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated Proved plus Probable Reserves. At least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated Proved plus Probable Reserves is the targeted level of certainty.

“**Proved Developed Reserves**” are those Reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (e.g. when compared to the cost of drilling a well) to put the Reserves on production. The developed category may be subdivided into producing and non-producing.

“**Developed Producing Reserves**” are those Reserves that are expected to be recovered from completion intervals open at the time of the estimate. These Reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

“**Developed Non-Producing Reserves**” are those Reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

“Undeveloped Reserves” are those Reserves expected to be recovered from known accumulations where a significant expenditure (e.g. when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the Reserves classification (Proved, probable, possible) to which they are assigned.

The forecast cost and price assumptions assume the continuation of current laws and regulations and increases in wellhead selling prices and take into account inflation with respect to future costs. The following table is a summary of pricing assumptions based on the December 31, 2025, three consultant average price forecast of McDaniels & Associates Consultants Ltd., GLJ Ltd., Sproule and North 40’s estimates.

**Summary of Pricing Assumptions
Effective December 31, 2025
Forecast Price and Costs**

Forecast	Oil			Gas		
Year	WTI Cushing Oklahoma (\$US)	Edmonton Light (\$C)	N40 Oil Price (\$C)	Henry Hub (\$US)	AECO Spot (\$C)	N40 Gas Price (\$C)
	(\$/bbl)			(\$/mmbtu)		
2026	59.92	77.54	69.64	3.74	3.00	2.80
2027	65.10	83.60	75.28	3.78	3.30	3.13
2028	70.28	90.17	81.27	3.85	3.49	3.32
2029	71.93	92.32	83.30	3.93	3.58	3.40
2030	73.37	94.17	84.97	4.01	3.65	3.46
2031	74.84	96.06	86.92	4.09	3.72	3.51
2032	76.34	97.98	88.63	4.17	3.80	3.59
2033	77.87	99.93	90.44	4.26	3.88	3.66
2034	79.42	101.93	92.25	4.34	3.95	3.75

Note: Inflation rate assumption is 2% per annum.

CAPITAL EFFICIENCIES

	2025	3- Year Average
Finding, development, and acquisition costs ⁽¹⁾		
Total proved (\$/boe)	\$17.17	\$22.85
Proved plus probable reserves (\$/boe)	\$13.20	\$18.99
Recycle Ratio ⁽²⁾ (times)	1.8	1.6

⁽¹⁾ Includes future development costs of \$85.3 million on a proved basis and \$124.7 million on a proved plus probable basis.

⁽²⁾ Based on the Company’s operating netbacks and F&D costs for proved plus probable reserves.

SELECTED QUARTERLY INFORMATION

Three Months Ended	Dec 31	Sept 30	Jun 30	Mar 31	Dec 31	Sept 30	Jun 30	Mar 31
	2025	2025	2025	2025	2024	2024	2024	2024
FINANCIAL								
Petroleum and natural gas revenue	\$26,669	\$27,891	\$29,818	\$38,595	\$30,591	\$25,197	\$26,057	\$27,260
Funds flow from operations ⁽¹⁾	\$9,489	\$11,968	\$13,126	\$20,442	\$14,712	\$11,702	\$12,555	\$13,049
Per share – basic	\$0.12	\$0.15	\$0.17	\$0.27	\$0.19	\$0.15	\$0.16	\$0.17
Per share – diluted	\$0.11	\$0.14	\$0.15	\$0.25	\$0.18	\$0.14	\$0.15	\$0.16
Net income (loss)	\$(53,680)	\$1,141	\$(8,210)	\$5,756	\$3,494	\$(1,130)	\$4,244	\$793
Per share – basic	\$(0.69)	\$0.02	\$(0.11)	\$0.08	\$0.05	\$(0.02)	\$0.06	\$0.01
Per share – diluted	\$(0.69)	\$0.01	\$(0.11)	\$0.07	\$0.04	\$(0.02)	\$0.05	\$0.01
Capital expenditures ⁽²⁾	19,797	\$15,943	\$16,553	\$34,977	\$27,847	\$22,314	\$3,554	\$14,711
Working capital surplus (deficiency) at end of period ⁽³⁾	\$(13,158)	\$(17,099)	\$(12,829)	\$(9,708)	\$(8,365)	\$(10,757)	\$1,086	\$(7,807)
Common shares outstanding end of period	77,773	77,612	77,612	76,624	76,624	76,624	76,624	76,624
OPERATING								
Sales volumes								
Oil and liquids (bbls/day)	3,821	4,054	4,135	4,754	3,809	3,169	3,034	3,465
Natural gas (mcf/day)	19,079	19,485	18,662	16,231	12,498	10,150	8,413	11,642
Total (boe per day) ⁽⁴⁾	7,001	7,301	7,245	7,459	5,892	4,860	4,436	5,405
% Oil and liquids	55	56	57	64	65	65	68	64
Commodity prices realized (before pipeline tariffs)								
Oil and liquids (\$/bbl)	67.19	75.34	74.94	85.83	85.33	87.55	94.73	81.14
Natural gas (\$/mcf)	2.58	0.71	1.91	2.47	1.73	0.77	1.33	2.84
Total (\$/boe)	43.70	43.73	47.69	60.07	58.84	58.69	67.31	58.14
Operating netback ⁽⁵⁾ (\$/boe)	19.66	20.84	23.07	32.63	30.12	27.59	34.25	29.12
Funds flow from operations netback (\$/boe) ⁽¹⁾	14.73	17.82	19.91	29.87	27.14	26.17	31.10	26.53
Net wells drilled	-	3.0	5.0	6.0	4.0	7.0	-	3.0
Net acres of land at end of period	288,609	262,380	266,003	285,113	265,397	267,272	283,585	298,158

⁽¹⁾ Funds flow from operations and funds flow from operations netback does not have a standardized meaning prescribed by IFRS. See Non-IFRS Measurements section of the MD&A.

⁽²⁾ Capital expenditures does not have a standardized meaning prescribed by IFRS. See Non-IFRS Measurements section of the MD&A.

⁽³⁾ Working capital surplus (deficiency) does not have a standardized measure prescribed by IFRS. See Non-IFRS Measurements section of the MD&A.

⁽⁴⁾ Boe conversion is 6:1.

⁽⁵⁾ Operating netback does not have a standardized meaning prescribed by IFRS. See Non-IFRS Measurements section of the MD&A.

SELECTED ANNUAL INFORMATION

	2025	2024	2023	2022	2021
FINANCIAL					
Petroleum and natural gas revenue	\$122,973	\$109,105	\$143,418	\$116,333	\$63,880
Funds flow from operations ⁽¹⁾	\$55,025	\$52,018	\$72,594	\$61,509	\$36,390
Per share – basic	\$0.71	\$0.68	\$0.95	\$0.81	\$0.48
Per share – diluted	\$0.66	\$0.63	\$0.90	\$0.77	\$0.47
Net income (loss)	\$(54,994)	\$7,402	\$20,134	\$30,865	\$15,301
Per share – basic	\$(0.71)	\$0.10	\$0.26	\$0.41	\$0.20
Per share – diluted	\$(0.71)	\$0.09	\$0.25	\$0.39	\$0.20
Capital expenditures ⁽²⁾	87,270	\$68,425	\$85,716	\$67,891	\$35,888
Working capital surplus (deficiency) ⁽³⁾ at end of period	\$(13,158)	\$(8,365)	(\$6,114)	\$7,139	\$13,486
Common shares outstanding end of period	77,773	76,624	76,624	76,624	75,250
OPERATING					
Sales volumes					
Oil and liquids (bbls/day)	4,189	3,370	4,144	2,560	2,104
Natural gas (mcf/day)	18,375	10,679	13,317	10,020	6,305
Total (boe per day) ⁽⁴⁾	7,251	5,150	6,363	4,230	3,154
% Oil and liquids	58	65	65	61	67
Commodity prices realized (before pipeline tariffs)					
Oil and liquids (\$/bbl)	76.30	86.89	89.54	106.16	74.04
Natural gas (\$/mcf)	1.89	1.72	2.95	5.75	4.22
Total (\$/boe)	48.85	60.43	64.48	77.88	57.83
Operating netback ⁽⁵⁾ (\$/boe)	24.10	30.14	34.41	45.28	33.94
Funds from operations netback (\$/boe) ⁽¹⁾	20.79	27.60	31.25	39.84	31.61
Net wells drilled	14.0	14.0	16.0	17.0	14.0
Net acres of land at end of period	288,609	265,397	285,480	224,578	256,346

⁽¹⁾ Funds flow from operations and funds flow from operations netback does not have a standardized meaning prescribed by IFRS. See Non-IFRS Measurements section of the MD&A.

