Touchstone Exploration Inc.

Management's Discussion and Analysis

For the three months and years ended December 31, 2023 and 2022

Management's Discussion and Analysis

This Management's Discussion and Analysis ("MD&A") of the financial condition and results of operations of Touchstone Exploration Inc. ("Touchstone", "we", "our", "us" or the "Company") for the three months and year ended December 31, 2023 with comparisons to the three months and year ended December 31, 2022 is dated March 20, 2024 and should be read in conjunction with the Company's audited consolidated financial statements as at and for the year ended December 31, 2023 (the "audited financial statements") and our 2023 Annual Information Form ("AIF"), each of which are available online on our SEDAR+ profile (www.sedarplus.ca) and website (www.touchstoneexploration.com). The audited financial statements have been prepared by Management in accordance with IFRS Accounting Standards as issued by the International Accounting Standards Board ("IFRS" or "GAAP"). The audited financial statements were prepared by Management and approved by the Company's Board of Directors ("Board").

Unless otherwise stated, all financial amounts presented herein are rounded to thousands of United States dollars ("$" or "US$").

The Company may also reference Canadian dollars ("C$") and Trinidad and Tobago dollars ("TT$") herein, which are the functional and operational currencies of the Company's parent company and operating subsidiaries, respectively. All production volumes disclosed herein are sales volumes and are based on Company working interest before royalty burdens. Certain prior year amounts have been reclassified to conform to the current year presentation. In all cases where percentage (%) figures are provided, such percentages have generally been rounded to the nearest whole number and limited to increases or decreases of 100 percent.

Certain measures in this MD&A do not have any standardized meaning prescribed under IFRS and therefore are considered non-GAAP financial measures. Readers are cautioned that this MD&A should be read in conjunction with Touchstone's disclosure under the "*Advisories*" section herein which provides information on non-GAAP financial measures, forward-looking statements, reserves disclosures, oil and natural gas measures, product type disclosures and references to Touchstone.

About Touchstone Exploration Inc.

Touchstone is incorporated under the laws of Alberta, Canada with its head office located in Calgary, Alberta. The Company, through its subsidiaries, is a petroleum and natural gas exploration and production company active in the Republic of Trinidad and Tobago ("Trinidad"). Touchstone is currently the largest independent onshore oil and natural gas producer in Trinidad, with assets in several reservoirs that have an extensive internally estimated inventory of petroleum and natural gas development and exploration opportunities. The Company's common shares are traded on the Toronto Stock Exchange and the AIM market of the London Stock Exchange under the stock symbol "TXP". Our strategy is to leverage Canadian experience and capability to our Trinidad onshore properties to create shareholder value.

Financial and Operational Results Overview

	Three months ended December 31, 2023	2022	% change	Year ended December 31, 2023	2022	% change
Operational						
Average daily production						
Crude oil[1] *(bbls/d)*	**1,133**	1,274	(11)	**1,181**	1,340	(12)
NGLs[1] *(bbls/d)*	**622**	-	n/a	**201**	-	n/a
Crude oil and liquids[1] *(bbls/d)*	**1,755**	1,274	38	**1,382**	1,340	3
Natural gas[1] *(Mcf/d)*	**40,491**	5,729	100	**15,593**	1,444	100
Average daily production *(boe/d)*[2]	**8,504**	2,229	100	**3,981**	1,581	100
Average realized prices[3]						
Crude oil[1] *($/bbl)*	**72.26**	75.10	(4)	**67.80**	85.52	(21)
NGLs[1] *($/bbl)*	**72.92**	-	n/a	**74.07**	-	n/a
Crude oil and liquids[1] *($/bbl)*	**72.49**	75.10	(3)	**68.72**	85.52	(20)
Natural gas[1] *($/Mcf)*	**2.43**	2.11	15	**2.36**	2.11	12
Realized commodity price *($/boe)*[2]	**26.53**	48.36	(45)	**33.10**	74.43	(56)
Production mix *(% of production)*						
Crude oil and liquids[1]	**21**	57		**35**	85	
Natural gas[1]	**79**	43		**65**	15	
Operating netback *($/boe)*[2]						
Realized commodity price[3]	**26.53**	48.36	(45)	**33.10**	74.43	(56)
Royalties[3]	**(5.53)**	(15.24)	(64)	**(8.38)**	(25.37)	(67)
Operating expenses[3]	**(3.46)**	(12.07)	(71)	**(6.68)**	(15.64)	(57)
Operating netback[3]	**17.54**	21.05	(17)	**18.04**	33.42	(46)
Financial *($000's except per share amounts)*						
Petroleum and natural gas sales	**20,759**	9,919	100	**48,098**	42,944	12
Cash from (used in) operating activities	**8,512**	(1,189)	n/a	**12,743**	5,752	100
Funds flow from operations	**10,489**	691	100	**13,730**	3,540	100
Net loss	**(21,236)**	(1,921)	100	**(20,598)**	(3,197)	100
Per share – basic and diluted	**(0.09)**	(0.01)	100	**(0.09)**	(0.01)	100
Exploration capital expenditures	**595**	2,290	(74)	**17,638**	9,788	80
Development capital expenditures	**591**	219	100	**1,311**	1,542	(15)
Capital expenditures[3]	**1,186**	2,509	(53)	**18,949**	11,330	67
Working capital deficit (surplus)[3]				**7,581**	(4,992)	n/a
Principal long-term bank debt				**15,000**	21,000	(29)
Net debt[3] – end of period				**22,581**	16,008	41
Share Information *(000's)*						
Weighted avg. shares outstanding: Basic and diluted	**234,213**	217,106	8	**233,487**	213,211	10
Outstanding shares – end of period				**234,213**	233,037	1

Notes:

(1) In the table above and elsewhere in this MD&A, references to "crude oil" refer to "light and medium crude oil" and "heavy crude oil" product types combined; references to "NGLs" refer to condensate; and references to "natural gas" refer to "conventional natural gas", all as defined in National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101"). In addition, references to "crude oil and liquids" in this MD&A include crude oil and NGLs. Refer to the "*Advisories - Product Type Disclosures*" section of this MD&A for further information.

(2) In the table above and elsewhere in this MD&A, references to "boe" mean barrels of oil equivalent that are calculated using the energy equivalent conversion method. Refer to the "*Advisories - Oil and Natural Gas Measures*" section in this MD&A for further information.

(3) Non-GAAP financial measure. See the "*Advisories - Non-GAAP Financial Measures*" section of this MD&A for further information.

Highlights of Touchstone's financial and operating results for the three months ended December 31, 2023 include:

- Average quarterly production increased 151 percent to 8,504 boe/d (79 percent natural gas) relative to 3,391 boe/d produced in the third quarter of 2023, reflecting a full quarter of Cascadura production volumes.
- Realized petroleum and natural gas sales of $20,759,000 compared to $11,682,000 in the third quarter of 2023, mainly attributed to incremental Cascadura natural gas and associated liquids sales.
  - Cascadura field production volumes in the quarter contributed $8,437,000 of net natural gas sales at an average realized price of $2.45 per Mcf and $4,170,000 of net NGL sales at an average realized price of $72.92 per barrel.
  - Natural gas production from the Coho-1 well averaged net volumes of 3.1 MMcf/d (517 boe/d) in the quarter and contributed $617,000 of net natural gas sales at an average realized price of $2.16 per Mcf.
- Generated an operating netback of $13,731,000, a 128 percent increase from the third quarter of 2023, benefiting from a full quarter of production from our Cascadura field. Operating netbacks were $17.54 per boe, representing a 9 percent decrease from the $19.27 per boe reported in the third quarter of 2023, attributed to an increased weighting of natural gas volumes to total production.
- Achieved quarterly record funds flow from operations of $10,489,000 in the fourth quarter compared to $2,432,000 in the preceding quarter, primarily driven by the $7,720,000 quarter-over-quarter increase in operating netback.
- Recorded net impairment expenses of $21,342,000 ($28,898,000 net of income tax), resulting in a net loss of $21,236,000 ($0.09 per basic share) recognized in the quarter.
- $1,186,000 in quarterly capital investments primarily focused on expenditures directed to Royston-1X production testing, final Cascadura facility commissioning and pre-drill expenditures relating to the Cascadura-2 well drilled in January and February 2024.
- Reduced net debt by 25 percent in the quarter, exiting the year with a cash balance of $8,186,000, a working capital deficit of $7,581,000 and a bank loan principal balance of $28,000,000, resulting in a net debt position of $22,581,000.

Highlights of Touchstone's financial and operating results for the year ended December 31, 2023 include:

- Commissioned and achieved first natural gas and associated liquids production from our Cascadura facility on September 6, 2023.
- Delivered average daily production volumes of 3,981 boe/d (65 percent natural gas), an increase of 152 percent year-over-year.
- Realized petroleum and natural gas sales of $48,098,000 compared to $42,944,000 in the prior year, as $15,742,000 of incremental Cascadura natural gas and associated liquids sales were partially offset by a $12,598,000 decrease in crude oil sales, reflecting a 21 percent decline in realized crude oil pricing and a 12 percent reduction in crude oil production.
- Generated funds flow from operations of $13,730,000 (2022 - $3,540,000) and an annual operating netback of $26,220,000 or $18.04 per boe (2022 - $19,281,000 and $33.42 per boe).
- Reported an annual net loss of $20,598,000 ($0.09 per basic share) compared to $3,197,000 ($0.01 per basic share) in 2022, driven by $21,389,000 in net non-financial asset impairment expenses ($28,945,000 net of income tax) recognized in 2023, partially offset by strong production and funds flow from operations.
- Executed an incident-free $18,949,000 capital program, primarily focused on completing the Cascadura natural gas facility and drilling and testing the Royston-1X exploration well.

- December 31, 2023 net debt was $22,581,000, resulting in a reduced net debt to annual funds flow from operations ratio of 1.64 times.
- Responsible operations remained a top priority throughout 2023, as Touchstone had one lost time injury and released its third environmental, social and governance report encompassing the 2022 year.
- Our December 31, 2023 reserves evaluation was highlighted by an increase in gross proved developed producing reserves of 180 percent to 13,547 Mboe relative to the prior year. Gross proved ("1P") reserves decreased by 12 percent to 33,696 Mboe, and gross proved plus probable ("2P") reserves declined by 10 percent to 67,379 Mboe from December 31, 2022 mainly as a result of the removal of eight future well locations, increased production volumes in 2023 and a limited 2023 development capital program. The reserves data was based on an independent reserve evaluation prepared by GLJ Ltd. ("GLJ") dated February 29, 2024 with an effective date of December 31, 2023 (the "Reserves Report").

Annual 2024 Guidance

Touchstone continues to focus on financial discipline and value creation. Our principal near term strategy is strategically balanced by maintaining base production levels and increasing cash flow generation via the development of our Cascadura field in 2024. On December 19, 2024, the Company issued a news release to announce the approval of its preliminary financial and operating guidance for 2024. This guidance is summarized in the table below.

2024 Preliminary Guidance Summary(1)	**Year ending December 31, 2024**
Capital expenditures(2) *($000's)*	33,000
Average daily production *(boe/d)*	9,100 to 9,700
% natural gas	82%
% crude oil and liquids	18%
Average Brent crude oil price *($/bbl)*	75.00
% realized discount to Brent benchmark price	18%
Funds flow from operations(3) *($000's)*	32,000
Net debt – end of year(2)(3) *($000's)*	25,000

Notes:
(1) Forward-looking statement representing Management estimates. See the "*Advisories - Forward-looking Statements*" section of this MD&A for further information.
(2) Non-GAAP financial measure. See the "*Advisories - Non-GAAP Financial Measures*" section of this MD&A for further information.
(3) The financial performance measures provided in the Company's 2024 preliminary guidance are based on the midpoint of the average production forecast, being 8,900 boe/d.

We currently have two producing Cascadura wells where our natural gas processing facility is located on the Cascadura A site, and we have budgeted to drill two wells on the Cascadura C site with one well drilled to date and drilling operations underway at the second location. Further Cascadura development capital expenditures are required to tie-in the wells to the natural gas facility and upgrade the facility from its current throughput of 90 MMcf/d to 140 MMcf/d. The initial 2024 capital budget also contemplates two CO-1 block crude oil development wells, one Coho development well, and one Coho exploration well. The first CO-1 development well was spud on February 28, 2024 with operations currently progressing.

The preliminary guidance contemplated an increase in the Company's revolving credit facility from $7 million to $20 million. On March 1, 2024, the Company and its lender executed a binding term sheet providing for a new $10 million five-year term loan facility and increasing our current revolving loan facility from $7 million to $10 million (the "Amended Bank Loan"). As of the date of this MD&A, the parties are currently drafting a third amended and restated loan agreement and perfecting the revised security documents, following which the additional borrowing capacity is expected to be effective. The updated bank debt structure did not materially change anticipated net finance expenses incorporated in our preliminary funds flow from operations guidance.

For further information regarding 2024 guidance and the related advisories, refer to the news release dated December 19, 2023 entitled "*Touchstone Announces 2024 Capital Budget, Preliminary 2024 Guidance and an Operational Update*" which is available online on our SEDAR+ profile (www.sedarplus.ca) and website (www.touchstoneexploration.com).

Business Overview

Principal Properties and Licences

Touchstone operates Trinidad-based upstream petroleum and natural gas activities under state exploration and production licences with the Government of Trinidad and Tobago Ministry of Energy and Energy Industries ("MEEI"), Lease Operatorship Agreements ("LOAs") with state owned Heritage Petroleum Company Limited ("Heritage") and private subsurface and surface leases with individual landowners.

A schedule of our Trinidad property interests as of December 31, 2023 is set forth below.

Property	**Working interest** *(%)*	**Licence type**	**Gross acres**[1]	**Net acres**[2]
Developed				
CO-1	100	Lease Operatorship	1,230	1,230
CO-2[3]	100	Lease Operatorship	469	469
WD-4	100	Lease Operatorship	700	700
WD-8	100	Lease Operatorship	650	650
Barrackpore	100	Private	211	211
Fyzabad	100	State and Private	564	564
Ortoire - Coho	80	State	1,317	1,054
Ortoire - Cascadura	80	State	2,377	1,902
San Francique[4]	100	Private	1,277	1,277
	92		**8,795**	**8,057**
Exploratory				
Cory Moruga	16	State	7,443	1,206
Ortoire	80	State	41,037	32,830
	70		**48,480**	**34,036**
Total	**73**		**57,275**	**42,093**

Notes:
(1) "Gross" means the total area of properties in which we have an interest.
(2) "Net" means the total area of properties in which we have an interest multiplied by the working interest owned by us.
(3) Subsequent to December 31, 2023, the Company entered into an agreement with a third party to dispose our interest in the CO-2 block (refer to the "*Capital Expenditures and Dispositions*" section of this MD&A for further information).
(4) The San Francique field was classified as held for sale as at December 31, 2023, with an effective date upon closing. The Company is currently awaiting regulatory approvals to close the asset disposition (refer to the "*Capital Expenditures and Dispositions*" section of this MD&A for further information).

MEEI exploration and production licences

The Company is party to exploration and production licences with the MEEI for our Fyzabad producing property and our Cory Moruga and Ortoire exploration fields. The licences typically are for an initial six-year term, with the option to extend certain acreage a further 19 years upon an approved commercial discovery. Our Fyzabad exploration and production licence contains no minimum work obligations and expires in August 2032. We hold a non-operating 16.2 percent interest in the Cory Moruga exploration block which we consider non-core, and our core focus is the Ortoire exploration block (refer to the "*Business Overview - Ortoire Operations*" section herein).

Lease operatorship agreements

Under our four LOAs (CO-1, CO-2, WD-4 and WD-8), we are subject to annual minimum production levels and minimum work commitments through 2030 specified under each LOA. Failing to reach either the annual minimum production levels or complete the annual minimum work obligations does not constitute a breach provided the minimal production levels have been attained or the minimum work obligations have been completed, as the case may be. The LOAs contain an aggregate minimum of 20 new infill wells and 40 well recompletions to be completed over the initial ten-year licence periods (refer to the "*Contractual Obligations and Commitments*" section herein for further information). The LOAs contain marketing arrangements for crude oil production. Under the LOAs, periodic crude oil sales are invoiced monthly based on Heritage's monthly average equity land blend indexed price and are payable in TT$ net of royalties and fees.

The following table sets forth information relating to our properties governed by LOAs as of December 31, 2023.

Field	**Current licence expiry**	**Carrying value**[1] *($000's)*	**Gross 1P reserves**[2] *(Mbbls)*	**Gross 2P reserves**[2] *(Mbbls)*	**Minimum work commitments**[3] *($000's)*
CO-1	December 31, 2030[4]	26,593	1,926	3,341	7,514
CO-2	December 31, 2030[4]	1,516	507	579	7,558
WD-4	December 31, 2030[4]	16,823	2,784	5,102	4,765
WD-8	December 31, 2030[4]	14,936	2,489	4,776	4,824
Total		**59,868**	**7,706**	**13,798**	**24,661**

Notes:

(1) Represents the field's estimated carrying value included in property, plant and equipment ("PP&E") as at December 31, 2023 including allocated overhead charges. The CO-1 and CO-2 fields fall under one cash-generating unit ("CGU"), and the $28,109,000 gross carrying value has been allocated to each field based on Management's best estimate.

(2) December 31, 2023 assigned gross light and medium crude oil reserves are the Company's working interest share before deduction of royalties. Refer to the "*Advisories - Reserves Disclosures*" section of this MD&A.

(3) Includes future estimates of minimum work obligations stipulated in the LOAs as of December 31, 2023. Refer to the "*Contractual Obligations and Commitments*" section of this MD&A for further details.

(4) The LOAs may be extended for a further five-year term pending mutual agreement to minimum work commitments over the extended period.

As at December 31, 2023, the Company recorded a $13,865,000 impairment reversal related to the Coora CGU. Subsequent to year-end, we entered into an agreement to dispose our interest in the CO-2 property to a third party. Refer to the "*Financial and Operational Results - Impairment of non-financial assets*" and the "*Capital Expenditures and Dispositions*" sections of this MD&A for further information.

Private lease agreements

We may also negotiate private surface and subsurface lease arrangements with individual landowners. Lease terms are typically 35 years in duration and contain no minimum work obligations. We are operating under a number of Trinidad private lease agreements which have expired and are currently in the process of renewal. Based on legal opinions received, Touchstone is continuing to recognize crude oil sales on the producing properties because the Company is the operator, is paying all associated royalties and taxes, and no title to the producing properties has been disputed. The continuation of production from expired private leases during the renegotiation process is common in Trinidad based on antiquated land title processes. During the year ended December 31, 2023, production volumes produced under expired private lease agreements represented approximately 1.3 percent of our total production (2022 - 3.8 percent).

Our San Francique property that was classified as held for sale at December 31, 2023, represented approximately 23 percent of our production under expired leases during the year ended December 31, 2023 (refer to the "*Capital Expenditures and Dispositions*" section of this MD&A for further information).

Crude oil and liquids marketing agreements

On January 14, 1974, Premier Consolidated Oilfields Limited, the Company's predecessor in interest, and Texaco Trinidad Inc., Heritage's predecessor, entered into a Crude Oil Purchase Agreement whereby Texaco Trinidad Inc. committed to purchase crude oil produced by POGL from all producing properties operating under MEEI licences and private lease agreements. The agreement was novated to Heritage on December 1, 2018. The agreement, as amended from time to time, has continued to have an indefinite term and may be terminated by either party upon three months' notice. Crude oil sales are invoiced monthly based on Heritage's monthly average equity land blend indexed price and are payable in US$.

On September 1, 2023, POGL and Heritage entered into a liquids sales agreement for all crude oil and liquids produced in the Ortoire block. Sales occur periodically and are invoiced on a monthly basis. The agreement has an initial one-year term and is automatically renewed for successive one year periods. Crude oil and liquids sales are invoiced monthly based on Heritage's monthly average equity land blend indexed price and are payable in US$.

Natural gas sales contract

On December 18, 2020, POGL, Heritage and NGC executed a natural gas sales agreement for all natural gas production from our Ortoire block. Natural gas sales are based on a fixed US$ price per MMBtu, with an annual 2 percent inflation escalator. The parties may renegotiate the natural gas sales price on each fifth anniversary of the initial October 10, 2022 production date. POGL shall deliver all natural gas production at the edge of the specific well site battery, with title, risk of loss and other customary matters dealt with at the delivery point, thereby eliminating transportation and processing charges. Payment terms are industry standard and are paid in US$ on a monthly basis.

Ortoire Operations

Licence

Effective October 31, 2014, POGL entered into an 80 percent operating working interest in the Ortoire exploration and production licence (the "Ortoire Licence") with the MEEI and Heritage, with Heritage holding the remaining 20 percent working interest. The Ortoire Licence was originally effective for an initial term of six years, under which any approved commercial discovery can be extended for a further 19 years.

In November 2022, all parties formally executed an extension of the exploration period of the Ortoire Licence to July 31, 2026, allowing us to continue exploration activities on acreage that have not been deemed commercial. The gross 1,317-acre Coho area and the gross 2,377-acre Cascadura area were previously approved for commercial development in February 2021 and March 2022, respectively.

Pursuant to the amended Ortoire Licence, we are required to drill three additional exploration wells to minimum depths of 6,000 true vertical feet prior to the end of the amended term, with one commitment well (Royston-1X) drilled in February 2023. Similar to the initial minimum work program, we are responsible for 100 percent of the drilling, completion and testing costs for the additional wells. Each party to the Ortoire Licence remains responsible for its working interest costs associated with the development of commercial fields, including expenditures relating to facilities construction and development well drilling.

Touchstone has conducted exploration and development activities in four areas within the Ortoire Licence to date: Coho, Cascadura, Chinook and Royston.

Coho

Throughout 2022, we constructed the Coho natural gas sales facility and pipeline to produce volumes from the Coho-1 well drilled in the third quarter of 2019. Production volumes are transported via a pipeline to a third-party natural gas facility. Upon facility commissioning and initial production in October 2022, Touchstone sold the tie-in pipeline to NGC.

