

NORTH 40

RESOURCES LTD.

March 25, 2025

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, 2024. Fourth quarter and full year highlights include:

- Annual average production rate of 5,150 boe/day (65 % oil and liquids).
- Total annual operating revenue of \$ 56.8 mm.
- Realized Q4 2024 average quarterly production of 5,892 boe/day (65% oil and liquids).
- Executed a \$ 68.4 million capital program in 2024 investing in fourteen wells.
- Booked proved plus probable reserves of 16.0 mmmboe, a 14 % increase over the same period 2023. Realized a F&D cost of \$17.95 per boe.
- In December 2024 acquired a 50 % working interest in a gas plant to serve associated gas production from the 2-13 Michichi battery.
- Completed the 2-13 Michichi battery construction in December 2024 and the pipeline was connected to our North 40 gas plant in late January 2025.

North 40 drilled fourteen horizontal wells in 2024 with ten wells drilled in the first three quarters and four wells drilled in Q4 2024. The fourteen wells included six horizontal Banff wells at Drumheller, four horizontal Ellerslie wells at Michichi, two horizontal Ellerslie wells at Wayne, one horizontal Ellerslie well at Sheerness and one exploration multi-leg lower Mannville oil well at Tide Lake.

Q1 2025

Drilled six Ellerslie horizontal oil wells in the Sheerness project area consisting of five delineation / development wells around our Michichi oil pool and one exploratory discovery. The wells are recovering frack fluid, but early results are quite encouraging.

Our original view that the Ellerslie channels would respond well to fracked horizontal wells is correct.

The crude oil is light and the associated and non-associated natural gas is liquid rich.

Our central oil battery and gas plant have lowered well capital costs and operating costs.

Q2 to Q4 2025 Operations

Starting in June our operations will be primarily focused in our Sheerness prospect region.

Horizontal development /delineation wells will be drilled around our Ellerslie discoveries.

Exploratory drilling will test new Ellerslie prospects.

An active re-activation / re-completion program will be undertaken in our property acquisition that closed in January 2025. Ellerslie tests will be conducted as well as other formations that are prospective.

Our Sheerness area has significant potential.

The Board of Directors has approved a 2025 capital budget of \$82 mm with 12 wells planned for the remainder of 2025.

Current North 40 production is approximately 7,500 BOE/day with oil and liquids representing 62% of production.

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 25, 2025 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, 2024 and December 31, 2023, together with the accompanying notes, which have been prepared in accordance with IFRS Accounting Standards ("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.

(millions)	Three months ended		Year ended	
	December 31		December 31	
	2024	2023	2024	2023
Cash provided by operating activities	\$12,811	\$21,770	\$46,568	\$69,700
Plus: Decommissioning expenditures	-	-	78	-
Plus: (Less): Net change in non-cash working capital	1,901	(4,481)	5,372	2,894
Funds flow from operations	\$14,712	\$17,289	\$52,018	\$72,594

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.

Capital Expenditures

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

(thousands, except per unit amounts and where indicated)	Three Months Ended		Year Ended	
	December 31		December 31	
	2024	2023	2024	2023
FINANCIAL				
Petroleum and natural gas revenue	\$30,591	\$34,594	\$109,105	\$143,418
Funds flow from operations ⁽¹⁾	\$14,712	\$17,289	\$52,018	\$72,594
Per share – basic	\$0.19	\$0.23	\$0.68	\$0.95
Per share – diluted	\$0.18	\$0.21	\$0.63	\$0.90
Net income	\$3,494	\$ 945	\$7,402	\$20,134
Per share – basic	\$0.05	\$0.01	\$0.10	\$0.26
Per share – diluted	\$0.04	\$0.01	\$0.09	\$0.25
Capital expenditures (before dispositions) ⁽²⁾	\$27,847	\$21,512	\$68,425	\$85,716
Working capital deficiency ⁽³⁾ at end of period	\$8,365	\$6,114	\$8,365	\$6,114
Common shares outstanding at end of period	76,624	76,624	76,624	76,624
OPERATING				
Sales volumes				
Oil and liquids (bbls/day)	3,809	4,076	3,370	4,144
Natural gas (mcf/day)	12,498	14,052	10,679	13,317
Total (boe/day) ⁽⁴⁾	5,892	6,418	5,150	6,363
% Oil and liquids	65	64	65	65
Commodity prices realized (before pipeline tariffs)				
Oil and liquids (\$/bbl)	85.33	87.40	86.89	89.54
Natural gas (\$/mcf)	1.73	2.54	1.72	2.95
Total (\$/boe)	58.84	61.08	60.43	64.48
Operating netback ⁽⁵⁾ (\$/boe)	30.12	30.74	30.14	34.41
Funds from operations netback (\$/boe) ⁽¹⁾	27.14	29.28	27.60	31.25
Net wells drilled	4.0	4.0	14.0	16.0
Net acres of land at end of period	265,397	285,480	265,397	285,480

⁽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, 2024, includes \$5.7 million in cash (\$8.0 million at December 31, 2023).

⁽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	
	2024	2023	2024	2023
Oil (bbls per day)	3,425	3,665	3,049	3,795
Liquids (bbls per day)	384	411	321	349
Natural gas (mcf per day)	12,498	14,052	10,679	13,317
BOE per day	5,892	6,418	5,150	6,363

Production in Q4 2024 and for the year ended December 31, 2024, averaged 5,892 boe per day (65% oil and liquids) and 5,150 boe per day (65% oil and liquids) respectively, compared to 6,418 boe per day (64% oil and liquids) and 6,363 boe per day (64% oil and liquids) in the comparable periods of 2023. Factors contributing to the decrease are natural expected declines (most notably from the Wayne wells drilled and brought on production in 2023) and shut-in of non-associated natural gas production.

Seven wells were brought on production in Q4 2024, three of these were in Sheerness and two in each of Wayne and Drumheller, contributing to the increase in production from 4,860 boe per day in Q3 2024. The four wells drilled in Wayne and Drumheller were brought on production late in Q4 2024. The three wells brought on production in Sheerness were restricted due to gas flaring and were producing without restriction in late January 2025 commensurate with the completion of a natural gas pipeline.

The Company brought 13 wells on production in 2024 of which seven were in Q4 compared to 14 wells brought on production in 2023 of which three wells were in Q4.

Oil and liquids production decreased 7% to 3,809 bbls per day in Q4 2024 compared to 4,076 bbls per day in Q4 2023 and decreased 19% to 3,370 bbls per day in 2024 compared to 4,144 bbls per day in 2023. Production increases from the wells drilled and brought

on production in 2024 were more than offset by natural expected production declines most significantly from three Wayne wells drilled and brought on production in Q1 2023 and another three Wayne wells brought on production early in Q3 2023.