⁽²⁾ Capital expenditures does not have a standardized meaning prescribed by IFRS. See Non-IFRS Measurements section of the MD&A.

⁽³⁾ Working capital surplus (deficiency) does not have a standardized measure prescribed by IFRS. See Non-IFRS Measurements section of the MD&A.

⁽⁴⁾ Boe conversion is 6:1.

⁽⁵⁾ Operating netback does not have a standardized meaning prescribed by IFRS. See Non-IFRS Measurements section of the MD&A.



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INDEPENDENT AUDITOR'S REPORT

To the Shareholders and Board of Directors of North 40 Resources Ltd.

Opinion

We have audited the financial statements of North 40 Resources Ltd. (the Company), which comprise:

- the statement of financial position as at December 31, 2025
- the statement of net income (loss) and comprehensive income (loss) for the year then ended
- the statement of changes in equity for the year then ended
- the statement of cash flows for the year then ended
- and notes to the financial statements, including a summary of material accounting policy information

(Hereinafter referred to as the “financial statements”).

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2025, and its financial performance and its cash flows for the year then ended in accordance with IFRS Accounting Standards as issued by the International Accounting Standards Board.

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the “***Auditor’s Responsibilities for the Audit of the Financial Statements***” section of our auditor’s report.

We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and we have fulfilled our other ethical responsibilities in accordance with these requirements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.



Other Information

Management is responsible for the other information. Other information comprises:

- the information, other than the financial statements and the auditor's report thereon, included in Management's Discussion and Analysis.

Our opinion on the financial statements does not cover the other information and we do not and will not express any form of assurance conclusion thereon.

In connection with our audit of the financial statements, our responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the financial statements or our knowledge obtained in the audit and remain alert for indications that the other information appears to be materially misstated.

We obtained the information, other than the financial statements and the auditor's report thereon, included in Management's Discussion and Analysis as at the date of this auditor's report.

If, based on the work we have performed on this other information, we conclude that there is a material misstatement of this other information, we are required to report that fact in the auditor's report.

We have nothing to report in this regard.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with IFRS Accounting Standards as issued by the International Accounting Standards Board, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Company's ability to continue as a going concern, disclosing as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company's financial reporting process.

Auditor's Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion.

Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists.

Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial statements.



As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit.

We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion.

The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Company to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

A handwritten signature in black ink that reads 'KPMG LLP'. The signature is written in a cursive, slightly slanted style. Below the signature is a horizontal line that starts under the 'K' and ends under the 'P'.

Chartered Professional Accountants

Calgary, Canada
March 30, 2026

NORTH 40

RESOURCES LTD.

**Financial Statements
For the year ended December 31, 2025**

North 40 Resources Ltd.

Statements of Financial Position

As at	December 31 2025	December 31 2024
<i>(\$ thousands)</i>		
ASSETS		
Current Assets		
Cash	-	5,710
Accounts receivable	11,086	13,261
Current income taxes (Note 10)	-	959
Prepays and deposits	957	839
Total Current Assets	12,043	20,769
Deposit on asset acquisition bid (Note 5)	300	1,200
Exploration and evaluation assets (Notes 4, 5 and 6)	6,606	15,927
Property, plant and equipment (Notes 5, 6 and 7)	150,470	185,931
Total Assets	169,419	223,827
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts payable and accrued liabilities	14,190	29,134
Current income taxes (Note 10)	237	-
Decommissioning obligations (Note 11)	435	-
Bank debt (Note 9)	10,339	-
Total Current Liabilities	25,201	29,134
Lease liabilities	192	184
Decommissioning obligations (Note 11)	30,042	9,115
Deferred income taxes (Note 15)	1,307	18,659
Total Liabilities	56,742	57,092
Shareholders' Equity		
Share capital (Note 12)	77,169	76,245
Contributed surplus	5,818	5,806
Retained earnings	29,690	84,684
Total Shareholders' Equity	112,677	166,735
Total Liabilities and Shareholders' Equity	169,419	223,827

Subsequent Events (Notes 5 and 12)

The accompanying notes are an integral part of these Financial Statements.

Approved on behalf of the Board:



Margaret McKenzie, Director



Tyson Birchall, Director

North 40 Resources Ltd.

Statements of Net Income (Loss) and Comprehensive Income (Loss)

	Years ended December 31	
	2025	2024
<i>(\$ thousands except per share amounts)</i>		
Revenue		
Petroleum and natural gas revenue (Note 13)	122,973	109,105
Less: Royalties	24,535	23,079
	98,438	86,026
Interest income	34	251
	98,472	86,277
Expenses		
Operating	29,217	24,784
Transportation	5,431	4,424
General and administrative	6,864	4,297
Share based compensation (Note 12)	883	1,034
Depletion and depreciation (Note 7)	47,120	36,275
Exploration expense (Note 4)	12,144	4,970
Impairment (Note 8)	62,159	-
Impairment on disposition (Note 6)	4,479	-
Finance expense	1,325	537
Total expenses	169,622	76,321
Income (loss) before taxes	(71,150)	9,956
Current income tax expense (Note 10)	1,196	488
Deferred income tax expense (recovery) (Note 15)	(17,352)	2,066
Income taxes	(16,156)	2,554
Net Income (Loss) and Comprehensive Income (Loss)	(54,994)	7,402
Net Income (Loss) per share (Note 14)		
Basic	\$(0.71)	\$0.10
Diluted	\$(0.71)	\$0.09

The accompanying notes are an integral part of these Financial Statements.

North 40 Resources Ltd.
Statements of Changes in Equity

	Share Capital	Contributed Surplus	Retained Earnings	Total Equity
<i>(\$ thousands)</i>				
Balance as at December 31, 2023	76,245	4,661	77,282	158,188
Net income	-	-	7,402	7,402
Share based compensation (Note 12)	-	1,145	-	1,145
Balance as at December 31, 2024	76,245	5,806	84,684	166,735
Balance as at December 31, 2024	76,245	5,806	84,684	166,735
Net loss	-	-	(54,994)	(54,994)
Transferred on conversion of Class B's and C's	924	(924)	-	-
Share based compensation (Note 12)	-	936	-	936
Balance as at December 31, 2025	77,169	5,818	29,690	112,677

The accompanying notes are an integral part of these Financial Statements.

North 40 Resources Ltd.