Our Coho-1 well produced a net average of 4.0 MMcf/d (672 boe/d) in 2023 compared to net average volumes of 1.4 MMcf/d (241 boe/d) in 2022, as natural gas production from the well commenced on October 10, 2022.

The following table sets forth information relating to the Coho field as of December 31, 2023.

Field	Current licence expiry	Carrying value(1) *($000's)*	Gross 1P reserves(2) *(Mboe)*	Gross 2P reserves(2) *(Mboe)*	Minimum work commitments(3) *($000's)*
Coho	October 31, 2039	6,652	711	2,963	50

Notes:
(1) Represents the field's carrying value included in PP&E as at December 31, 2023 including allocated overhead charges.
(2) December 31, 2023 assigned gross conventional natural gas reserves are the Company's working interest share before deduction of royalties. Refer to the "*Advisories - Reserves Disclosures*" section of this MD&A.
(3) Includes future estimates of Ortoire Licence financial obligations related to the Coho area as of December 31, 2023. Refer to the "*Contractual Obligations and Commitments*" section of this MD&A for further details.

Based on a reduction of assigned reserves primarily from the water isolation workover performed in the fourth quarter of 2023, Touchstone recorded a $143,000 impairment expense related to the Coho CGU at December 31, 2023. Refer to the "*Financial and Operational Results - Impairment of non-financial assets*" section of this MD&A for further information.

Cascadura

Throughout late 2022 and 2023, Touchstone constructed the Cascadura natural gas facility on our Cascadura A location. The facility currently processes and separates natural gas and associated liquids production from our Cascadura-1ST1 and Cascadura Deep-1 wells and is tied into an NGC pipeline. Produced NGL volumes are currently trucked and sold to Heritage at our Barrackpore liquids sales battery. The facility sustains its own power requirements through onsite solar systems and natural gas generators and is entirely independent of the Trinidad power grid. The facility currently has a maximum gross capacity of approximately 90 MMcf/d of natural gas and 2,250 bbls/d of associated liquids (17,250 boe/d).

The facility safely delivered first natural gas on September 6, 2023, with annual net production from the two wells averaging 11.6 MMcf/d (1,927 boe/d) and 201 bbls/d of NGLs during 2023 despite only four months of production.

Touchstone has regulatory approvals to drill up to eight wells on two well pads (Cascadura B and C), including the establishment of associated pipelines and infrastructure within the area. In 2023, the Company constructed the Cascadura C location, which is approximately 1.5 kilometres from the facility. Drilling operations on the Cascadura C location and preparations to expand the facility to a gross capacity of 140 MMcf/d commenced subsequent to December 31, 2023.

The following table sets forth information relating to the Cascadura field as of December 31, 2023.

Field	Current licence expiry	Carrying value(1) *($000's)*	Gross 1P reserves(2) *(Mboe)*	Gross 2P reserves(2) *(Mboe)*	Minimum work commitments(3) *($000's)*
Cascadura	October 31, 2039	30,315	24,214	47,507	92

Notes:
(1) Represents the field's carrying value included in PP&E as at December 31, 2023 including allocated overhead charges.
(2) December 31, 2023 assigned gross conventional natural gas and natural gas liquids reserves are the Company's working interest share before deduction of royalties. Refer to the "*Advisories - Reserve Disclosures*" section of this MD&A.
(3) Includes future estimates of Ortoire Licence financial obligations related to the Cascadura area as of December 31, 2023. Refer to the "*Contractual Obligations and Commitments*" section of this MD&A for further details.

Chinook

The Chinook-1 exploration well was drilled in the second half of 2020. The well was drilled on the crest of the structure, encountering three distinct thrust sheets all with Herrera Formation sands. All three sheets were tested and yielded sub-commercial volumes of light crude oil. Based on seismic data, the structure appears to climb significantly to the northeast towards the Kokanee structure, where the sheets can be further evaluated with an exploration well from the former BW-9 wellsite approximately 1.3 kilometres from the Chinook-1 well.

Royston

The Royston-1 exploration well was drilled in the third quarter of 2021 to a total depth of 10,700 feet and identified over 1,000 feet of Herrera section in the overthrust and intermediate sheets, encountering light, sweet crude oil in both sheets. Mechanical challenges prevented meaningful production from the well, with 4,274 net barrels produced in 2022.

In February 2023, we drilled the Royston-1X exploration well, which was a sidetrack from the original Royston-1 well. Royston-1X kicked off from the Royston-1 wellbore at a depth of approximately 7,150 feet and reached a total measured depth of 11,316 feet. Subsequent to five production tests, the well was deemed uneconomic to produce. The following table sets forth information relating to the Royston area as of December 31, 2023.

Field	**Current licence expiry**	**Carrying value**[1] *($000's)*	**Gross 1P reserves**[2] *(Mbbls)*	**Gross 2P reserves**[2] *(Mbbls)*	**Minimum work commitments**[3] *($000's)*
Royston	July 31, 2026[3]	5,030	640	2,560	-

Notes:
(1) Represents the field's carrying value included in E&E assets as at December 31, 2023 including allocated overhead charges.
(2) December 31, 2023 assigned gross light and medium crude oil reserves are the Company's working interest share before deduction of royalties. Refer to the "*Advisories - Reserves Disclosures*" section of this MD&A.
(3) The Company has not submitted a field development plan to the MEEI for the Royston area and therefore no reservoir area or future work commitments have been defined.

Financial and Operational Results

Production volumes

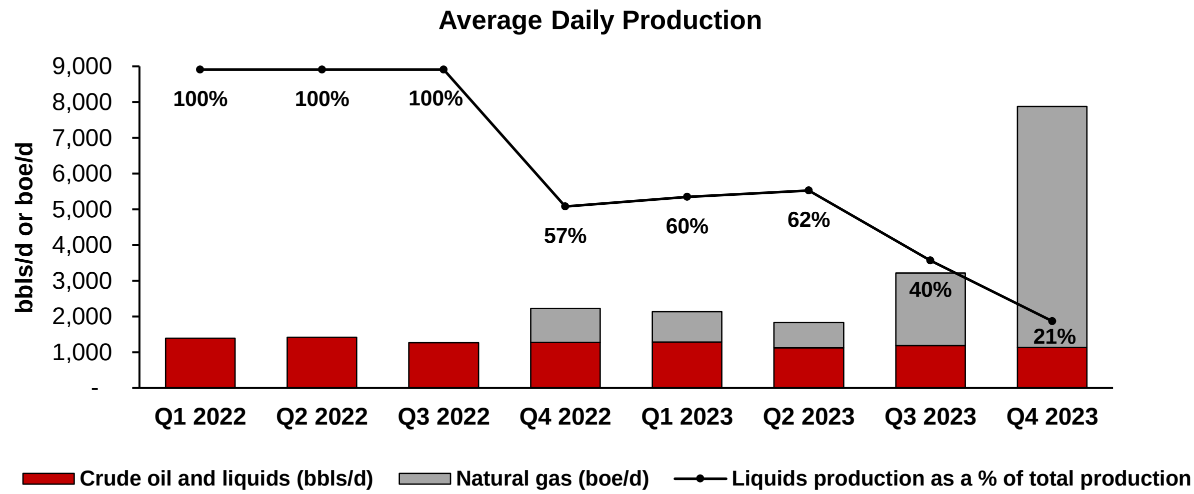
	Three months ended December 31,		% change	**Year ended December 31,**		% change
	2023	2022		**2023**	2022	
Production						
Crude oil *(bbls)*	**104,280**	117,240	(11)	**431,119**	489,136	(12)
NGLs *(bbls)*	**57,183**	-	n/a	**73,363**	-	n/a
Crude oil and liquids *(bbls)*	**161,463**	117,240	38	**504,482**	489,136	3
Natural gas *(Mcf)*	**3,725,201**	527,105	100	**5,691,547**	527,105	100
Total production *(boe)*	**782,330**	205,091	100	**1,453,073**	576,987	100
Average daily production						
Crude oil *(bbls/d)*	**1,133**	1,274	(11)	**1,181**	1,340	(12)
NGLs *(bbls/d)*	**622**	-	n/a	**201**	-	n/a
Crude oil and liquids *(bbls/d)*	**1,755**	1,274	38	**1,382**	1,340	3
Natural gas *(Mcf/d)*	**40,491**	5,729	100	**15,593**	1,444	100
Average daily production *(boe/d)*	**8,504**	2,229	100	**3,981**	1,581	100
Production mix						
Crude oil and liquids *(%)*	**21**	57		**35**	85	
Natural gas *(%)*	**79**	43		**65**	15	

Touchstone achieved record annual production in 2023 and record quarterly production in the fourth quarter of 2023. The fourth quarter of 2023 represented the first full quarter of Cascadura production, which increased our natural gas production weighting to 79 percent in the quarter and 65 percent on an annual basis.

Fourth quarter and annual 2023 crude oil production volumes decreased 11 percent and 12 percent from the prior year equivalent periods, respectively. Compared to 2022, the 2023 decreases mainly reflected natural declines, as 2022 oil production volumes included flush production from the three development wells brought onstream in the first quarter of 2022 and we sold 4,274 incremental net barrels of Royston-1 well production test volumes predominately in the first half of the prior year.

Our Coho-1 natural gas well contributed average net production volumes of 3.1 MMcf/d (517 boe/d) in the fourth quarter of 2023, a 46 percent decline in comparison to the 5.7 MMcf/d (955 boe/d) produced during the prior year equivalent quarter. The decline in natural gas production was due to a combination of natural decline and increased downtime in the fourth quarter of 2023 from third party processor downtime and operational works conducted on the well to mitigate water production volumes. On an annual basis, Coho-1 produced a net average of 4.0 MMcf/d (672 boe/d) in 2023 compared to 1.4 MMcf/d (241 boe/d) in 2022, as first natural gas production from the well commenced on October 10, 2022.

On September 6, 2023 and September 14, 2023, we achieved first production from our Cascadura-1ST1 well and Cascadura Deep-1 well, respectively. The wells contributed average net natural gas production volumes of 37.4 MMcf/d (6,232 boe/d) in the fourth quarter of 2023 and 11.6 MMcf/d (1,927 boe/d) during 2023. In addition, the wells produced a net average of 622 and 201 bbls/d of NGLs during the three months and year ended December 31, 2023, respectively.

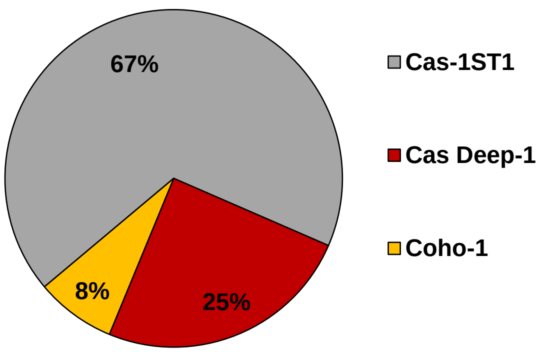


The following table summarizes crude oil and liquids production by property during the three months and years ended December 31, 2023 and 2022.

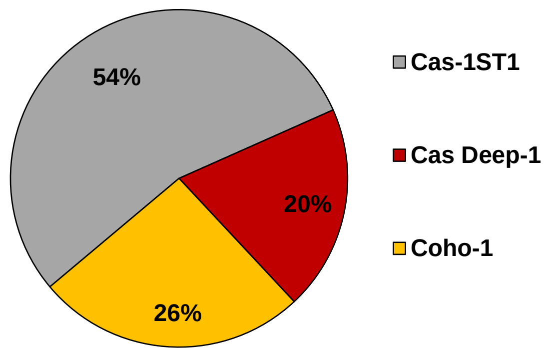
(bbls)	Three months ended December 31, 2023	2022	% change	Year ended December 31, 2023	2022	% change
CO-1	**30,989**	33,961	(9)	**125,556**	138,339	(9)
CO-2	**4,647**	4,208	10	**20,481**	13,561	51
WD-4	**39,048**	47,888	(18)	**156,928**	197,970	(21)
WD-8	**19,856**	19,959	(1)	**83,594**	85,376	(2)
Fyzabad	**5,966**	6,126	(3)	**24,985**	27,524	(9)
Other	**3,774**	5,098	(26)	**19,575**	26,366	(26)
Cascadura	**57,183**	-	n/a	**73,363**	-	n/a
Crude oil and liquids production	**161,463**	117,240	38	**504,482**	489,136	3

The following graphs disclose natural gas production by well during the three months and year ended December 31, 2023.

Natural Gas Production by Well for the Three Months Ended December 31, 2023



Natural Gas Production by Well for the Year Ended December 31, 2023



Commodity prices

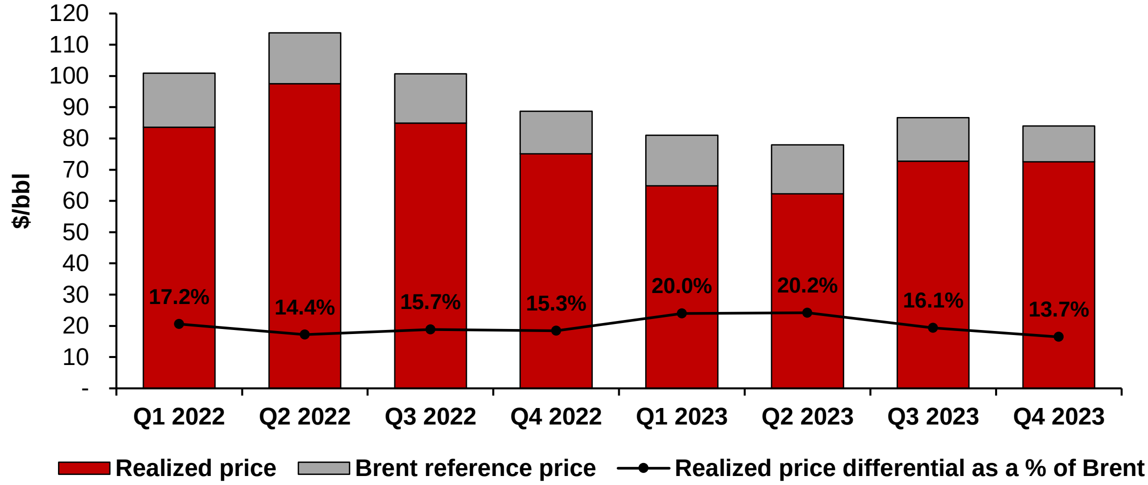
	Three months ended December 31,		% change	Year ended December 31,		% change
	2023	2022		**2023**	2022	
Avg. benchmark prices[1]						
Brent *($/bbl)*	**84.01**	88.72	(5)	**82.49**	100.93	(18)
WTI *($/bbl)*	**78.32**	82.64	(5)	**77.62**	94.23	(18)
Average realized prices[2]						
Crude oil *($/bbl)*	**72.26**	75.10	(4)	**67.80**	85.52	(21)
NGLs *($/bbl)*	**72.92**	-	n/a	**74.07**	-	n/a
Crude oil and liquids *($/bbl)*	**72.49**	75.10	(3)	**68.72**	85.52	(20)
Natural gas *($/Mcf)*	**2.43**	2.11	15	**2.36**	2.11	12
Realized commodity price *($/boe)*	**26.53**	48.36	(45)	**33.10**	74.43	(56)

Notes:
(1) Average of the daily closing spot prices for a given product over the specified period. Source: US Energy Information Administration.
(2) Non-GAAP financial measure. See the "*Advisories - Non-GAAP Financial Measures*" section of this MD&A for further information.

Our crude oil and liquids prices received are based on quality differentials and international marketing arrangements and therefore are attributed to factors that are beyond our control. Our crude oil and NGL realized prices are primarily driven by the Brent benchmark price, as Trinidad crude oil and liquids are exported for refining and classified as waterborne crude.

Fourth quarter and annual 2023 average Dated Brent benchmark pricing decreased 5 and 18 percent in comparison to both prior year periods, respectively. The coordinated production and export curtailments undertaken by certain crude oil-producing countries continued throughout the quarter, but increased uncertainty around the future magnitude and duration of those curtailments negatively impacted crude oil prices. While recent conflicts in the Middle East have not had a material impact on crude oil supply, the potential for disruption to crude oil production in the region, combined with increased global recessionary concerns, has resulted in increased price volatility.

Average Realized Crude Oil and Liquids Price(1) and Differential to Brent



Note:
(1) Non-GAAP financial measure. See the "*Advisories - Non-GAAP Financial Measures*" section of this MD&A for further information.

Touchstone realized an average crude oil price of $72.26 per barrel in the fourth quarter of 2023 compared to an average of $75.10 per barrel reported in the equivalent quarter of 2022. Relative to the fourth quarter of 2022, the 4 percent decrease in 2023 was predominately driven by the aforementioned 5 percent decrease in Brent reference pricing, slightly offset by a decrease of the realized price differential in relation to Brent benchmark pricing from 15.4 percent to 14.0 percent.

In 2023 we realized an average crude oil price of $67.80 per barrel, a 21 percent decrease relative to the $85.52 per barrel price received in 2022. The 2023 annual decrease from the corresponding 2022 year reflected an 18 percent decrease in the average Brent reference price and a widening of our realized price differential in relation to Brent reference pricing from 15.3 percent to 17.8 percent.

The Company realized average NGL prices of $72.92 and $74.07 during the three months and year ended December 31, 2023, which represented Cascadura field volumes sold from September to December 2023. Touchstone receives the same price for NGLs and crude oil through various marketing arrangements with Heritage.

We realized average Coho-1 natural gas prices of $2.16 and $2.12 per Mcf during the three months and year ended December 31, 2023, respectively, compared to $2.11 per Mcf in both corresponding 2022 periods. The 2023 increase relative to 2022 was the result of an annual 2 percent inflation escalator in the NGC marketing contract which came into effect on October 10, 2023. Touchstone is obligated to pay a $0.125 per Mcf processing fee to the third-party natural gas facility operator which is netted against natural gas sales and the realized prices disclosed above.

Cascadura fourth quarter and annual 2023 natural gas sales volumes realized average prices of $2.45 and $2.44 per Mcf, respectively. The Cascadura realized natural gas price was subject to the 2 percent annual inflation escalator in the marketing contract as noted above.

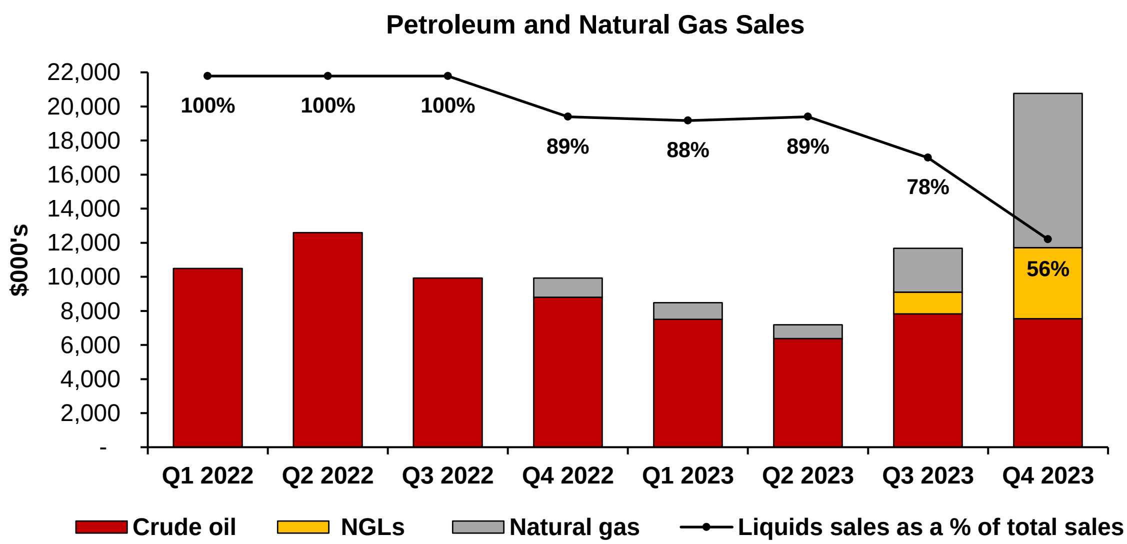
Petroleum and natural gas sales

($000's unless otherwise stated)	Three months ended December 31, **2023**	2022	% change	Year ended December 31, **2023**	2022	% change
Crude oil	**7,535**	8,805	(14)	**29,232**	41,830	(30)
NGLs	**4,170**	-	n/a	**5,434**	-	n/a
Natural gas	**9,054**	1,114	100	**13,432**	1,114	100
Petroleum and natural gas sales	**20,759**	9,919	100	**48,098**	42,944	12
Sales mix						
Crude oil and liquids *(%)*	**56**	89		**72**	97	
Natural gas *(%)*	**44**	11		**28**	3	

We sell all produced crude oil and NGL volumes to Heritage, with title transferring at our various sales batteries. As of December 31, 2023, we held 4,566 barrels of crude oil and liquids inventory in comparison to 4,021 barrels as of December 31, 2022. We sell our Coho and Cascadura natural gas volumes to NGC, with title transferring at each facility.

Petroleum and natural gas sales in the fourth quarter of 2023 increased 109 percent to $20,759,000 from $9,919,000 in the comparative quarter of 2022. Compared to the fourth quarter of 2023, crude oil sales declined by $1,270,000, with $297,000 reflecting a decrease in realized pricing and $973,000 attributed to a reduction in sales volumes. In the fourth quarter of 2023, we recorded $4,170,000 in NGL sales associated with Casacdura natural gas volumes. Further, 2023 fourth quarter natural gas sales increased by $7,940,000 from the prior year equivalent period, with $1,192,000 of the variance attributed to an increase in average realized prices and $6,748,000 reflecting increased sales volumes from the Cascadura field.