Natural gas production decreased 11% and 20% in Q4 and 2024 respectively compared to the same periods in 2023. Expected natural declines from associated natural gas production as well as shut-in natural gas production contributed significantly to the decrease.

The Company shut in non-associated natural gas production (excluding the Drumheller natural gas well drilled in 2023 which was being evaluated) on April 1, 2023, due to low natural gas price realizations. The volume was brought back on production later in 2023. In 2024, the Company again shut in non-associated natural gas production due to low natural gas price realizations. More wells were shut in during 2024 and at an earlier date than in 2023.

OPERATING NETBACKS⁽¹⁾

(\$ per BOE)	Three Months Ended December 31		Year Ended December 31	
	2024	2023	2024	2023
Revenue ⁽¹⁾	\$56.43	\$58.59	\$57.89	\$61.75
Royalties	(11.30)	(13.17)	(12.25)	(13.61)
Operating expenses	(12.70)	(12.37)	(13.15)	(11.22)
Transportation expenses	(2.31)	(2.31)	(2.35)	(2.51)
Operating netback ⁽²⁾	\$30.12	\$30.74	\$30.14	\$34.41

⁽¹⁾ Includes pipeline tariff amount of \$2.41 and \$2.55 per boe for the three months and year ended December 31, 2024, and \$2.49 and \$2.73 per boe in the comparable periods of 2023 respectively.

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

The operating netback was lower in Q4 2024 and 2024 compared to the same periods in 2023 primarily due to lower oil and natural gas prices and higher operating expenses partially offset by lower royalties.

COMMODITY PRICES

(\$ per bbl, before pipeline tariffs)	Three Months Ended December 31		Year Ended December 31	
	2024	2023	2024	2023
WTI (US\$/bbl)	\$70.32	\$78.27	\$75.76	\$77.62
MSW benchmark price ⁽¹⁾	\$94.95	\$99.60	\$97.60	\$100.42
WCS benchmark price ⁽²⁾	\$80.75	\$76.72	\$83.56	\$79.58
Realized crude oil price	\$89.11	\$91.21	\$90.46	\$92.68

⁽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 in Q4 2024 was \$89.11 per barrel which is 2% lower than the Q4 2023 price of \$91.21 per barrel. WTI benchmark prices decreased 10% from \$78.27 per barrel in Q4 2023 to \$70.32 per barrel in Q4 2024 resulting in a decrease in North 40's realized price. The decline in the benchmark WTI price was partially offset by a decrease in the average Canadian stream differentials and a weaker Canadian dollar.

North 40's realized crude oil price decreased 2% in 2024 to \$90.46 per barrel from \$92.68 per barrel realized in 2023. WTI benchmark prices decreased 2% from \$77.62 per barrel in 2023 to \$75.76 per barrel in 2024 contributing to most of the decrease in North 40's realized price which was partially offset by a weaker Canadian dollar and stronger Canadian stream differentials.

WTI benchmark prices declined in the second half of 2024 as demand concerns over economic growth, particularly in China, overcame supply concerns from geopolitical conflicts, particularly in the Middle East and Russia / Ukraine and support from OPEC+ production curtailments. Canadian differentials, particularly the WCS differential, narrowed through 2024 after the Trans Mountain pipeline expansion came online.

(\$ per mcf, before pipeline tariffs)	Three Months Ended December 31		Year Ended December 31	
	2024	2023	2024	2023
AECO Daily (5A) index	\$1.46	\$2.30	\$1.48	\$2.64
Realized natural gas price	\$1.73	\$2.54	\$1.72	\$2.95

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 decreased 32% to \$1.73 per mcf in Q4 2024 from \$2.54 per mcf in Q4 2023 and decreased 42% to \$1.72 per mcf for 2024 from \$2.95 per mcf in 2023.

Natural gas prices moved lower and remained weak in 2024 due to higher production in Western Canada, lower demand and higher storage levels following milder weather.

REVENUE

(\$ thousands)	Three Months Ended		Year Ended	
	December 31		December 31	
	2024	2023	2024	2023
Oil and liquids	\$28,972	\$31,695	\$103,608	\$130,563
Natural gas	1,619	2,899	5,497	12,855
Petroleum and natural gas revenue	\$30,591	\$34,594	\$109,105	\$143,418
% Oil and liquids	95	92	95	91

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

Revenue in Q4 2024 decreased to \$30.6 million from \$34.6 million in Q4 2023. Approximately 60% of the revenue decrease resulted from lower production volume with the remainder due to lower realized prices for oil, natural gas and liquids. Lower crude oil production volumes had the largest impact on the revenue decrease.

Revenue for the year ended December 31, 2024 decreased by 24% from \$143.4 million in 2023 to \$109.1 million in 2024 for the same reasons as the Q4 decrease. Lower crude oil production represented approximately 70% of the decrease.

Oil and liquids revenue represented 95% of total revenue in Q4 2024 and decreased 9%, from \$31.7 million in Q4 2023 to \$29.0 million in Q4 2024. Crude oil realizations were 2% lower and oil production volumes were 7% lower in Q4 2024 compared to the same quarter last year. Oil and liquids revenue for 2024 represented 95% of total annual revenue and decreased 21% to \$103.6 million from \$130.6 million in 2023. Oil production volumes were 20% lower and crude oil realizations were 2% lower in 2024 compared to 2023.

Natural gas revenue declined 44% in Q4 2024 from \$2.9 million in Q4 2023 to \$1.6 million in Q4 2024. The decrease is due to a 32% decline in price realizations and an 11% decrease in production volume in Q4 2024 compared to the same period in 2023. Natural gas revenue for 2024 represented 5% of total revenue and decreased 57% compared to 2023 due to a 42% decrease in price and a 30% decrease in production volume.

Oil pipeline tariffs of \$0.9 million and \$3.6 million are included in revenue for the fourth quarter and the year ended December 31, 2024 respectively. This compares to \$1.1 million and \$4.9 million in the same periods of 2023. The custody transfer to the purchaser is at the point the oil is offloaded at the terminal. Gas pipeline tariffs of \$0.4 million and \$1.2 million are also included in revenue for the three months and year ended December 31, 2024, respectively. This compares to \$0.4 million and \$1.5 million in the same periods of 2023. 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		Year Ended	
	December 31		December 31	
	2024	2023	2024	2023
Royalties	\$6,128	\$7,780	\$23,079	\$31,610
Per BOE	\$11.30	\$13.18	\$12.25	\$13.61
% of Revenue before pipeline tariffs	19%	22%	20%	21%

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 on a boe basis decreased to \$11.30 and \$12.25 per boe in Q4 2024 and 2024 respectively compared to \$13.18 and \$13.61 per boe in the comparable periods of 2024 commensurate with lower realized prices. On an absolute basis, royalties decreased to \$6.1 million in Q4 2024 compared to \$7.8 million in Q4 2023. Royalties were \$23.1 million for 2024 compared to \$31.6 million in 2023 with the decrease due to lower production volumes and lower price realizations.

