Tourmaline Delivers Record Production, Increases 2p Reserves To 5 Billion Boe And Declares An Increased Quarterly Base Dividend And A Special Dividend

06.03.2024 | CNW

CALGARY, March 6, 2024 - Tourmaline Oil Corp. (TSX: TOU) ("Tourmaline" or the "Company") is pleased to release fi
operating results for the full year and fourth quarter of 2023, announce an increase in both 2023 reserves and the quar
dividend, as well as declare a special dividend and a quarterly dividend.

HIGHLIGHTS

- Full-year 2023 cash flow(1) ("CF") was $3.71 billion ($10.73 per diluted share(2)). Fourth quarter 2023 CF was $91
($2.62 per diluted share).
- Tourmaline generated $1.69 billion of free cash flow(3) ("FCF") in 2023 (2022 - $3.21 billion).
- Full year 2023 earnings were $1.74 billion ($5.03 per diluted share).
- Successfully closed the acquisition of Bonavista Energy Corp. ("Bonavista"), adding over 60,000 boepd of low-de
long-life production.
- Tourmaline will pay a special dividend of $0.50/share on March 21, 2024, to shareholders of record on March 14,
Tourmaline intends to pay special dividends in all four quarters of 2024, inclusive of this Q1 2024 special dividend
Tourmaline has also increased its quarterly base dividend by 7% to $0.30/share.
- Year-end 2023 proved, developed producing ("PDP") reserves of 1.20 billion boe were up 39.3% after accounting
annual production of 189.9 million boe. Total proved ("TP") reserves of 2.61 billion boe were up 20.8% after acco
2023 production. Proved plus probable ("2P") reserves of 5.01 billion boe were up 15.5% after accounting for 202
production.
- After 15 years of operation, Tourmaline now has 22.7 TCF of economic 2P natural gas reserves, all of which is pi
connected to markets across North America. At year-end 2023, 83.5% of the current drilling inventory was not bo
2023 year-end reserve report.
- Year-end 2023 2P oil, condensate, and natural gas liquids ("NGL") reserves of 1.22 billion barrels represent the s
largest conventional liquids reserve base in Canada, based on public disclosure.
- Given continuing weak natural gas prices, the Company has elected to reduce the forecast 2024 capital expendit
$2.35 billion to $2.13 billion including reduced 2024 forecast spending on exploratory drilling from $100.0 million
$40.0 million and a reduction in EP capital of $150.0 million. The budget reductions include a reduction in the rig
deferral of select exploration drilling and facility projects. Tourmaline continues to focus on optimizing free cash fl
shareholder returns.
- Fourth quarter 2023 average production was 556,957 boepd, up 9% from Q4 2022. Full year 2023 average produ
520,366 boepd was up 4% over full year 2022 average production of 500,832 boepd.
- Tourmaline has an average of 726 mmcfpd hedged in 2024 at a weighted average fixed price of $5.34/mcf.
- Montney well performance in NEBC continues to improve with 2023 wells outperforming wells from the previous t
Both natural gas, and particularly liquids production, are exceeding previous year's performance. As a result, des
activity reduction, Tourmaline anticipates 2024 liquids production to be slightly higher than prior guidance.
- At current strip pricing(4), the Company expects to generate 2024 CF of $3.32 billion ($9.34 per diluted share) an
$1.19 billion ($3.35 per diluted share(5)).
- The Company expects to generate over $1 billion(6) of FCF in every year of the Company's five year EP growth p
- Exit 2023 net debt(7) was $1.78 billion (0.48 times Q4 2023 annualized cash flow). The net debt reflects cash pai
million and net debt assumed in connection with the Bonavista acquisition, which closed on November 17, 2023.
Company intends to deleverage throughout 2024 and remains committed to a long-term net debt target of $1.2-1.

PRODUCTION UPDATE

- Fourth quarter 2023 average production was 556,957 boepd, up 9% from Q4 2022. Full year 2023 average produ
520,366 boepd was up 4% over full year 2022 average production of 500,832 boepd.
- With the announced significant 2024 capital budget reduction, 2024 average production of 580,000-590,000 boe
anticipated with Q1 average production of 590,000-595,000 boepd expected.

- 2023 average liquids production (oil, condensate, NGLs) of 118,808 bbls/d was up 6% over 2022 liquids producti 112,460 bbls/d.
- Forecast liquids production of approximately 144,000 bbls/d is ahead of the original forecast, despite a reduction forecast average production. Daily liquids production has eclipsed 150,000 bbls/d on several days thus far in Q1 2
- In addition to being Canada's largest and most active natural gas producer, Tourmaline is now the largest NGL pr Canada and the second largest condensate producer, based on public disclosure. Condensate and NGL producti are expected to increase significantly over the next 4 years with the Company's Conroy North Montney, Doe Sout and North Deep Basin growth projects.

FINANCIAL HIGHLIGHTS

- Full year 2023 CF was $3.71 billion ($10.73 per diluted share) and full year FCF was $1.69 billion ($4.88 per dilut
- Fourth quarter 2023 CF was $918.0 million ($2.62 per diluted share on Q4 average production of 556,957 boepd) FCF was $282.0 million.
- Full year 2023 earnings were $1.74 billion ($5.03 per diluted share).
- Tourmaline's Board of Directors has declared a special dividend of $0.50/share to be paid on March 21, 2024, to shareholders of record on March 14, 2024. Tourmaline intends to pay special dividends in all four quarters of 202 of this Q1 2024 special dividend.
- Tourmaline paid $6.55 per share in combined base and special dividends in 2023, a 10% trailing yield based on a 2023 share price of $63.58 per share in 2023.
- Tourmaline increased the base dividend twice during 2023 and has elected to increase the base dividend by 7% $0.30/share for the first quarter of 2024. Tourmaline has now increased the base dividend a total of thirteen times dividend was initiated in Q1 of 2018.
- Full year 2023 capital expenditures were $2.07 billion, including Q4 2023 capital expenditures of $636.0 million. C capital spending included $22.2 million of spending associated with the Bonavista assets acquired in November 2
- Exit 2023 net debt was $1.78 billion including cash paid of $651.0 million and net debt assumed relating to the ac Bonavista. Tourmaline intends to reduce net debt throughout 2024 and remains committed to its long-term net de $1.2-1.4 billion.

2023 RESERVES

- Year-end 2023 PDP reserves of 1.20 billion boe were up 39.3% after accounting for 2023 annual production of 18 boe. TP reserves of 2.61 billion boe were up 20.8% after accounting for 2023 production. 2P reserves of 5.01 billi up 15.5% after accounting for 2023 production. The 2023 organic EP program had an increased emphasis on co PDP rather than 2P reserve growth compared to previous years, hence the record PDP growth.
- After 15 years of operation, Tourmaline now has 22.7 TCF of economic 2P natural gas reserves, all of which is pi connected to markets across North America. At year-end 2023, 83.5% of the current drilling inventory was not bo 2023 year- end reserve report.
- Year-end 2023 oil, condensate, and NGL 2P reserves of 1.22 billion barrels represent the second largest convent reserve base in Canada, based on public disclosure.
- Tourmaline has only booked 3,903 gross locations of a total drilling inventory of 23,724 gross locations (16.5% of inventory) to achieve year-end 2023 2P reserves of 5.0 billion boe.
- Tourmaline replaced 368% of its 2023 annual production of 189.9 million boe with 2P additions of 698 million boe 2023 production.
- Tourmaline's 2023 PDP finding, development and acquisition ("FD&A") costs were $8.94 per boe excluding chan development capital ("FDC"), yielding a PDP reserve recycle ratio[8][9] of 2.2.
- TP FD&A costs in 2023 were $10.71 per boe[10], including changes in FDCs, three-year TP FD&A costs are $8.5 including changes in FDC.
- 2P FD&A costs in 2023 were $9.80 per boe, including changes in FDC, 3-year 2P FD&A costs were $7.38/boe, in changes in FDC. The higher 2023 2P FD&A costs reflect incremental inflation in the FDC account as well as the i focus on conversions to PDP. Approximately 69% of the 266 net wells drilled in 2023 were conversions from unde PDP.
- Tourmaline's 2P reserve value (before taxes) equates to $117.48 per diluted share (after tax reserve value of $90 diluted share) using the January 1, 2024, engineering price deck and a 10% discount rate. TP reserve value (befo $76.70 per diluted share and $60.54 per diluted share (after tax). PDP reserve value is $44.85 per diluted share (and $37.46 per diluted share (after tax). Year-over-year reserve values were down due to a combination of lower prices, drill and complete capital cost inflation (5% year-over-year) and a lower natural gas premium related to the marketing portfolio reflecting lower year-over-year forecast benchmark prices in the markets outside of Alberta w Company sells its natural gas.