During the year ended December 31, 2023, petroleum and natural gas sales were $48,098,000, representing a $5,154,000 or 12 percent increase from the $42,944,000 recognized in the 2022 year. Relative to the prior year, crude oil sales recognized during the 2023 year declined by $12,598,000, with $7,636,000 attributed to decreases in average realized pricing and $4,962,000 of the variance reflecting decreased sales volumes. An incremental $5,434,000 in Cascadura field NGL sales was recorded during the year ended December 31, 2023. In addition, in 2023 we recognized an increase of $12,318,000 in natural gas sales relative to the 2022 year, with $10,895,000 of the increase from additional sales volumes and $1,423,000 from an increase in average realized annual pricing.



Other revenue

We recorded $9,000 and $64,000 of other revenue during the three months and year ended December 31, 2023, respectively, which mainly consisted of consideration for selling crude oil on behalf of a third-party operator (2022 - $12,000 and $42,000).

Royalties

Touchstone is obligated to pay a state royalty rate of 12.5 percent on all petroleum and natural gas production under MEEI and Heritage licences. For private leases, the Company incurs private royalties between 10 and 12.5 percent of crude oil sales.

In addition to state royalties, our LOAs with Heritage governing our CO-1, CO-2, WD-4 and WD-8 blocks apply a sliding scale overriding royalty ("ORR") structure indexed to the average price of crude oil realized in a production month. Base ORR rates are applicable to pre-defined monthly base production levels which decline by 2 percent per annum over the specific licence. For any monthly volumes sold in excess of base production levels, the Company incurs reduced enhanced ORR rates. For any production in excess of defined enhanced production levels, we incur super enhanced ORR rates which represent 50 percent of enhanced ORR rates. The following table summarizes royalty rates attributable to our LOAs based on monthly realized crude oil pricing received.

Monthly realized oil price *($)*	**LOA Royalty Rates** *(%)*		
	Base ORR	**Enhanced ORR**	**Super Enhanced ORR**
30.01 - 40.00	20.00	7.50	3.75
40.01 - 50.00	25.00	8.00	4.00
50.01 - 70.00	28.00	15.50	7.75
70.01 - 90.00	33.00	17.00	8.50
90.01 - 200.00	35.00	20.00	10.00

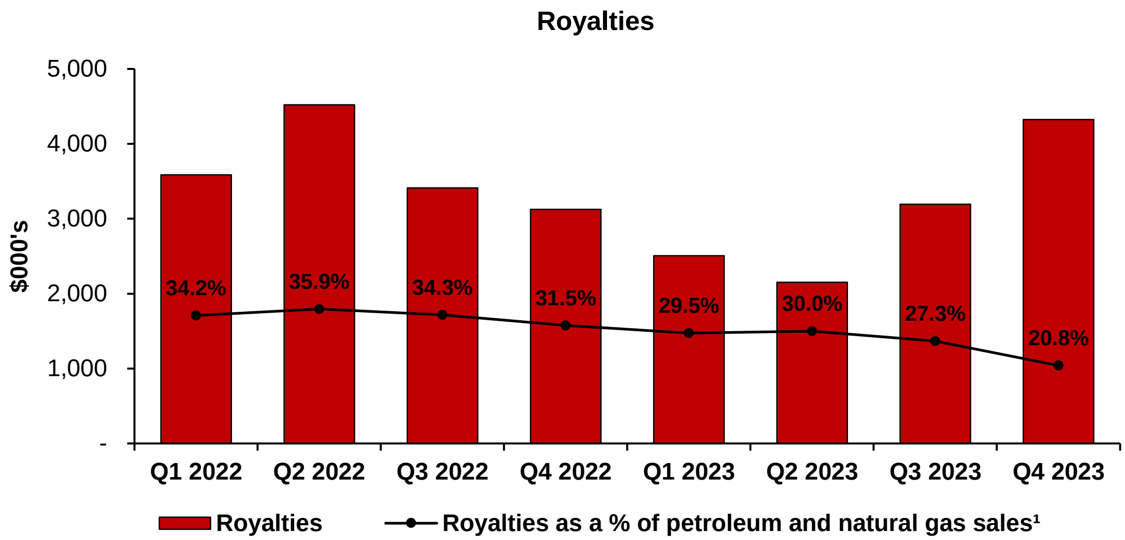
The following table sets forth royalty expenses for the periods indicated.

($000's unless otherwise stated)	**Three months ended December 31,**		% change	**Year ended December 31,**		% change
	2023	2022		**2023**	2022	
State royalties	**2,605**	1,184	100	**5,886**	4,994	18
Private royalties	**77**	81	(5)	**284**	401	(29)
Overriding royalties	**1,642**	1,860	(12)	**6,003**	9,246	(35)
Royalties	**4,324**	3,125	38	**12,173**	14,641	(17)
$ per boe(1)	**5.53**	15.24	(64)	**8.38**	25.37	(67)
As a % of petroleum and natural gas sales(1)	**20.8**	31.5	(34)	**25.3**	34.1	(26)

Note:
(1) Non-GAAP financial measure. See the "*Advisories - Non-GAAP Financial Measures*" section of this MD&A for further information.

Relative to 2022, royalty expenses increased by 38 percent in the fourth quarter of 2023, primarily driven by increased natural gas sales and incremental NGL sales from our Ortoire concession which were only subject to the 12.5 percent state royalty, partially offset by decreased Heritage overriding royalties based on decreased crude oil pricing and production. Fourth quarter 2023 royalty expenses on a boe basis and as a percentage of petroleum and natural gas sales declined from the 2022 equivalent period based on increased Ortoire 2023 production solely subject to the state royalty.

Royalty expenses for the year ended December 31, 2023 decreased 17 percent to $12,173,000 from $14,641,000 reported in the prior year. Relative to 2022, state royalty expenses increased by 18 percent predominately from increased Ortoire field production, which was fully offset by reductions in private and overriding royalty expenses based on declines in crude oil realized pricing and production. 2023 annual royalty expenses per boe and as a percentage of petroleum and natural gas sales decreased from 2022, reflecting increased annual Ortoire production subject to lower royalty rates and a 21 percent decrease in crude oil realized pricing and corresponding sliding scale royalty rates.



Note:
(1) Non-GAAP financial measure. See the "*Advisories - Non-GAAP Financial Measures*" section of this MD&A for further information.

Operating expenses

($000's except per boe amounts)	**Three months ended December 31,** 2023	2022	% change	**Year ended December 31,** 2023	2022	% change
Operating expenses	**2,704**	2,475	9	**9,705**	9,022	8
$ per boe[1]	**3.46**	12.07	(71)	**6.68**	15.64	(57)

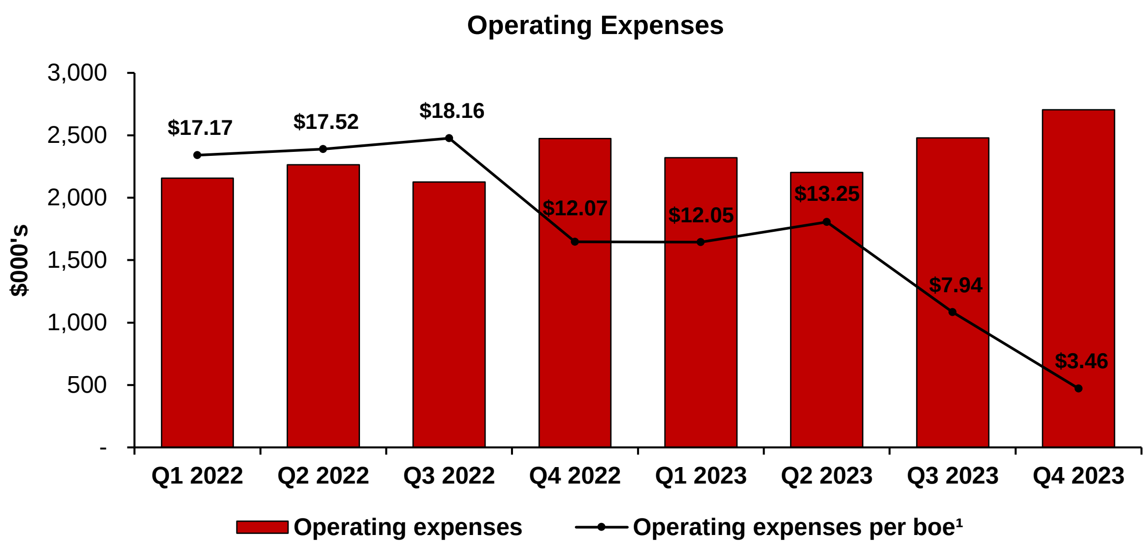
Note:
(1) Non-GAAP financial measure. See the "*Advisories - Non-GAAP Financial Measures*" section of this MD&A for further information.

Operating expenses include all periodic lease, field-level and transportation expenses and directly attributable employee salaries and benefits. The Company's operating expenses by product type and field are approximations prepared by Management, and a number of assumptions are required to allocate these costs.

Fourth quarter and annual operating expenses increased by 9 percent and 8 percent from the comparative periods of 2022, respectively. Relative to the prior year equivalent periods, 2023 fourth quarter and annual crude oil related operating expenses decreased by approximately $427,000 and $974,000, respectively, attributed to reduced variable costs associated with decreased 2023 crude oil production. Operating expenses allocated to the Coho field increased by an estimated $37,000 and $891,000 in the three months and year ended December 31, 2023, respectively, compared to the same periods of 2022. The 2023 increases relative to 2022 were a result of a workover to isolate a water zone performed in the fourth quarter of 2023, and a full year of operations as Coho commenced production in October 2022. Touchstone recognized an estimated $619,000 and $766,000 in incremental operating costs attributed to Cascadura natural gas and NGL production during the three months and year ended December 31, 2023, respectively.

Operating expenses per boe decreased 71 and 57 percent in the three months and year ended December 31, 2023, respectively, compared to the same periods of 2022. The per unit decreases in comparison to the comparative 2022 periods were primarily attributed to incremental Cascadura production.

In the fourth quarter of 2023, crude oil operating expenses were approximately $16.79 per barrel, a 10 percent decrease from the estimated $18.58 per barrel incurred in the fourth quarter of 2022, predominately from decreased variable operating costs from less production. 2023 crude oil and liquids production averaged estimated operating expenses of $17.98 per barrel in comparison to $17.84 per barrel in the prior year, as a reduction in variable operating expenses due to lower 2023 production was offset by increases in employee headcount related salaries and inflationary pressures on various cost categories. Coho-1 natural gas production averaged estimated operating expenses of $7.02 and $4.86 per boe during the three months and year ended December 31, 2023, respectively, compared to an estimated $3.38 per boe incurred in both prior year periods, reflecting a major workover performed and head licence performance payments in 2023. In addition, Cascadura natural gas and NGL production averaged incremental estimated operating expenses of $0.98 and $0.99 per boe during the three months and year ended December 31, 2023.

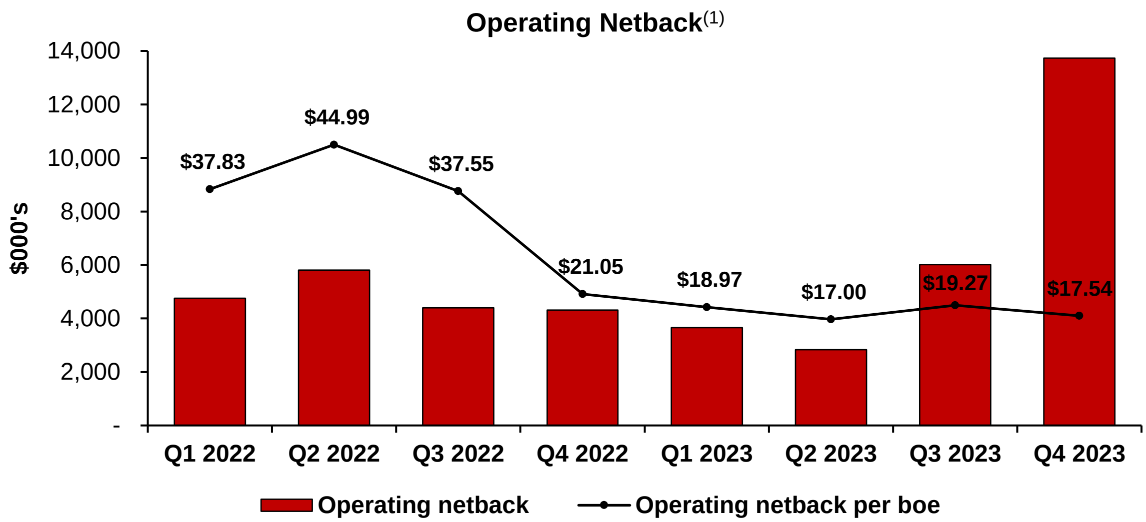


Note:
(1) Non-GAAP financial measure. See the "*Advisories - Non-GAAP Financial Measures*" section of this MD&A for further information.

Operating netback

	Three months ended December 31, 2023	2022	% change	Year ended December 31, 2023	2022	% change
($000's)						
Petroleum and natural gas sales	**20,759**	9,919	100	**48,098**	42,944	12
Royalties	**(4,324)**	(3,125)	38	**(12,173)**	(14,641)	(17)
Operating expenses	**(2,704)**	(2,475)	9	**(9,705)**	(9,022)	8
Operating netback(1)	**13,731**	4,319	100	**26,220**	19,281	36
($/boe)						
Realized commodity price(1)	**26.53**	48.36	(45)	**33.10**	74.43	(56)
Royalties(1)	**(5.53)**	(15.24)	(64)	**(8.38)**	(25.37)	(67)
Operating expenses(1)	**(3.46)**	(12.07)	(71)	**(6.68)**	(15.64)	(57)
Operating netback(1)	**17.54**	21.05	(17)	**18.04**	33.42	(46)

Note:
(1) Non-GAAP financial measure. See the "*Advisories - Non-GAAP Financial Measures*" section of this MD&A for further information.



Note:
(1) Non-GAAP financial measure. See the "*Advisories - Non-GAAP Financial Measures*" section of this MD&A for further information.

General and administration ("G&A") expenses

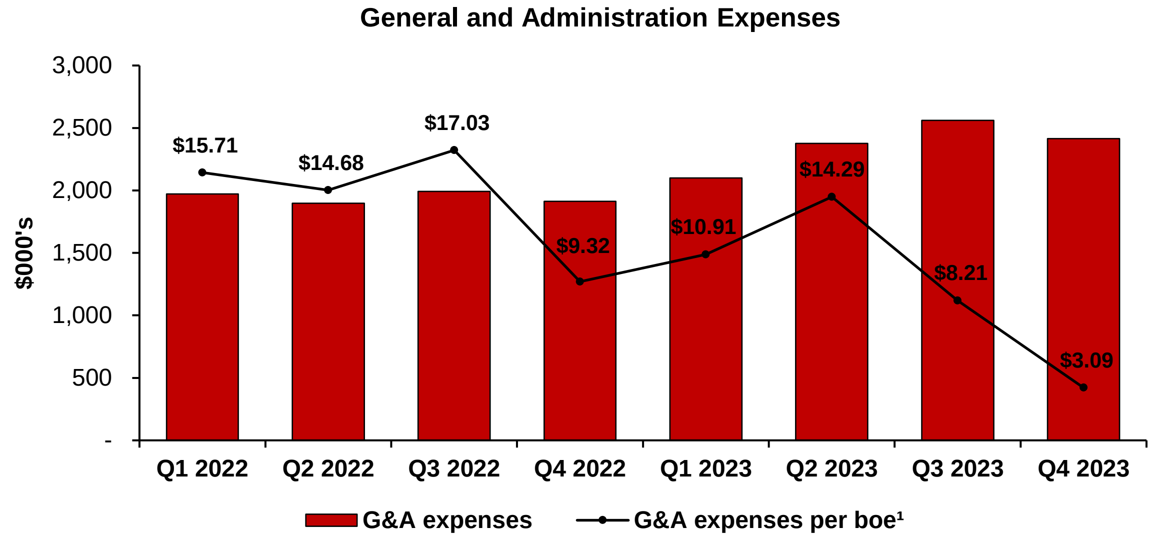
($000's except per boe amounts)	**Three months ended December 31,**		% change	**Year ended December 31,**		% change
	2023	2022		**2023**	2022	
Gross G&A expenses	**2,518**	2,268	11	**10,278**	8,862	16
Capitalized G&A expenses	**(104)**	(356)	(71)	**(827)**	(1,087)	(24)
G&A expenses	**2,414**	1,912	26	**9,451**	7,775	22
$ per boe[1]	**3.09**	9.32	(67)	**6.50**	13.48	(52)

Note:
(1) Non-GAAP financial measure. See the "*Advisories - Non-GAAP Financial Measures*" section of this MD&A for further information.

Gross G&A expenses increased 11 percent and 16 percent in the three months and year ended December 31, 2023, respectively, compared to the same periods in 2022. The increases in both 2023 periods compared to the prior year were primarily attributable to increases in employee headcount and related salary and benefit expenses, travel expenses, professional and legal fees and information technology expenses.

Capitalized G&A expenses declined in the three months and year ended December 31, 2023 compared to the same periods in 2022 predominately from decreased employee hours allocated to capital projects, slightly offset by a higher employee headcount.

Fourth quarter 2023 G&A expenses were $3.09 per boe, representing a 67 percent decrease from the $9.32 per boe reported in the fourth quarter of 2022. A 26 percent increase in fourth quarter 2023 net G&A expenses in relation to the prior year equivalent quarter was fully offset by a 281 percent increase in production volumes on a boe basis. Annual 2023 G&A expenses on a boe basis declined 52 percent from the 2022 year, as a 152 percent increase in production volumes achieved in 2023 fully offset a 22 percent increase in net G&A expenditures.



Note:
(1) Non-GAAP financial measure. See the "*Advisories - Non-GAAP Financial Measures*" section of this MD&A for further information.

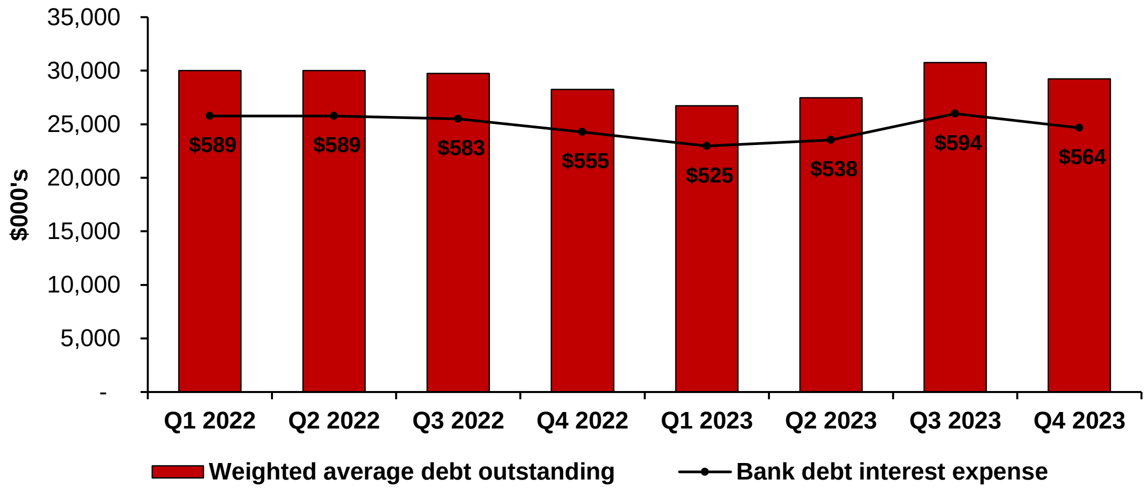
Net finance expenses

($000's except per boe amounts)	Three months ended December 31, **2023**	2022	% change	Year ended December 31, **2023**	2022	% change
Interest income	**(1)**	(11)	(91)	**(58)**	(34)	71
Finance lease interest income	**(9)**	(12)	(25)	**(43)**	(63)	(32)
Lease liability interest	**84**	53	58	**287**	242	19
Bank debt interest	**564**	555	2	**2,221**	2,316	(4)
Debt issuance expense	**-**	-	-	**114**	-	n/a
Accretion on bank debt	**8**	9	(11)	**15**	66	(77)
Other liability revaluation loss (gain)	**2**	101	(98)	**(351)**	240	n/a
Accretion on decommissioning liabilities	**69**	54	28	**257**	222	16
Other	**-**	41	(100)	**11**	53	(79)
Net finance expenses	**717**	790	(9)	**2,453**	3,042	(19)
Cash net finance expenses(1)	**638**	592	8	**2,533**	2,481	2
Non-cash net finance expenses (income)(1)	**79**	198	(60)	**(80)**	561	n/a
Net finance expenses	**717**	790	(9)	**2,453**	3,042	(19)
$ per boe(1)	**0.92**	3.85	(76)	**1.69**	5.27	(68)

Note:
(1) Non-GAAP financial measure. See the "*Advisories - Non-GAAP Financial Measures*" section of this MD&A for further information.

Net finance expenses in the fourth quarter of 2023 were $717,000 compared to $790,000 recognized in the same period of 2022. For the year ended December 31, 2023, net finance expenses were $2,453,000, representing a $589,000 or 19 percent decrease from the $3,042,000 recognized in the prior year.

Relative to the fourth quarter and annual periods of 2022, bank debt interest costs and weighted average principal debt outstanding were consistent in both corresponding periods of 2023. During year ended December 31, 2023, the Company incurred $114,000 in debt issuance costs from the inception of a bank debt revolving facility in June 2023 (refer to the "*Liquidity and Capital Resources - Bank Debt*" section herein for further details).



We granted our former lender a production payment equal to 1.33 percent of petroleum and natural gas sales from Trinidad land holdings, payable quarterly through October 31, 2023. The production liability was revalued at each reporting period based on changes to internally forecasted petroleum and natural gas production and forward product pricing. During the 2023 year, the production liability was repaid and extinguished, and the Company recognized a $2,000 liability revaluation loss and a $351,000 revaluation gain for the three months and year ended December 31, 2023 (2022 - losses of $101,000 and $240,000).