Statements of Cash Flows

	Years ended December 31	
	2025	2024
<i>(\$ thousands)</i>		
Cash provided by (used in):		
Operating activities		
Net income (loss) for the year	(54,994)	7,402
Adjusted for:		
Depletion and depreciation (Note 7)	47,120	36,275
Exploration expense (Note 4)	12,144	4,970
Impairment (Note 8)	62,159	-
Impairment on disposition (Note 6)	4,479	-
Accretion expense (Note 11)	586	271
Share based compensation (Note 12)	883	1,034
Deferred income tax expense (recovery) (Note 15)	(17,352)	2,066
	55,025	52,018
Decommissioning expenditures (Note 11)	-	(78)
Change in non-cash working capital (Note 17)	4,443	(5,372)
	59,468	46,568
Financing activities		
Increase in bank debt (Note 9)	10,339	-
Repayment of lease liabilities	(13)	(115)
	10,326	(115)
Investing activities		
Deposit paid on acquisition bid	900	(1,200)
Exploration and evaluation expenditures (Note 4)	(7,330)	(10,744)
Property, plant and equipment expenditures (Note 7)	(52,118)	(57,681)
Acquisitions (Note 5)	(27,822)	-
Proceeds from dispositions (Note 6)	27,000	15,550
Change in non-cash working capital (Note 17)	(16,134)	5,296
	(75,504)	(48,779)
Change in cash	(5,710)	(2,326)
Cash, beginning of year	5,710	8,036
Cash, end of year	-	5,710
Cash income tax paid	-	976
Interest paid	\$432	-

The accompanying notes are an integral part of these Financial Statements.

North 40 Resources Ltd.

Notes to the Financial Statements

December 31, 2025, and 2024 (*all tabular amounts in thousands of Canadian \$, except per share amounts or as otherwise indicated*)

1. CORPORATE INFORMATION

North 40 Resources Ltd. (the "Company" or "North 40"), is a privately held oil and gas exploration and development company incorporated in the province of Alberta, Canada on October 16, 2007. The address of the principal place of business is 400, 215 – 9th Avenue SW, Calgary, Alberta, Canada T2P 1K3.

The Company explores, acquires, develops, and produces oil and natural gas reserves in the Western Canadian Sedimentary Basin.

2. BASIS OF PRESENTATION

(a) Statement of Compliance

These financial statements have been prepared by management in accordance with IFRS Accounting Standards as issued by the International Accounting Standards Board ("IASB").

These financial statements have been prepared using the accounting policies and methods as described in Note 3 below.

These financial statements were approved and authorized for issuance by the Board of Directors on March 30, 2026.

(b) Basis of measurement

These financial statements have been prepared on a going concern basis under the historical cost basis, which contemplates the realization of assets and settlement of liabilities in the normal course of business as they become due.

(c) Functional and presentation currency

These financial statements are presented in Canadian dollars, which is the Company's functional currency.

(d) Use of estimates and judgements

The preparation of financial statements in conformity with IFRS Accounting Standards as issued by the IASB requires management to make judgements, assumptions and estimates that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and revenues and expenses for the periods reported. Actual results may differ from such estimates. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future years affected.

Significant estimates and judgements made by management in the preparation of financial statements are outlined below.

(i) Decommissioning obligations

Decommissioning obligations and the related accretion expense require the use of estimates with respect to the amount and timing of decommissioning expenditures. Actual costs and cash outflows can differ from estimates because of changes in laws and regulations, market conditions, discovery and analysis of site conditions and changes in technology. Changes to assumptions related to future expected costs, discount rates and timing may have a material impact on the amounts presented.

(ii) Impairment indicators

Judgements are required to assess when internal or external impairment indicators or indicators of impairment reversal exist and impairment testing is required. In determining the recoverable amount of property, plant and equipment, which includes petroleum and natural gas assets, impairment tests are based on estimates of proved and probable oil and natural gas reserves, which are based upon a number of significant assumptions, such as forecasted production volumes, forecasted oil and natural gas commodity prices, forecasted operating costs, forecasted royalty costs and forecasted future development costs. The estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. Assets are grouped into CGUs for purposes of impairment assessment.

(iii) Income taxes

Tax regulations and legislation and the interpretations thereof are subject to change. The deferred income tax calculation recognizes the extent that temporary differences will be realized (asset) or payable (liability) in future periods. The calculation of deferred income tax involves a significant amount of estimation including an evaluation of when the temporary differences will reverse an analysis of the amount of future taxable income and the application of tax laws. Changes in tax regulations and legislation and the other assumptions listed are subject to measurement uncertainty.

(iv) Exploration and evaluation assets

The application of the Company's accounting policy for exploration and evaluation assets requires management to make certain judgements in determining whether it is likely that future economic benefits exist when activities have not reached a stage where technical feasibility and commercial viability can be reasonably determined.

(v) Reserves

Estimates of recoverable quantities of proved and probable reserves include estimates and assumptions regarding production volumes, future commodity prices, exchange rates, discount rates, timing of future development costs and production and transportation costs for future cash flows as well as the interpretation of complex geological and geophysical models and data. Changes in reported reserves can affect the impairment of assets, the reported amount of decommissioning obligations, the economic feasibility of exploration and evaluation assets and the amounts reported for depletion of property and equipment. Reserves estimates were prepared by internal engineers in accordance with definitions prescribed by the Canadian Oil and Gas Evaluations Handbook and National Instrument 51-101.

(vi) Business combinations

In a business combination, management makes estimates of the fair value of assets acquired and liabilities assumed which includes assessing the value of petroleum and natural gas properties based upon the estimation of recoverable quantities of proved and probable oil and natural gas reserves being acquired. An acquisition date fair value of petroleum and natural gas properties involves significant estimates, including the estimate of proved and probable oil and natural gas reserves and the related cash flows and discount rates.

(vii) Share-based compensation

Share based compensation recorded pursuant to share based compensation plans are subject to estimated fair values based on estimated share price, risk free interest rate, forfeiture rates, volatility, and the future attainment of performance criteria, if any.

3. MATERIAL ACCOUNTING POLICIES

(a) Exploration and Evaluation Assets

(i) Capitalization

All costs incurred after the rights to explore an area have been obtained, such as geological and geophysical costs, other direct costs of exploration (drilling, testing, and evaluating the technical feasibility and commercial viability of extraction) and appraisal, are accumulated and capitalized as exploration and evaluation assets.

Costs incurred prior to acquiring the legal rights to explore are expensed as incurred.

(ii) Depletion

Exploration and evaluation costs are not depleted prior to the conclusion of appraisal activities. At the completion of appraisal activities, if technical feasibility is demonstrated and commercial reserves are discovered, then the carrying value of the relevant exploration and evaluation asset will be reclassified as a petroleum and natural gas asset into the CGU to which it relates, but only after the carrying value of the relevant exploration and evaluation asset has been assessed for impairment and, where appropriate, its carrying value adjusted. The technical feasibility and commercial viability of extracting a resource is determinable based on several factors including the assignment of proved and probable reserves, completion of drilling and testing. Upon determination, exploration and evaluation costs attributable to those reserves are reclassified to depletable property and equipment. If it is determined that technical feasibility and commercial viability have not been achieved in relation to the exploration and evaluation assets appraised, all other associated costs are written down to the recoverable amount in net income.

Expired land leases included as undeveloped land in exploration and evaluation assets are recognized in exploration and evaluation cost in net income upon expiry.

(iii) Impairment

If and when facts and circumstances indicate that the carrying value of an exploration and evaluation asset may exceed its recoverable amount, an impairment review is performed. For exploration and evaluation assets, when there are such indications, an impairment test is carried out. In addition, exploration and evaluation assets are tested for impairment when they are transferred to property and equipment. The equivalent carrying value of the CGU is compared against the recoverable amount of the CGU and any resulting impairment loss is written off to net income. The recoverable amount is the greater of fair value, less costs to sell, or value in use.