2024 CAPITAL PROGRAM

- As previously disclosed in January 2024, the Company's focus in 2024 is on optimizing FCF and shareholder retu such, the Company has elected to reduce the forecast 2024 capital expenditures from $2.35 billion to $2.13 billion budget reductions include a reduction in the rig count and deferral of select exploration drilling and facility projects the Company's extensive Tier 1 drilling inventory (approximately 17 years of Tier 1 inventory alone) is profitable a prices of $1.50/mcf, Tourmaline does not believe that selling incremental gas volumes into a weak gas market is decision or return proposition for shareholders. The Company's base gas production is protected by a strong 202 hedge book as well as a diversified export portfolio accessing premium priced North American markets.
- Full year 2024 average production guidance is now 580,000-590,000 boepd, a 2.5% decrease despite the 9.4% r the 2024 forecast capital expenditures. Forecast average 2024 natural gas production has been reduced by appr 100 mmcfpd from previous guidance, and average liquids production has been increased by approximately 1,000
- Should natural gas pricing recover on a sustained basis during the second half of 2024, the Company can pivot a grow production toward 2024 exit. The Company anticipates accumulating approximately 50 DUCs, during the ba year, under the revised plan.

MARKETING UPDATE

- Tourmaline's average realized natural gas price in 2023 was $4.83/mcf, 80% above the average 2023 AECO 5A of $2.68/mcf. The Company's marketing diversification portfolio and strategic hedging program allow Tourmaline consistently outperform local hub pricing.
- Tourmaline expects to exit 2024 with 1.21 bcfpd in exports to targeted markets including 754 mmbtupd delivered Western US, and Pacific Northwest premium markets. In these premium markets, Tourmaline has an average of mmbtupd hedged in 2024 at a fixed price of $9.04 US/mmbtu.
- In January 2024, Tourmaline completed its second liquified natural gas ("LNG") agreement, increasing its exposu (Japan Korea Marker), by entering into a netback agreement with Trafigura Pte Limited based on 62,500 mmbtup seven-year term, starting January 2027, with the potential for extension to December 2039. This agreement is no upon incremental FERC approvals.
- The Company's first LNG deal with Cheniere Energy at the Sabine Pass facility commenced in January 2023 and inclusion of financial hedges, generated approximately $0.6 billion, above the AECO 5A index price, to Tourmalin year of a 15-year contract.
- Tourmaline has an average of 726 mmcfpd hedged in 2024 at a weighted average fixed price of $5.34/mcf.

EP UPDATE

- Tourmaline drilled 266.3 net wells in 2023 and the Company expects to drill approximately 271 net wells in 2024.
- Montney well performance in NEBC continues to improve with 2023 wells outperforming wells from the previous t Both natural gas and particularly liquids production are exceeding previous years' performance. The Company co lengthen horizontals and develop Montney completion techniques in advance of the significant North Montney de project scheduled for the second half of the five-year plan, when stronger intra-basin gas pricing is anticipated.
- Tourmaline has received 252 new drilling permits in BC since January 2023, as well as permits related to the Nor infrastructure projects.
- The 2024 program has delivered several Alberta Deep Basin pads above performance curve expectations at Sm and along the Bonavista Glauconite trend. The Horse 10-26 three-well Wilrich C pad tested at average per well ra mmcfpd of natural gas over a 70-hour test during January. The Kakwa 10-2 three-well, Wilrich pad, tested at ave rates of 19.9 mmcfpd of natural gas over a 112-hour test and was turned over to production in February. The Car two-well Glauconite pad had an average per well IP30 of 5.1 mmcfpd of natural gas and 166 bbls/d of condensat recent two down-dip Glauconite trend wells have significantly outperformed expectations. The first tested at an av rate of 7.7 mmcfpd and 946 bbls/d of condensate on a 134-hour flow test and was turned over to production on F 2024 and the second well has averaged 8 mmcfpd of natural gas, 850 bbls/d of condensate and 1,170 bbls/d of N the first 7 days of production. The Company also successfully drilled the first monobore design for the Glauconite expected to ultimately reduce drilling costs by 15-20%.
- Capital efficiencies(11) of approximately $10,000 per flowing barrel are expected with the 2024 EP program.

ENVIRONMENTAL PERFORMANCE IMPROVEMENT

- Tourmaline's 'clean-tech' engineering team continues to develop and implement new proprietary emission reducti technologies, execute expanded water management initiatives, explore industry leading methane mitigation techn manage related third-party environmental research.
- Since embarking on the diesel displacement initiative for drilling rigs and frac spreads over 6 years ago, the Comp displaced 135.7 million litres of diesel since June 2017 providing an emission reduction of 87,419 tonnes of CO_2 a approximately $129.3 million (including the cost of the replacement natural gas).
- The compressed natural gas in long-haul trucking joint development with Clean Energy Fuels Corp., announced i continues to progress with the first fueling station in Edmonton operational and the second and third locations in G Grande Prairie expected to startup in 2H 2024.

- Tourmaline continues to strive to have the lowest freshwater intensity in industry (lowest in 2022 at 0.11 bbl/boe, after fracturing, based on public data for Alberta producers producing over 20 million boe per year of hydrocarbon Company's extensive water storage and recycling facilities could prove highly beneficial in the event of drought re restrictions later in the year.

DIVIDEND

- In addition to the announced special dividend payable on March 21, 2024, to shareholders of record at the close o on March 14, 2024, the Company's Board of Directors has declared a quarterly base dividend on its common sha amount of $0.30 per common share, representing an increase of 7% over the previous quarterly dividend. The inc base dividend reflects the ongoing financial strength and profitability of the Company. The dividend will be payabl 28, 2024, to shareholders of record at the close of business on March 15, 2024. Both the special dividend and the base dividend are designated as an eligible dividend for Canadian income tax purposes.

BOARD OF DIRECTORS

- The Company sadly reports the passing of Ronald C. Wigham, director, business colleague and great friend, on J 2024. Ron became a director of Tourmaline on March 7, 2016. Prior to that, in his Capital Markets position at Pet Ron played a major role in the initial capitalization and IPOs of both Tourmaline and Duvernay Oil Corp.