Foreign exchange and foreign currency translation

Touchstone's presentation currency is the United States dollar. Our parent company has a Canadian dollar functional currency while our Trinidadian subsidiaries have Trinidad and Tobago dollar functional currencies. In each reporting period, the change in values of the C$ and TT$ relative to the US$ reporting currency are recognized. The applicable foreign exchange ("FX") rates used to translate our TT$ and C$ denominated items are set forth in the following table.

Applicable FX rates	**Three months ended December 31,**		% change	**Year ended December 31,**		% change
	2023	2022		**2023**	2022	
US$:C$ avg. FX rate(1)	**1.361**	1.358	-	**1.350**	1.302	4
US$:TT$ avg. FX rate(2)	**6.751**	6.749	-	**6.750**	6.754	-
	December 31, 2023	September 30, 2023	% change	**December 31, 2023**	December 31, 2022	% change
US$:C$ closing FX rate(1)	**1.325**	1.359	(3)	**1.325**	1.357	(2)
US$:TT$ closing FX rate(2)	**6.716**	6.749	-	**6.716**	6.742	-

Notes:
(1) Source: TSX InfoSuite average daily exchange rates for the specified periods and daily exchange rates for the specified dates.
(2) Source: Central Bank of Trinidad and Tobago average daily buying and selling exchange rates for the specified periods and average daily buying and selling exchange rates for the specified dates.

The revenues and expenses of our Canadian head office and Trinidadian operations are translated to US$ at the average monthly exchange rates relative to the date of the transactions. Fluctuations in the exchange rate between the TT$ and the US$ and the C$ to US$ could have a material effect on our reported results. Refer to the "*Market Risk Management - Foreign currency risk*" section of this MD&A for further information. During the three months and year ended December 31, 2023, the C$ was consistent with and depreciated 4 percent relative to the US$, respectively, in comparison to the corresponding average rates observed in the 2022 equivalent periods. Relative to the US$, the TT$ remained range bound during the three months and years ended December 31, 2023 and 2022. In aggregate, we recorded foreign exchange gains of $129,000 and $196,000 during the three months and year ended December 31, 2023, respectively (2022 - $148,000 loss and a $333,000 gain). Foreign exchange gains and losses include amounts that are unrealized in nature and may be reversed in the future as a result of fluctuations in prevailing exchange rates.

The assets and liabilities of our parent company and subsidiaries are translated to US$ dollars at the exchange rate on the reporting period date for presentation purposes, with all foreign currency differences recorded in other comprehensive loss. Relative to the US$, the C$ closed 3 percent stronger on December 31, 2023 versus September 30, 2023 and 2 percent stronger in comparison to the corresponding rate on December 31, 2022. In comparison to the US$, the TT$ remained consistent over the corresponding periods. We recognized foreign currency translation gains of $368,000 and $393,000 during the three months and year ended December 31, 2023, respectively (2022 - gain of $19,000 and a loss of $298,000).

Equity-based awards

We have a stock option plan ("Legacy Plan") pursuant to which options to purchase common shares of the Company were granted by our Board to directors, officers, and employees.

On May 11, 2023, the Board adopted an omnibus incentive compensation plan (the "Omnibus Plan"), which was approved by our shareholders at our annual general and special meeting on June 29, 2023. The Omnibus Plan was adopted by the Board primarily to allow for a variety of equity-based awards that provide the Company with the ability to grant different types of incentives to our directors, officers, employees and consultants including stock options, restricted share units and performance share units.

No additional stock options will be granted under the Legacy Plan, and all outstanding stock options previously issued pursuant to the Legacy Plan will continue to be governed by such plan and will continue to vest in accordance with their existing vesting schedules. The maximum number of common shares reserved for issuance under the Legacy Plan and the Omnibus Plan at any time is limited to 10 percent of our issued and outstanding common shares, on a non-diluted basis. As of December 31, 2023, we had 14,327,935 stock options outstanding, which represented 6.1 percent of our issued and outstanding common shares (2022 - 11,928,435 and 5.1 percent, respectively).

The following table sets forth equity compensation expenses recorded in relation to issued stock options pursuant to our incentive compensation plans for the periods indicated.

($000's)	**Three months ended December 31,**		% change	**Year ended December 31,**		% change
	2023	2022		**2023**	2022	
Gross equity-based compensation	**418**	431	(3)	**1,381**	1,654	(17)
Capitalized equity-based compensation	**-**	(61)	(100)	**(138)**	(313)	(56)
Equity-based compensation expense	**418**	370	13	**1,243**	1,341	(7)

Equity-based compensation expenses declined 3 percent and 17 percent in the fourth quarter and 2023 year, respectively, compared to the equivalent periods in 2022. The decreases in gross equity-based compensation and capitalized equity-based compensation during the three months and year ended December 31, 2023 compared to the same periods of 2022 were primarily attributable to decreases in the fair value of equity-based awards granted in 2022 versus previously granted awards. In addition, the Company issued its Board approved 2023 annual stock option awards on September 18, 2023.

Further information regarding our equity compensation plans is included in Note 16 "*Shareholders' Capital*" of our audited financial statements.

Depletion and depreciation expense

($000's except per boe amounts)	Three months ended December 31, 2023	2022	% change	Year ended December 31, 2023	2022	% change
Depletion expense	**1,803**	1,134	59	**4,975**	3,755	32
Depreciation expense	**182**	90	100	**1,034**	578	79
Depletion and depreciation expense	**1,985**	1,224	62	**6,009**	4,333	39
Depletion expense $ per boe(1)	**2.30**	5.53	(58)	**3.42**	6.51	(47)

Note:
(1) Non-GAAP financial measure. See the "*Advisories - Non-GAAP Financial Measures*" section of this MD&A for further information.

Our petroleum and natural gas producing development assets included in PP&E are subject to depletion expense. The net carrying values of our producing development assets are depleted using the unit of production method by reference to the ratio of production in the period over the related proved plus probable reserves while also considering the estimated future development costs necessary to bring those reserves into production. Depletion expenses fluctuate based on the amount and type of capital spending, the recognition or reversal of development asset impairments, the quantity of reserves added and production volumes. As at December 31, 2023, $105,252,000 in future development costs were included in development asset cost bases for depletion calculation purposes (2022 - $71,638,000).

For the three months and year ended December 31, 2023, depletion expense associated with our petroleum and natural gas development assets included in PP&E increased by 59 percent and 32 percent, respectively, compared to the same periods of 2022. The 2023 year-over-year increases in depletion expenses in comparison to 2022 was primarily driven by additional production volumes from our Coho and Cascadura fields.

On a per boe basis, the Company's depletion rates decreased 58 percent and 47 percent during the three months and year ended December 31, 2023, respectively, in comparison to the equivalent prior year periods, primarily based on Coho and Cascadura incremental production volumes.

Assets in the E&E phase are not amortized. Depreciation expense is recorded on corporate assets on a declining balance basis, and right-of-use ("ROU") assets are depreciated over their estimated useful lives on a straight-line basis. The increases in depreciation expense reported during the three months and year ended December 31, 2023 relative to the equivalent 2022 periods reflected higher net asset carrying values associated with ROU assets as a result of increased lease liability carrying values and corporate PP&E expenditures, as well as an increase in depreciation of drilling rig mobilization expenses which were recorded when the associated drilling rig was in use in the first quarter of 2023.

Impairment of non-financial assets

Entities are required to conduct an impairment test where there is an indication of impairment or reversal of a non-financial asset. Impairment is recognized when the carrying value of an asset or group of assets exceeds its recoverable amount, defined as the higher of its value in use or fair value less costs of disposal. Any asset impairment that is recorded is recoverable to its original value less any associated depletion and depreciation expense should there be indicators that the recoverable amount of the asset has increased in value since the time of recording the initial impairment. Touchstone assesses E&E asset and PP&E indicators of impairment and impairment reversal on each reporting date.

E&E asset impairment

E&E asset impairment expense by property for the specified periods are disclosed in the following table.

Property *($000's)*	**Three months ended December 31,**		% change	**Year ended December 31,**		% change
	2023	2022		**2023**	2022	
Cory Moruga	**19**	14	36	**66**	195	(66)
Ortoire	**32,649**	-	n/a	**32,649**	-	n/a
E&E asset impairment expense	**32,668**	14	100	**32,715**	195	100

During the three months and year ended December 31, 2023, we recognized E&E asset impairments of $19,000 and $66,000, respectively, related to our non-core Cory Moruga property (2022 - $14,000 and $195,000). Our 16.2 percent non-operated working interest in the Cory Moruga licence continues to have an estimated recoverable value of $nil.

As a result of allocating future capital spending to align with the Company's long-term priorities and the results of production tests which deemed the Royston-1X well uneconomic, indicators of impairment were noted in the Ortoire area. The Company performed an impairment test which concluded that the recoverable amount of the area was not sufficient to support its carrying value, resulting in an aggregate pre-tax impairment expense of $32,649,000 recorded at December 31, 2023.

$10,743,000 of the impairment expense was originally incurred on the Chinook-1 well, while the remaining $21,906,000 reflected expenditures on the Royston area of the block, predominantly encompassing Royston-1 and Royston-1X drilling and production testing costs. The residual $5,030,000 Ortoire block E&E asset carrying value as at December 31, 2023 included historical Royston area seismic, road and drilling lease expenditures.

Upon first production in September 2023, the Company transferred $32,204,000 of E&E costs related to our Cascadura field to PP&E. Immediately prior to transferring the assets to PP&E, we performed the required impairment test and determined that the recoverable amount of the asset exceeded its carrying value, resulting in no impairment expense recognized.

PP&E impairment

The following table discloses PP&E impairment expenses (reversal) by CGU for the specified periods.

CGU *($000's)*	**Three months ended December 31,**		% change	**Year ended December 31,**		% change
	2023	2022		**2023**	2022	
Coho	**143**	-		**143**	-	
Coora	**(13,865)**	-		**(13,865)**	-	
Fyzabad	**2,270**	-		**2,270**	-	
Net PP&E impairment reversal	**(11,452)**	-	n/a	**(11,452)**	-	n/a

On December 31, 2023, we evaluated our petroleum and natural gas development assets included in PP&E for indicators of any potential impairment or reversal. As a result of these assessments, the following indicators of potential impairment were identified for the specified CGUs.

Coho CGU - based on a reduction of assigned reserves from negative Coho-1 well technical revisions attributed to workover conducted in the fourth quarter of 2023 that isolated the lower portion of perforations.

Coora CGU - based on a decline in evaluated reserves from the removal of six proved undeveloped locations specific to the CO-2 block. Subsequent to year-end, we entered into an agreement to dispose our interest in the CO-2 property to a third party (refer to the "*Capital Expenditures and Dispositions*" section of this MD&A for further information).

Fyzabad CGU - based on a reduction in assigned reserves from the removal of future capital operations (recompletion operations) based on forecasted field activities and the potential disposition of the property (refer to the "*Capital Expenditures and Dispositions*" section herein for further information).

We performed impairment tests to estimate the recoverable amounts of the three CGUs. The tests concluded that the recoverable amounts for the Coho and Fyzabad CGUs were not sufficient to support their carrying values, and the recoverable amount of the Coora CGU was greater than its carrying value. As a result, we recognized an aggregate pre-tax impairment expense of $2,413,000 related to the Coho and Fyzabad CGUs and a pre-tax impairment reversal of $13,865,000 associated with the Coora CGU at December 31, 2023.

In addition, the Company recorded an impairment expense of $126,000 related to slow moving oilfield capital inventory that was not assigned to a specific CGU at December 31, 2023 (2022 - $nil). Touchstone also performed an impairment test on its San Francique CGU immediately prior to transferring the assets and related liabilities to held for sale. The test determined that the CGU's fair value exceeded its carrying value, resulting in no impairment expense recognized (refer to the "*Capital Expenditures and Dispositions*" section of this MD&A for further information).

Calculating E&E asset and petroleum and natural gas development asset CGU recoverable amounts involves several assumptions and estimates which are subject to estimation uncertainty, as well as a significant degree of judgement. The estimated recoverable amounts of Touchstone's PP&E CGUs at December 31, 2023 were determined using value in use calculations incorporating discounted after-tax cash flows of proved plus probable reserves using forward crude oil and natural gas prices and cost estimates as assessed by the Company's independent qualified reserves evaluator. Discounted future cash flows for each CGU were determined by applying an after-tax 20 percent discount rate. Inputs used in the measurement of estimated recoverable amounts were not based on market data and fall within level 3 of the fair value hierarchy.

As future commodity prices remain volatile, impairments or impairment reversals could be recorded in future periods. Changes in any of the key judgements, such as revisions in reserves, forecasted production, forecasted commodity prices, inflation rates, operating and future development expenditures, future tax rates and/or after-tax discount rates would impact the estimated recoverable amounts. Further information regarding impairments recorded during the year ended December 31, 2023 and their related measurement uncertainty is included in Note 9 "Impairment" of our audited financial statements.

Other expenses

($000's except per boe amounts)	**Three months ended December 31,**		% change	**Year ended December 31,**		% change
	2023	2022		**2023**	2022	
Other expenses	**-**	122	(100)	**(552)**	794	n/a
$ per boe[(1)]	**-**	0.59	(100)	**(0.38)**	1.38	n/a

Note:
(1) Non-GAAP financial measure. See the "*Advisories - Non-GAAP Financial Measures*" section of this MD&A for further information.

For the three months and year ended December 31, 2022, the Company incurred $122,000 and $794,000 in expenses related to an oil spill that occurred as a result of vandalism in June 2022, respectively. In the fourth quarter of 2022 we filed an insurance claim through our general and pollution liability policy which had a $250,000 deductible for all pollution claims. We received insurance proceeds of $552,000 during the

2023 year from this claim.

Income taxes

Current income tax

The Company's two Trinidad exploration and production subsidiaries are subject to the following Trinidad petroleum taxes:

- Supplemental Petroleum Tax — 18 percent of gross liquids revenue less related royalties
- Petroleum Profits Tax ("PPT") — 50 percent of net taxable profits
- Unemployment Levy ("UL") — 5 percent of net taxable profits
- Green Fund Levy ("GFL") — 0.3 percent of gross revenue

SPT is levied on a quarterly basis and is applicable to crude oil and liquids volumes. Actual rates vary based on the average realized selling prices of crude oil and liquids in the applicable quarter. The SPT rate is zero when the weighted average realized price of crude oil and liquids for a given quarter is below $75.00 per barrel and 18 percent when weighted average realized prices fall between $75.00 and $90.00 per barrel. For quarterly average prices greater than $90.00, the SPT rate is 18 percent plus 0.2 percent per $1.00 above $90.00 per barrel. The tax base for the calculation of SPT is crude oil and liquids sales less related royalties paid, less 30 percent investment tax credits on mature oilfields for allowable tangible and intangible capital expenditures incurred in the applicable fiscal quarter. Our Ortoire property is not considered a mature oilfield, and thus no capital spending investment tax credits are applicable.

PPT and UL taxes are levied on an annual basis and are calculated based on net taxable profits. Net taxable profits are determined by calculating gross revenue less: royalty expenses, SPT paid during the year, capital allowances, operating expenses, G&A expenses, and certain finance expenses. PPT losses may be carried forward indefinitely to reduce PPT in future years but can only be used to shelter a maximum of 75 percent of income subject to PPT per annum. UL losses cannot be carried forward to reduce future year UL. Developmental and exploratory capital expenditure allowances are amortized on a five-year straight-line basis.

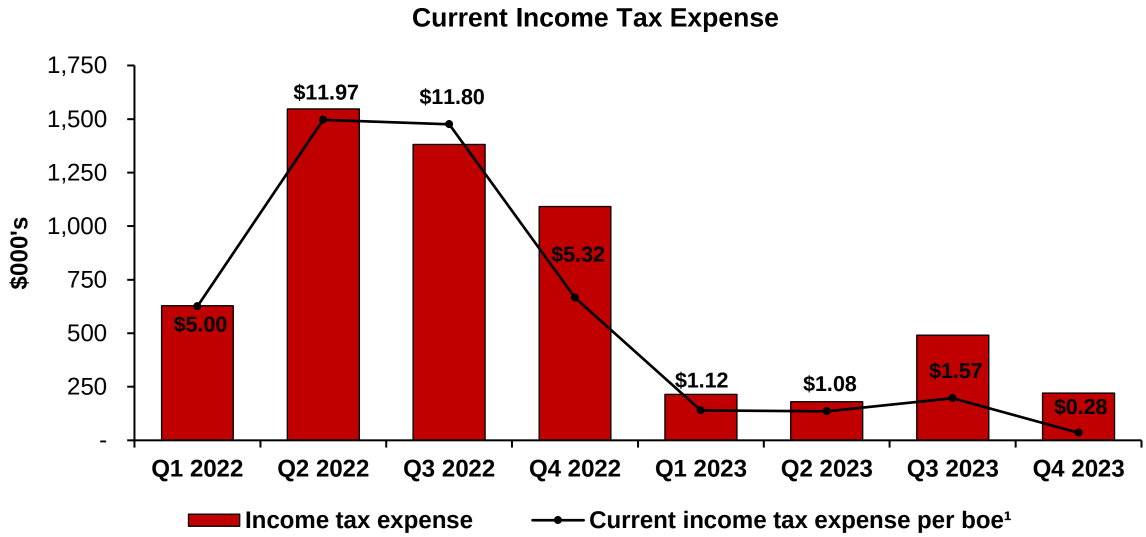
Our Trinidad oilfield service subsidiary, which primarily leases oilfield service equipment to third-party contractors for use in our exploration and production subsidiaries, is subject to the greater of a 30 percent corporate income tax calculated on net taxable profits or a 0.6 percent business levy calculated on gross revenue. The service company is also subject to the GFL noted above. All corporate income tax losses can be carried forward indefinitely, and allowances vary from 10 percent to 33.3 percent for various capital expenditures incurred in the year.

The following table sets forth current income tax expenses for the periods indicated.

($000's except per boe amounts)	**Three months ended December 31,**		% change	**Year ended December 31,**		% change
	2023	2022		**2023**	2022	
SPT	**-**	979	(100)	**234**	3,422	(93)
PPT	**(5)**	53	n/a	**376**	755	(50)
UL	**(2)**	22	n/a	**150**	303	(50)
Other	**227**	38	100	**346**	168	100
Current income tax expenses	**220**	1,092	(80)	**1,106**	4,648	(76)
$ per boe[(1)]	**0.28**	5.32	(95)	**0.76**	8.06	(91)

Note:
(1) Non-GAAP financial measure. See the "*Advisories - Non-GAAP Financial Measures*" section of this MD&A for further information.

During the three months and year ended December 31, 2023, we recognized current income tax expenses of $220,000 and $1,106,000, respectively, compared to $1,092,000 and $4,648,000 in the same periods of 2022. Relative to the corresponding periods of 2022, the decreases noted in the fourth quarter and annual 2023 periods was based on reduced SPT expenses and a decline in estimated 2023 Trinidad-based net taxable profits. Increased 2023 net taxable profits derived from our Cascadura field were largely sheltered by previous tax pools. 2023 SPT expenses were incurred from September Cascadura NGL sales, which averaged a realized price above the $75.00 per barrel SPT threshold and were thus subject to SPT.



Note:
(1) Non-GAAP financial measure. See the "*Advisories - Non-GAAP Financial Measures*" section of this MD&A for further information.

Deferred income tax

The Company's $21,433,000 net deferred income tax liability balance represented the estimated future tax consequences attributable to differences between financial statement carrying amounts of assets and liabilities and their respective income tax bases as at December 31, 2023 (2022 - $14,557,000). The deferred income tax balance remained in a liability position mainly from the discrepancy between the financial statement carrying values and the income tax values of the Company's petroleum and natural gas development assets included in PP&E.

During the three months and year ended December 31, 2023, we recognized deferred income tax expenses of $8,009,000 and $6,779,000, respectively, compared to recoveries of $266,000 and $1,000 in the equivalent periods of 2022. 2023 deferred income tax expenses primarily reflected PP&E impairment reversals recognized at December 31, 2023, which increased the discrepancy between the income tax base and our PP&E financial statement carrying balances.

Further information regarding our current and deferred income taxes is included in Note 15 "*Income Taxes*" of our audited financial statements.

Net loss

We recorded a net loss of $21,236,000 ($0.09 per basic and diluted share) in the fourth quarter of 2023 compared to a net loss of $1,921,000 ($0.01 per basic share) in the prior year equivalent quarter. Compared to the prior year fourth quarter, the variance from the same period of 2023 was predominately driven by E&E asset impairment expenses of $32,668,000, partially offset by net PP&E impairment reversals of $3,770,000 (net of income tax) and a $9,798,000 increase in funds flow from operations.

Touchstone recognized a net loss of $20,598,000 ($0.09 per basic share) in 2023 in comparison to a net loss of $3,197,000 ($0.01 per basic share) recorded in the 2022 year. Relative to the 2022 year, the year-over-year variance was mainly attributed to E&E asset impairment expenses of $32,715,000 and an increase in deferred income tax expenses of $6,780,000 recorded in 2023, partially offset by the recognition of net PP&E impairment reversals of $11,326,000 and a $10,190,000 annual increase in funds flow from operations.

The following table sets forth details of the change in net loss from the three months and year ended December 31, 2022 to the three months and year ended December 31, 2023.

($000's)	**Three months ended December 31,**	**Year ended December 31,**
Net loss – 2022	(1,921)	(3,197)
Cash items		
Funds flow from operations	**9,798**	**10,190**
Decommissioning expenditures	**(2)**	**(112)**
Cash variances	**9,796**	**10,078**
Non-cash items		
Gain on asset dispositions	**846**	**1,526**
Unrealized foreign exchange	**336**	**(94)**
Equity-based compensation expense	**(48)**	**98**
Depletion and depreciation expense	**(761)**	**(1,676)**
Impairment expense	**(21,328)**	**(21,194)**
Non-cash finance expenses	**119**	**641**
Deferred income tax	**(8,275)**	**(6,780)**
Non-cash variances	**(29,111)**	**(27,479)**
Net loss – 2023	**(21,236)**	**(20,598)**

Cash from operating activities

The following table details the change in cash (used in) from operating activities from the three months and year ended December 31, 2022 to the three months and year ended December 31, 2023.