Royalties as a percentage of revenue were 19% and 22% in the fourth quarters of 2024 and 2023 respectively. Royalties as a percentage of revenue decreased to 20% for the year ended December 31, 2024 compared to 21% for the same period in 2023.

Majority of the Company's royalties are freehold royalties. Freehold mineral tax is included in royalties for financial reporting purposes.

OPERATING AND TRANSPORTATION

<i>(thousands, except per unit amounts)</i>	Three Months Ended December 31		Year Ended December 31	
	2024	2023	2024	2023
Operating expenses	\$6,883	\$7,307	\$24,784	\$26,049
Per BOE	\$12.70	\$12.37	\$13.15	\$11.22
Transportation expenses	\$1,254	\$1,363	\$4,424	\$5,828
Per BOE	\$2.31	\$2.31	\$2.35	\$2.51

Operating expenses averaged \$12.70 (\$6.9 million) and \$13.15 per boe (\$24.8 million) for the fourth quarter and year ended December 31, 2024, respectively compared to \$12.37 (\$7.3 million) and \$11.22 per boe (\$26.0 million) for the same periods in 2023. Main contributors to the increase were water handling costs, maintenance and chemical costs. A decrease in production volume also contributed to the increase in the per boe costs as fixed costs are allocated over less production volume.

Transportation costs, which are clean oil trucking expenses, averaged \$2.31 (\$1.3 million) and \$2.35 (\$4.4 million) per boe in the fourth quarter and the year ended December 31, 2024, respectively compared to \$2.31 (\$1.4 million) and \$2.51 (\$5.8 million) per boe in the same periods of 2023. 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	
	2024	2023	2024	2023
Gross G&A	\$1,563	\$2,021	\$4,708	\$4,366
Capitalized G&A	(150)	(164)	(411)	(295)
Net G&A	\$1,413	\$1,857	\$4,297	\$4,071
Per BOE	\$2.61	\$3.14	\$2.28	\$1.75

Net general and administrative ("G&A") expenses were \$1.4 million and \$4.3 million for the fourth quarter and the year ended December 31, 2024 respectively compared to \$1.9 million and \$4.1 million in the comparable periods of 2023.

G&A in Q4 was lower primarily due to lower bonus payments partially offset by higher professional services associated with legal services when compared to Q4 2023. G&A for 2024 increased slightly from 2023 due to the addition of office staff in 2024 as well as increases in legal services and computer software costs mostly offset by lower bonus payments and consulting services.

On a boe basis, net G&A was \$2.61 and \$2.28 per boe in Q4 and for the year ended December 31, 2024 respectively compared to \$3.14 and \$1.75 per boe in same periods of 2023.

Capitalized G&A relates to a portion of the Company's engineering compensation.

SHARE BASED COMPENSATION

<i>(thousands, except per unit amounts)</i>	Three Months Ended December 31		Year Ended December 31	
	2024	2023	2024	2023
Share based compensation	\$279	\$256	\$1,145	\$1,319
Capitalized share-based compensation	(27)	(20)	(111)	(136)
	\$252	\$236	\$1,034	\$1,183
Per BOE	\$0.46	\$0.40	\$0.55	\$0.51

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 June 2023, the Board of Directors extended the expiry of certain Class B and Class C shares and options to September 2026 from September 2023. The term extension is a modification under IFRS and requires an update to the calculation of share-based compensation expense.

Incremental value of \$0.6 million was determined for the vested Class B shares and options. This incremental value was recognized immediately and \$0.5 million has been expensed and \$0.1 million has been capitalized in 2023.

Incremental value of \$1.1 million was determined for the Class C shares and options and will be recognized over the estimated remaining expected term of 1.8 years for the Class C shares and options. The Company recognized \$144,125 and \$548,790 as share based compensation expense and capitalized \$15,530 and \$61,782 in the fourth quarter and for the year ended December 31, 2024 respectively related to this Class C incremental value. The Company recognized \$141,794 and \$309,391 as share based compensation expense and capitalized \$15,717 and \$33,024 in the comparable periods of 2023 respectively.

Detailed information regarding the Class B and Class C shares and options have been disclosed in Note 11 of the financial statements.

DEPLETION AND DEPRECIATION

<i>(thousands, except per unit amounts)</i>	Three Months Ended December 31		Year Ended December 31	
	2024	2023	2024	2023
Depletion and depreciation	\$9,883	\$11,294	\$36,275	\$44,223
Per BOE	\$18.23	\$19.13	\$19.25	\$19.04

The Company recognized depletion and depreciation expense ("D&D") of \$9.9 million (\$18.23 per boe) and \$36.3 million (\$19.25 per boe) for the quarter and the year ended December 31, 2024, respectively compared to \$11.3 million (\$19.13 per boe) and \$44.2 million (\$19.04 per BOE) in the same periods of 2023. The D&D expense was based on an internal evaluation of proved and probable reserves and an internal estimate of future development costs.

D&D expense decreased in the fourth quarter of 2024 compared to Q4 2023 largely due to lower production volume and a lower per unit rate. The decrease in depletion expense for year ended December 31, 2024 compared to 2023 is largely due to lower production volume partially offset by a slightly higher rate.

The D&D expense recognized was comprised primarily of depletion expenses with minor amounts relating to depreciation of office 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. The Company uses total proved plus probable reserves as its depletion base in the calculation of depletion.

EXPLORATION EXPENSE

<i>(thousands, except per unit amounts)</i>	Three months ended December 31		Year ended December 31	
	2024	2023	2024	2023
Exploration expense	\$46	\$3,750	\$4,970	\$4,027
Per BOE	\$0.08	\$6.35	\$2.64	\$1.73

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. This compares to \$3.8 million (\$6.35 per boe) in Q4 2023 and \$4.0 million (\$1.73 per boe) in the comparable periods of 2023. Exploration expense in 2023 relates to costs related to an unsuccessful test well at Tide Lake and undeveloped land expiries.

Property and Equipment

At December 31, 2024 and 2023, there were no indicators of impairment identified and an impairment test was not performed.

FINANCE EXPENSE

<i>(thousands)</i>	Three Months Ended December 31		Year Ended December 31	
	2024	2023	2024	2023
Accretion of decommissioning obligations	\$76	\$58	\$271	\$230
Interest	15	-	43	-
Banking fees	50	17	199	143
Interest on leased liabilities	6	3	24	17
Total	\$147	\$78	\$537	\$390
Per BOE	\$0.27	\$0.13	\$0.29	\$0.17

Finance expense relates to accretion on decommissioning obligations, interest, banking fees and interest on lease liabilities. Banking fees include standby fees and fees associated with the annual bank facility review. Accretion of decommissioning obligations and interest on lease liabilities are non-cash charges.