Impairments of exploration and evaluation assets are only reversed when there is significant evidence that the impairment has been reversed but only to the extent of what the carrying amount would have been had no impairment been recognized.

(b) Property, Plant and Equipment

(i) Capitalization

The Company's property, plant and equipment, which include oil and natural gas development and production assets, are measured at cost less accumulated depletion and depreciation and accumulated impairment losses. The development and production assets are grouped into CGUs for the purpose of impairment testing.

The initial cost of an asset comprises its purchase price or construction cost, any costs directly attributable to bringing the asset into operation, the initial estimate of any decommissioning liability, if any, and for qualifying assets, borrowing costs. The purchase price or construction cost is the aggregate amount paid and the fair value of any other consideration given to acquire the asset. Non-monetary exchanges of assets are measured at fair value unless the exchange transaction lacks commercial substance or the fair value of neither the asset received, nor the asset given up is reliably measurable. The cost of the acquired asset is measured at the fair value of the asset given up unless the fair value of the asset received is more reliable. The gain or loss on derecognition of the asset given up is recognized in net income.

Expenditures on major maintenance, inspections or overhauls are capitalized when the item enhances the life or performance of an asset above its original standard. Where an asset or part of an asset that was separately depreciated is replaced and it is probable that future economic benefits associated with the item will flow to the Company, the expenditure is capitalized and the carrying amount of the replaced asset is derecognized. All other maintenance expenditures are expensed as incurred.

(ii) Depletion and Depreciation

The net carrying amount of development and production assets is depleted using the unit-of-production method by reference to the ratio of production in the period to the related proved plus probable reserves, taking into account estimated future development costs necessary to bring those reserves into production. These estimates are reviewed at least annually.

Proved and probable reserves are estimated annually using internal reserve engineering reports in accordance with Canadian Oil and Gas Evaluation Handbook (COGE) and represent the estimated quantities of crude oil and natural gas which geological, geophysical, and engineering data demonstrate with a specified degree of certainty to be recoverable in future years from known reservoirs and which are considered commercially producible. There should be a 50 percent statistical probability that the actual quantity of recoverable reserves will be more than the amount estimated as proved and probable and a 50 percent statistical probability that it will be less. The equivalent statistical probabilities for the proved component of proved and probable reserves are 90 percent.

Such reserves may be considered commercially producible if management has the intention of developing and producing them and such intention is based upon a reasonable assessment of the future economics of such production, a reasonable expectation that there is a market for all or substantially all the expected crude oil and natural gas production, and evidence that the necessary production, transmission and transportation facilities are available or can be made available.

Corporate assets are stated in the statement of financial position at cost less accumulated depreciation. Depreciation is calculated on a declining balance method to write off costs of these assets, less estimated residual values, over their estimated residual lives. The useful lives of the Company's corporate assets are as follows:

Depreciation methods, useful lives and residual values are reviewed at least annually.

(iii) Impairment

The carrying amounts of the Company's property, plant and equipment are reviewed at each reporting period to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated.

For the purpose of impairment testing, assets are grouped into CGUs, the smallest group of assets that generate cash inflows from continuing use that are largely independent from the cash inflows of other assets or groups of assets. The recoverable amount of a CGU is the greater of its value in use and its estimated fair value less costs to sell.

In estimating value in use, the projected future cash flow from proved and probable reserves and undeveloped properties are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and risks specific to the assets.

Fair value less cost to sell is determined as the amount that would be obtained from the sale of a CGU in an arm's length transaction between knowledgeable and willing parties. The fair value less costs to sell of oil and gas assets is generally determined as the net present value of the estimated future cash flows expected to arise from the CGU. These cash flows are discounted by an appropriate discount rate which would be applied by such a market participant to arrive at a net present value of the CGU.

An impairment loss is recognized if the carrying amount of an asset or CGU exceeds its estimated recoverable amount. Impairment losses are recognized in the statement of income (loss) and comprehensive income (loss). Impairment losses recognized in respect of CGUs are allocated to reduce the carrying amounts of the assets in the unit on a pro rata basis.

(c) Provisions

A provision is recognized if, as a result of a past event, the Company has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flow at a pretax rate that reflects current market assessments of the time value of money and the risks specific to the liability. Provisions are not recognized for future operating losses.

a. Decommissioning Obligations

The Company's activities give rise to dismantling, decommissioning, and site disturbance remediation activities. Provisions are made for the estimated costs of abandonment and site restoration and capitalized to the relevant asset category.

Decommissioning obligations are measured at the present value of management's best estimate of the expenditure required to settle the present obligation at the date of the statement of financial position, using a risk free discount rate. Subsequent to initial measurement the obligation is adjusted at the end of each period to reflect the passage of time and changes to the estimated future cash flows underlying the obligation.

The increase in the provision due to the passage of time (accretion) is recognized as finance expense whereas increases or decreases due to changes in the estimated future cash flows are capitalized. Actual costs incurred upon settlement of the decommissioning obligations are charged against the provision to the extent the provision was established.

(d) Business Combinations

Business combinations are accounted for using the acquisition method of accounting in which identifiable assets acquired, and liabilities assumed in a business combination are recognized and measured at their fair value at the date of acquisition. If the cost of the acquisition is less than the fair value of the net asset acquired, the difference is recognized in net income. If the cost of the acquisition is greater than the fair value of the net assets acquired, the difference is recognized as goodwill.

(e) Financial Instruments

Recognition and Measurement

Trade receivables issued are initially recognized when they are originated. All other financial assets and financial liabilities are initially recognized when the Company becomes a party to the contractual provisions of the instrument.

A financial asset or liability (unless it is a trade receivable without a significant financing component) is initially measured at fair value plus, for an item not at fair value through profit or loss, transaction costs that are directly attributable to its acquisition or issue. A trade receivable without a significant financing component is initially measured at the transaction price.

Classification of Financial Assets and Liabilities

IFRS 9 contains three principal classification categories for financial assets: measured at amortized cost, fair value through other comprehensive income (FVOCI), or fair value through profit or loss (FVTPL). The classification of financial assets under IFRS 9 is generally based on the business model in which a financial asset is managed and its contractual cash flow characteristics.

The following table shows the original measurement categories under IFRS 9 for each class of the Company's financial assets and financial liabilities.

Financial Instrument	Measurement Category	
	Classification	Subsequent Measurement
Cash	Amortized cost	Amortized cost using effective interest method
Accounts receivables	Amortized cost	Amortized cost using effective interest method
Accounts payable and accrued liabilities	Amortized cost	Amortized cost using effective interest method
Bank debt	Amortized costs	Amortized cost using effective interest method

(f) Share Based Compensation Expense

The fair value of share-based compensation granted to directors, officers, employees, and consultants is measured on the issue date using the Black Scholes pricing model. The fair value is subsequently recognized as share-based compensation expense over the vesting period with a corresponding increase to contributed surplus. Upon conversion of the Class B and Class C shares to common shares, consideration paid by the Class B and Class C shareholders and the value in contributed surplus pertaining to the converted Class B and Class C shares and options are recorded as share capital. A forfeiture rate is estimated on the issue date with the difference between the estimated and actual forfeitures adjusted through share-based compensation expense.

(g) Revenues

Revenue Recognition

Under IFRS 15, revenue from the sale of crude oil, natural gas and natural gas liquids is measured based on the consideration specified in contracts with customers and recognizes revenue when it transfers control of the product to the purchaser. This is generally at the time the customer obtains legal title to the product and when it is physically transferred to the delivery mechanism agreed with the purchaser, often pipelines or other transportation methods.