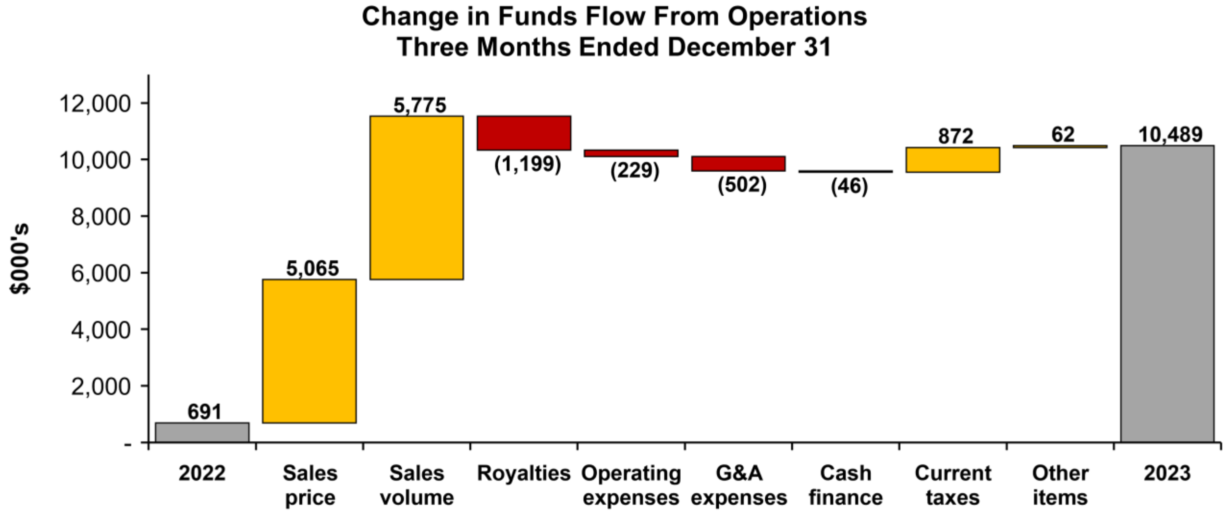
($000's)	**Three months ended December 31,**	**Year ended December 31,**
Cash (used in) from operating activities – 2022	(1,189)	5,752
Change in funds flow from operations	**9,798**	**10,190**
Net change in non-cash working capital	**(97)**	**(3,199)**
Cash from operating activities – 2023	**8,512**	**12,743**

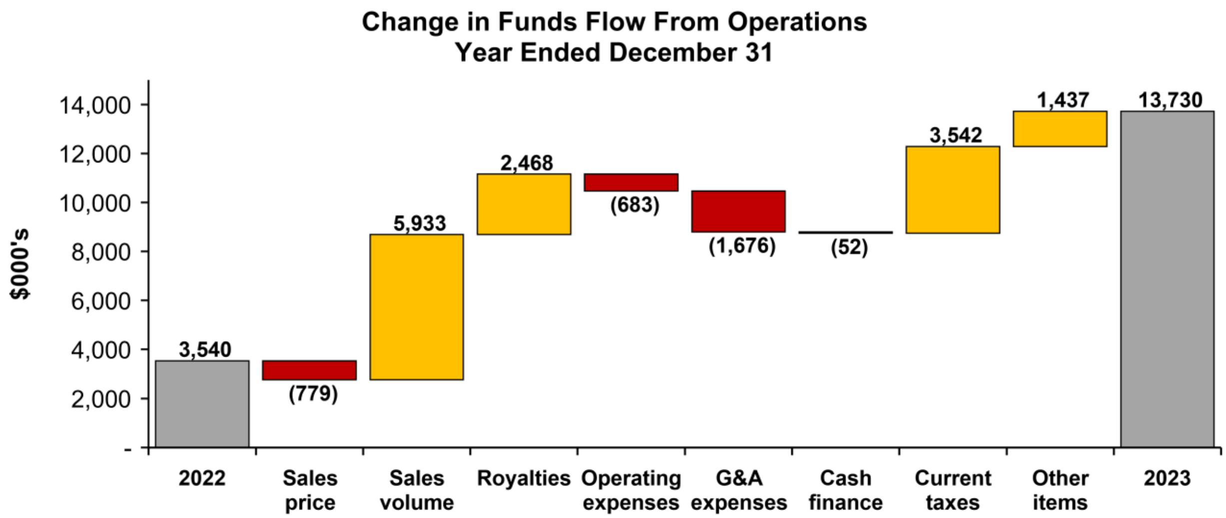
Funds flow from operations

We generated funds flow from operations of $10,489,000 in the fourth quarter of 2023, a $9,798,000 increase from the $691,000 reported in the prior year comparative quarter. Relative to the fourth quarter of 2022, the year-over-year increase reflected a $9,412,000 increase in operating netback, predominately from incremental Cascadura natural gas and NGL production volumes. Increased fourth quarter 2023 G&A expenses were offset by reduced current income tax expenses in comparison to the prior year fourth quarter.

On an annual basis, we generated funds flow from operations of $13,730,000 in 2023 compared to $3,540,000 in 2022. In 2023, we achieved an operating netback increase of $6,939,000 in comparison to the prior year. In relation to 2022, we incurred lower current income tax expenses and recorded insurance proceeds received in relation to a June 2022 environmental incident, which were partially offset by increased G&A expenses recognized in 2023.

The following graphs summarize the change in funds flow from operations from the three months and year ended December 31, 2022 to the three months and year ended December 31, 2023.





Net loss and funds flow from operations sensitivity

The following table illustrates sensitivities of operating items to operational and business environment changes and the resulting estimated impact to net loss and funds flow from operations for the year ended December 31, 2023.

	Assumption(1)	Change	Impact on annual net loss(2) *($000's)*	Impact on annual funds flow from operations(2) *($000's)*
Business environment				
Crude oil price *($/bbl)*(3)	67.80	10%	**108**	**146**
Crude oil price *($/bbl)*(3)	67.80	-10%	**(2,202)**	**(1,600)**
NGL price *($/bbl)*(3)	74.07	10%	**(281)**	**(275)**
NGL price *($/bbl)*(3)	74.07	-10%	**(196)**	**(202)**
Interest rate on revolving debt *(%)*(4)	7.29	0.5	**(24)**	**(17)**

	Assumption[(1)]	Change	Impact on annual net loss[(2)] *($000's)*	Impact on annual funds flow from operations[(2)] *($000's)*
Operational				
Crude oil and liquids production *(bbls/d)*	1,382	5%	**932**	**931**
Crude oil and liquids production *(bbls/d)*	1,382	-5%	**(1,099)**	**(1,015)**
Natural gas production *(Mcf/d)*	15,593	5%	**394**	**478**
Natural gas production *(Mcf/d)*	15,593	-5%	**(423)**	**(507)**
Royalty expenses *($/boe)*[(3)]	8.38	±5%	**671**	**496**
Operating expenses *($/boe)*[(3)]	6.68	±5%	**512**	**400**
G&A expenses *($/boe)*[(3)]	6.72	±5%	**468**	**417**

Notes:
(1) Assumptions are indicative of actual prices and volumes realized and actual results for the year ended December 31, 2023. The Company's natural gas sales price was fixed and thus not included in the sensitivity analysis.
(2) Calculations are estimates, are performed independently and will not be indicative of actual results that would occur when multiple variables change concurrently. Calculations are performed prior to the impact of non-financial asset impairment tests.
(3) Non-GAAP financial measure. See the "*Advisories - Non-GAAP Financial Measures*" section of this MD&A for further information.
(4) The interest rate on the Company's revolving loan facility is fixed on an annual basis. The calculation assumes that rate changed by 50 basis points as of the May 30, 2023 determination date.

Capital Expenditures and Dispositions

E&E asset expenditures

E&E asset expenditures include asset additions in areas that have been determined to be in the exploration phase. Touchstone's core exploration property is the Ortoire block. E&E asset expenditures during the respective periods are summarized in the following table.

($000's)	**Three months ended December 31,**		% change	**Year ended December 31,**		% change
	2023	2022		**2023**	2022	
Licence financial obligations	**72**	69	4	**296**	588	(50)
Drilling, completions and well testing	**436**	(157)	n/a	**8,678**	1,153	100
Equipment and facilities	**-**	1,873	(100)	**7,709**	6,201	24
Capitalized G&A	**95**	200	(53)	**559**	698	(20)
Other	**(8)**	305	n/a	**396**	1,148	(66)
E&E asset expenditures	**595**	2,290	(74)	**17,638**	9,788	80

Our 2023 capital program remained predominately focused on exploration activities on our Ortoire property, as we invested $595,000 and $17,638,000 during the three months and year ended December 31, 2023, respectively. Fourth quarter 2023 investments included two production tests on the Royston-1X sidetrack well drilled in the first quarter of 2023, with a total of five tests completed in 2023. $7,709,000 of our E&E investments were construction and commissioning operations directed toward the Cascadura natural gas and liquids facility that came online in September 2023. Upon first production, the carrying value of the Cascadura field was transferred from E&E assets to PP&E.

Fourth quarter and annual 2022 E&E asset expenditures were $2,290,000 and $9,788,000, respectively. Touchstone's 2022 capital program remained heavily focused on exploration activities on the Ortoire property, where our investments primarily focused on the completion of our Coho natural gas facility, expenditures for the Cascadura natural gas and liquids facility and Royston-1 well production testing operations completed in the first quarter of 2022.

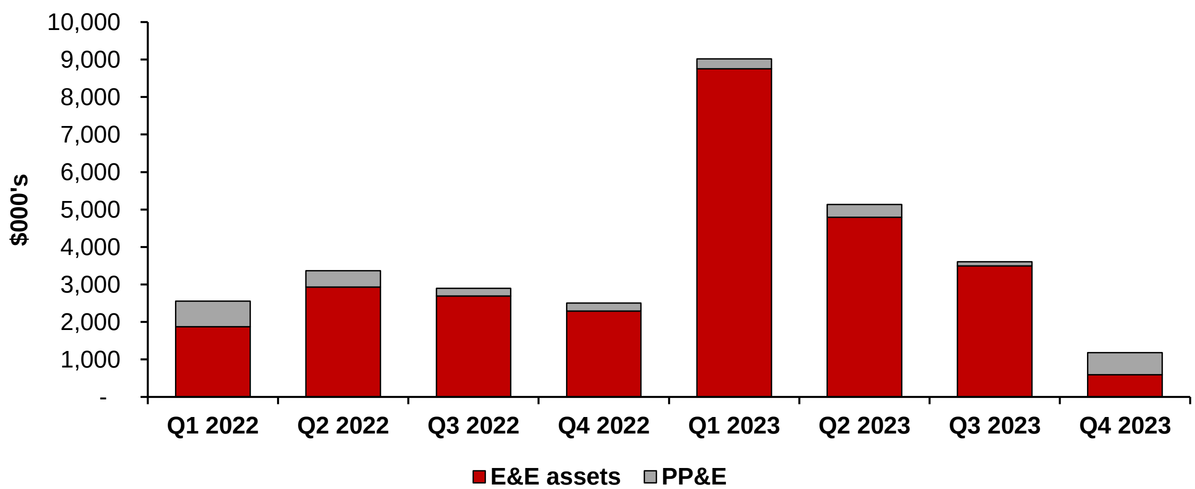
PP&E expenditures

($000's)	Three months ended December 31, 2023	2022	% change	Year ended December 31, 2023	2022	% change
Drilling and completions	**386**	51	100	**593**	1,059	(44)
Equipment and facilities	**177**	-	-	**177**	-	-
Capitalized G&A	**9**	156	(94)	**268**	389	(31)
Corporate and other	**19**	12	58	**273**	94	100
PP&E expenditures	**591**	219	100	**1,311**	1,542	(15)

During the three months and year ended December 31, 2023, we invested $591,000 and $1,311,000 on PP&E, respectively. Annual expenditures focused on eight well recompletions, final Cascadura facility commissioning costs, pre-drill expenditures relating to the Cascadura-2 development well and investments in corporate information technology infrastructure.

Fourth quarter and annual 2022 expenditures on PP&E totaled $219,000 and $1,542,000, respectively. Expenditures were predominately related to completion costs for our three wells drilled in the fourth quarter of 2021 as well as lease preparation costs for two future CO-1 drilling locations.

Capital Expenditures(1)



Note:
(1) Non-GAAP financial measure. See the "*Advisories - Non-GAAP Financial Measures*" section of this MD&A for further information.

Dispositions

In January 2023, we entered into an Asset Exchange Agreement for the exchange of certain onshore Trinidad assets with a privately held Trinidadian entity for no cash consideration. Pursuant to the agreement, Touchstone agreed to swap its operated 100 percent working interests in the Fyzabad, San Francique and Barrackpore producing blocks for the counterparty's working interest in the Rio Claro, Balata East and Balata East Deep Horizons blocks for no cash consideration with the asset exchange becoming effective upon closing.

Given regulatory delays, the parties executed a Supplemental Agreement to the Asset Exchange Agreement in October 2023, which amended the asset swap into two asset exchanges. The amended arrangement contemplates an initial exchange of our 100 percent working interest in the privately leased San Francique field to the counterparty's 100 percent working interests in the Balata East and Balata East Deep Horizons blocks. All applications have been submitted and the parties are awaiting final regulatory approvals. Accordingly, the Company classified the carrying values of its San Francique CGU assets and liabilities (net liability of $1,221,000) to held for sale as at December 31, 2023. The parties expect to commence regulatory applications relating to the second asset exchange upon closing of the initial exchange.

In 2021 we executed sale and purchase agreements with a third party to dispose our non-core New Dome, Palo Seco and South Palo Seco properties for aggregate consideration of $350,000, subject to customary closing adjustments. The transactions were effective December 31, 2021, and we closed the New Dome and South Palo Seco dispositions on April 30, 2022 with a net $85,000 gain on asset dispositions recorded during the year ended December 31, 2022. The Palo Seco property disposition closed on May 31, 2023, and the Company recognized a net $800,000 gain on asset dispositions during the year ended December 31, 2023.

In conjunction with initial Coho production on October 2022, Touchstone sold a gathering line tying in the Coho natural gas facility to a third-party natural gas processing facility to NGC for net proceeds of $1,200,000. A net $846,000 loss on asset dispositions was recorded in connection with the transaction during the year ended December 31, 2022.

Subsequent to December 31, 2023, we entered into an agreement with a third party to dispose our interest in the CO-2 block. Touchstone considers the property to be non-core due to limited economics, operating expenses that were higher than our corporate average and extensive work obligations required through the licence term. The property generated estimated operating netbacks of approximately $293,000 and contributed average crude oil sales of 56 bbls/d during the year ended December 31, 2023 (2022 - $172,000 and 37 bbls/d, respectively).

Decommissioning Liabilities and Abandonment Fund

Our decommissioning and reclamation liabilities relate to future site restoration and well abandonment costs including the costs of production equipment removal and land reclamation based on current Trinidad environmental regulations. The estimates are reviewed at least quarterly and adjusted as new information regarding the liability is determined and include assumptions in respect of actual costs to abandon wells and facilities and reclaim a property, the time frame in which such costs will be incurred, historical well production and annual inflation factors.

Pursuant to production and exploration licences with the MEEI, we are obligated to remit $0.25 per boe sold into an escrow account in the name of the MEEI. The payments are used as a contingency fund for remediation of pollution arising from petroleum operations conducted under the relevant licence and the eventual abandonment of wells and decommissioning of facilities used for operations conducted under the relevant licence. The MEEI shall return the funds in the escrow account once all obligations in respect of environmental remediation are fulfilled to their satisfaction. Contributions to the fund are reflected on the consolidated balance sheet as long-term abandonment fund assets.

With respect to well decommissioning liabilities associated with our LOAs with Heritage, we are obligated for our proportional cost of all abandonments defined as our percentage of crude oil sold in a well in comparison to the well's cumulative historical production. Touchstone is not responsible for the decommissioning of existing infrastructure and sales facilities. We are required to remit $0.25 per barrel sold to Heritage into a joint well abandonment fund. These funds are used solely for well decommissioning. Any costs of wells that are abandoned during the relevant licence term are credited against any future contributions of the well abandonment fund. Upon expiration of the relevant agreement, Heritage shall calculate our total abandonment liability. If our liability exceeds the well abandonment fund, we are obligated to pay the difference. Conversely, if the proceeds of the fund exceed the liability, the surplus shall be returned to Touchstone. These amounts are also recognized as long-term abandonment fund assets on the consolidated balance sheet.

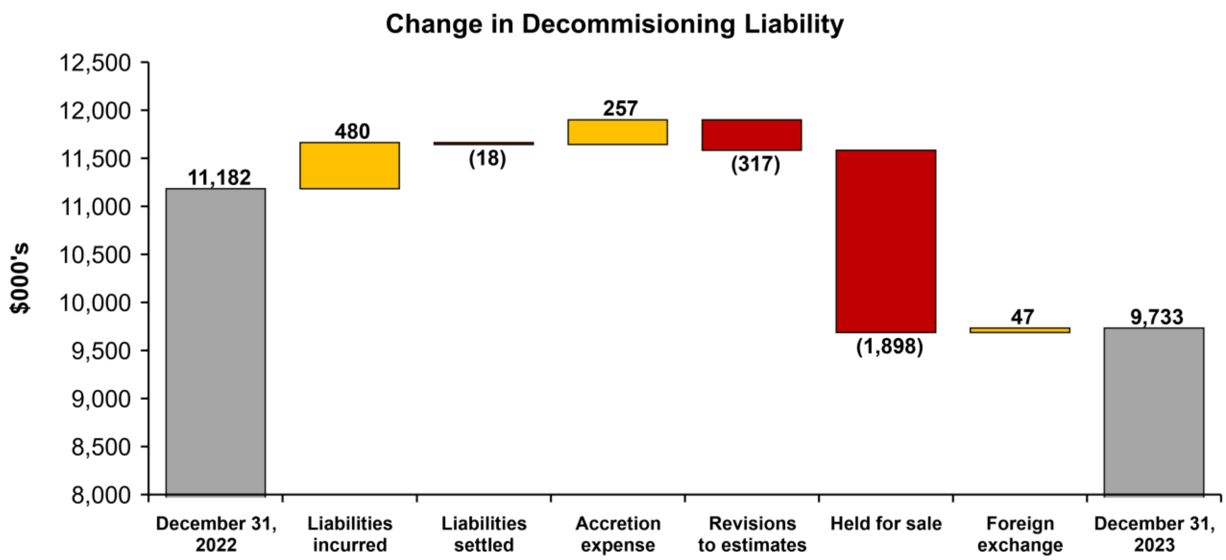
As of December 31, 2023, we reported $2,081,000 of accrued or paid contributions into MEEI and Heritage abandonment funds as long-term abandonment fund assets (2022 - $1,446,000).

Pursuant to our Heritage operating agreements, we fund Heritage's $0.25 per barrel obligation with respect to Heritage's head licence commitments with the MEEI. As the Company cannot access the contributions for our future well abandonments, the payments are included in operating expenses as incurred. Additionally, we are further obligated to remit $0.03 per barrel to Heritage into a general abandonment fund. The non-refundable proceeds are used as a contingency fund for the decommissioning and removal of infrastructure and facilities within a field and are expensed to operating expenses as incurred.

We are responsible for all site restoration, well abandonment costs and removal of infrastructure and facilities used in petroleum operations conducted on our private production and exploration agreements.

Touchstone estimated the net present value of the cash flows required to settle decommissioning liabilities to be $9,733,000 as at December 31, 2023 compared to $11,182,000 as of December 31, 2022. The decrease in the estimated decommissioning liability at December 31, 2023 in comparison to December 31, 2022 was primarily attributed to a $1,898,000 reclassification of the San Francique CGU decommissioning liabilities to liabilities associated with assets held for sale (refer to the "*Capital Expenditures and Dispositions*" section herein). Relative to 2022, increased liabilities from the Cascadura facility were slightly offset by a reduction in the estimated weighted average long-term inflation rate from 2.4 percent in December 31, 2022 to 2.1 percent in December 31, 2023. In addition, $69,000 and $257,000 of accretion expenses were recognized during the three months and year ended December 31, 2023, respectively, to reflect the increase in decommissioning liabilities associated with the passage of time (2022 - $54,000 and $222,000). Decommissioning liability details as at and during the year ended December 31, 2023, excluding those classified as held for sale, are summarized in the table and graph below.

Number of well locations (net)	Number of facility locations (net)	Undiscounted balance *($000's)*	Inflation adjusted balance *($000's)*	Discounted balance *($000's)*
635.6	3.6	12,420	14,910	9,733



Environmental stewardship is a core value at Touchstone, and abandonment and reclamation activities are made in a prudent, responsible manner with the oversight of the Board and in accordance with local regulations. Decommissioning liabilities are considered critical accounting estimates. There are significant uncertainties related to future decommissioning expenditures, and the impact on our consolidated financial statements could be material. The eventual timing of and costs for these expenditures could differ from current estimates. Further information regarding decommissioning liabilities is included in Note 14 "*Decommissioning Liabilities and Abandonment Fund*" of our audited financial statements.

Liquidity and Capital Resources

Liquidity

Our policy is to maintain a strong capital base to preserve investor, creditor, and market confidence and to sustain the future development of our business. We consider our capital structure to include shareholders' equity, working capital and bank debt. Touchstone's capital management objective is to fund current period decommissioning and capital expenditures necessary for the replacement of production declines using only funds flow from operations. Exploration and development activities are anticipated to be financed with a combination of funds flow from operations and other sources of capital. We use shareholders' equity and bank debt as our primary sources of capital.

At December 31, 2023, the Company had a working capital deficiency and obtained a waiver from its lender with respect to a covenant violation. Subsequent to December 31, 2023, Touchstone and its lender entered into a binding term sheet, subject to customary closing conditions and a material adverse change clause, that is expected to provide an addition $13 million of bank debt capacity (see the "*Bank debt*" section below). If the Company had an adverse outcome to closing this financing, we would be required to seek alternative sources of financing to manage liquidity.