---

(1) This news release contains certain specified financial measures consisting of non-GAAP financial measures, non-GAAP ratios, capital management measures and supplementary financial measures. See "Non-GAAP and Other Financial Measures" in this news release for information regarding the following non-GAAP financial measures, non-GAAP ratios, capital management measures and supplementary financial measures used in this news release: "cash flow", "capital expenditures", "free cash flow", "operating netback", "operating netback per boe", "cash flow per boe", "cash flow per diluted share", "free cash flow per diluted share", "adjusted working capital" and "net debt". Since these specified financial measures do not have standardized meanings under International Financial Reporting Standards ("GAAP"), securities regulations require that, among other things, they be identified, defined, qualified and, where required, reconciled with their nearest GAAP measure and compared to the prior period. See "Non-GAAP and Other Financial Measures" in this news release and in the Company's Management's Discussion and Analysis for the year ended December 31, 2023 (the "Annual MD&A"), which information is incorporated by reference into this news release, for further information on the composition of and, where required, reconciliation of these measures.

(2) "Cash flow per diluted share" is a non-GAAP financial ratio. Cash flow, a non-GAAP financial measure, is used as a component of the non-GAAP financial ratio. See "Non-GAAP and Other Financial Measures" in this news release and in the Annual MD&A.

(3) "Free cash flow" is a non-GAAP financial measure defined as cash flow less capital expenditures, excluding acquisitions and dispositions. Free cash flow is prior to dividend payments. See "Non-GAAP and Other Financial Measures" in this news release.

(4) Based on oil and gas commodity strip pricing at February 15, 2024.

(5) Calculated as forecast 2024 FCF divided by diluted share count (based on diluted Common Shares of 355 million).

(6) Based on oil and gas commodity strip pricing at February 15, 2024

(7) "Net debt" is a capital management measure. See "Non-GAAP and Other Financial Measures" in this news release and in the Annual MD&A.

(8) Non-GAAP financial ratio. See "Non-GAAP and Other Financial Measures" in this news release and in the Annual MD&A. The recycle ratio is calculated by dividing the cash flow per boe by the appropriate F&D or FD&A costs related to the reserve additions for that year.

(9) Non-GAAP financial ratio. See "Non-GAAP and Other Financial Measures" in this news release and in the Annual MD&A.

(10) Non-GAAP financial ratio. See "Non-GAAP and Other Financial Measures" in this news release and in the Annual MD&A.

(11) "Capital efficiencies" are calculated as capital expenditures divided by estimated production added over the period.

·CORPORATE SUMMARY - DECEMBER 31, 2023

	Three Months Ended December 31,			Year Ended December 31	
	2023	2022	Change	2023	2022
OPERATIONS					
Production					
Natural gas (mcf/d)	2,543,185	2,376,463	7 %	2,409,349	2,330,234
Crude oil, condensate and NGL (bbl/d)	133,093	115,513	15 %	118,808	112,460
Oil equivalent (boe/d)	556,957	511,590	9 %	520,366	500,832
Product prices(1)					
Natural gas ($/mcf)	$ 4.25	$ 6.89	(38) %	$ 4.83	$ 5.87
Crude oil, condensate and NGL ($/bbl)	$ 54.29	$ 63.01	(14) %	$ 56.79	$ 66.97
Operating expenses ($/boe) (2)	$ 4.22	$ 4.38	(4) %	$ 4.51	$ 4.30
Transportation costs ($/boe) (3)	$ 5.41	$ 5.08	6 %	$ 5.27	$ 4.92
Operating netback ($/boe) (4)	$ 19.80	$ 30.56	(35) %	$ 22.17	$ 27.04
Cash general and administrative expenses ($/boe)(5)	$ 0.58	$ 0.56	4 %	$ 0.68	$ 0.57
FINANCIAL ($000, except share and per share)					
Total revenue from commodity sales and realized gains	1,658,883	2,176,463	(24) %	6,706,997	7,742,837
Royalties	150,466	292,784	(49) %	638,419	1,115,549
Cash flow	918,008	1,402,647	(35) %	3,707,683	4,883,949
Cash flow per share (diluted)	$ 2.62	$ 4.08	(36) %	$ 10.73	$ 14.26
Net earnings	700,202	(30,366)	2,406 %	1,735,880	4,487,049
Net earnings per share (diluted)	$ 2.00	$ (0.09)	2,322 %	$ 5.03	$ 13.10
Capital expenditures (net of dispositions)(6)	635,987	505,982	26 %	2,073,249	1,879,347
Weighted average shares outstanding (diluted)				345,383,038	342,533,099
Net debt				(1,779,732)	(494,442)
PROVED + PROBABLE RESERVES(7)					
Natural gas (bcf)				22,719.0	20,663.8
Crude oil (mbbls)				130,423	114,367
Natural gas liquids (mbbls)				1,091,453	941,936
Mboe				5,008,374	4,500,272

Notes:

(1) Product prices include realized gains and losses on risk management activities and financial instrument contracts.

(2) Supplementary financial measure. See "Non-GAAP and Other Financial Measures" in this news release and in the Annual MD&A.

(3) Supplementary financial measure. See "Non-GAAP and Other Financial Measures" in this news release and in the Annual MD&A.

(4) Excluding interest and financing charges. Non-GAAP financial measure and non-GAAP ratio. See "Non-GAAP and Other Financial Measures" in this news release and in the Annual MD&A.

(5) Non-GAAP financial measure and non-GAAP ratio. See "Non-GAAP and Other Financial Measures" in this news release and in the Annual MD&A.

(6) Non-GAAP financial measure. See "Non-GAAP and Other Financial Measures" in this news release and in the Annual MD&A.

(7) Reserves are "Company gross reserves", which are defined as the working interest share of reserves prior to the deduction of interest owned by others (burdens). Royalty interest reserves are not included in Company gross reserves.

2023 RESERVE SUMMARY

The following tables summarize the Company's gross reserves defined as the working interest share of reserves prior to the deduction of interest owned by others (burdens). Royalty interest reserves are not included in Company gross reserves. Company net reserves are defined as the working net carried and royalty interest reserves after deduction of all applicable burdens.

Reserves and Future Net Revenue Data (Forecast Prices and Costs)

Summary of Crude Oil, Natural Gas and Natural Gas Liquids Reserves and

Net Present Values of Future Net Revenue

as of December 31, 2023

Forecast Prices and Costs[1]

	Light & Medium Crude Oil		Conventional Natural Gas		Shale Natural Gas[2]		Natural Gas Li	
Reserves Category	Company Gross (Mbbls)	Company Net (Mbbls)	Company Gross (MMcf)	Company Net (MMcf)	Company Gross (MMcf)	Company Net (MMcf)	Company Gross (Mbbls)	Com Net (Mb
Proved Developed Producing	20,376	16,292	2,892,941	2,588,087	2,661,037	2,278,248	258,459	203,
Proved Developed Non-Producing	1,431	1,128	64,168	57,453	140,178	121,110	10,591	8,19
Proved Undeveloped	45,941	35,146	2,833,505	2,506,388	3,396,307	2,884,604	279,797	218,
Total Proved	67,748	52,566	5,790,614	5,151,928	6,197,522	5,283,962	548,848	429,
Total Probable	62,674	48,798	4,023,444	3,472,530	6,707,412	5,503,946	542,605	397,
Total Proved Plus Probable	130,423	101,365	9,814,058	8,624,458	12,904,934	10,787,908	1,091,453	827,

Reserves Category	Net Present Values of Future Net Revenue ($000s)						
	Before Income Taxes Discounted at (2) (%/year)						After Incom (%/year)
	0	5	8	10	15	20	0
Proved Developed Producing	23,311,365	18,672,128	16,621,131	15,491,694	13,276,124	11,661,846	19,103,911
Proved Developed Non-Producing	828,650	629,421	547,297	503,002	417,723	356,851	613,914
Proved Undeveloped	24,851,199	15,635,099	12,230,542	10,496,597	7,381,369	5,363,428	18,634,395
Total Proved	48,991,214	34,936,647	29,398,970	26,491,292	21,075,215	17,382,126	38,352,219
Total Probable	48,818,795	24,294,804	17,264,446	14,085,317	9,034,400	6,208,721	36,443,748
Total Proved Plus Probable	97,810,009	59,231,451	46,663,417	40,576,609	30,109,615	23,590,846	74,795,967

Notes:

(1) Numbers may not add due to rounding.