(h) Income Taxes

Income tax expense is comprised of current and deferred tax. Income tax expense is recognized in income or loss except to the extent that it relates to items recognized directly in equity, in which case it is recognized in equity. Deferred income tax assets and liabilities are recognized as non-current.

Current tax is the expected tax payable in respect of taxable income, using tax rates enacted or substantially enacted at the reporting date as well as adjustments to tax payable in respect of previous years. Deferred tax is recognized using the balance sheet method whereby temporary differences between carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes are calculated. Deferred tax is not recognized on the initial recognition of assets or liabilities in a transaction that is not a business combination. In addition, deferred tax is not recognized for taxable temporary differences arising on the initial recognition of goodwill. Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted at the reporting date. Deferred tax assets are recognized to the extent that it is probable that future taxable profits will be available against which the temporary difference can be utilized. Deferred tax assets are reviewed at each reporting date and reduced to the extent that it is no longer probable that the related tax benefit will be realized.

Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset and they relate to income taxes levied by the same tax authority on the same taxable entity, or on different taxable entities, when the intent is to settle current tax assets and liabilities on a net basis or the tax assets and liabilities are expected to be realized simultaneously.

(i) Earnings Per Share

Earnings per share is presented for basic and diluted earnings. Basic per share information is computed by dividing the net income (loss) for the period attributable to equity owners of the Company by the weighted average number of common shares outstanding during the period. The weighted average number of common shares for diluted earnings per share information is calculated using the treasury stock method whereby it is assumed that proceeds obtained upon exercise of Class B and Class C shares and options issued under the Company's Share-Based Compensation Plan would be used to purchase common shares at the average market price during the period. Under the treasury stock method share-based compensation plans have a dilutive effect only when the average market price of the common shares during the period exceeds the exercise price of the shares (shares are "in-the-money"). Exercise of in-the-money Class B and Class C shares and options is assumed at the beginning of

the year or date of issuance, if later. Should the Company have a net loss for the period, Class B and Class C shares would be anti-dilutive and therefore will have no effect on the determination of loss per share.

(j) Future Accounting Pronouncements

In May 2024, the IASB issued amendments to IFRS 9 Presentation and Disclosure in Financial Instruments and IFRS 7 Financial Instruments: Disclosures relating to settling financial liabilities using an electronic payment system and assessing contractual cash flow characteristics of financial assets. The amendments are effective January 1, 2026, but will not have a material impact on the Company's financial statements.

In April 2024, the IASB issued IFRS 18 Presentation and Disclosure in Financial Statements, which will replace International Accounting Standard 1 Presentation of Financial Statements. IFRS 18 will establish a revised structure for the Statement of Net Income (Loss) and Comprehensive Income (Loss) and improve comparability across entities and reporting periods. IFRS 18 is effective for annual reporting periods beginning on or after January 1, 2027, with early adoption permitted. The standard is to be applied retrospectively, with certain transition provisions. The Company is currently evaluating the impact of adopting IFRS 18 on its financial statements.

4. EXPLORATION AND EVALUATION ASSETS

(\$)	December 31 2025	December 31 2024
Balance, beginning of year	15,927	19,275
Acquisitions (Note 5)	26,349	-
Additions	7,330	10,744
Dispositions (Note 6)	(23,004)	(4,956)
Exploration expense	(12,143)	(4,970)
Transferred to property, plant and equipment (Note 7)	(7,853)	(4,166)
Balance, end of year	6,606	15,927

Exploration and evaluation ("E&E") assets consist of the Company's undeveloped land, geological and geophysical assets and exploration drilling projects in which technical feasibility or commercial viability has yet to be determined.

Exploration expense in 2025 relates to undeveloped land expiries and costs related to drilling two test evaluation wells in prior years.

5. ACQUISITIONS

2025

On November 20, 2025, the Company completed the acquisition of certain crude oil and natural gas properties in Sheerness (Aerial) and related infrastructure for cash consideration of \$15.4 million. The effective date of the acquisition was October 1, 2025. The acquisition has been accounted for as a business combination under IFRS 3. Petroleum and natural gas revenues of \$0.4 million and net operating income of \$0.3 million were included in the statement of net income (loss) and comprehensive income (loss) from the closing date of November 20, 2025, to December 31, 2025. If the acquisition had occurred on January 1, 2025, the estimated incremental petroleum and natural gas revenues and net operating income for the year ended December 31, 2025, would have been \$5.3 million and \$3.2 million, respectively.

The following purchase price allocation was based on the asset acquired and the liabilities assumed:

(\$)	As at November 20, 2025
Net assets (liabilities) acquired	
Exploration and evaluation assets	11,999
Property, plant & equipment	7,880
Decommissioning obligations	(4,449)
Net assets acquired	15,430
Consideration	
Cash	15,430
Total consideration	15,430

The acquisition date fair value attributed to property, plant and equipment was derived from the estimate of proved and probable oil and gas reserves and the related cash flows utilizing discount rates between 10% and 20%. The fair value of the decommissioning obligations was initially estimated using a discount rate of 9%. The exploration and evaluation assets fair value was determined based on future net cash flows to be derived from potential drilling locations from undeveloped lands.

On January 13, 2025, the Company completed the acquisition of certain crude oil and natural gas properties in Sheerness (Aerial), primarily inactive wells and related infrastructure, with minimal current production for cash consideration of \$12.4 million. The effective date of the acquisition was January 13, 2025. The acquisition has been accounted for as an asset acquisition as the acquired assets did not meet the definition of a business.

The following purchase price allocation was based on the asset acquired and the liabilities assumed:

(\$)	As at January 13, 2025
Net assets (liabilities) acquired	
Exploration and evaluation assets	14,350
Property, plant & equipment	3,839
Decommissioning obligations	(5,797)
Net assets acquired	12,392
Consideration	
Cash	12,392
Total consideration	12,392

A deposit of \$1.2 million was paid in 2024 in connection with this acquisition.

The Company has entered into a purchase and sale agreement for \$3.0 million which is subject to customary closing adjustments and closed in Q1 2026. A deposit of \$300,000 was paid in 2025 related to this agreement. The assets were financed by persons related to a director and an arm's length party in exchange for a royalty interest and infrastructure volumetric payment.

2024

On December 19, 2024, the Company closed an acquisition of a 50% working interest in a natural gas plant and related infrastructure in Sheerness (Michichi). As consideration for the assets, the Company paid \$6.3 million cash and a 50% working interest in a segment of a pipeline. The Company incurred transaction costs of \$0.1 million which were capitalized to property, plant and equipment.

The Company assessed the transaction using the concentration test in accordance with IFRS 3 and accounted for the acquisition as an asset acquisition. The purchase price was allocated as follows:

(\$)	
Net assets (liabilities) acquired	
Property, plant & equipment	7,582
Decommissioning obligations	(146)
Net assets acquired	7,436
Consideration	
Cash	6,250
Interest in a pipeline	1,050
Transaction costs	136
Total consideration and transaction costs	7,436

6. DISPOSITIONS

2025

In Q4 2025, the Company sold a royalty interest and infrastructure volume payment on future production from certain lands in Sheerness (Aerial) included in the acquisition described in Note 5 (November 20, 2025). Proceeds from the sale were \$15.0 million and were allocated to E&E assets (\$11.7 million) and to property plant and equipment (\$3.3 million). There was no gain or loss recognized on the disposition.

Persons related to a directors purchased a portion of these interests for proceeds totalling \$5.6 million. An arm's length third party purchased the remainder of these interests.

North 40 entered into a purchase and sale agreement on June 4, 2025, for the disposition of its non-core Entice assets for \$0.3 million in cash (\$0.2 million after final adjustments). In Q2 2025 the Company determined the closing was highly probable and reclassified the Entice assets to asset held for sale. Reclassification of the assets resulted in recognition of an impairment on disposition of \$4.5 million based on the sales price. The transaction closed on July 30, 2025.