As at December 31, 2023, we had a cash balance of $8,186,000, a working capital deficit of $7,581,000 and a principal long-term bank debt balance of $15,000,000. The following table summarizes our changes in cash during the specified periods.

($000's)	**Three months ended December 31,**		% change	**Year ended December 31,**		% change
	2023	2022		**2023**	2022	
Net cash from (used in):						
Operating activities	**8,512**	(1,189)	n/a	**12,743**	5,752	100
Investing activities	**(2,371)**	(1,734)	37	**(21,115)**	(16,476)	28
Financing activities	**(1,731)**	10,714	n/a	**130**	9,052	(99)
Change in cash	**4,410**	7,791	(43)	**(8,242)**	(1,672)	100
Cash, beginning of period	**3,794**	8,732		**16,335**	17,936	
Impact of FX on cash balances	**(18)**	(188)	(90)	**93**	71	31
Cash, end of period	**8,186**	16,335	(50)	**8,186**	16,335	(50)

Our December 31, 2023 cash and working capital balances declined in comparison to December 31, 2022 based on capital investments directed toward our Ortoire block. We achieved initial production from our Cascadura field in September 2023, which led to increased cash flows from operating activities in the fourth quarter of 2023. In addition, our $7,581,000 working capital deficit as at December 31, 2023 included the full $7 million revolving credit facility principal balance in current liabilities, the balance which will be payable in a minimum of two years upon closing of our Amended Bank Loan (see the "*Bank debt*" section below).

Our principal near term strategy is balanced between maintaining base production levels and increasing cash flow generation via the development of our Cascadura field in 2024. We will continue to take a measured approach to future developmental and exploration capital expenditures to manage financial liquidity while proceeding with this plan. We expect to use the additional credit capacity from our Amended Bank Loan to fund our 2024 forecasted capital expenditures, which are anticipated to increase production and cash flows from operations (refer to the "*Annual 2024 Guidance*" section of this MD&A for further details).

Bank debt

Touchstone Exploration (Trinidad) Ltd., the Company's indirectly wholly owned Trinidadian subsidiary, entered into a $20 million, seven-year term credit facility arrangement effective June 15, 2020 with Republic Bank Limited, a chartered bank owned by Republic Financial Holdings Limited. Republic Financial Holdings

Limited is headquartered in Trinidad and the registered owner of ten banks in the Caribbean region, as well as other financial services subsidiaries.

On May 25, 2023, the parties entered into a second amended and restated loan agreement (the "loan agreement"), which provided for a $7 million revolving loan facility in addition to our existing $30 million term facility. Details of the loan agreement are set forth below.

Facility	Term loan	Revolving loan
Amount	$30,000,000	$7,000,000
Maturity date	June 15, 2027	May 30, 2024 - the parties have the option to extend annually by additional periods of up to one year
Interest rate	7.85 percent per annum	7.29 percent through May 2024 - reset annually
Interest payments	Payable quarterly in arrears	Payable monthly in arrears
Principal payments	Twenty $1.5 million quarterly payments from September 15, 2022 to June 15, 2027; additional principal may be repaid with no penalty	Principal may be repaid at any time, on or before the maturity date without penalty and any amounts repaid may be redrawn at any time

As at December 31, 2023, the Company had $28,000,000 in aggregate principal bank debt outstanding, with $13,000,000 classified as short term on the consolidated balance sheet (2022 - $27,000,000 and $6,000,000, respectively). The $7,000,000 revolving loan facility was fully drawn on June 1, 2023. As at December 31, 2023, the balance of our term loan indebtedness was $21,000,000, with fourteen equal and consecutive quarterly principal payments of $1,500,000 outstanding.

The loan agreement is principally secured by a pledge of equity interests and fixed and floating security interests over all present and after acquired assets of Touchstone Exploration (Trinidad) Ltd. and POGL. The loan agreement contains industry standard representations and warranties, undertakings, events of default, and financial covenants assessed on an annual basis. Pursuant to the loan agreement, a failure of any covenant constitutes an event of default, upon where the lender can declare the principal balance and any accrued interest immediately due and payable. We routinely review all operational and financial covenants based on actual and forecasted results and can amend development and exploration plans to comply with the covenants. We are committed to having an adaptable capital expenditure program that can be adjusted to a tightening of liquidity sources if necessary.

The following table lists the financial covenants applicable on a consolidated basis as at December 31, 2023, all of which are evaluated on an annual basis.

Financial covenant description	Limit	Year ended December 31, 2023
Net senior funded debt(1) to trailing annual EBITDA(2)	2.50 times	**1.10**
Net senior funded debt to book value of equity(3)	0.70 times	**0.19**
Debt service coverage(4)	Minimum of 2.50 times	**1.80**

Notes:

(1) Net senior funded debt is defined in the loan agreement as all obligations for senior secured and unsecured borrowed money which bears interest less restricted and unrestricted cash balances. Lease liabilities are excluded from the calculation of net senior funded debt.

(2) EBITDA is defined in the loan agreement as earnings (loss) before interest expenses, income tax expenses, all non-cash items including depreciation and amortization, and losses attributable to extraordinary and non-recurring items.

(3) Book value of equity is defined in the loan agreement as shareholders' capital, contributed surplus and retained earnings or deficit excluding increases and decreases in retained earnings from E&E asset and PP&E impairments or reversals and excluding payments of dividends.

(4) Debt service coverage is defined in the loan agreement as the ratio of trailing annual EBITDA plus restricted and unrestricted cash balances to the total of bank debt interest expense due for the future annual period and scheduled principal payments in respect of outstanding bank debt principal for the future annual period.

As at December 31, 2023, the Company was compliant with all covenants provided for in the loan agreement aside from the debt service coverage financial covenant. Touchstone breached the debt service coverage covenant as a result of the $7 million principal amount of the revolving facility included as a future payment in the 2024 annual period. Per the covenant, the balance cannot be excluded until the parties renew the facility prior to May 30, 2024. Prior to December 31, 2023, Touchstone received a waiver from its lender for the anticipated breach confirming that the breach was waived and would not be enforced as an event of default.

On March 1, 2024, the Company and its lender executed a binding term sheet providing for a new $10 million five year term loan facility and increasing the current revolving loan facility from $7 million to $10 million. The term sheet is subject to customary conditions precedent and material adverse change clauses prior to the final agreement being executed. As of the date of this MD&A, the parties are currently drafting a third amended and restated loan agreement and perfecting the revised security documents, following which the additional borrowing capacity will be effective. We intend to use the additional borrowing capacity to finance our 2024 capital program (refer to the "*2024 Annual Guidance*" section herein).

At all times, we must maintain a cash reserves balance of not less than the equivalent of two subsequent quarterly interest payments related to the term loan facility. Accordingly, Touchstone classified $785,000 of cash as long-term restricted on the consolidated balance sheet as at December 31, 2023 (2022 - $1,021,000).

Further information regarding the loan arrangement is included in Note 13 "*Bank Debt*" of our audited financial statements, and copies of the loan agreement and amendments may be accessed online on our SEDAR+ profile (www.sedarplus.ca).

Shareholders' equity

The Company is authorized to issue an unlimited number of voting common shares without nominal or par value. From time to time, we may access capital markets to meet our additional financing needs and to maintain flexibility in funding our capital programs. The following table summarizes our outstanding common shares and stock options as at the date of this MD&A, December 31, 2023 and December 31, 2023.

	March 20, 2024	**December 31, 2023**	December 31, 2022
Common shares outstanding	**234,212,726**	**234,212,726**	233,037,226
Stock options outstanding	**14,327,935**	**14,327,935**	11,928,435
Fully diluted common shares	**248,540,661**	**248,540,661**	244,965,661

Relative to 2022, our common shares increased in 2023 as a result of 1,175,500 stock options exercised which were originally granted in accordance with our Legacy Plan.

Further information regarding our shareholders' capital and equity-based compensation is included in the "*Financial and Operational Results - Equity-based awards*" section herein and in Note 16 "*Shareholders' Capital*" of our audited financial statements.

Capital management

When evaluating our capital structure, Management's long-term strategy is to maintain net debt to trailing twelve-month funds flow from operations at or below a ratio of two times in a normalized commodity price environment. This ratio may increase at certain times as a result of increased capital expenditures or low commodity prices.

We also monitor our capital management through the net debt to managed capital ratio. Our strategy is to utilize more equity than debt, thereby targeting net debt to managed capital at a ratio of less than 0.4 to 1.

The following table details our internal capital management calculations for the periods specified.

($000's)	**Target measure**	**December 31, 2023**	December 31, 2022
Net debt[1]		**22,581**	16,008
Shareholders' equity		**59,766**	78,380
Managed capital[1]		**82,347**	94,388
Annual funds flow from operations		**13,730**	3,540
Net debt to funds flow from operations ratio[1]	At or < 2.0 times	**1.64**	4.52
Net debt to managed capital ratio[1]	< 0.4 times	**0.27**	0.17

Note:
(1) Non-GAAP financial measure. See the "*Advisories - Non-GAAP Financial Measures*" section of this MD&A for further information.

Refer to the *Market Risk Management - Liquidity risk*" section herein for further details regarding our approach to managing liquidity.

Contractual Obligations and Commitments

We have contractual obligations in the normal course of business which include minimum work obligations under various operating agreements with Heritage, exploration commitments under our Cory Moruga and Ortoire block exploration and production licences with the MEEI, and various lease commitments. The following table outlines our estimated minimum contractual payments as at December 31, 2023.

($000's)	**Total**	**Estimated payments due by year**			
		2024	**2025**	**2026**	**Thereafter**
Operating agreement commitments					
CO-1 block	**7,514**	4,251	1,484	55	1,724
CO-2 block	**7,558**	4,327	1,479	50	1,702
WD-4 block	**4,765**	1,442	1,476	48	1,799
WD-8 block	**4,824**	1,439	1,472	44	1,869
Fyzabad block	**683**	79	80	82	442
Coho area of Ortoire block	**50**	6	5	2	37
Cascadura area of Ortoire block	**92**	11	10	4	67
Cory Moruga exploration block	**1,099**	105	110	116	768
Ortoire exploration block	**11,794**	5,194	168	5,284	1,148
Office and equipment leases	**686**	190	208	196	92
Minimum payments	**39,065**	**17,044**	**6,492**	**5,881**	**9,648**

Under the terms of our Heritage operating agreements, we are obligated to fulfill minimum work commitments on an annual basis over the specific licence term. With respect to these obligations, we are required to drill eight development wells and perform four heavy workover commitments in 2024. Subsequent to December 31, 2023, the Company entered into an agreement to dispose our interest in the CO-2 property to a third-party, which upon closing will reduce the Company's estimated minimum payments and decrease its 2024 obligations by three wells and three heavy workovers (refer to the "*Capital Expenditures and Dispositions*" section herein for further information).

As at December 31, 2023, we are obligated to drill two exploration wells on our Ortoire field prior to the end of the July 31, 2026 licence term.

The Company is a party to lease arrangements for a drilling rig, office facilities, vehicles and equipment. As of December 31, 2023, we recognized $4,328,000 in aggregate lease liabilities, of which $2,888,000 was classified as long-term on the consolidated balance sheet (2022 - $2,255,000 and $1,373,000, respectively). During the year ended December 31, 2023, the Company entered into a minimum five-year lease for additional office space in Trinidad as well as various motor vehicle leases with four-year terms, resulting in a combined $2,934,000 lease liability and associated ROU asset recognized. Further information regarding our lease obligations is included in Note 12 "*Lease Liabilities*" of our audited financial statements.

Market Risk Management

We are exposed to normal financial risks inherent in the international oil and natural gas industry including, but not limited to, commodity price risk, foreign exchange rate risk, credit risk and liquidity risk. The risk exposures are proactively reviewed, and Management seeks to mitigate these risks through various business processes and internal controls.

Management has overall responsibility for the establishment of risk management strategies and objectives. Our risk management policies are designed to identify the risks faced by the Company, to set appropriate risk limits, and to monitor adherence to risk limits. Risk management policies are reviewed and revised regularly to reflect changes in market conditions and our operating activities. Management of cash flow variability is an integral component of our business strategy. Changing business conditions are monitored regularly and, where material, reviewed with the Board to establish risk management guidelines to be used by Management.

Commodity price risk

Our operational results and financial condition are dependent on the commodity prices received for our crude oil, NGL and natural gas production. We are a party to a long-term fixed price natural gas contract for our Ortoire natural gas production. However, movements in crude oil and liquids pricing could affect our cash from operating activities, the value of our development properties, the level of capital expenditures and our ability to meet financial obligations as they come due.

Crude oil prices have fluctuated widely in recent years due to global and regional factors including supply and demand fundamentals, ongoing geopolitical factors, inventory levels, weather, and economic factors. Further, our realized crude oil and liquids prices are based on quality differentials and international marketing arrangements and therefore are attributed to factors that are beyond our control (refer to the "*Business Risks - Commodity prices and marketing*" section herein). Our long-term fixed price natural gas sales agreement with NGC contains options for price negotiations on each fifth anniversary of our initial October 2022 production date. The price of natural gas in Trinidad is predominately based on domestic supply and demand, with demand largely from domestic power generation and petrochemical facilities. There can be no guarantee that we may be able to negotiate future price increases for natural gas, and a material decline in natural gas sales prices will result in a reduction of the Company's cash from operating activities and financial position.

Touchstone does not currently hedge our commodity price given that over 50 percent of our forecasted petroleum and natural gas sales is expected to be derived from natural gas production governed by the fixed price contract through October 2027. The Company will continue to monitor forward commodity prices and may enter future commodity-based risk management contracts to reduce the volatility of crude oil and liquids sales and protect future development and exploration capital programs. Additionally, we continually review our capital program and implement initiatives to adapt to such price changes (refer to the "*Financial and Operational Results - Net loss and funds flow from operations sensitivity*" section of this MD&A for further information).

Foreign currency risk

Foreign currency exchange risk arises from changes in foreign exchange rates that may affect the fair value or future cash flows of our financial assets or liabilities. Touchstone does not hedge its foreign exchange risk. As we primarily operate in Trinidad, fluctuations in the exchange rate between the TT$ and the US$ could have a significant effect on financial results. Although the sales prices of crude oil are determined by reference to US$ denominated benchmark prices, the majority of the invoices for such sales are paid in TT$, exposing the Company to foreign exchange risk. To mitigate this risk, we attempt to match revenues received in TT$ by entering into contracts denominated and payable in TT$ when possible. We also attempt to limit our exposure to foreign currency risk through collecting and paying foreign currency denominated balances in a timely fashion. In addition, we have further foreign exchange risk regarding our US$ denominated debt and related interest payments. These risks are mitigated by the fact that the TT$ is informally pegged to the US$ and all NGL and natural gas sales are denominated and payable in $US. Touchstone has further foreign exchange exposure on cash balances denominated in C$ and pounds sterling, on head office costs and our production liability denominated in C$, and costs denominated and payable in pounds sterling required to maintain our AIM listing. Any material movements in the C$ to US$ and the pounds sterling to US$ exchange rates may result in unanticipated fluctuations or have a material effect on our reporting results.

For the year ended December 31, 2023, with all other variables held constant, a 5 percent change in the C$ to US$ and TT$ to US$ exchange rates would have resulted in an approximate $193,000 increase or decrease in comprehensive loss (2022 - $691,000). Increases or decreases in the foreign exchange rates applicable to TT$, C$ and pounds sterling dollar-denominated payables and receivables would have resulted in an approximate $175,000 increase or decrease in comprehensive loss for the year ended December 31, 2023 (2022 - $51,000). Refer to the "*Financial and Operational Results - Foreign exchange and foreign currency translation*" section of this MD&A for further information.

Interest rate risk

Interest rate risk arises from changes in market interest rates that may affect comprehensive income (loss) and cash flows. The Company's revolving loan facility is subject to interest rate risk given the interest rate is set on an annual basis if extended by both parties. The interest rate from May 30, 2023 to May 29, 2024 is 7.29 percent. Refer to the "*Financial and Operational Results - Net loss and funds flow from operations sensitivity*" section of this MD&A for further information. As at December 31, 2022, the Company did not hold any variable interest rate debt.

Credit risk

Credit risk arises from the potential that Touchstone may incur a loss if a counterparty to a financial instrument fails to meet its obligation in accordance with the agreed terms. We may be exposed to third-party credit risk through our contractual arrangements with current or future joint operation partners, marketers of our commodities and other parties. Credit risk is considered to be low for the Company's accounts receivable, as Touchstone's credit exposure typically pertains to monthly commodity sales and joint interest billings due from Trinidad government owned petroleum and natural gas entities, and value added taxes ("VAT") due from the Trinidad government.

However, the Company historically has aged accounts receivables owing for VAT. In comparison to December 31, 2022, our past due VAT accounts receivable balance increased by $868,000 as of December 31, 2023 based on increased capital expenditures. Subsequent to December 31, 2023, approximately $1,507,000 in past due VAT was collected. Although ultimate collection is erratic and therefore the timing thereof cannot be estimated with any certainty, Management believes that the VAT accounts receivable balances are ultimately collectable as we have not experienced any past collection issues. The following table details the composition and aging of our accounts receivable as of December 31, 2023.

Composition	Counterparty	Balance due *($000's)*	Balance due *(%)*	Accounts receivable aging	
				Current *($000's)*	Over 90 days *($000's)*
Crude oil and liquids sales	Heritage	**2,587**	**20**	2,587	-
Natural gas sales	NGC	**3,837**	**30**	3,837	-
Joint interest billings	Heritage and NGC	**702**	**6**	702	-
VAT	Trinidad government	**5,058**	**39**	757	4,301
Finance leases	Third-party lessees	**55**	**-**	55	-
Other	Various	**613**	**5**	552	61
Accounts receivable		**12,852**	**100**	**8,490**	**4,362**

Effective March 1, 2021, we executed separate arrangements to lease our oilfield service rigs and swabbing units to two third-party contractors. We have determined that the credit risk related to the associated receivable balance is negligible, as the assets are secured by the underlying equipment, with ownership transferring to the counterparties upon receipt of the final lease payments. As of December 31, 2023, our aggregate finance lease receivable balance was $350,000, of which $295,000 was included in long-term other assets on the consolidated balance sheet (2022 - $534,000 and $457,000, respectively).

Further details relating to our financial assets and credit risk can be found in Note 6 "*Financial Assets and Credit Risk*" of our audited financial statements.

Liquidity risk

Liquidity risk is the risk that we will not be able to meet our obligations associated with our financial liabilities. Liquidity risk also includes the risk of not being able to liquidate assets in a timely manner at a reasonable price. Management believes that future cash flows will be adequate to settle financial obligations as they come due.

Our approach to managing liquidity is to ensure that it will have sufficient liquidity to meet liabilities when due, under both normal and unusual conditions without incurring unacceptable losses or jeopardizing our business objectives. Stewardship of our capital structure and liquidity risk is managed through our financial and operating forecast process. The forecast of our future cash flows is based on estimates of petroleum and natural gas production, crude oil and liquids forward prices, capital expenditures, royalty expenses, operating expenses, G&A expenses, income tax expenses and other investing and financing activities. The forecast is regularly updated based on changes in commodity prices, capital expenditures, production expectations, income tax and royalty regulations, and other factors that in our view would impact cash flows from operating, investing and financing activities.

The following table sets forth estimated undiscounted cash outflows and financial maturities of our financial liabilities as at December 31, 2023.

($000's)	**Recognized in financial statements**	**Undiscounted cash outflows[1]**	**Financial maturity by period**		
			Less than 1 year	**1 to 3 years**	**Thereafter**
Accounts payable and accrued liabilities[2]	Yes – liability	**13,573**	13,573	-	-
Income taxes payable	Yes – liability	**240**	240	-	-
Lease liabilities[3]	Yes – liability	**5,604**	1,746	1,634	2,224
Bank debt principal[4]	Yes – liability	**28,000**	13,000	12,000	3,000
Bank debt interest[4]	No – recognized as incurred	**3,235**	1,665	1,492	78
Financial liabilities		**50,652**	**30,224**	**15,126**	**5,302**

Notes:
(1) The undiscounted cash outflows equal their financial statement carrying values, with the exception of lease liabilities and bank debt principal.
(2) Excludes the current portion of lease liabilities.
(3) Includes the notional interest and principal payments.
(4) The Company entered into a binding term sheet with its lender that will modify Company's bank debt facility and related payments subsequent to December 31, 2023 (refer to the "*Liquidity and Capital Resources - Bank debt*" section herein).

To manage our capital structure, we may reduce our fixed cost structure, adjust capital and exploration spending, issue new equity or seek additional sources of debt financing. We actively monitor our liquidity to ensure that cash flows, potential credit facility capacity and working capital are adequate to support our current and future financial liabilities, as well as the Company's capital programs and future work commitments.

Related Party Transactions

Our Corporate Secretary and former director is a senior partner of our Canadian legal counsel, Norton Rose Fulbright Canada LLP. For the three months and year ended December 31, 2023, $31,000 and $204,000 in legal fees and disbursements charged by Norton Rose Fulbright Canada LLP were incurred, respectively (2022 - $89,000 and $204,000). $11,000 was included in accounts payable and accrued liabilities as at December 31, 2023 (2022 - $44,000).

Our Trinidad-based director is a member of the board of directors of a private Trinidad engineering services company that occasionally provides oilfield supplies to Touchstone. For the three months and year ended December 31, 2023, $1,000 and $13,000 in products were purchased, respectively (2022 - $21,000 and $41,000). As at December 31, 2023, $2,000 was included in accounts payable and accrued liabilities (2022 - $16,000).

In 2023, a Trinidad charitable entity separate from the Company was established. The Company's Chief Executive Officer, Chief Financial Officer and Trinidad-based director serve as independent board members of the entity. For the three months and year ended December 31, 2023, the Company donated $16,000 and $16,000 to the charitable entity, respectively (2022 - $nil and $nil).

We have determined that our key management personnel consist of our executive officers and directors. Touchstone provides salaries and directors' fees, annual incentive payments and other benefits to our key management personnel. In addition, we provide equity-based compensation to our key management personnel under our stock option plan.