(2) Shale Natural Gas is required to be presented separately from Conventional Natural Gas as its own product type pursuant to National Instrument 51-101 - Standards of Disclosure for Oil and Gas Activities ("NI 51-101"). While the Tourmaline Montney reserves do not strictly fit the definition of "shale gas" as defined in NI 51-101 because the natural gas is not "primarily adsorbed" as stated within the definition, the Montney reserves have been included as shale gas for purposes of this disclosure.

(3) The after-tax net present value of the Company's oil and gas properties reflects the tax burden on the properties on a stand-alone basis. It does not consider the Company's tax situation, or tax planning. It does not provide an estimate of the value at the Company level which may be significantly different. The Company's financial statements and management's discussion and analysis should be consulted for information at the Company level.

Total Future Net Revenue ($000s)

(Undiscounted)

as of December 31, 2023

Forecast Prices and Costs[1]

Reserves Category	Revenue	Royalties	Operating Costs	Capital Development Costs	Abandonment and Reclamation Costs[2]	Future Net Revenue Before Income Tax	Incor Tax
Proved Developed Producing	42,354,921	6,218,326	10,782,756	29,233	2,013,241	23,311,365	4,207
Proved Developed Non-Producing	1,602,576	279,174	383,809	75,000	35,943	828,650	214,7
Proved Undeveloped	51,867,252	8,597,793	9,224,651	8,683,270	510,339	24,851,199	6,216
Total Proved	95,824,749	15,095,293	20,391,216	8,787,503	2,559,523	48,991,214	10,63
Total Probable	98,973,172	20,630,710	20,550,284	8,160,365	813,018	48,818,795	12,37
Total Proved Plus Probable	194,797,921	35,726,003	40,941,500	16,947,868	3,372,541	97,810,009	23,01

Notes:

(1) Numbers may not add due to rounding.

(2) Abandonment and Reclamation Costs includes all active and inactive assets, with or without associated reserves, inclusive of all wells (existing and undrilled), facilities and pipelines.

(3) The after-tax net present value of the Company's oil and gas properties reflects the tax burden on the properties on a stand-alone basis. It does not consider the Company's tax situation, or tax planning. It does not provide an estimate of the value at the Company level, which may be significantly different. The Company's financial statements and management's discussion and analysis should be consulted for information at the Company level.

Summary of Pricing and Inflation Rate Assumptions

Forecast Prices and Costs (1)

Crude Oil and Natural Gas Liquids Pricing

Year	Inflation(2) %	CAD/USD Exchange Rate $US/$Cdn(3)	NYMEX WTI Near Month Futures Contract Crude Oil at Cushing, Oklahoma Constant 2024 $US/Bbl	NYMEX WTI Near Month Futures Contract Crude Oil at Cushing, Oklahoma Then Current $US/Bbl	MSW, Light Crude Oil (40 API, 0.3%S) at Edmonton Then Current $Cdn/Bbl	Alberta Natural Gas Liquids (Then Current Dollars) Spec Ethane $Cdn/Bbl	Edmonton Propane $Cdn/Bbl	Edmonton Butane $Cdn/Bbl	Edmonton C5+ Stream Quality $Cdn/Bbl
2024	0.0	0.752	73.67	73.67	92.91	6.88	29.65	47.69	96.79
2025	2.0	0.752	73.51	74.98	95.04	10.76	35.13	48.83	98.75
2026	2.0	0.755	73.18	76.14	96.07	13.16	35.43	49.36	100.71
2027	2.0	0.755	73.18	77.66	97.99	13.44	36.14	50.35	102.72
2028	2.0	0.755	73.18	79.22	99.95	13.71	36.87	51.35	104.78
2029	2.0	0.755	73.18	80.80	101.95	14.00	37.60	52.38	106.87
2030	2.0	0.755	73.18	82.42	103.98	14.28	38.35	53.43	109.01
2031	2.0	0.755	73.18	84.06	106.07	14.58	39.12	54.50	111.19
2032	2.0	0.755	73.18	85.75	108.18	14.87	39.90	55.58	113.41
2033	2.0	0.755	73.18	87.46	110.35	15.17	40.70	56.70	115.67
2034	2.0	0.755	73.18	89.21	112.56	15.48	41.52	57.83	117.98
2035	2.0	0.755	73.18	90.99	114.81	15.79	42.35	58.99	120.34
2036	2.0	0.755	73.18	92.82	117.10	16.10	43.20	60.17	122.75
2037	2.0	0.755	73.18	94.67	119.44	16.42	44.06	61.37	125.20
2038	2.0	0.755	73.18	96.56	121.83	16.75	44.94	62.60	127.71
2039+	2.0	0.755	73.18	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr

Year	Natural Gas and Sulphur Pricing								
	NYMEX Henry Hub Near Month Contract		Midwest Price @ Chicago	AECO/NIT Spot		Alberta Plant Gate			Hunting Sumas $US/ MMbtu
						Spot		ARP $Cdn/ MMbtu	
	Constant 2024 $US/ MMbtu	Then Current $US/MMbtu	Then Current $US/ MMbtu	Then Current $Cdn/ MMbtu	Dawn Price @ Ontario Then Current $US/MMbtu	Constant 2024 $Cdn/ MMbtu	Then Current $Cdn/ MMbtu		
2024	2.75	2.75	2.58	2.20	2.68	1.92	1.92	1.92	2.83
2025	3.57	3.64	3.46	3.37	3.57	3.02	3.08	3.08	3.72
2026	3.86	4.02	3.85	4.05	3.95	3.61	3.75	3.75	4.10
2027	3.87	4.10	3.92	4.13	4.03	3.61	3.83	3.83	4.19
2028	3.86	4.18	4.01	4.21	4.11	3.61	3.91	3.91	4.27
2029	3.86	4.27	4.08	4.30	4.19	3.62	4.00	4.00	4.36
2030	3.86	4.35	4.17	4.38	4.27	3.62	4.08	4.08	4.44
2031	3.87	4.44	4.25	4.47	4.37	3.63	4.17	4.17	4.54
2032	3.86	4.53	4.34	4.56	4.45	3.63	4.25	4.25	4.63
2033	3.86	4.62	4.43	4.65	4.54	3.63	4.34	4.34	4.72
2034	3.86	4.71	4.51	4.74	4.63	3.63	4.43	4.43	4.82
2035	3.86	4.80	4.60	4.84	4.72	3.63	4.51	4.51	4.91
2036	3.86	4.90	4.70	4.94	4.82	3.63	4.60	4.60	5.01
2037	3.86	5.00	4.80	5.03	4.92	3.63	4.70	4.70	5.11
2038	3.86	5.10	4.88	5.13	5.02	3.63	4.79	4.79	5.22
2039+	3.86	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	3.63	+2.0%/yr	+2.0%/yr	+2.0%/

Notes:

(1) Crude oil and natural gas benchmark reference pricing, inflation and exchange rates utilized by GLJ in the GLJ Reserve Report and Deloitte LLP in the Deloitte Reserve Report, were an average of forecast prices and costs published by Sproule Associates Ltd. as at December 31, 2023 and GLJ and McDaniel & Associates Consultants Ltd. as at January 1, 2024 (each of which is available on their respective websites at www.sproule.com, www.gljpc.com, and www.mcdan.com). GLJ assigns a value to the Company's existing physical diversification contracts for natural gas for consuming markets at Dawn, Chicago, Ventura, Malin, PG&E, Iroquois, Kingsgate, and US Gulf Coast based on forecasted differentials to NYMEX Henry Hub as per the aforementioned consultant average price forecast, contracted volumes and transportation costs. No incremental value is assigned to potential future contracts which were not in place as of December 31, 2023.