INCOME TAXES

North 40 recognized a current income tax expense of \$0.2 million in Q4 2024 and \$0.5 million for Q4 2024 and for the year ended December 31, 2024 compared to a recovery of \$0.9 million and an expense of \$3.6 million in the comparable periods of 2023 respectively.

Deferred income taxes arise from differences between the accounting 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, 2024, a deferred income tax expense of \$1.0 million and \$2.1 million, respectively, was recognized compared to a deferred income tax expense of \$1.0 million and \$2.8 million for the comparable periods in 2023.

The following tax pool balances are estimated at December 31, 2024 and 2023:

<i>(thousands)</i>	Maximum Annual Deduction	2024	2023
Canadian oil and gas property expense (COGPE)	10%	\$5,736	\$15,110
Canadian development expense (CDE)	30%	58,022	53,033
Undepreciated capital cost (UCC)	25%	51,723	40,618
		\$115,481	\$108,761

NET INCOME AND COMPREHENSIVE INCOME

<i>(thousands)</i>	Three Months Ended December 31		Year Ended December 31	
	2024	2023	2024	2023
Net income and comprehensive income	\$3,494	\$945	\$7,402	\$20,134
Per share – basic	\$0.05	\$0.01	\$0.10	\$0.26
– diluted	\$0.04	\$0.01	\$0.09	\$0.25

North 40 recognized 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 three months and year ended December 31, 2024, respectively and net income and comprehensive income of \$0.9 million (\$0.01 per basic and diluted share) and \$20.1 million (\$0.26 per basic and \$0.25 per diluted share) for the comparable periods in 2023.

The increase in net income for the three months December 31, 2024, as compared to the same period in 2023 is primarily due to decreases in royalties, operating expenses, general and administrative costs, depletion and depreciation, and exploration expense partially offset by a decrease in petroleum and natural gas revenue and higher current and deferred income tax expense.

The decrease in net income for the year ended December 31, 2024, as compared to the same period in 2023 is primarily due to a decrease in petroleum and natural gas revenue and exploration expense partially offset by decreases in royalties, operating and transportation expenses, depletion and depreciation, and income taxes.

CAPITAL EXPENDITURES

Capital expenditures by type and by area for the three months and year ended December 31, 2024 and 2023 were as follows:

<i>(thousands)</i>	Three Months Ended December 31		Year Ended December 31	
	2024	2023	2024	2023
Land and lease rentals ⁽¹⁾	\$ 174	\$ 892	\$1,545	\$1,911
Seismic and geological	(360)	31	2,087	1,925
Drilling and completion	16,133	12,749	40,038	46,796
Equipping and tie-ins	2,098	5,765	11,245	24,878
Facilities	9,652	1,904	13,089	9,805
Office and other	150	171	421	401
Total capital expenditures	\$27,847	\$21,512	\$68,425	\$85,716

(1) Net of land fund reimbursements

<i>(thousands)</i>	Three Months Ended		Year Ended	
	December 31		December 31	
	2024	2023	2024	2023
Sheerness	\$18,933	\$11,257	\$36,497	\$17,452
Wayne	7,235	325	8,821	30,699
Drumheller	2,478	2,122	17,385	19,568
Tide Lake	(280)	5,692	2,930	6,061
Matziwin	(315)	1,796	1,832	7,673
Other	(204)	320	960	4,263
Total capital expenditures	\$27,847	\$21,512	\$68,425	\$85,716

Wells drilled by property were as follows:

	Three Months Ended		Year Ended	
	December 31		December 31	
	2024	2023	2024	2023
Sheerness	-	2	5	3
Wayne	2	-	2	6
Drumheller	2	-	6	3
Tide Lake	-	2	1	2
Matziwin South ⁽¹⁾	-	-	-	1
Princess	-	-	-	1
Total	4	4	14	16

⁽¹⁾ Included in Matziwin 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 a 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 battery to the newly acquired natural gas plant.

Fourth quarter 2023 capital expenditures were \$21.5 million and includes the following activities:

- freehold lease extensions at Matziwin,
- drilling, completion, and equipping of three wells and the drilling of another. Three of these wells were brought on production in the quarter,
- completion and start-up of water disposal facilities at Drumheller, and
- construction of a pipeline in the Matziwin area.

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 \$36.6 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.

Capital expenditures in 2023 were \$85.7 million which included the drilling of 16 wells. The majority of the capital was spent at Wayne where six wells were drilled and an oil battery was constructed. The battery became operational in Q2. Activity at Drumheller included the drilling of three wells, one of which is a water disposal well, and construction of water disposal facilities which became operational in the fourth quarter.

Activities at Sheerness in 2023, included acquisition of land leases, purchase of 3D seismic data at Sheerness, and the drilling of three wells. All three wells were brought on production in 2023. Other activities include: drilling of two wells at Tide Lake, one well at each of Matziwin South and Princess, freehold lease extensions, pipeline construction at Matziwin, workover and recompletion operations, and equipment purchases for future locations.

LAND

North 40's land holdings per area at December 31, 2024 and 2023 were as follows:

<i>(acres)</i>	December 31, 2024	December 31 2023
Sheerness	119,160	118,843
Wayne	15,951	15,630
Drumheller	55,874	57,175
Tide Lake	26,427	11,235
Matziwin	24,249	38,731
Princess	1,261	18,858
Other	22,475	25,008
Total	265,397	285,480

The land holdings consist of 72% crown and 28% freehold leases at December 31, 2024. Working interest in North 40's land holdings is 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 \$9.1 million at December 31, 2024 (\$7.6 million at December 31, 2023).

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. A risk-free rate of 3.35% (3.05% at December 31, 2023) and an inflation rate of 2.00% (2.20% at December 31, 2023) were used to calculate the best estimate of the decommissioning obligation.

The increase in the decommissioning obligation at December 31, 2024, compared to December 31, 2023, is largely due to new liabilities recognized for wells drilled and new facilities, an increase in decommissioning cost estimates partially offset by an increase in discount rates and an increase in reserve life assumptions.

LIQUIDITY AND CAPITAL RESOURCES

At December 31, 2024, the Company had no drawn debt and a working capital deficit of \$8.4 million comprised of \$5.7 million in cash and a working capital deficit of \$14.1 million. All activities to date have been funded with proceeds from the Company's initial equity financing, cash flow from operations, land fund reimbursements and interest income on cash balances.

At December 31, 2024, the Company had a \$35.0 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, 2024 that reduces the amount otherwise available to be drawn on the operating facility.

The facility includes a financial covenant that requires the working capital ratio (adjusted for unrealized hedging, the current portion of debt, and the undrawn availability under the facility) be not less than 1.0 at each fiscal quarter end. The Company was in compliance with this covenant at December 31, 2024. 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. A review was completed December 23, 2024 and the facility was increased by \$5 million to \$35 million. The next review date has been set for May 31, 2025.