Key management personnel compensation paid or payable during the years ended December 31, 2023 and 2022 are disclosed below.

($000's)	**Year ended December 31,**	
	2023	2022
Salaries and benefits included in G&A expenses	**1,244**	1,094
Director fees included in G&A expenses	**381**	395
Equity-based compensation	**886**	1,034
Capitalized salaries, benefits and equity-based compensation	**107**	306
Key management compensation	**2,618**	2,829

The 2023 decrease in key management compensation compared to 2022 was primarily attributable to decreases in equity-based compensation, as the fair value of equity-based awards granted in 2023 and 2022 decreased based on lower Company share prices versus previously granted awards.

The compensation paid to our non-executive directors during the year ended December 31, 2023 is set forth in the following table.

Director *($000's)*	**Fees earned**	**Equity-based compensation**	**All other compensation**	**Total compensation**
Jenny Alfandary	45	41	9	**95**
Priya Marajh	44	40	7	**91**
Kenneth R. McKinnon	48	60	8	**116**
Peter Nicol	46	56	7	**109**
Beverley Smith	46	50	7	**103**
Stanley T. Smith	48	58	8	**114**
Harrie Vredenburg	45	49	7	**101**
John D. Wright	59	62	7	**128**
Director compensation	**381**	**416**	**60**	**857**

Subsequent Events

Subsequent to December 31, 2023, the Company and its lender executed a binding term sheet providing for a $13 million increase in borrowing capacity (refer to the "*Liquidity and Capital Resources - Bank debt*" section herein for further information).

Subsequent to December 31, 2023, Touchstone entered into an agreement with a third party to dispose our interest in the CO-2 block (refer to the "*Capital Expenditures and Dispositions*" section of this MD&A for further information).

Changes in Accounting Policies Including Initial Adoption

There were no changes in accounting policies during the three months and year ended December 31, 2023 that had a material effect on the reported comprehensive loss or net assets of the Company. A list of our accounting policies adopted in 2023 is included in Note 4 "*Changes to Accounting Policies*" of our audited financial statements.

Standards Issued but Not Yet Effective

There are no standards or interpretations issued, but not yet adopted, that are anticipated to have a material effect on the reported comprehensive loss or net assets of the Company. A list of future accounting pronouncements affecting the Company is included in Note 4 "*Changes to Accounting Policies*" of our audited financial statements.

Off-balance Sheet Arrangements

The Company does not believe it has any guarantees or off-balance sheet arrangements that have, or are reasonably likely to have, a material current or future effect on the Company's financial condition, results of operations, liquidity or capital expenditures, other than the commitments disclosed in the "*Contractual Obligations and Commitments*" section herein.

Significant Accounting Estimates, Judgements and Assumptions

The preparation of financial statements in conformity with IFRS requires Management to make estimates, judgements, and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, revenues and expenses. Actual results may differ from estimates, and those differences may be material. The estimates, judgements and assumptions used are subject to updates based on experience and the application of new information. Estimates and underlying assumptions are reviewed on an ongoing basis, and any revisions to accounting estimates are recognized in the period in which the estimates are revised.

A full list of the significant estimates and judgements made by Management in the preparation of the audited financial statements is included in Note 5 "*Use of Estimates, Judgements and Assumptions*" of our audited financial statements.

The Company believes it has hired individuals and consultants who have the skills required to make such estimates and ensures that individuals or departments with the most knowledge of the activity are responsible for the estimates. Furthermore, past estimates are reviewed and compared to actual results, and actual results are compared to budgets to make more informed decisions on future estimates.

Business Risks

For a full understanding of risks that affect Touchstone, the following should be read in conjunction with our 2023 AIF dated March 20, 2024, which is available online on our SEDAR+ profile (www.sedarplus.ca) and website (www.touchstoneexploration.com). Refer to the "*Advisories - Forward-Looking Statements*" section in this MD&A for additional information regarding the risks to which Touchstone and our business operations are subject to.

As a participant in the international oil and natural gas industry, we are exposed to a variety of risks including, but not limited to, political, operational, financial, and environmental risks. As discussed in the "*Liquidity and Capital Resources*" and "*Market Risk Management*" sections of this MD&A, we are exposed to normal financial risks inherent in the international oil and natural gas industry including, among others, commodity price risk, foreign exchange rate risk, credit risk and liquidity risk. The following are certain key risks, uncertainties and opportunities associated with the Company's business that can impact financial results.

Operational matters

The operation of oil and natural gas wells and sales facilities may involve a number of operational and natural hazards. Operational risks include competition, reservoir performance uncertainties, well blow-outs and other operating hazards, lack of infrastructure or transportation to access markets and monetize reserves, and regulatory, environmental and safety concerns. The Company works to mitigate these risks by employing highly skilled personnel and utilizing available technology. We maintain a corporate insurance program in amounts consistent with industry practices to protect against insurable losses. Business interruption insurance may also be purchased for selected facilities, to the extent that such insurance is available. We may become liable for damages arising from such events against which we cannot insure or against which we may elect not to insure because of high premium costs or other reasons. Costs incurred to repair such damage or pay such liabilities will reduce cash from operating activities and may reduce future capital investments.

The oil and natural gas industry is intensely competitive, with the Company competing against companies that may have greater technical and financial resources. There is competition for new exploration and development properties, infrastructure and sales contracts, drilling and other specialized technical equipment and for experienced key human resources.

Exploration

As a participant in the oil and natural gas industry, we are exposed to a high level of exploration and production risk, upon which there is no assurance that hydrocarbon reserves will be discovered and economically produced. Our current and future (to the extent discovered or acquired) proved reserves will decline as reserves are produced from our properties unless we can acquire or develop new reserves. The business of exploring for, developing or acquiring reserves is capital intensive and is subject to numerous estimates and interpretations of geological and geophysical data. There can be no assurance that the Company's future exploration, development and acquisition activities will result in material additions of proved reserves. To manage this risk, to the extent possible, we employ or contract highly qualified geologists, use technology such as seismic and current information system technology as primary exploration tools, and focus our exploration efforts in known hydrocarbon-producing basins. We may also choose to mitigate exploration risk through acquisitions that may require raising additional funds.

It is difficult to project the costs of implementing any exploratory drilling program due to the inherent uncertainties of drilling in unknown formations; the costs associated with encountering various drilling conditions such as unexpected formations or over pressured zones; premature declines of reservoirs and the invasion of water into producing formations; potential environmental damage, blow-outs, cratering, fires and spills, all of which could result in personal injuries, loss of life or threaten wildlife and damage to property of the Company and others; tools lost in the hole; and changes in drilling plans and locations as a result of prior exploratory wells or additional seismic data and interpretations thereof.

Foreign location of assets and foreign economic and political risk

Touchstone is subject to additional risks associated with international operations. Our operations may be adversely affected by changes in foreign government policies and legislation or social instability and other factors which are not within our control, including, but not limited to: nationalization, expropriation of property without fair compensation or marketable compensation; changes in laws and policies impacting foreign trade and investment; renegotiation or nullification of existing concessions and contracts; the imposition of specific drilling obligations and the development and abandonment of fields; changes in energy and environmental policies or the personnel administering them; changes in petroleum and natural gas pricing policies; the actions of national labour unions; currency fluctuations and devaluations; currency exchange controls; economic sanctions; taxation of the oil and natural gas sector; and other risks arising out of foreign governmental sovereignty over the areas in which Touchstone's operations are or will be conducted. If the Company's operations are disrupted and/or the economic integrity of its projects are threatened for unexpected reasons, its business may be harmed. Prolonged problems may threaten the commercial viability of our operations. In addition, there can be no assurance that contracts, licences, regulatory applications or other legal arrangements will not be adversely affected by changes in governments in foreign jurisdictions, the actions of government authorities or others, or the effectiveness and enforcement of such arrangements.

Although Management considers political conditions in Trinidad as generally stable, changes may occur in its political, fiscal and legal systems, which might affect the ownership or operation of our interests including, inter alia, changes in exchange rates, exchange control regulations, expropriation of petroleum and natural gas rights, changes in government and in legislative, fiscal and regulatory regimes. Our current business strategy, including our risk management strategies, has been formulated in the light of the current political and regulatory environment and likely future changes. The political and regulatory environment may change in the future, and such changes may have a material adverse effect on the Company.

Commodity prices and marketing

Numerous factors beyond our control do and will continue to affect the marketability and price of crude oil and liquids acquired, produced or discovered by the Company. Accordingly, commodity prices are the Company's most significant financial risk. Prices for crude oil are subject to large fluctuations in response to relatively minor changes in the supply of and demand, market uncertainty, and a variety of additional factors beyond our control. These factors include, but are not limited to, the impact of pandemics; economic and political conditions in the United States, Canada, Europe, Russia, China and emerging markets; global energy policy such as the actions of Organization of Petroleum Exporting Countries ("OPEC") and other oil and natural gas exporting nations; governmental regulation; global political stability, the foreign supply and demand of crude oil; risks of supply disruption, the price of foreign imports; and the availability of alternative fuel sources. Crude oil prices may continue to be volatile for a variety reasons including market uncertainties over the supply and demand due to the current state of the global economy, the impact of regional and/or global health-related events on economic activity levels and energy demand such as a resurgence of the COVID-19 pandemic, OPEC and non-OPEC producers' actions in respect of supply, political uncertainties, slowing growth in emerging economies, weakening global relationships and trade relationships, sanctions imposed on certain oil producing nations by other countries and ongoing geopolitical conflicts, including the impact and duration of the ongoing military actions between Russia and Ukraine, as well as Israel and Palestine. Further, crude oil prices are also subject to the availability of foreign markets and Heritage's ability to access such markets. We monitor market conditions and may selectively utilize derivative instruments to reduce our exposure to crude oil price movements. However, we are of the view that it is neither appropriate nor possible to eliminate 100 percent of our exposure to crude oil and liquids price volatility. Refer to the "*Market Risk Management - Commodity price risk*" section herein for further information on how we manage commodity price risk.

These factors could result in a material decrease in our expected petroleum and natural gas sales and a reduction in our petroleum and natural gas production, development and exploration activities. Any substantial and extended decline in the price of petroleum and natural gas would have an adverse effect on the carrying value of the Company's reserves, borrowing capacity, petroleum and natural gas sales, profitability and cash from operating activities and may have a material adverse effect on our business, financial condition, results of operations and prospects.

Environmental regulations

We are subject to environmental laws and regulations that affect aspects of our past, present and future operations. Extensive environmental laws and regulations in Trinidad set various standards regulating certain aspects of health and environmental quality, including air emissions, noise pollution, water quality, wastewater discharges and the generation, transport and disposal of waste and hazardous substances; provide for penalties and other liabilities for the violation of such standards; and establish obligations to remediate current and former facilities and locations where operations are or have been conducted. In addition, special provisions may be appropriate or required in environmentally sensitive areas of operation. We adopt prudent and industry-recommended field operating procedures for all operations, as well as maintaining a robust health, safety and environmental program to protect the environment, our employees and consultants, and the public.

These environmental laws and regulations impose certain costs and risks on the Company, and there remain some uncertainty regarding the impact of climate change and environmental laws and regulations on Touchstone, as we are unable to predict additional legislation or amendments that the Trinidadian government may enact in the future. Any new laws and regulations, or additional requirements to existing laws and regulations, could have a material impact on the Company's operations and cash flows. Although we believe that we are in material compliance with current applicable environmental legislation, no assurance can be given that environmental compliance requirements will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on our business, financial condition, results of operations and prospects.

Sole purchaser risk and the ability to market

We are exposed to sole purchaser risk in Trinidad as Heritage is the sole purchaser of crude oil and liquids production, and NGC is sole purchaser of natural gas production. Our ability to market our petroleum and natural gas products depends upon numerous factors beyond our control, including: the availability of third-party pipeline capacity; the supply of and demand for petroleum and natural gas; the availability of alternative fuel sources; the counterparty's future financial viability; and the effects of weather conditions. Deliverability uncertainties relate to third-party processing and storage facilities, operational problems affecting pipelines and facilities as well as government regulation relating to prices, taxes, royalties, land tenure, allowable production, the export of crude oil and liquids, and domestic usage of natural gas. Because of these factors, we could be unable to market or to obtain competitive prices for the petroleum and natural gas we produce.

The amount of petroleum and natural gas that we can produce and sell is subject to the accessibility, availability, proximity and capacity of these third-party processing facilities and pipeline systems and over which we do not have control. From time to time, these facilities may discontinue or decrease operations either as a result of normal servicing requirements or as a result of unexpected events. A discontinuation or decrease of operations could have a materially adverse effect on our ability to market our future petroleum and natural gas production. The lack of availability of capacity in any of the third-party processing facilities and pipeline systems could result in our inability to realize the full economic potential of our production or in a material reduction of the price offered for our production. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as delays in constructing new infrastructure systems and facilities, could harm our business and, in turn, our financial condition, results of operations and cash from operating activities.

Climate change

Our exploration and production facilities and other operations and activities emit greenhouse gas ("GHG") which may require us to comply with emerging GHG emissions legislation. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place to prevent climate change or mitigate its effects. The direct or indirect costs of compliance with GHG-related regulations may have a material adverse effect on our business, financial condition, results of operations, prospects, our cost of capital and access to capital markets. Climate change has been linked to long-term shifts in climate patterns and extreme weather conditions both of which pose the risk of causing operational difficulties. Further, climate change and its associated impacts may increase our exposure to, and magnitude of, each of the risks identified herein.

For further information regarding Touchstone's ongoing environmental stewardship, community involvement and governance standards, please refer to our 2022 ESG Report which can be accessed on our website (www.touchstoneexploration.com).

Reserves estimates

The reserves information included herein and in our Reserves Report is only an estimate. Reserve values are based on a number of variables and assumptions such as future commodity prices, forecasted production volumes, forecasted operating and future development costs, and future governmental regulations. The actual production and ultimate reserves from our properties may be greater or less than the estimates prepared by our independent qualified reserves evaluator. Our reserves evaluator forecasts reserve volumes and future cash flows based upon current and historical well performance through to the economic production limit of individual wells. Notwithstanding established precedence and contractual options for the continuation and renewal of our existing licence, sub-licence and marketing agreements, in many cases the forecasted economic limit of individual wells is beyond the current term of the relevant agreements, and there is no certainty as to any renewal of our existing production and marketing arrangements. Refer to the "*Advisories - Reserves Disclosures*" section herein for further information.

Trinidad exploration and production agreements

The current exploration and production licences, LOAs and joint operating agreements with respect to our properties contain significant obligations on the part of the Company's subsidiaries including minimum work commitments which, upon a continuing default, may give rise to the termination of our operatorship interest therein. There are no assurances that all of these commitments will be fulfilled within the periods allowed. As such, we may lose certain exploration and production rights on the licenced areas affected and may be subject to certain financial penalties that would be levied by Heritage, the MEEI, or the other parties thereto, as applicable. The current forms of licences and sub-licences, as applicable, may, in certain circumstances, be terminated at Heritage's or the MEEI's discretion and are subject to a defined term, and there is no certainty as to any renewal.

Further, the Company is operating under a number of private lease agreements which have expired and are currently being renegotiated. Based on opinions obtained from Trinidad legal counsel, the Company is continuing to recognize crude oil sales as operator and is paying all associated royalties and taxes, and no title to our land in Trinidad has been disputed. However, there is no certainty that such expired lease agreements will be renewed, on terms satisfactory to the Company or at all, or that our rights as operator will not be disputed. Refer to the "*Business Overview - Principal Properties and Licences"* section herein for further information.

Security

Trinidad has a history of security problems. Violent crime and murder rates, partly as a result of gang crime related to drug trafficking, continues to remain a top priority for the Trinidad government to address. The Company and its personnel are subject to these risks, but through effective security and social programs, Touchstone believes security risks can be managed. The Company maintains insurance in an amount that it considers adequate and consistent with industry practice and its operations; however, it is difficult to obtain insurance coverage to protect against all incidents of crime. The Company may not be able to establish or maintain the safety of its operations and personnel in Trinidad and this violence may affect its operations in the future. Continued or heightened security concerns in Trinidad could have a material adverse impact on the Company's operations. Further, if the perception of overall security and crime rates in Trinidad deteriorates, the Trinidad economy may face lower growth rates, which could negatively affect the Company's financial condition and results of operations.

Pandemics

Global or domestic pandemics, epidemics or infectious disease outbreaks in the jurisdictions in which we operate, including COVID-19, Middle East Respiratory Syndrome, Severe Acute Respiratory Syndrome, H1N1 influenza virus, avian flu or any other similar illnesses, could have, without limitations, an adverse impact on our results, business, operations, financial condition, access to capital and liquidity, cost of borrowing, cash flows, reputation, business plans and/or the economy. The duration and the impact of a pandemic may also disrupt access to materials and services, increase employee absenteeism from illness and decrease commodity prices.

The Company's business, operations and financial condition were significantly adversely affected by COVID-19. Actions taken to reduce the spread of COVID-19 resulted in volatility and disruptions in regular business operations, supply chains and financial markets, as well as declining trade and market sentiment. The extent to which Touchstone's operational and financial results are affected by COVID-19, or any other potential pandemic, in the future will depend on whether, and to what extent, actions are taken by businesses and governments in response to any such pandemic and the speed and effectiveness of responses to combat any such pandemic.

Control Environment

Management, including the Company's President and Chief Executive Officer and Chief Financial Officer, assessed the design and effectiveness of internal control over financial reporting ("ICFR") and disclosure controls and procedures ("DC&P") as at December 31, 2023. In making our assessment, Management used the "*Committee of Sponsoring Organizations of the Treadway Commission Framework in Internal Control - Integrated Framework"* issued in 2023 (the "2013 Framework") to evaluate the design and effectiveness of ICFR. Under the supervision of the Chief Executive Officer and the Chief Financial Officer, Touchstone conducted an evaluation of the effectiveness of the Company's ICFR as at December 31, 2023 in accordance with the 2013 Framework. Based on this evaluation, the officers concluded that both ICFR and DC&P were effective as at December 31, 2023. There were no changes during the three months and year ended December 31, 2023 that had materially affected, or were reasonably likely to materially affect, ICFR.

ICFR is a process designed to provide reasonable assurance that all assets are safeguarded, and transactions are appropriately authorized to facilitate the preparation of relevant, reliable and timely information. Internal control systems, no matter how well designed, have inherent limitations and may not prevent or detect misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Furthermore, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with the policies or procedures may deteriorate.

Summary of Quarterly Results

The following is a summary of our unaudited quarterly results for the eight most recently completed fiscal quarters.

Three months ended	Dec. 31, 2023	Sept. 30, 2023	June 30, 2023	March 31, 2023	Dec. 31, 2022	Sept. 30, 2022	June 30, 2022	March 31, 2022
Operational								
Average daily production *(boe/d)*	**8,504**	3,391	1,827	2,139	2,229	1,272	1,420	1,396
Net wells drilled	**-**	-	-	0.8	-	-	-	-
Realized commodity price[1] *($/boe)*	**26.53**	37.44	43.19	44.03	48.36	84.85	97.48	83.55
Operating netback[1] *($/boe)*	**17.54**	19.27	17.00	18.97	21.05	37.55	44.99	37.83
Financial *($000's except per share amounts)*								
Petroleum and natural gas sales	**20,759**	11,682	7,181	8,476	9,919	9,933	12,596	10,496
Cash from (used in) operating activities	**8,512**	343	2,975	913	(1,189)	3,058	3,533	350
Funds flow from operations	**10,489**	2,432	6	803	691	256	1,150	1,443
Net (loss) earnings	**(21,236)**	988	(71)	(279)	(1,921)	(778)	(262)	(236)
Per share – basic and diluted	**(0.09)**	0.00	(0.00)	(0.00)	(0.01)	(0.00)	(0.00)	(0.00)
E&E asset expenditures	**595**	3,498	4,795	8,750	2,290	2,692	2,932	1,874
PP&E expenditures	**591**	111	340	269	219	207	436	680
Capital expenditures[1]	**1,186**	3,609	5,135	9,019	2,509	2,899	3,368	2,554
Working capital deficit (surplus)[1]	**7,581**	13,419	10,913	4,383	(4,992)	4,537	(346)	(4,259)
Principal long-term bank loan	**15,000**	16,500	18,000	19,500	21,000	22,500	24,000	25,500
Net debt[1] – end of period	**22,581**	29,919	28,913	23,883	16,008	27,037	23,654	21,241
Share Information *(000's)*								
Weighted average – basic	**234,213**	233,541	233,144	233,037	217,106	212,647	212,204	210,823
Weighted average – diluted	**234,213**	237,138	233,144	233,037	217,106	212,647	212,204	210,823
Outstanding shares – end of period	**234,213**	234,213	233,428	233,037	233,037	213,113	212,275	211,164

Note:
(1) Non-GAAP financial measure. See the "*Advisories - Non-GAAP Financial Measures*" section of this MD&A for further information.

The oil and natural gas industry is cyclical. Our financial position, results of operations and cash flows are principally affected by production levels and commodity prices, particularly crude oil and liquids prices. Commodity price fluctuations can indirectly impact expected production by changing the amount of funds available to reinvest in exploration, development and acquisition activities in the future. Changes in commodity prices impact revenue and cash flow available for exploration and development and the economics of potential capital projects as low commodity prices can potentially reduce the quantities of reserves that are commercially recoverable. Our capital program is dependent on cash generated from operating activities and access to capital markets. The following significant items impacted our unaudited financial and operating results over the past eight fiscal quarters:

- We achieved record production levels and funds flow from operations in the fourth quarter of 2024, which reflected a full quarter of Cascadura field production volumes. Combined with minimal capital spending of $1.2 million, we decreased corporate net debt levels by 25 percent from the preceding quarter. An aggregate $28.9 million (net of income tax) of net impairment expenses mainly related to our Chinook and Royston exploration assets led to a quarterly net loss of $21.2 million.
- In the third quarter of 2023, we generated $2.4 million of funds flow from operations, as we brought on initial natural gas production from our Cascadura wells, thereby achieving an 86 percent increase in quarterly average production on a boe basis from the preceding quarter. Net debt increased by $1.0 million from the second quarter of 2023, as we invested $3.6 million in quarterly capital investments predominately relating to final construction and commissioning of the Cascadura natural gas facility.