In Q1 2025, the Company sold a royalty interest and infrastructure volume payment on future production from certain lands in Sheerness (Aerial) included in the acquisition described in Note 5 (January 13, 2025). Proceeds from the sale were \$12.0 million

and were allocated to E&E assets (\$11.3 million) and to property plant and equipment (\$0.7 million). There was no gain or loss recognized on the disposition.

Persons related to two directors purchased a portion of these interests for proceeds totalling \$6.0 million. An arm's length third party purchased the remainder of these interests.

2024

In Q4 2024, the Company sold a royalty interest and an infrastructure volumetric payment on current and future production from certain lands in Sheerness (Michichi) area.

In this area, the Company purchased a 50% interest in a natural gas plant as described in Note 5, constructed an oil battery and began construction on a natural gas pipeline to connect the oil battery to the natural gas plant. Production volume processed at the infrastructure described are subject to the infrastructure volumetric payment.

Proceeds from the sale were \$15.6 million and were allocated to E&E assets (\$5.0 million) and to property plant and equipment (\$10.6 million). There was no gain or loss recognized on the disposition.

Two of the Company's directors and persons related to those directors purchased a portion of these interests for proceeds totalling \$7.8 million. An arm's length third party purchased the remainder of these interests.

7. PROPERTY, PLANT AND EQUIPMENT

(\$)	December 31 2025	December 31 2024
Property, plant and equipment, at cost	425,259	346,933
Accumulated depletion, impairment and depreciation	(274,789)	(161,002)
Net book value, end of year	150,470	185,931
Reconciliations of movements during the year:		
Cost, beginning of year	346,933	294,109
Accumulated depletion and depreciation, beginning of year	(161,002)	(124,727)
Net book value, beginning of year	185,931	169,382
Additions	52,349	50,500
Acquisitions (Note 5)	11,719	7,582
Right-of-use assets	-	188
Dispositions (Note 6)	(4,181)	(10,593)
Transferred from exploration and evaluation assets (Note 4)	7,853	4,166
Changes in decommissioning obligations (Note 11)	10,557	981
Depletion and depreciation	(47,120)	(36,275)
Impairment (Note 8)	(62,159)	-
Impairment on disposition (Note 6)	(4,479)	-
Net book value, end of year	150,470	185,931

Included in the calculation of depletion was an estimate for future development costs of \$124.7 million at December 31, 2025 (\$105.6 million at December 31, 2024). An estimated future salvage value of \$12.8 million was excluded from the calculation of depletion at December 31, 2024 (\$9.3 million at December 31, 2024).

Included in the December 31, 2025, property, plant and equipment balance is the right-of-use asset of \$0.2 million (\$0.2 million at December 31, 2024).

Included in additions is capitalized general and administrative expenses of \$0.4 million (\$0.5 million in 2024).

8. IMPAIRMENT

(\$)	December 31 2025	December 31 2024
Impairment of property, plant and equipment	62,159	-

North 40 has one CGU as of December 31, 2025. At December 31, 2025, indicators of impairment were identified due to a lower commodity price environment and negative technical revisions for crude oil. As a result, an impairment test was performed. The recoverable value was estimated at fair value less costs to sell based on before tax discounted cash flows from proved and probable oil and gas reserves, based on the underlying composition of reserve categories.

At December 31, 2025, it was determined that the carrying value exceeded the estimated recoverable amount and a \$62.2 million impairment was recognized. The before tax discount rate applied in the calculation ranged between 10% and 20% depending on the reserve category.

The results of the impairment tests are sensitive to changes in any of the key significant assumptions including forecasted oil and commodity prices, forecasted production volumes, forecasted operating costs, royalty costs and future development costs which impact the estimate of cash flows from proved and probable oil and gas reserves, in addition to the discount rate, of which changes could increase or decrease the estimated recoverable amount of the CGU and result in additional impairment charges or in the recovery of previously recorded impairment charges. All estimates are subject to uncertainty.

The following table outlines forecasted oil and natural gas prices and exchange rates used in the Company's impairment test as at December 31, 2025. The forecasted oil and natural gas prices are based on those used by the independent third-party external reserve evaluator at December 31, 2025, and are a key assumption in assessing the recoverable amount.

Year	Oil			Gas		
	WTI Cushing Oklahoma (\$US)	Edmonton Light (\$C)	N40 Oil Price (\$C)	Henry Hub (\$US)	AECO Spot (\$C)	N40 Gas Price (\$C)
		(\$/bbl)			(\$/mmbtu)	
2026	59.92	77.54	69.64	3.74	3.00	2.80
2027	65.10	83.60	75.28	3.78	3.30	3.13
2028	70.28	90.17	81.27	3.85	3.49	3.32
2029	71.93	92.32	83.30	3.93	3.58	3.40
2030	73.37	94.17	84.97	4.01	3.65	3.46
2031	74.84	96.06	86.92	4.09	3.72	3.51
2032	76.34	97.98	88.63	4.17	3.80	3.59
2033	77.87	99.93	90.44	4.26	3.88	3.66
2034	79.42	101.93	92.25	4.34	3.95	3.75

2.0% per annum increase thereafter

A one percent change in the discount rate or a five percent change in the forward price over the life of the reserves would result in changes in impairment of \$3.8 million and \$20.0 million respectively.

9. CREDIT FACILITY

At December 31, 2025, the Company had a \$45.0 million revolving demand operating facility with a Canadian chartered bank. The facility bears interest based on the prime rate or Canadian Overnight Repo Rate Average ("CORRA") rates plus a margin. Interest rates applicable to draws and standby fees are based on a pricing margin grid and will change as a result of the ratio of net debt to cash flow as calculated in accordance with the credit facility agreement. Standby fees on undrawn amounts are currently 0.50%. The Company has a letter of credit outstanding for \$0.1 million at December 31, 2025, that reduces the amount otherwise available to be drawn on the operating facility.

The facility includes a financial covenant that requires the "Adjusted Working Capital" ratio (as defined in the credit agreement, with undrawn capacity under the facility included in the definition of current assets) be not less than 1.0 at each fiscal quarter end. The Company was in compliance with this covenant at December 31, 2025. Advances under the facility are secured by a first floating charge debenture and borrowings under the facility may be made by way of prime loans and CORRA loans. The credit facility is subject to periodic review at the lenders' discretion. The next review date has been set for on or before May 31, 2026.

At December 31, 2025, there was \$10.3 million drawn on the facility (nil at December 31, 2024).

10. CURRENT INCOME TAXES

(\$)	December 31 2025	December 31 2024
Balance, beginning of year	(959)	(487)
Current income tax expense	1,196	488
Payments ⁽¹⁾	-	(960)
Balance, end of year	237	(959)

⁽¹⁾ Includes instalments.

11. DECOMMISSIONING OBLIGATIONS

The Company's decommissioning obligations result from its responsibility to abandon and reclaim its net ownership interests in oil and natural gas assets including well sites, gathering systems and processing facilities. The Company estimates the total inflation adjusted and undiscounted amount of cash flows required to settle its decommissioning obligations is approximately \$64.3 million (\$30.2 million at December 31, 2024).

A reconciliation of the decommissioning obligations is provided below.