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, 2025. The agreement includes a funding limit of \$17 million, which may be increased at the sole discretion of the party. At December 31, 2024, there is \$3.3 million remaining on the funding limit.

RESERVE INFORMATION

North 40's reserves have been internally evaluated by the Company's engineers as at December 31, 2024 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, 2024:

<i>(Company Interest)</i>	Oil and Liquids (Mbbbls)	Natural Gas (MMcf)	Oil Equivalent (Mboe)
Proved developed producing	4,930	15,244	7,471
Proved developed non-producing	11	912	162
Proved undeveloped	3,340	7,310	4,558
Total proved	8,281	23,466	12,191
Probable	2,646	6,859	3,790
Total proved plus probable	10,927	30,325	15,981

The following table summarizes changes in reserves during 2024:

<i>(Mboe)</i>	Proved Producing	Total Proved	Total Probable	Total Proved & Probable
December 31, 2023	5,404	9,560	4,492	14,052
Production – 2024	(1,885)	(1,885)	-	(1,885)
Additions	1,693	3,394	(208)	3,186
Net acquisitions	-	-	-	-
Technical revisions	2,259	1,122	(494)	628
December 31, 2024	7,471	12,191	3,790	15,981

The following table summarizes net reserves values at December 31, 2024:

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

<i>(\$ Million)</i>	0%	5%	10%	15%	20%
Proved developed producing	172	151	130	115	104
Proved developed non-producing	1	1	1	1	1
Proved undeveloped	88	63	46	35	26
Total proved	261	215	177	151	131
Probable	101	70	53	42	35
Total proved plus probable	362	285	230	193	166

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 January 1, 2025 price forecast of McDaniels & Associates Consultants Ltd. and North 40's estimates.

**Summary of Pricing Assumptions
Effective December 31, 2024
Forecast Price and Costs**

Forecast 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)		
2025	72.50	95.89	89.05	3.50	2.75	3.33
2026	73.95	97.11	90.22	3.83	3.57	4.37
2027	75.43	98.34	91.31	3.90	3.64	4.51
2028	76.94	100.31	93.13	3.98	3.71	4.60
2029	78.48	102.31	94.99	4.06	3.79	4.68
2030	80.05	104.36	96.89	4.14	3.86	4.77
2031	81.65	106.45	98.83	4.22	3.94	4.86
2032	83.28	108.57	100.80	4.31	4.02	4.95
2033	84.95	110.75	102.82	4.39	4.10	5.06

Note: Inflation rate assumption is 2% per annum.

CAPITAL EFFICIENCIES

	2024	3- Year Average
Finding, development, and acquisition costs ⁽¹⁾		
Total proved (\$ per boe)	\$20.96	\$25.27
Proved plus probable reserves (\$ per boe)	\$17.95	\$23.11
Recycle Ratio ⁽²⁾ (times)	1.7	1.8

⁽¹⁾ Includes future development costs of \$80.8 million on a proved basis and \$105.6 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
	2024	2024	2024	2024	2023	2023	2023	2023
FINANCIAL								
Petroleum and natural gas revenue	\$30,591	\$25,197	\$26,057	\$27,260	\$34,594	\$44,318	\$33,839	\$30,668
Funds flow from operations ⁽¹⁾	\$14,712	\$11,702	\$12,555	\$13,049	\$17,289	\$22,560	\$16,989	\$15,755
Per share – basic	\$0.19	\$0.15	\$0.16	\$0.17	\$0.23	\$0.29	\$0.22	\$0.21
Per share – diluted	\$0.18	\$0.14	\$0.15	\$0.16	\$0.21	\$0.28	\$0.21	\$0.20
Net income (loss)	\$3,494	\$(1,130)	\$4,244	\$793	\$ 945	\$9,306	\$4,572	\$5,311
Per share – basic	\$0.05	\$(0.02)	\$0.06	\$0.01	\$0.01	\$0.12	\$0.06	\$0.07
Per share – diluted	\$0.04	\$(0.02)	\$0.05	\$0.01	\$0.01	\$0.11	\$0.06	\$0.07
Capital expenditures ⁽²⁾	\$27,847	\$22,314	\$3,554	\$14,711	\$21,512	\$17,740	\$18,656	\$27,808
Working capital surplus (deficiency) at end of period ⁽³⁾	\$(8,365)	\$(10,757)	\$1,086	\$(7,807)	\$(6,114)	\$(1,857)	\$(6,644)	\$(4,946)
Common shares outstanding end of period	76,624	76,624	76,624	76,624	76,624	76,624	76,624	76,624
OPERATING								
Sales volumes								
Oil and liquids (bbls/day)	3,809	3,169	3,034	3,465	4,076	4,740	4,203	3,544
Natural gas (mcf/day)	12,498	10,150	8,413	11,642	14,052	12,550	12,767	13,907
Total (boe/day) ⁽⁴⁾	5,892	4,860	4,436	5,405	6,418	6,832	6,331	5,862
% Oil and liquids	65	65	68	64	64	69	66	60
Commodity prices realized (before pipeline tariffs)								
Oil and liquids (\$/bbl)	85.33	87.55	94.73	81.14	87.40	97.95	84.41	86.71
Natural gas (\$/mcf)	1.73	0.77	1.33	2.84	2.54	2.92	2.72	3.60
Total (\$/boe)	58.84	58.69	67.31	58.14	61.08	73.33	61.53	60.96
Operating netback ⁽⁵⁾ (\$/boe)	30.12	27.59	34.25	29.12	30.74	40.47	32.91	32.96
Funds flow from operations netback (\$/boe) ⁽¹⁾	27.14	26.17	31.10	26.53	29.28	35.89	29.49	29.86
Net wells drilled	4.0	7.0	-	3.0	4.0	3.0	3.0	6.0
Net acres of land at end of period	265,397	267,272	283,585	298,158	285,480	297,608	307,909	191,849

⁽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.

Significant factors and trends that have impacted the Company's results during the above periods include:

- Organic growth in production volume from the Company's drilling program.
- In early 2020, crude oil prices experienced a rapid and sudden decline as the COVID-19 global pandemic began to negatively impact crude oil demand and a dispute amongst major oil producing nations resulted in additional crude oil supply. Crude oil prices began a gradual increase mid-year supported by coordinated production cuts by OPEC and OPEC+, voluntary production curtailments by producers and reduced drilling activity. In 2021, global demand, notably in large economies such as the United States and China, was increasing in response to continued recovery from the COVID-19 pandemic, vaccination programs and significant adherence to production cuts by OPEC and OPEC+. This was partially offset by new waves of COVID-19 and the spread of variant cases.
- The volatility in commodity prices and the resultant effect on revenue, funds flow from operations, and net income.
- Current income tax expense was first recognized in Q1 2022.