(2) Inflation rates used for forecasting prices and costs, with the exception of capital expenditures, which have been forecasted to have nil inflation until 2026, at which time the inflation profile is as published in these tables.

(3) Exchange rates used to generate the benchmark reference prices in this table.

RESERVES PERFORMANCE RATIOS

The following tables highlight Tourmaline's reserves, F&D and FD&A costs as well as the associated recycle ratios.

Reserves, Capital Expenditures and Cash Flow(1)

As at, and for the Year ended December 31,	2023	2022	2021
Reserves (Mboe)			
Proved Producing	1,204,499	1,001,175	947,293
Total Proved	2,614,619	2,321,959	2,187,870
Proved Plus Probable	5,008,374	4,500,272	4,242,981
Capital Expenditures ($ millions)			
Exploration and Development(2)	2,023	1,677	1,437
Net Property Acquisitions (Dispositions)(3)	51	202	196
Net Corporate Acquisitions (Dispositions)(3)	1,442	188	1,232
Less: Topaz Property Acquisitions(4)	-	-	(161)
Total(5)	3,516	2,067	2,704
Cash Flow ($/boe)			
Cash Flow	19.52	26.72	18.19
Cash Flow - Three Year Average	21.58	19.67	13.97

Notes:

(1) Cash flow is defined as cash provided by operations adjusted for the change in non-cash operating working capital (deficit) and current income taxes. See "Non-GAAP and Other Financial Measures" below and in the Annual MD&A for further discussion.

(2) Includes capitalized G&A of $43 million, $47 million, and $38 million for 2023, 2022, and 2021, respectively.

(3) Includes purchase price (cash and/or common shares) plus net debt, if applicable.

(4) Includes property acquisitions incurred by Topaz from non-related parties, prior to June 8, 2021, when it was a controlled subsidiary of Tourmaline.

(5) Represents the capital expenditures used for purposes of F&D and FD&A calculations.

Finding and Development Costs

Finding and Development Costs, Excluding FDC	2023	2022	2021	3-Year Avg.
Total Proved				
Reserve Additions (MMboe)	209.3	284.6	257.6	
F&D Costs ($/boe)	9.66	5.89	5.58	6.83
F&D Recycle Ratio(1)	2.0	4.5	3.3	3.2
Total Proved Plus Probable				
Reserve Additions (MMboe)	230.7	387.0	232.2	
F&D Costs ($/boe)	8.77	4.33	6.19	6.04
F&D Recycle Ratio(1)	2.2	6.2	2.9	3.6

Finding and Development Costs, Including FDC	2023	2022	2021	3-Year Avg.
Total Proved				
Change in FDC ($ millions)	231.8	1,202	197.2	
Reserve Additions (MMboe)	209.3	284.6	257.6	
F&D Costs ($/boe)	10.77	10.12	6.34	9.00
F&D Recycle Ratio(1)	1.8	2.6	2.9	2.4
Total Proved Plus Probable				
Change in FDC ($ millions)	912.9	2,380.7	41.6	
Reserve Additions (MMboe)	230.7	387.0	232.2	
F&D Costs ($/boe)	12.72	10.49	6.37	9.97
F&D Recycle Ratio(1)	1.5	2.5	2.9	2.2

Finding, Development and Acquisition Costs

Finding, Development and Acquisition Costs, Excluding FDC	2023	2022	2021	3-Year Avg.
Total Proved				
Reserve Additions (MMboe)	482.6	316.9	657.8	
FD&A Costs ($/boe)	7.28	6.52	4.11	5.69
FD&A Recycle Ratio(1)	2.7	4.1	4.4	3.8
Total Proved Plus Probable				
Reserve Additions (MMboe)	698.0	440.1	1,089.7	
FD&A Costs ($/boe)	5.04	4.70	2.48	3.72
FD&A Recycle Ratio(1)	3.9	5.7	7.3	5.8

Finding, Development and Acquisition Costs, Including FDC	2023	2022	2021	3-Year Avg.
Total Proved				
Change in FDC ($ millions)	1,654.1	1,337.3	1,201.1	
Reserve Additions (MMboe)	482.6	316.9	657.8	
FD&A Costs ($/boe)	10.71	10.74	5.94	8.56
FD&A Recycle Ratio(1)	1.8	2.5	3.1	2.5
Total Proved Plus Probable				
Change in FDC ($ millions)	3,326.1	2,593.0	2,241.2	
Reserve Additions (MMboe)	698.0	440.1	1,089.7	
FD&A Costs ($/boe)	9.80	10.59	4.54	7.38
FD&A Recycle Ratio(1)	2.0	2.5	4.0	2.9

Note:

(1) The recycle ratio is calculated by dividing the cash flow per boe by the appropriate F&D or FD&A costs related to the reserve additions for that year.

Conference Call Tomorrow at 9:00 a.m. MT (11:00 a.m.) ET

Tourmaline will host a conference call tomorrow, March 7, 2024 starting at 9:00 a.m. MT (11:00 a.m. ET).

To participate without operator assistance, you may register and enter your phone number at https://emportal.ink/3SqA9kS to receive an instant automated call back.

To participate using an operator, please dial 1-888-664-6383 (toll-free in North America), or 1-416-764-8650 (international dial-in), a few minutes prior to the conference call.

Reader Advisories

CURRENCY

All amounts in this news release are stated in Canadian dollars unless otherwise specified.

FORWARD-LOOKING INFORMATION

This news release contains forward-looking information and statements (collectively, "forward-looking information") within the meaning of applicable securities laws. The use of any of the words "forecast", "expect", "anticipate", "continue", "estimate", "objective", "ongoing", "on track", "may", "will", "project", "should", "believe", "plans", "intends" and similar expressions are intended to identify forward-looking information. More particularly and without limitation, this news release contains forward-looking information concerning Tourmaline's plans and other aspects of its anticipated future operations, management focus, objectives, strategies, financial, operating and production results, business opportunities and shareholder return plan, including the following: the future declaration and payment of base and special dividends and the timing and amount thereof which assumes, among other things, the availability of free cash flow to fund such dividends; anticipated 2024 cash flow and free cash flow; long-term net debt targets and the Company's expectation that it will deleverage throughout 2024; anticipated free cash flow in each year of the Company's five year EP growth plan; anticipated liquids and natural gas production and production growth for various periods including estimated production levels for the first quarter of 2024 and full-year 2024; condensate and NGL production growth anticipated from the Company's Conroy North Montney, Doe South Montney and North Deep Basin grown projects; expected full-year 2024 EP capital budget and 2024 spending on exploratory drilling; anticipated capital efficiencies; the number of DUCs that the Company anticipates accumulating during 2024; the Company's ability to materially grow production toward 2024 exit if natural gas pricing recovers on a sustained basis; the number of wells expected to be drilled in 2024; anticipated drilling cost reductions associated with monobore design for the Glauconite; anticipated natural gas prices; sustainability and environmental improvement initiatives; anticipated natural gas volumes to targeted premium export markets at the end of 2024; the anticipated timing of the Company's second and third compressed natural gas fueling stations becoming operational; as well as Tourmaline's future drilling prospects and plans, business strategy, future development and growth opportunities, prospects and asset base. The forward-looking information is based on certain key expectations and assumptions made by Tourmaline, including expectations and assumptions concerning the following: prevailing and future commodity prices and currency exchange rates; the degree to which Tourmaline's operations and production may be disrupted or by circumstances attributable to supply chain disruptions; applicable royalty rates and tax laws; interest rates; inflation rates; future well production rates and reserve volumes; operating costs, receipt of regulatory approvals and the timing thereof; the performance of existing and future wells; the success obtained in drilling new wells; anticipated timing and results of capital expenditures; the sufficiency of budgeted capital expenditures in carrying out planned activities; the timing, location and extent of future drilling operations; the benefits to be derived from acquisitions; the state of the economy and the exploration and production business; the availability and cost of financing, labour and services; ability to maintain investment grade credit rating; and ability to market crude oil, natural gas and natural gas liquids successfully. Without limitation of the foregoing, future dividend payments, if any, and the level thereof is uncertain, as the Company's dividend policy and the funds available for the payment of dividends from time to time is dependent upon, among other things, free cash flow, financial requirements for the Company's operations and the execution of its growth strategy, fluctuations in working capital and the timing and amount of capital expenditures, debt service requirements and other factors beyond the Company's control. Further, the ability of Tourmaline to pay dividends is subject to applicable laws (including the satisfaction of the solvency test contained in applicable corporate legislation) and contractual restrictions contained in the instruments governing its indebtedness, including its credit facility.