(\$)	December 31 2025	December 31 2024
Balance, beginning of year	9,115	7,644
Liabilities incurred	1,791	1,392
Liabilities acquired with acquisitions	10,247	146
Change in estimates	2,184	(260)
Change in discount rate on acquisition	6,753	-
Decommissioning expenditures	-	(78)
Obligations disposed	(199)	-
Accretion expense	586	271
Balance, end of year	30,477	9,115
Expected to be incurred within one year	435	-
Expected to be incurred beyond one year	30,042	9,115
Key assumptions		
Risk free rate	3.55%	3.35%
Inflation rate	2.00%	2.00%

12. SHARE CAPITAL

Authorized

Unlimited number of common voting shares ("common shares") without nominal or par value
Unlimited number of Class B common non-voting shares ("Class B") without nominal or par value
Unlimited number of Class C common non-voting shares ("Class C") without nominal or par value

Issued and Outstanding	December 31 2025		December 31 2024	
	Number	Amount	Number	Amount
Common Shares				
Balance, beginning of period	76,624	\$76,093	76,624	\$76,093
Issued on conversion of Class B's and C's	1,149	949	-	-
Balance, end of period	77,773	\$77,042	76,624	\$76,093
Class B Common Non-Voting Shares				
Balance, beginning of period	4,870	\$49	4,870	\$49
Converted to common shares	(1,100)	(11)	-	-
Balance, end of period	3,770	\$38	4,870	\$49
Class C Common Non-Voting Shares				
Balance, beginning of period	10,380	\$103	10,380	\$103
Converted to common shares	(715)	(7)	-	-
Forfeited	(715)	(7)	-	-
Balance, end of period	8,950	\$89	10,380	\$103
Total		\$77,169		\$76,245

Common Shares

Common shares are subject to the provisions and terms contained in Schedule A of the Company's Articles of Incorporation and to the provisions and terms of the respective share subscription agreements among the Company and its shareholders.

Class B Shares and Options on Class B Shares

Class B shares and options on Class B shares have been reserved for issue to directors, officers, employees, and consultants of the Company. The aggregate number of Class B shares and options issued may not exceed 10% of the issued and outstanding common shares of the Company.

Class B shares are convertible to common shares of the Company until expiry in September 2029 at an exercise price of \$1.00 per share. One third of the Class B shares purchased and options granted will vest equally on each of the second, third and fourth anniversary of the issue date. At December 31, 2025, 3,770,000 Class B shares and 1,106,417 options were vested (4,870,000 and 901,917 respectively at December 31, 2024).

The number and weighted average exercise price of the options on Class B shares are as follows:

	Number of Options	Weighted Average Exercise Price
Balance, January 1, 2024	1,732,000	\$0.77
Granted	565,000	1.00
Balance, December 31, 2024	2,297,000	\$0.83
Granted	245,000	1.40
Exercised	(370,858)	(0.89)
Forfeited	(134,142)	(1.07)
Balance, December 31, 2025	2,037,000	\$0.78

The fair market value of each Class B option granted in 2025 was estimated on the date of issue using the Black-Scholes pricing model and the following assumptions in the calculations:

Risk-free interest rate (%)	2.90
Expected life (years)	2.0- 3.0
Estimated volatility of underlying common shares (%)	60
Share Price (\$)	2.40
Estimated forfeiture rate (%)	nil

The Company recognized share-based compensation of \$673,986 related to the Class B shares and options for the year ended December 31, 2025 (\$362,666 in 2024) and capitalized \$25,482 (\$32,752 in 2024).

During the year, 1,100,000 Class B shares and 370,858 options on Class B shares were converted to common shares through a cashless exercise.

In November 2025, the Board of Directors extended the expiry of certain Class B shares and options to September 2029 from September 2026. The term extension is a modification under IFRS and requires an update to the calculation of share-based compensation expense. The incremental value of \$0.4 million was determined for the vested Class B shares and options and was immediately recognized in Q4 2025.

On January 1, 2026, the Company granted 815,000 options on Class B shares with an exercise price of \$1.80 per share to officers and employees.

Class C Shares and Options on Class C Shares

Class C shares and options on Class C shares have been reserved for issue to directors, officers, employees, and consultants of the Company. The aggregate number of Class C shares and options issued may not exceed 20% of the issued and outstanding common shares of the Company.

Class C shares are convertible to common shares of the Company if a liquidity event occurs before September 2029 at certain minimum price thresholds per share. A liquidity event includes the sale of all or substantially all of the common shares of the Company or assets for consideration that includes cash and/or securities, the liquidation of the Company, or any listing of the Company on a recognized exchange. The Class C shares were issued with various minimum price vesting and exercise price thresholds.

A summary of the number of Class C shares (assuming exercise of options on Class C shares) that vest and are convertible upon achieving price thresholds and at various exercise prices is as follows:

Number of Class C Shares Convertible	Liquidity Event Price Per Fully Diluted Share	Conversion Price Per Share
2,098,166	\$1.50	\$1.00
2,098,166	\$2.00	\$1.15
2,098,166	\$2.25	\$1.30
2,098,166	\$2.50	\$1.45
2,098,166	\$2.75	\$1.60
2,098,166	\$3.00	\$1.75

The number and weighted average exercise price of the options on Class C shares are as follows:

	Number of Options	Weighted Average Exercise Price
Balance, January 1, 2024	3,074,000	\$0.77
Granted	825,000	1.00
Balance, December 31, 2024	3,899,000	\$0.82
Granted	485,000	1.40
Exercised	(343,332)	(0.85)
Forfeited	(401,668)	(0.93)
Balance, December 31, 2025	3,639,000	\$0.77

The fair market value of each Class C option granted in 2025 was estimated on the date of issue using the Black-Scholes pricing model and the following assumptions in the calculations:

Risk-free interest rate (%)	2.90
Expected life (years)	2.5
Estimated volatility of underlying common shares (%)	60
Share Price (\$)	2.40
Estimated forfeiture rate (%)	nil

In addition, the Company assumed the probability of a liquidity event within the term to be 25% and the probability of achieving the price thresholds disclosed in the table above to be 95%, 90%, 90%, 85%, 85% and 80%, respectively.

The Company recognized share-based compensation expense of \$262,101 related to the Class C shares and options for the year ended December 31, 2025 (\$671,737 in 2024) and capitalized \$28,022 (\$78,124 in 2024).

In November 2025, the Board of Directors extended the expiry of certain Class C shares and options to September 2029. The term extension is a modification under IFRS and requires an update to share-based compensation expense. The incremental value of

\$0.6 million was determined and will be recognized over the estimated remaining expected term of 2.0 years. The Company recognized \$27,000 in Q4 2025.

During the period, 715,000 Class C shares and 343,332 options on Class C shares were converted to common shares through a cashless exercise.

On January 1, 2026, the Company granted 1,420,000 options on Class C shares with an exercise price of \$1.80 per share to officers and employees.

13. REVENUES

The Company produces crude oil, natural gas, and natural gas liquids from its assets in Alberta. The Company sells its production pursuant to variable-price physical delivery contracts. The transaction price for variable-price contracts is based on a benchmark commodity price, adjusted for quality, location or other factors whereby each component of the pricing component is fixed or variable, depending on the contract terms. Under the contracts, the Company is required to deliver fixed or variable quantities of crude oil, natural gas and natural gas liquids to the contract counterparty.

Petroleum and natural gas revenue is recognized when control is transferred from North 40 to its customers which is typically when the product enters the terminal or pipeline. Revenue is measured based on the consideration specified in a contract with the customer and the volumes delivered. North 40's revenue was generated in Alberta and sold to customers in the oil and natural gas business subject to normal credit terms and under customary industry sale and payment terms at monthly market prices. Contract terms are one year or less. Crude oil and natural gas revenues are collected on or about the 25th day of the month following production.