SELECTED ANNUAL INFORMATION

	2024	2023	2022	2021	2020
FINANCIAL					
Petroleum and natural gas revenue	\$109,105	\$143,418	\$116,333	\$63,880	\$30,114
Funds flow from operations ⁽¹⁾	\$52,018	\$72,594	\$61,509	\$36,390	\$14,463
Per share – basic	\$0.68	\$0.95	\$0.81	\$0.48	\$0.19
Per share – diluted	\$0.63	\$0.90	\$0.77	\$0.47	\$0.19
Net income (loss)	\$7,402	\$20,134	\$30,865	\$15,301	\$(910)
Per share – basic	\$0.10	\$0.26	\$0.41	\$0.20	\$(0.01)
Per share – diluted	\$0.09	\$0.25	\$0.39	\$0.20	\$(0.01)
Capital expenditures ⁽²⁾	\$68,425	\$85,716	\$67,891	\$35,888	\$16,663
Working capital surplus (deficiency) ⁽³⁾ at end of period	\$(8,365)	\$(6,114)	\$7,139	\$13,486	\$13,186
Common shares outstanding end of period	76,624	76,624	76,624	75,250	75,250
OPERATING					
Sales volumes					
Oil and liquids (bbls/day)	3,370	4,144	2,560	2,104	1,749
Natural gas (mcf/day)	10,679	13,317	10,020	6,305	4,955
Total (boe/day) ⁽⁴⁾	5,150	6,363	4,230	3,154	2,575
% Oil and liquids	65	65	61	67	68
Commodity prices realized (before pipeline tariffs)					
Oil and liquids (\$/bbl)	86.89	89.54	106.16	74.04	43.64
Natural gas (\$/mcf)	1.72	2.95	5.75	4.22	2.59
Total (\$/boe)	60.43	64.48	77.88	57.83	34.63
Operating netback ⁽⁵⁾ (\$/boe) (before hedging)					
Hedging Settlements	30.14	34.41	45.28	33.94	18.22
Hedging Settlements	-	-	-	-	(0.98)
Operating netback (\$/boe) (after hedging settlements)	30.14	34.41	45.28	33.94	17.24
Funds from operations netback (\$/boe) ⁽¹⁾	27.60	31.25	39.84	31.61	15.35
Net wells drilled	14.0	16.0	17.0	14.0	6.0
Net acres of land at end of period	265,397	285,480	224,578	256,346	255,254

⁽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.



KPMG LLP

205 5th Avenue SW
Suite 3100
Calgary, AB T2P 4B9
Tel 403-691-8000
Fax 403-691-8008
www.kpmg.ca

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, 2024
- the statement of net income and comprehensive income 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, 2024, 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 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.

KPMG LLP, an Ontario limited liability partnership and member firm of the KPMG global organization of independent member firms affiliated with KPMG International Limited, a private English company limited by guarantee. KPMG Canada provides services to KPMG LLP.



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 the 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.

KPMG LLP

Chartered Professional Accountants

Calgary, Canada

March 25, 2025

NORTH 40

RESOURCES LTD.

Financial Statements
For the year ended December 31, 2024

North 40 Resources Ltd.

Statements of Financial Position

As at	December 31 2024	December 31 2023
<i>(\$ thousands)</i>		
ASSETS		
Current Assets		
Cash	5,710	8,036
Accounts receivable	13,261	11,693
Current income taxes (Note 9)	959	487
Prepays and deposits	839	1,036
Total Current Assets	20,769	21,252
Deposit on asset acquisition bid (Note 19)	1,200	-
Exploration and evaluation assets (Note 4 and 6)	15,927	19,275
Property, plant and equipment (Notes 5, 6 and 7)	185,931	169,382
Total Assets	223,827	209,909
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts payable and accrued liabilities	29,134	27,366
Total Current Liabilities	29,134	27,366
Lease liabilities	184	118
Decommissioning obligations (Note 10)	9,115	7,644
Deferred income taxes (Note 14)	18,659	16,593
Total Liabilities	57,092	51,721
Shareholders' Equity		
Share capital (Note 11)	76,245	76,245
Contributed surplus	5,806	4,661
Retained earnings	84,684	77,282
Total Shareholders' Equity	166,735	158,188
Total Liabilities and Shareholders' Equity	223,827	209,909

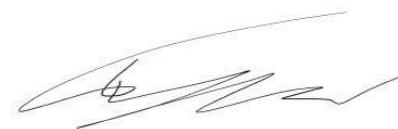
Subsequent Events (Notes 11 and 19)

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 and Comprehensive Income

Years ended December 31

2024 2023

(\$ thousands except per share amounts)

	2024	2023
Revenue		
Petroleum and natural gas revenue (Note 12)	109,105	143,418
Less: Royalties	23,079	31,610
	86,026	111,808
Interest income	251	523
	86,277	112,331
Expenses		
Operating	24,784	26,049
Transportation	4,424	5,828
General and administrative	4,297	4,071
Share based compensation (Note 11)	1,034	1,183
Depletion and depreciation (Note 7)	36,275	44,223
Exploration expense (Note 4)	4,970	4,027
Finance expense	537	390
Total expenses	76,321	85,771
Income before taxes	9,956	26,560
Current income tax expense (Note 9)	488	3,629
Deferred income tax expense (Note 14)	2,066	2,797
Income taxes	2,554	6,426
Net Income and Comprehensive Income	7,402	20,134
Net Income per share (Note 13)		
Basic	\$0.10	\$0.26
Diluted	\$0.09	\$0.25

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, 2022	76,245	3,342	57,148	136,735
Net income	-	-	20,134	20,134
Share based compensation (Note 11)	-	1,319	-	1,319
Balance as at December 31, 2023	76,245	4,661	77,282	158,188
Balance as at December 31, 2023	76,245	4,661	77,282	158,188
Net income	-	-	7,402	7,402
Share based compensation (Note 11)	-	1,145	-	1,145
Balance as at December 31, 2024	76,245	5,806	84,684	166,735

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

North 40 Resources Ltd.