Statements relating to "reserves" are also deemed to be forward looking information, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated and that the reserves can be profitably produced in the future.

Although Tourmaline believes that the expectations and assumptions on which such forward-looking information is based are reasonable, undue reliance should not be placed on the forward-looking information because Tourmaline can give no assurances that it will prove to be correct. Since forward-looking information addresses future events and conditions, by its very nature it involves inherent risks and uncertainties. Actual results could differ materially from those currently anticipated due to a number of factors and risks. These include, but are not limited to: the risks associated with the oil and gas industry in general such as operational risks in development, exploration and production; delays or changes in plans with respect to exploration or development projects or capital expenditures; supply chain disruptions; the uncertainty of estimates and projections relating to reserves, production, revenues, costs and expenses; health, safety and environmental risks; commodity price and exchange rate fluctuations; interest rate fluctuations; changes in rates of inflation; marketing and transportation; loss of markets; environmental risks;

competition; incorrect assessment of the value of acquisitions; failure to complete or realize the anticipated benefits of acquisitions or dispositions; stock market volatility; ability to access sufficient capital from internal and external sources; uncertainties associated with counterparty credit risk; failure to obtain required regulatory and other approvals including drilling permits and the impact of not receiving such approvals on the Company's long-term planning; climate change risks; severe weather (including wildfires and drought); risks of wars or other hostilities or geopolitical events, civil insurrection and pandemics; risks relating to Indigenous land claims and duty to consult; data breaches and cyber attacks; risks relating to the use of artificial intelligence; changes in legislation, including but not limited to tax laws, royalties and environmental regulations (including greenhouse gas emission reduction requirements and other decarbonization or social policies) and general economic and business conditions and markets. Readers are cautioned that the foregoing list of factors is not exhaustive.

Additional information on these and other factors that could affect Tourmaline, or its operations or financial results, are included in the Company's most recently filed Management's Discussion and Analysis (See "Forward-Looking Statements" therein), Annual Information Form (See "Risk Factors" and "Forward-Looking Statements" therein) and other reports on file with applicable securities regulatory authorities which may be accessed through the SEDAR+ website (www.sedarplus.ca) or Tourmaline's website (www.tourmalineoil.com).

The forward-looking information contained in this news release is made as of the date hereof and Tourmaline undertakes no obligation to update publicly or revise any forward-looking information, whether as a result of new information, future events or otherwise, unless expressly required by applicable securities laws.

RESERVES DATA

The reserves data set forth above is based upon the reports of GLJ Ltd. ("GLJ") and Deloitte LLP, each dated effective December 31, 2023, which have been consolidated into one report by GLJ and adjusted to apply certain of GLJ's assumptions and methodologies and pricing and cost assumptions. The price forecast used in the reserve evaluations is an average of forecast prices published by Sproule Associates Ltd. as at December 31, 2023 and GLJ and McDaniel & Associates Consultants Ltd. as at January 1, 2024 (each of which is available on their respective websites at www.sproule.com, www.gljpc.com, and www.mcdan.com), and will be contained in the Company's Annual Information Form for the year ended December 31, 2023, which will be filed on SEDAR+ (accessible at www.sedarplus.ca) on or before April 1, 2024.

There are numerous uncertainties inherent in estimating quantities of crude oil, natural gas and NGL reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth above are estimates only. In general, estimates of economically recoverable crude oil, natural gas and NGL reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially. For those reasons, estimates of the economically recoverable crude oil, NGL and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times, may vary. The Company's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material.

All evaluations and reviews of future net revenue are stated prior to any provisions for interest costs or general and administrative costs and after the deduction of estimated future capital expenditures for wells to which reserves have been assigned. The after-tax net present value of the Company's oil and gas properties reflects the tax burden on the properties on a stand-alone basis and utilizes the Company's tax pools. It does not consider the corporate tax situation, or tax planning. It does not provide an estimate of the after-tax value of the Company, which may be significantly different. The Company's financial statements and the management's discussion and analysis should be consulted for information at the level of the Company.

The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to effects of aggregations. The estimated values of future net revenue disclosed in this news release do not represent fair market value. There is no assurance that the forecast prices and cost assumptions used in the reserve evaluations will be attained and variances could be material.

The reserve data provided in this news release presents only a portion of the disclosure required under National Instrument 51-101. All of the required information will be contained in the Company's Annual Information Form for the year ended December 31, 2023, which will be filed on (SEDAR+ accessible at www.sedarplus.ca) on or before April 1, 2024.

BOE EQUIVALENCY

In this news release, production and reserves information may be presented on a "barrel of oil equivalent" or "BOE" basis. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In addition, as the value ratio between natural gas and crude oil based on the current prices of natural gas and crude oil is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

INDUSTRY METRICS

This news release contains metrics commonly used in the oil and natural gas industry. Each of these metrics is determined by the Company as set out below or elsewhere in this news release. These metrics are "F&D" costs, "FD&A" costs, "recycle ratio", "F&D recycle ratio", and "FD&A recycle ratio". These metrics are considered "non-GAAP ratios" and do not have standardized meanings and may not be comparable to similar measures presented by other companies. As such, they should not be used to make comparisons. See "Non-GAAP and Other Financial Measures" in this news release and in the Annual MD&A. The non-GAAP financial measures used as a component of these non-GAAP ratios are capital expenditures and cash flow.

Management uses these oil and gas metrics for its own performance measurements and to provide shareholders with measures to compare the Company's performance over time, however, such measures are not reliable indicators of the Company's future performance and future performance may not compare to the performance in previous periods.

"F&D" costs are calculated by dividing the sum of the total capital expenditures for the year (in dollars) by the change in reserves within the applicable reserves category (in boe). F&D costs, including FDC, includes all capital expenditures in the year as well as the change in FDC required to bring the reserves within the specified reserves category on production.

"FD&A" costs are calculated by dividing the sum of the total capital expenditures for the year inclusive of the net acquisition costs and disposition proceeds (in dollars) by the change in reserves within the applicable reserves category inclusive of changes due to acquisitions and dispositions (in boe). FD&A costs, including FDC, includes all capital expenditures in the year inclusive of the net acquisition costs and disposition proceeds as well as the change in FDC required to bring the reserves within the specified reserves category on production.

The "recycle ratio" is calculated by dividing the cash flow per boe by the appropriate F&D or FD&A costs related to the reserve additions for that year.

The Company uses F&D and FD&A as a measure of the efficiency of its overall capital program including the effect of acquisitions and dispositions. The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year.