(\$)	December 31 2025	December 31 2024
Crude oil revenues	103,091	97,396
Natural gas revenues	10,361	5,497
Natural gas liquids revenues	9,521	6,212
Total	122,973	109,105

14. NET INCOME (LOSS) PER SHARE

	December 31 2025	December 31 2024
Net Income (loss) per share		
Basic	\$(0.71)	\$0.10
Diluted	\$(0.71)	\$0.09
Weighted average shares outstanding		
Basic	77,144	76,624
Diluted	83,884	83,965

15. INCOME TAXES

The following table reconciles the income tax expense computed by applying the Canadian statutory rate to the net income before income tax per the statement of net income and comprehensive income with the income tax expense recorded:

(\$ except statutory tax rate)	December 31 2025	December 31 2024
Net income (loss) before income tax	(71,150)	9,956
Canadian statutory income tax rate	23.00%	23.00%
Expected income tax at statutory rates	(16,365)	2,290
Add (deduct):		
Non-deductible share-based compensation and other	209	264
Provision for income tax	(16,156)	2,554
Current income tax	1,196	488
Deferred income tax	(17,352)	2,066

The components of deferred income tax at December 31, 2025, and 2024 are as follows:

(\$)	December 31 2025	December 31 2024
Deferred income tax liability:		
Capital assets carrying value in excess of tax value	(8,361)	(20,798)
	(8,361)	(20,798)
Deferred income tax asset:		
Decommissioning obligations	7,010	2,097
Other	44	42
	7,054	2,139
Deferred income tax	(1,307)	(18,659)

The Company had approximately \$120.7 million in available tax pools at December 31, 2025 (\$115.5 million at December 31, 2024).

16. KEY MANAGEMENT PERSONNEL

The Company considers its directors and executives to be key management personnel.

The key management personnel compensation was comprised of the following:

(\$)	December 31 2025	December 31 2024
Salaries and other short-term benefits	2,079	1,950
Share-based compensation	482	938
Total	2,561	2,888

For the year ended December 31, 2025, the share-based compensation includes \$0.3 million (\$0.6 million in 2024) related to modification to certain terms on the Class B and Class C shares and certain options on Class B and Class C shares as described in Note 12.

17. SUPPLEMENTAL CASH FLOW INFORMATION

Changes in non-cash working capital is comprised of the following:

(\$)	December 31 2025	December 31 2024
Source / (use) of cash:		
Accounts receivable	2,175	(1,568)
Prepaid expenses and deposits	(118)	197
Accounts payable and accrued liabilities	(14,944)	1,768
Current income taxes	1,196	(472)
Change in non-cash working capital	(11,691)	(75)
Related to:		
Operating activities	4,443	(5,372)
Investing activities	(16,134)	5,296

18. COMMITMENTS

(\$)	Within 1 year	After 1 year but not more than 5 years	Total
Firm transportation – natural gas	374	477	851
Office lease	195	445	640
Total	569	922	1,491

19. RELATED PARTIES

2025

In Q4 2025, the Company sold a royalty interest and an infrastructure volumetric payment on current and future production on certain lands in the Sheerness area for proceeds of \$15.0 million. Persons related to one of the Company's directors purchased a portion of these interests for proceeds totalling \$5.6 million. An arm's length third party purchased the remainder of these interests.

In Q1 2025, the Company sold a royalty interest and an infrastructure volumetric payment on current and future production on certain lands in the Sheerness area for proceeds of \$12.0 million. Persons related to two of the Company's directors purchased a portion of these interests for proceeds totalling \$6.0 million. An arm's length third party purchased the remainder of these interests.

2024

In 2024, the Company sold a royalty interest and an infrastructure volumetric payment on current and future production on certain lands in the Sheerness area for proceeds of \$15.6 million. Two of the Company's directors and persons related to those directors purchased a portion of these interests for proceeds totalling \$7.8 million. An arm's length third party purchased the remainder of these interests.

In 2024, the Company purchased mineral rights on a section of undeveloped land from a third party. Two directors and an arm's length third party funded the purchase in exchange for a royalty on future production from the land.

20. CAPITAL RISK MANAGEMENT

The Company's objectives when managing capital are to deploy capital to provide an appropriate return on shareholder investment and to maintain financial flexibility to execute on strategic opportunities and meet financial obligations. The Company manages its capital structure and makes adjustments to respond to changes in economic conditions and the risk characteristics of its underlying oil and natural gas assets.

The Company has entered into a Royalty Acquisition Agreement (the "agreement") with an arm's length party (the "party") whereby the party will fund certain crown land purchases incurred by the Company in exchange for a royalty on future production from those crown lands. The term of the agreement is to October 31, 2026. At December 31, 2025, there is \$2.2 million remaining on the funding limit.

The Company considers its capital structure to include shareholder's equity, the bank credit facility and working capital. In order to maintain or adjust the capital structure, the Company may from time to time issue new shares, draw on the bank credit facility and/or adjust its capital spending.

21. FINANCIAL RISK MANAGEMENT

Credit risk

The Company may be exposed to certain losses in the event that counterparties fail to meet their obligations in accordance with agreed terms. The Company mitigates this risk by entering into transactions with highly rated major financial institutions and by routinely assessing the financial strength of its customers.

At December 31, 2025, and December 31, 2024, financial assets on the statement of financial position are comprised of cash, current income tax and trade and other receivables and the maximum credit risk associated with these financial instruments is the total carrying amount of these financial assets.

Cash equivalents include short-term deposits placed with financial institutions with strong investment grade ratings.

Accounts receivable for crude oil and natural gas sales are collected on or about the 25th day of the month following production. At December 31, 2025, 90% of the accounts receivable amount relates to production revenue (96% at December 31, 2024).

Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they are due. The Company's approach to managing liquidity is to ensure that it will have sufficient liquidity to meet its liabilities when due, under both normal and stressed conditions. The Company utilizes authorizations for expenditures on both operated and non-operated projects to manage capital expenditures.

The Company's financial liabilities on the statement of financial position consist of trade and other payables.

The Company expects to satisfy obligations under trade and other payables in less than one year.

The Company has a \$45 million revolving demand operating facility with a Canadian chartered bank which could be accessed if required. At December 31, 2025, \$10.3 million was drawn on this facility.

Market risk

Market risk is comprised of currency risk, interest rate risk and commodity price risks which consist primarily of fluctuations in petroleum and natural gas prices. The valuation of the financial assets and liabilities on the statement of financial position as at December 31, 2025, and December 31, 2024, has not been significantly impacted by changes in currency rates. Currency rates influence petroleum and natural gas prices; however, this influence on commodity prices and the resulting impact on financial assets and liabilities cannot be accurately quantified.

Interest rate risk

The Company is exposed to interest rate risk to the extent that changes in market interest rates will impact any bank interest earned/indebtedness that has a floating interest rate, potentially affecting future cash flows. As a means to mitigating exposure to interest rate risk, the Company has the ability to enter into interest rate swap agreements. There were no outstanding contracts at December 31, 2025, and 2024.

Commodity price risk

The Company may be exposed to commodity price risk arising from the effect that fluctuations of future commodity prices may have on the fair value or future cash flows of financial assets and liabilities. There were no outstanding contracts at December 31, 2025, and 2024.

Corporate Information

OFFICERS

Don Robson
President and Chief Executive Officer

Kim Schoenroth
*Vice President Finance and Chief
Financial Officer*

Gerald Aleman
Vice President, Production

Calvin House
*Vice President, Land and Business
Development*

Preston Kraft
Vice President, Operations

Dermot O'Connor
Vice President, Exploration

Lonny Tetley
Corporate Secretary

DIRECTORS

Clayton Woitas
Executive Chairman

Tyson Birchall

Jeff Lebbert

Margaret McKenzie

Don Robson

Grant Zawalsky

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