Statements of Cash Flow

Years ended December 31

	2024	2023
<i>(\$ thousands)</i>		
Cash provided by (used in):		
Operating activities		
Net income for the year	7,402	20,134
Adjusted for:		
Depletion and depreciation (Note 7)	36,275	44,223
Exploration expense (Note 4)	4,970	4,027
Accretion expense (Note 10)	271	230
Share based compensation (Note 11)	1,034	1,183
Deferred income tax expense (Note 14)	2,066	2,797
	52,018	72,594
Decommissioning expenditures (Note 10)	(78)	-
Net change in non-cash working capital (Note 16)	(5,372)	(2,894)
	46,568	69,700
Financing activities		
Repayment of lease liabilities	(115)	(132)
	(115)	(132)
Investing activities		
Deposit paid on acquisition bid (Note 19)	(1,200)	-
Exploration and evaluation expenditures (Note 4)	(10,744)	(6,417)
Property, plant and equipment expenditures (Notes 5, 6 and 7)	(57,681)	(79,299)
Proceeds from dispositions (Notes 6 and 7)	15,550	-
Net change in non-cash working capital (Note 16)	5,296	5,118
	(48,779)	(80,598)
Change in cash	(2,326)	(11,030)
Cash, beginning of year	8,036	19,066
Cash, end of year	5,710	8,036
Cash income tax paid	976	8,664

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

North 40 Resources Ltd.

Notes to the Financial Statements

December 31, 2024 and 2023 (*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 25, 2025.

(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 impairment indicators exist, and impairment testing is required. In determining the recoverable amount of assets, in the absence of quoted market prices, impairment tests are based on estimates of reserves, which are dependent upon certain assumptions including: production rates, future oil and natural gas prices, future operating and transportation costs, royalties, discount rates and other relevant assumptions. 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) 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) 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

(e) 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.

(f) 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.

(g) 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.

(h) 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.

4. EXPLORATION AND EVALUATION ASSETS

(\$)	December 31 2024	December 31 2023
Balance, beginning of year	19,275	23,318
Additions	10,744	6,417
Dispositions (Note 6)	(4,956)	-
Exploration expense	(4,970)	(4,027)
Transferred to property, plant and equipment (Note 7)	(4,166)	(6,433)
Balance, end of year	15,927	19,275

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 relates to undeveloped land expiries and costs related to drilling an unsuccessful test well.

5. ACQUISITIONS

On December 19, 2024, the Company closed an acquisition of a 50% working interest in a natural gas plant and related infrastructure. 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	Total
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

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

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 2024	December 31 2023
Property, plant and equipment, at cost	346,933	294,109
Accumulated depletion and depreciation	(161,002)	(124,727)
Net book value, end of year	185,931	169,382

Reconciliations of movements during the year:

Cost, beginning of year	294,109	207,099
Accumulated depletion and depreciation, beginning of year	(124,727)	(80,504)
Net book value, beginning of year	169,382	126,595
Additions	50,500	79,436
Acquisitions (Note 5)	7,582	-
Right-of-use assets	188	-
Dispositions (Note 6)	(10,593)	-
Transferred from exploration and evaluation assets (Note 4)	4,166	6,433
Changes in decommissioning obligations (Note 10)	981	1,141
Depletion and depreciation	(36,275)	(44,223)
Net book value, end of year	185,931	169,382

Included in the calculation of depletion was an estimate for future development costs of \$105.6 million at December 31, 2024 (\$105.6 million at December 31, 2023). An estimated future salvage value of \$9.3 million was excluded from the calculation of depletion at December 31, 2024 (\$7.0 million at December 31, 2023).

Included in the December 31, 2024 property, plant and equipment balance is the right-of-use asset of \$0.2 million (\$0.1 million at December 31, 2023).

Included in additions is capitalized general and administrative expenses of \$0.5 million (\$0.4 million in 2023).

At December 31, 2024, and December 31, 2023, there were no indicators of impairment identified and an impairment test was not performed.

8. CREDIT FACILITY

At December 31, 2024, the Company had a \$35.0 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, 2024 that reduces the amount otherwise available to be drawn on the operating facility.

The facility includes a financial covenant that requires the working capital ratio (adjusted for unrealized hedging, the current portion of debt, and the undrawn availability under the facility) be not less than 1.0 at each fiscal quarter end. The Company was in compliance with this covenant at December 31, 2024. 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. A review was completed December 23, 2024 and the facility was increased by \$5 million to \$35 million. The next review date has been set for May 31, 2025.

9. CURRENT INCOME TAXES

(\$)	December 31 2024	December 31 2023
Balance, beginning of year	(487)	4,548
Current income tax expense	488	3,629
Payments ⁽¹⁾	(960)	(8,664)
Balance, end of year	(959)	(487)

⁽¹⁾ Includes instalments.

10. 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 \$30.2 million (\$15.5 million at December 31, 2023).

A reconciliation of the decommissioning obligations is provided below.

(\$)	December 31 2024	December 31 2023
Balance, beginning of year	7,644	6,273
Liabilities incurred	1,392	1,197
Liabilities acquired	146	-
Change in estimates	(260)	(56)
Decommissioning expenditures	(78)	-
Accretion expense	271	230
Balance, end of year	9,115	7,644
Key assumptions		
Risk free rate	3.35%	3.05%
Inflation rate	2.00%	2.20%

11. 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 2024		December 31 2023	
	Number (thousands)	Consideration	Number (thousands)	Consideration
Common Shares				
Balance, beginning of year	76,624	\$76,093	76,624	\$76,093
Balance, end of year	76,624	\$76,093	76,624	\$76,093
Class B Common Non-Voting Shares				
Balance, beginning of year	4,870	\$49	4,870	\$49
Balance, end of year	4,870	\$49	4,870	\$49
Class C Common Non-Voting Shares				
Balance, beginning of year	10,380	\$103	10,380	\$103
Balance, end of year	10,380	\$103	10,380	\$103
Total		\$76,245		\$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 2026 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, 2024, 4,870,000 Class B shares and 901,917 options were vested (4,870,000 and 613,500 respectively at December 31, 2023).

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, 2023	1,402,000	\$0.70
Granted	400,000	1.00
Forfeited	(70,000)	(0.61)
Balance, December 31, 2023	1,732,000	\$0.77
Granted	565,000	1.00
Balance, December 31, 2024	2,297,000	\$0.83

The fair market value of each Class B option granted in 2024 was estimated on the date of issue using the Black-Scholes pricing model and the following weighted average assumptions in the calculations:

Risk-free interest rate (%)	3.85
Expected life (years)	2.0- 3.0
Estimated volatility of underlying common shares (%)	60
Share Price (\$)	2.00
Estimated forfeiture rate (%)	nil

The Company recognized share-based compensation expense of \$362,666 related to the Class B shares and options for the year ended December 31, 2024 (\$775,921 in 2023) and capitalized \$32,752 (\$97,079 in 2023).

In June 2023, the Board of Directors extended the expiry of certain Class B shares and options to September 2026 from September 2023. The term extension is a modification under IFRS and requires an update to the calculation of share-based compensation expense. The incremental value of \$0.6 million was determined for the vested Class B shares and options. This incremental value is recognized immediately and \$0.5 million was expensed and \$0.1 million has been capitalized in Q2 2023.