FINANCIAL OUTLOOKS

Also included in this news release are estimates of Tourmaline's 2024 cash flow and free cash flow and long-term net debt targets, which are based on, among other things, the various assumptions as to production levels, capital expenditures and other assumptions disclosed in this news release and including Tourmaline's estimated 2024 average production of 585,000 boepd, 2024 commodity price assumptions for natural gas ($2.25/mcf NYMEX US, $2.03/mcf AECO, $9.88/mcf JKM US), crude oil ($75.30/bbl WTI US) and an exchange rate assumption of $0.74 (US/CAD). To the extent such estimates constitute a financial outlook, it was approved by management and the Board of Directors of Tourmaline on March 6, 2024 and is included to provide readers with an understanding of Tourmaline's anticipated cash flow, free cash flow and net debt levels based on the capital expenditure, production, pricing, exchange rate and other assumptions described herein and readers are cautioned that the information may not be appropriate for other purposes.

NON-GAAP AND OTHER FINANCIAL MEASURES

This news release contains the terms "cash flow", "capital expenditures", "free cash flow", and "operating netback", which are considered "non-GAAP financial measures" and the terms "cash flow per diluted share", "free cash flow per diluted share", "operating netback per boe", "cash flow per-boe", "finding and development costs", "finding, development and acquisition costs" and "recycle ratio", which are considered "non-GAAP financial ratios". These terms do not have a standardized meaning prescribed by GAAP. In addition, this news release contains the terms "adjusted working capital" and "net debt", which are considered "capital management measures" and do not have standardized meanings prescribed by GAAP. Accordingly, the Company's use of these terms may not be comparable to similarly defined measures presented by other companies. Investors are cautioned that these measures should not be construed as an alternative to or more meaningful than the most directly comparable GAAP measures in evaluating the Company's performance. See "Non-GAAP and Other Financial Measures" in the most recent Management's Discussion and Analysis for more information on the definition and description of these terms.

Non-GAAP Financial Measures

Cash Flow

Management uses the term "cash flow" for its own performance measure and to provide shareholders and potential investors with a measurement of the Company's efficiency and its ability to generate the cash necessary to fund its future growth expenditures, to repay debt or to pay dividends. The most directly comparable GAAP measure for cash flow is cash flow from operating activities. A summary of the reconciliation of cash flow from operating activities to cash flow, is set forth below:

	Three Months Ended December 31,		Years Ended December 31,	
(000s)	2023	2022	2023	2022
Cash flow from operating activities (per GAAP)	$ 1,012,819	$ 1,115,399	$ 4,406,092	$ 4,692,731
Current income taxes	(75,669)	(7,599)	(431,298)	(11,934)
Current income taxes paid	6,051	-	40,548	-
Change in non-cash working capital (deficit)	(25,193)	294,847	(307,659)	203,152
Cash flow	$ 918,008	$ 1,402,647	$ 3,707,683	$ 4,883,949

Capital Expenditures

Management uses the term "capital expenditures" as a measure of capital investment in exploration and production activity, as well as property acquisitions and divestitures, and such spending is compared to the Company's annual budgeted capital expenditures. The most directly comparable GAAP measure for capital expenditures is cash flow used in investing activities. A summary of the reconciliation of cash flow used in investing activities to capital expenditures, is set forth below:

	Three Months Ended December 31,		Years Ended December 31,	
(000s)	2023	2022	2023	2022
Cash flow used in investing activities (per GAAP)	$ 1,196,019	$ 548,471	$ 2,602,360	$ 1,971,129
Corporate acquisitions	(650,986)	-	(650,986)	(67,770)
Change in non-cash working capital (deficit)	90,954	(42,489)	121,875	(24,012)
Capital expenditures	$ 635,987	$ 505,982	$ 2,073,249	$ 1,879,347

Free Cash Flow

Management uses the term "free cash flow" for its own performance measure and to provide shareholders and potential investors with a measurement of the Company's efficiency and its ability to generate the cash necessary to fund its future growth expenditures, to repay debt and provide shareholder returns. Free cash flow is defined as cash flow less capital expenditures, excluding acquisitions and dispositions. Free cash flow is prior to dividend payment. The most directly comparable GAAP measure for cash flow is cash flow from operating activities. See "Non-GAAP Financial Measures - Cash Flow" and " Non-GAAP Financial Measures - Capital Expenditures" above.

	Three Months Ended December 31,		Years Ended December 31,	
(000s)	2023	2022	2023	2022
Cash flow	$ 918,008	$ 1,402,647	$ 3,707,683	$ 4,883,949
Capital expenditures	(635,987)	(505,982)	(2,073,249)	(1,879,347)
Property acquisitions	-	12,126	58,536	273,843
Proceeds from divestitures	-	(109)	(7,789)	(71,489)
Free Cash Flow	$ 282,021	$ 908,682	$ 1,685,181	$ 3,206,956

Operating Netback

Management uses the term "operating netback" as a key performance indicator and one that is commonly presented by other oil and natural gas producers. Operating netback is defined as the sum of commodity sales from production, premium on risk management activities and realized (loss) on financial instruments less the sum of royalties, transportation costs and operating expenses. A summary of the reconciliation of operating netback from commodity sales from production, which is a GAAP measure, is set forth below:

	Three Months Ended December 31,		Years Ended December 31,	
(000s)	2023	2022	2023	2022
Commodity sales from production	$ 1,366,040	$ 1,932,515	$ 5,351,253	$ 8,110,837
Premium on risk management activities	191,236	409,241	811,263	517,109
Realized gain (loss) on financial instruments	101,607	(165,293)	544,481	(885,109)
Royalties	(150,466)	(292,784)	(638,419)	(1,115,549)
Transportation costs	(276,991)	(238,937)	(1,000,570)	(898,871)
Operating expenses	(216,462)	(206,344)	(857,173)	(785,611)
Operating netback	$ 1,014,964	$ 1,438,398	$ 4,210,835	$ 4,942,806

Non-GAAP Financial Ratios

Operating Netback per-boe

Management calculates "operating netback per-boe" as operating netback divided by total production for the period. Operating netback per-boe is a key performance indicator and measure of operational efficiency and one that is commonly presented by other oil and natural gas producers. A summary of the calculation of operating netback per boe, is set forth below:

	Three Months Ended December 31,		Years Ended December 31,	
($/boe)	2023	2022	2023	2022
Revenue, excluding processing income	$ 32.37	$ 46.24	$ 35.31	$ 42.36
Royalties	(2.94)	(6.22)	(3.36)	(6.10)
Transportation costs	(5.41)	(5.08)	(5.27)	(4.92)
Operating expenses	(4.22)	(4.38)	(4.51)	(4.30)
Operating netback	$ 19.80	$ 30.56	$ 22.17	$ 27.04

Cash Flow per-boe

Management uses cash flow per boe to highlight how much cash flow is generated by each boe produced. The ratio is calculated by dividing cash flow by total production for the period. See "Non-GAAP Financial Measures - Cash Flow". See "Reserves Performance Ratios" section for information on annual cash flow per boe and comparative period data used.

Finding and Development Costs, Finding, Development and Acquisition Costs and Recycle Ratio

See "Reserves Performance Ratios" and "Industry Metrics" for information on the composition of the non-GAAP financial measures used as a component of and comparative period data for finding and development costs, finding, development and acquisition costs and recycle ratio.

Capital Management Measures

Adjusted Working Capital

Management uses the term "adjusted working capital" for its own performance measures and to provide shareholders and potential investors with a measurement of the Company's liquidity. A summary of the reconciliation of working capital (deficit) to adjusted working capital (deficit), is set forth below:

	As at December 31,	
(000s)	2023	2022
Working capital (deficit)	$ (298,280)	$ 809,449
Fair value of financial instruments - short-term (asset)	(437,535)	(709,286)
Lease liabilities - short-term	5,796	3,109
Decommissioning obligations - short-term	45,000	30,000
Unrealized foreign exchange in working capital - (asset) liability	5,524	(8,605)
Adjusted working capital (deficit)	$ (679,495)	$ 124,667

Net Debt

Management uses the term "net debt", as a key measure for evaluating its capital structure and to provide shareholders and potential investors with a measurement of the Company's total indebtedness. A summary of the composition of net debt, is set forth below:

	As at December 31,	
(000s)	2023	2022
Bank debt	$ (651,594)	$ (170,767)
Senior unsecured notes	(448,643)	(448,342)
Adjusted working capital (deficit)	(679,495)	124,667
Net debt	$ (1,779,732)	$ (494,442)

Supplementary Financial Measures

The following measures are supplementary financial measures: cash flow per diluted share, reserve value per diluted share, operating expenses ($/boe), cash general and administrative expenses ($/boe) and transportation costs ($/boe). These measures are calculated by dividing the numerator by a diluted share count or by total production for the period, depending on the financial measure discussed.

ESTIMATED DRILLING INVENTORY

This press release discloses drilling locations. Drilling locations are categorized as follows: (i) proved undeveloped locations; (ii) probable undeveloped locations; (iii) unbooked locations; and (iv) an aggregate total of (i), (ii) and (iii). Of the 23,724 (gross) locations disclosed in this press release, 2,132 are proved undeveloped locations, 36 are proved non-producing locations, 1,735 are probable undeveloped locations, and 19,821 are unbooked. Proved producing wells, proved undeveloped locations, proved non-producing locations, probable undeveloped locations and probable non-producing locations are booked and derived from the Company's most recent independent reserves evaluation as prepared by GLJ and Deloitte LLP as of December 31, 2023, and account for drilling locations that have associated proved and/or probable reserves, as applicable. Unbooked locations are internal estimates based on the Company's prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Unbooked locations do not have attributed reserves or resources (including contingent and prospective). Unbooked locations have been identified by management as an estimation of the Company's multi-year drilling activities based on evaluation of applicable geologic, seismic, engineering, production and reserves information. There is no certainty that the Company will drill all unbooked drilling locations and if drilled there is no certainty that such locations will result in additional oil and gas reserves, resources or production. The drilling locations on which the Company will actually drill wells, including the number and timing thereof is ultimately dependent upon the availability of funding, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results, additional reservoir information that is obtained and other factors. While a certain number of the unbooked drilling locations have been derisked by drilling existing wells in relative close proximity to such unbooked drilling locations, the majority of other unbooked drilling locations are farther away from existing wells where management has less information about the characteristics of the reservoir and therefore there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty that such wells will result in additional oil and gas reserves, resources or production.

SUPPLEMENTAL INFORMATION REGARDING PRODUCT TYPES

This news release includes references to full-year 2023 production, Q4 2023 production and Q1 2024 and full-year 2024 expected average daily production. The following table is intended to provide supplemental information about the product type composition for each of the production figures that are provided in this news release:

	Light and Medium Crude Oil(1)	Conventional Natural Gas	Shale Natural Gas	Natural Gas Liquids(1)	C T
	Company Gross (Bbls)	Company Gross (Mcf)	Company Gross (Mcf)	Company Gross (Bbls)	C (
2023 Average Daily Production	44,916	1,281,130	1,128,219	73,892	5
Q4 2023 Average Daily Production	48,043	1,390,610	1,152,575	85,050	5
Q1 2024 Expected Average Daily Production	49,350	1,525,500	1,159,500	95,650	5
2024 Expected Average Daily Production	50,325	1,486,150	1,160,000	93,650	5

(1) For the purposes of this disclosure, condensate has been combined with Light and Medium Crude Oil as the associated revenues and certain costs of condensate are similar to Light and Medium Crude Oil. Accordingly, NGLs in this disclosure exclude condensate.

CREDIT RATINGS

Credit ratings are intended to provide investors with an independent measure of credit quality of an issue of securities. Credit ratings are not recommendations to purchase, hold or sell securities and do not address the market price or suitability of a specific security for a particular investor. There is no assurance that any rating will remain in effect for any given period of time or that any rating will not be revised or withdrawn entirely by a rating agency in the future if, in its judgment, circumstances so warrant.

INITIAL PRODUCTION RATES

Any references in this news release to initial production rates are useful in confirming the presence of hydrocarbons; however, such rates are not determinative of the rates at which such wells will continue production and decline thereafter and are not necessarily indicative of long-term performance or ultimate recovery. While encouraging, readers are cautioned not to place reliance on such rates in calculating the aggregate production for the company. Such rates are based on field estimates and may be based on limited data available at this time.

GENERAL

See also "Forward-Looking Statements", and "Non-GAAP and Other Financial Measures" in the most recently filed Management's Discussion and Analysis.

CERTAIN DEFINITIONS:

1H	first half
2H	second half
bbl	barrel
bbls/day	barrels per day
bbl/mmcf	barrels per million cubic feet
bcf	billion cubic feet
bcfe	billion cubic feet equivalent
bpd or bbl/d	barrels per day
boe	barrel of oil equivalent
boepd or boe/d	barrel of oil equivalent per day
bopd or bbl/d	barrel of oil, condensate or liquids per day
DUC	drilled but uncompleted wells
EP	exploration and production
gj	gigajoule
gjs/d	gigajoules per day
JKM	Japan Korea Marker
mbbls	thousand barrels
mmbbls	million barrels
mboe	thousand barrels of oil equivalent
mboepd	thousand barrels of oil equivalent per day
mcf	thousand cubic feet
mcfpd or mcf/d	thousand cubic feet per day
mcfe	thousand cubic feet equivalent
mmboe	million barrels of oil equivalent
mmbtu	million British thermal units
mmbtu/d	million British thermal units per day
mmcf	million cubic feet
mmcfpd or mmcf/d	million cubic feet per day

MPa	megapascal
mstb	thousand stock tank barrels
natural gas	conventional natural gas and shale gas
NCIB	normal course issuer bid
NGL or NGLs	natural gas liquids
Tcf	trillion cubic feet

ABOUT TOURMALINE OIL CORP.

Tourmaline is Canada's largest and most active natural gas producer dedicated to producing the lowest emission and lowest-cost natural gas in North America. We are an investment grade exploration and production company providing strong and predictable operating and financial performance through the development of our three core areas in the Western Canadian Sedimentary Basin. With our existing large reserve base, decades-long drilling inventory, relentless focus on execution and cost management, and industry-leading environmental performance, we are excited to provide shareholders an excellent return on capital, and an attractive source of income through our base dividend and surplus free cash flow distribution strategies.

SOURCE Tourmaline Oil Corp.

Contact
Tourmaline Oil Corp.: Michael Rose, Chairman, President and Chief Executive Officer, (403) 266-5992 OR Tourmaline Oil Corp.: Brian Robinson, Chief Financial Officer, (403) 767-3587; brian.robinson@tourmalineoil.com OR Tourmaline Oil Corp.: Scott Kirker, Chief Legal Officer and External Affairs, (403) 767-3593; scott.kirker@tourmalineoil.com OR Tourmaline Oil Corp.: Jamie Heard, Vice President, Capital Markets, (403) 767-5942; jamie.heard@tourmalineoil.com OR Tourmaline Oil Corp., Suite 2900, 250 - 6th Avenue S.W., Calgary, Alberta T2P 3H7, Phone: (403) 266-5992; Facsimile: (403) 266-5952, E-mail: info@tourmalineoil.com, Website: www.tourmalineoil.com