The incremental value is the difference in value immediately before the modification (term extension) and immediately after the modification. The following assumptions were used in the calculations:

	Before Modification	After Modification
Weighted average risk-free interest rate (%)	4.83	4.55
Expected life (years)	0.5	1.8
Estimated volatility of underlying common shares (%)	60	60
Share Price (\$)	1.99	1.99
Estimated forfeiture rate (%)	nil	nil

On January 1, 2025, the Company granted 245,000 options on Class B shares with an exercise price of \$1.40 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 2026 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
2,379,833	\$1.50	\$1.00
2,379,833	\$2.00	\$1.15
2,379,833	\$2.25	\$1.30
2,379,833	\$2.50	\$1.45
2,379,833	\$2.75	\$1.60
2,379,833	\$3.00	\$1.75

In June 2023, the Board of Directors eliminated the terms to increase both the liquidity event price and the conversion price by eight percent compounded annually beginning in June 2023 until the date the Company enters into a definitive agreement for the completion of a liquidity event.

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, 2023	2,544,000	\$0.71
Granted	600,000	1.00
Forfeited	(70,000)	(0.62)
Balance, December 31, 2023	3,074,000	\$0.77
Granted	825,000	1.00
Balance, December 31, 2024	3,899,000	\$0.82

The fair market value of each Class C option granted in 2023 was estimated on the date of issue using the Black-Scholes pricing model and the following assumptions in the calculations:

Risk-free interest rate (%)	3.85
Expected life (years)	2.5
Estimated volatility of underlying common shares (%)	60
Share Price (\$)	2.00
Estimated forfeiture rate (%)	nil

In addition, the Company assumed the probability of a liquidity event within the seven-year 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 \$671,737 related to the Class C shares and options for the year ended December 31, 2024 (\$407,117 in 2023) and capitalized \$78,124 (\$39,248 in 2023).

In June 2023, the Board of Directors extended the expiry of certain Class C shares and options to September 2026. The term extension is a modification under IFRS and requires an update to the share-based compensation expense. The incremental value of \$1.1 million was determined and will be recognized over the estimated remaining expected term of 1.8 years for the Class C shares and options. The Company recognized \$610,572 for the year ended December 31, 2024 (\$309,392 in 2023) which are included in the amounts described in the paragraph above.

The incremental value is the difference in value immediately before the modification (term extension) and immediately after the modification. The following assumptions were used in the calculations:

	Before Modification	After Modification
Weighted average risk-free interest rate (%)	4.83	4.55
Expected life (years)	0.5	1.8
Estimated volatility of underlying common shares (%)	60	60
Share Price (\$)	1.99	1.99
Estimated forfeiture rate (%)	nil	nil

On January 1, 2025, the Company granted 485,000 options on Class C shares with an exercise price of \$1.40 per share to officers and employees.

12. 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 2024	December 31 2023
Crude oil revenues	97,396	123,512
Natural gas revenues	5,497	12,855
Natural gas liquids revenues	6,212	7,051
Total	109,105	143,418

13. NET INCOME PER SHARE

	December 31 2024	December 31 2023
Net Income per share		
Basic	\$0.10	\$0.26
Diluted	\$0.09	\$0.25
Weighted average shares outstanding		
Basic	76,624	76,624
Diluted	83,965	80,738

14. 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:

	December 31 2024	December 31 2023
(\$ except statutory tax rate)		
Net income before income tax	9,956	26,560
Canadian statutory income tax rate	23.00%	23.00%
Expected income tax at statutory rates	2,290	6,109
Add (deduct):		
Non-deductible share-based compensation and other	264	317
Provision for income tax	2,554	6,426
Current income tax	488	3,629
Deferred income tax	2,066	2,797

The components of deferred income tax at December 31, 2024 and 2023 are as follows:

	December 31 2024	December 31 2023
(\$)		
Deferred income tax liability:		
Capital assets carrying value in excess of tax value	(20,798)	(18,378)
	(20,798)	(18,378)
Deferred income tax asset:		
Decommissioning obligations	2,097	1,758
Other	42	27
	2,139	1,785
Deferred income tax	(18,659)	(16,593)

The Company had approximately \$115.5 million in available tax pools at December 31, 2024 (\$108.8 million at December 31, 2023).

15. 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 2024	December 31 2023
(\$)		
Salaries and other short-term benefits	1,950	2,370
Share-based compensation	938	1,194
Total	2,888	3,564

For the year ended December 31, 2024, the share-based compensation includes \$0.6 million (\$1.0 million in 2023) 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.

16. SUPPLEMENTAL CASH FLOW INFORMATION

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

	December 31 2024	December 31 2023
(\$)		
Source / (use) of cash:		
Accounts receivable	(1,568)	(840)
Prepaid expenses and deposits	197	(345)
Accounts payable and accrued liabilities	1,768	8,443
Current income taxes	(472)	(5,035)
Change in non-cash working capital	(75)	2,224
Related to:		
Operating activities	(5,372)	(2,894)
Investing activities	5,296	5,118

17. COMMITMENTS

(\$)	Within 1 year	After 1 year but not more than 5 years	Total
Firm transportation – natural gas	251	398	649
Office lease	64	640	704
Total	315	1,038	1,353

18. RELATED PARTIES

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.

19. SUBSEQUENT EVENT

In January 2025, the Company closed the purchase of oil and natural gas assets with minimal current production and related infrastructure in the Sheerness area. The assets consist of approximately 35 sections of land which has been developed by vertical wells identifying multi-zone potential with horizontal drilling potential. The purchase price for this acquisition was \$12 million. The Company was required to pay a deposit of \$1.2 million in 2024 related to this purchase.

The Company sold a royalty interest for proceeds of \$12 million to fund this purchase. Two of the Company's directors and persons related to those 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.

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, 2025. The agreement includes a funding limit of \$17 million, which may be increased at the sole discretion of the party. At December 31, 2024, there is \$3.3 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, 2024 and December 31, 2023, 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, 2024, 96% of the accounts receivable amount relates to production revenue (89% at December 31, 2023).

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 \$35 million revolving demand operating facility with a Canadian chartered bank which could be accessed if required.

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, 2024 and December 31, 2023 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, 2024 and 2023.

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, 2024 and 2023.

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

Steven Metzger
Vice President, Exploration

Lonny Tetley
Corporate Secretary

DIRECTORS

Clayton Woitas
Executive Chairman

Tyson Birchall

Jeff Lebbert

Margaret McKenzie

Don Robson

Grant Zawalsky

HEAD OFFICE

North 40 Resources Ltd.
Suite 400
215 - 9th Avenue, SW
Calgary, AB T2P 1K3

Phone: 403.817.9310
Fax: 403.974.6826

AUDITORS

KPMG LLP
Calgary, AB

BANKER

National Bank of Canada

LEGAL COUNSEL

Burnet, Duckworth & Palmer LLP
Calgary, AB

WEBSITE

www.north40resources.com