- We recorded negligible funds flow from operations in the second quarter of 2023, as operating netbacks declined by $0.8 million from the prior quarter based on a 13 percent and a 4 percent decline in crude oil production and realized pricing, respectively. Touchstone entered into a $7 million additional revolving facility with its current lender in the quarter which was fully drawn on June 1, 2023. $5.1 million in quarterly capital investments led to a $5 million increase in net debt from the preceding quarter.
- First quarter 2023 funds flow from operations were $0.8 million, relatively consistent with the preceding quarter. In the quarter we drilled the Royston-1X sidetrack well and continued constructing the Cascadura natural gas facility, incurring an aggregate $9.0 million in capital expenditures. These investments decreased our cash and working capital balances, as we exited the quarter with $23.9 million in net debt, a $7.9 million increase from the previous quarter.
- In the fourth quarter of 2022, we generated $0.7 million of funds flow from operations, as we brought on initial natural gas production from our Coho-1 well, thereby achieving a 75 percent increase in quarterly average production on a boe basis from the preceding quarter. In addition, we completed two private placements raising net proceeds of $12.3 million, leading to an $11 million decrease in net debt from the previous quarter.
- In the third quarter of 2022, we recorded $0.3 million in funds flow from operations, which decreased by $0.8 million from the previous quarter based on a 10 percent decline in production and a 13 percent reduction in realized commodity prices, partially offset by reduced royalty and operating expenses. We invested $2.9 million in capital expenditures, resulting in a 14 percent increase in net debt from the second quarter of 2022.
- We generated $1.2 million in funds flow from operations in the second quarter of 2022, which reflected a $0.5 million provision for oil spill reclamation costs due to vandalism. We continued with development costs relating to our Coho and Cascadura production facilities, investing $3.4 million in capital projects. As a result, net debt increased by $2.4 million or 11 percent from the prior quarter.
- We generated $1.4 million in funds flow from operations in the first quarter of 2022, with average daily crude oil production of 1,396 bbls/d. Capital expenditures of $2.6 million led to an increase in net debt of $1.2 million from the preceding quarter.

Advisories

Non-GAAP Financial Measures

This MD&A or documents referred to in this MD&A reference various non-GAAP financial measures, non-GAAP ratios, capital management measures and supplementary financial measures as such terms are defined in National Instrument 52-112 *Non-GAAP and Other Financial Measures Disclosure*. Such measures are not recognized measures under GAAP and do not have a standardized meaning prescribed by IFRS and therefore may not be comparable to similar financial measures disclosed by other issuers. Readers are cautioned that the non-GAAP financial measures referred to herein should not be construed as alternatives to, or more meaningful than, measures prescribed by IFRS, and they are not meant to enhance the Company's reported financial performance or position. These are complementary measures that are commonly used in the oil and natural gas industry and by the Company to provide shareholders and potential investors with additional information regarding the Company's performance, liquidity and ability to generate funds to finance its operations. Below is a description of the non-GAAP financial measures, non-GAAP ratios, capital management measures and supplementary financial measures disclosed in this MD&A.

Funds flow from operations

Funds flow from operations is included in the Company's consolidated statements of cash flows. Touchstone considers funds flow from operations to be a key measure of operating performance as it demonstrates the Company's ability to generate the funds necessary to finance capital expenditures and repay debt. Management believes that by excluding the temporary impact of changes in non-cash operating working capital, funds flow from operations provides a useful measure of the Company's ability to generate cash that is not subject to short-term movements in non-cash operating working capital.

Operating netback

Touchstone uses operating netback as a key performance indicator of field results. The Company considers operating netback to be a key measure as it demonstrates Touchstone's profitability relative to current commodity prices and assists Management and investors with evaluating operating results on a historical basis. Operating netback is a non-GAAP financial measure calculated by deducting royalties and operating expenses from petroleum and natural gas sales. The most directly comparable financial measure to operating netback disclosed in the Company's consolidated financial statements is petroleum and natural gas revenue net of royalties. Operating netback per boe is a non-GAAP ratio calculated by dividing the operating netback by total production volumes for the period. Presenting operating netback on a per boe basis allows Management to better analyze performance against prior periods on a comparable basis. The following table presents the computation of operating netback for the periods indicated.

($000's unless otherwise stated)	**Three months ended December 31,**		**Year ended December 31,**	
	2023	2022	**2023**	2022
Petroleum and natural gas sales	**20,759**	9,919	**48,098**	42,944
Less: royalties	**(4,324)**	(3,125)	**(12,173)**	(14,641)
Petroleum and natural gas revenue, net of royalties	**16,435**	6,794	**35,925**	28,303
Less: operating expenses	**(2,704)**	(2,475)	**(9,705)**	(9,022)
Operating netback	**13,731**	4,319	**26,220**	19,281
Total production *(boe)*	**782,330**	205,091	**1,453,073**	576,987
Operating netback *($/boe)*	**17.54**	21.05	**18.04**	33.42

Cash and non-cash net finance expenses

Cash and non-cash net finance expenses are non-GAAP financial measures. Cash finance expenses are calculated as net finance expenses as determined in accordance with IFRS, less accretion on bank debt, accretion on decommissioning obligations, and other liability revaluation loss (gain), all of which are non-cash in nature. The Company discloses net finance expenses as cash or non-cash to demonstrate the true cost of finance expenses to assist Management with evaluating results on a historical basis.

Capital expenditures

Capital expenditures is a non-GAAP financial measure that is calculated as the sum of exploration and evaluation asset expenditures and property, plant and equipment expenditures included in the Company's consolidated statements of cash flows and is most directly comparable to cash used in investing activities. Touchstone considers capital expenditures to be a useful measure of its investment in its existing asset base. The following table presents the computation of capital expenditures and reconciles capital expenditures to cash used in investing activities for the periods indicated.

($000's)	**Three months ended December 31,**		**Year ended December 31,**	
	2023	2022	**2023**	2022
E&E asset expenditures	**595**	2,290	**17,638**	9,788
PP&E expenditures	**591**	219	**1,311**	1,542
Capital expenditures	**1,186**	2,509	**18,949**	11,330
Abandonment fund expenditures	**373**	75	**626**	160
Proceeds from asset dispositions	**-**	(1,200)	**(250)**	(1,346)
Net change in non-cash working capital	**812**	350	**1,790**	6,332
Cash used in investing activities	**2,371**	1,734	**21,115**	16,476

Working capital, net debt and managed capital

Touchstone closely monitors its capital structure with the goal of maintaining a strong financial position to fund current operations and future growth. The above measures are capital management measures used by Management to steward the Company's overall debt position and assess overall financial strength.

Management monitors working capital, net debt and managed capital as part of the Company's capital structure to evaluate its true debt and liquidity position and to manage capital and liquidity risk. Working capital is calculated by subtracting current liabilities from current assets as they appear on the applicable consolidated balance sheet. Net debt is calculated by summing the Company's working capital and the principal (undiscounted) long-term amount of senior secured debt and is most directly comparable to total liabilities disclosed in the Company's consolidated balance sheets. Management defines managed capital as the sum of net debt and shareholders' equity.

The following table presents working capital, net debt and managed capital computations for the periods indicated.

($000's)	**December 31, 2023**	December 31, 2022
Current assets	**(22,570)**	(26,415)
Current liabilities	**30,151**	21,423
Working capital deficit (surplus)	**7,581**	(4,992)
Principal long-term balance of bank debt	**15,000**	21,000
Net debt	**22,581**	16,008
Shareholder's equity	**59,766**	78,380
Managed capital	**82,347**	94,388

The following table reconciles total liabilities to net debt for the periods indicated.

($000's)	**December 31, 2023**	December 31, 2022
Total liabilities	**79,182**	69,497
Lease liabilities	**(2,888)**	(1,373)
Decommissioning liabilities	**(9,733)**	(11,182)
Deferred income tax liability	**(21,433)**	(14,557)
Variance of carrying value and principal value of bank debt	**23**	38
Current assets	**(22,570)**	(26,415)
Net debt	**22,581**	16,008

Net debt to funds flow from operations ratio

The Company monitors its capital structure using a net debt to funds flow from operations ratio, which is a non-GAAP ratio and a capital management measure calculated as the ratio of the Company's net debt to trailing annual funds flow from operations. The net debt to funds flow from operations ratio is the desired target Touchstone strives to achieve and maintain. This ratio may increase at certain times as a result of increased capital expenditures or low commodity prices.

Net debt to managed capital ratio

The Company further monitors its capital structure using a net debt to managed capital ratio, which is a non-GAAP ratio and capital management measure calculated as the ratio of the Company's net debt to managed capital. The Company's net debt to managed capital ratio is the desired target that the Company strives to maintain, as Management's strategy is to utilize more equity than debt.

Supplementary Financial Measures

The following supplementary financial measures are referenced herein.

Realized commodity price per boe - is comprised of petroleum and natural gas sales as determined in accordance with IFRS, divided by the Company's total production volumes for the period.

Royalties per boe - is comprised of royalties as determined in accordance with IFRS, divided by the Company's total production volumes for the period.

Royalties as a percentage of petroleum and natural gas sales - is comprised of royalties as determined in accordance with IFRS, divided by petroleum and natural gas sales as determined in accordance with IFRS.

Operating expenses per boe - is comprised of operating expenses as determined in accordance with IFRS, divided by the Company's total production volumes for the period.

G&A expenses per boe - is comprised of G&A expenses as determined in accordance with IFRS, divided by the Company's total production volumes for the period.

Net finance expenses per boe - is comprised of net finance expenses as determined in accordance with IFRS, divided by the Company's total production volumes for the period.

Depletion expense per boe - is comprised of depletion expenses as determined in accordance with IFRS, divided by the Company's total production volumes for the period. Depletion expense is a component of depletion and depreciation expense as disclosed in the Company's financial statements.

Other expenses per boe - is comprised of other expenses as determined in accordance with IFRS, divided by the Company's total production volumes for the period.

Current income tax expense per boe - is comprised of current income tax expenses as determined in accordance with IFRS, divided by the Company's total production volumes for the period.

Forward-looking Statements

Certain information provided in this MD&A, including documents incorporated by references herein, may constitute forward-looking statements and information (collectively, "forward-looking statements") within the meaning of applicable securities laws. All statements and information, other than statements of historical fact, made by Touchstone that address activities, events, or developments that the Company expects or anticipates will or may occur in the future are forward-looking statements.

Such forward-looking statements include, without limitation, forecasts, estimates, expectations and objectives for future operations that are subject to assumptions, risks and uncertainties, many of which are beyond the control of the Company. Forward-looking statements are statements that are not historical facts and are generally, but not always, identified by the words "expect", "plan", "anticipate", "believe", "intend", "maintain", "continue to", "pursue", "design", "result in", "sustain" "estimate", "potential", "growth", "near-term", "long-term", "forecast", "contingent" and similar expressions, or are events or conditions that "will", "would", "may", "could" or "should" occur or be achieved. Readers are cautioned that the assumptions used in the preparation of such forward-looking statements, 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.

In particular, forward-looking statements contained in this MD&A may include, but are not limited to, the Company's internal projections, estimates or expectations with respect to the following:

- business plans, operational strategies, priorities and development plans, including the Company's 2024 guidance;

- financial condition and outlook and results of operations, including future liquidity and financial capacity and expectations of future growth, including expectations of future production levels and cash flows to be derived therefrom;
- the intended use of proceeds and expected timing of closing the Amended Bank Loan and expectations that the proceeds from the Amended Bank Loan will fund the Company's initial 2024 budgeted capital program;
- future demand for the Company's petroleum and natural gas products and economic activity in general;
- general economic and political developments in Trinidad and globally;
- the performance characteristics of the Company's petroleum and natural gas properties including current and future crude oil and liquids and natural gas production levels and estimated field production levels;
- expectations regarding the ability of the Company to raise capital and to continually add to reserves through exploration, acquisitions and development;
- future capital expenditure programs, including the anticipated timing of completion, allocation and costs thereof and the method of funding;
- future development and exploration activities to be undertaken in various areas and timing thereof, including the fulfillment of minimum work obligations and exploration commitments;
- terms and estimated future expenditures of the Company's contractual commitments and their timing of settlement;
- terms and title of exploration and production licences and the expected formal extension or execution of certain contracts;
- expectations regarding the Company's ability to fulfill the contractual obligations required to retain its rights to explore, develop and exploit any of its properties;
- receipt of anticipated and future regulatory approvals;
- access to third-party facilities and infrastructure;
- expected levels of royalties, operating expenses, G&A expenses, net finance expenses, current income tax expenses and other costs associated with the Company's business;
- treatment under current and future governmental regulatory regimes, environmental legislation, royalty regimes and tax laws enacted in the Company's areas of operations;
- current risk management strategies and the benefits to be derived therefrom, including the future use of commodity derivatives to manage commodity price risk;
- the foreign currency risk strategies of the Company, the benefits to be derived therefrom and the Company's ability to reverse unrealized foreign exchange gains and losses in the future;
- the Company's ability to reverse previously recognized non-financial asset impairment expenses in the future;
- credit risk assumptions and the Company's expectation to receive past due VAT amounts from the Trinidad government;
- future liquidity and future sources of liquidity and the Company's expectation to settle all current and future financial liabilities in a timely manner;
- future compliance with the Company's bank debt covenants and its ability to make future scheduled interest and principal payments;
- the potential of future acquisitions or dispositions and receiving regulatory approvals and closing currently proposed transactions, including estimated timing thereof;

- estimated amounts, timing and the anticipated sources of funding for the Company's decommissioning liabilities;
- effect of business and environmental risks on the Company; and
- the statements under "*Significant Accounting Estimates, Judgements and Assumptions*".

In addition, information and statements relating to reserves are by their nature forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated, and can be profitably produced in the future. The recovery and reserve estimates of Touchstone's reserves provided herein are estimates only, and there is no guarantee that the estimated reserves will be recovered. Consequently, actual results may differ materially from those anticipated in the forward-looking statements (refer to "*Advisories - Reserves Disclosures*" for further advisories regarding petroleum and natural gas reserves).

In addition, this MD&A includes a summary of the Company's initial 2024 capital budget and preliminary guidance, which includes, but is not limited to, forward looking statements relating to: the focus of Touchstone's 2024 capital plan, including pursuing developmental drilling activities and optimizing existing natural gas and liquids infrastructure capacity; anticipated 2024 annual average production; forecasted production decline rates; anticipated timing of developmental and exploration drilling production; anticipated 2024 capital expenditures including estimations of costs and inflation incorporated therein; expected drilling activities, including locations and the timing thereof; anticipated timing of well tie-in operations; forecasted 2024 average Brent reference price and the Company's budgeted realized price in relation thereto; forecasted royalty, operating, general and administration, cash finance and income tax expenses; anticipated funds flow from operations and net debt; and Touchstone's future financial position, including the sufficiency of resources to fund future capital expenditures and maintain financial liquidity.

This MD&A contains future-oriented financial information and financial outlook information (collectively, "FOFI") about Touchstone's prospective results of operations and production included in its 2024 guidance, all of which are subject to the same assumptions, risk factors, limitations, and qualifications as set forth in the paragraphs above. The FOFI contained in this MD&A was approved by Management as of December 19, 2023 and was provided for the purpose of providing further information about Touchstone's future business operations. This information has been provided for illustration only and, with respect to future periods, is based on budgets and forecasts that are speculative and are subject to a variety of contingencies and may not be appropriate for other purposes. Touchstone and its Management believe that FOFI has been prepared on a reasonable basis, reflecting Management's best estimates and judgments, and represents, to the best of Management's knowledge and opinion, the Company's expected course of action. However, because this information is highly subjective, it should not be relied on as necessarily indicative of future results. Touchstone disclaims any intention or obligation to update or revise any FOFI contained herein, whether as a result of new information, future events or otherwise, unless required pursuant to applicable law. Readers are cautioned that the FOFI contained herein should not be used for purposes other than for which it is disclosed herein, and the financial outlook information contained herein is not conclusive and is subject to change. Variations in forecasted crude oil and liquids prices, differences in the amount and timing of capital expenditures, and variances in average production estimates and decline rates can have a significant impact on the key performance measures included in the guidance disclosed herein. Management does not have firm commitments for all of the costs, expenditures, prices or other financial assumptions used to prepare the financial outlook or assurance that such operating results will be achieved and, accordingly, the complete financial effects of the forecasted costs, expenditures, prices and operating results are not objectively determinable. The actual results of the Company's operations and the resulting financial results will vary from the amounts set forth herein and such variations may be material.

The Company's actual decisions, activities, results, performance, or achievement could differ materially from those expressed in, or implied by, such forward-looking statements and accordingly, no assurances can be given that any of the events anticipated by the forward-looking statements will transpire or occur or, if any of them do, what benefits that Touchstone will derive from them. Although the Company believes that the expectations reflected in the forward-looking statements are reasonable, it cannot guarantee future results, levels of activity, performance or achievement since such expectations are inherently subject to significant business, economic, operational, competitive, political and social uncertainties and contingencies, many of which are beyond the Company's control.

The Company is exposed to numerous operational, technical, financial and regulatory risks and uncertainties, many of which are beyond its control and may significantly affect anticipated future results. The Company is exposed to risks associated with negotiating with foreign governments as well as country risk associated with conducting international activities. Operations may be unsuccessful or delayed as a result of competition for services, supplies and equipment, mechanical and technical difficulties, ability to attract and retain qualified employees on a cost-effective basis, extreme weather-related events, and commodity and marketing risk. The Company is subject to significant drilling risks and uncertainties including the ability to find petroleum and natural gas reserves on an economic basis and the potential for technical problems that could lead to well blow-outs and environmental damage. The Company is exposed to risks relating to the inability to obtain timely regulatory approvals, surface access, access to third-party gathering and processing facilities, transportation and other third-party operation risks. The Company is subject to industry conditions including changes in laws and regulations, the adoption of new environmental laws and regulations and changes in how they are interpreted and enforced. There are uncertainties in estimating the Company's reserve base due to the complexities in estimated future production, costs and timing of expenses and future capital. The Company is subject to the risk that it will not be able to fulfill the contractual obligations required to retain its rights to explore, develop and exploit any of its properties. The financial risks the Company is exposed to include, but are not limited to, the impact of global economic conditions, the impact of significant volatility in market prices for crude oil and liquids, the impact (and duration thereof) of ongoing geopolitical events and their effect on market prices for crude oil and liquids, the ability to access sufficient capital from internal and external sources, changes in income tax laws, royalties and incentive programs relating to the Trinidad oil and natural gas industry, fluctuations in interest rates, and fluctuations in foreign exchange rates. The Company is subject to local regulatory legislation, the compliance with which may require significant expenditures and non-compliance with which may result in fines, penalties or production restrictions or the termination of licence, exploration, lease operating or joint operating rights related to the Company's interests in Trinidad. Readers are cautioned that the foregoing list of risk factors is not exhaustive. Additional information on these and other factors that could affect the Company's operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed online on our SEDAR+ profile (www.sedarplus.ca).

Management has included the above summary of assumptions and risks related to forward-looking statements and other information provided in this MD&A in order to provide shareholders and investors with a more complete perspective on the Company's current and future operations, and such information may not be appropriate for other purposes. Actual results, performance or achievement could differ materially from that expressed in or implied by any forward-looking statements in this MD&A, and accordingly, investors should not place undue reliance on any such forward-looking statements.

Any forward-looking statement is made only as of the date of this MD&A, and Touchstone undertakes no obligation or intent to update or revise any forward-looking statement or statements to reflect information, events, results, circumstances or otherwise after the date on which such statement is made or to reflect the occurrence of unanticipated events, except as required by law, including applicable securities laws. New factors emerge from time to time, and it is not possible for Touchstone to predict all of such factors or to assess in advance the impact of each such factor on Touchstone's business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statements.

All forward-looking statements and FOFI contained in this MD&A are expressly qualified by this cautionary statement.

Readers are further cautioned that the preparation of consolidated financial statements in accordance with IFRS requires Management to make certain judgments and estimates that affect the reported amounts of assets, liabilities, revenues, and expenses. These estimates may change, having either a positive or negative effect on comprehensive income (loss), as further information becomes available and as the economic environment or other factors change.

Reserves Disclosures

Touchstone's December 31, 2023 light and medium crude oil, heavy crude oil, conventional natural gas and natural gas liquid reserves in Trinidad were evaluated by independent reserves evaluator, GLJ, in accordance with definitions, standards and procedures contained in the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook") and NI 51-101. The disclosure in this MD&A highlights certain information contained in the Reserves Report but represents only a portion of the disclosure required under NI 51-101. Full disclosure and related advisories with respect to the Company's reserves as at December 31, 2023 are included in the Company's 2023 AIF dated March 20, 2024, which can be accessed online on the Company's SEDAR+ profile (www.sedarplus.ca) and on our website (www.touchstoneexploration.com).

Unless otherwise noted, reserve references herein are Company "gross reserves". Company gross reserves are the Company's total working interest reserves before the deduction of any royalties payable by the Company. Estimates of reserves and future net revenue for individual properties may not reflect the same level of confidence as estimates of reserves and future net revenue for all properties, due to the effect of aggregation. There are numerous uncertainties inherent in estimating quantities of petroleum and natural gas reserves. The recovery, reserve estimates of petroleum and natural gas reserves provided herein are estimates only, and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates provided herein.

"Proved 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.

"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.

"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.

Certain terms used herein but not defined are defined in NI 51-101, CSA Staff Notice 51-324 - *Revised Glossary to NI 51-101 Standards of Disclosure for Oil and Gas Activities* ("CSA 51-324") and/or the COGE Handbook and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101, CSA 51-324 and the COGE Handbook, as the case may be.

Oil and Natural Gas Measures

To provide a single unit of production for analytical purposes, natural gas production has been converted mathematically to barrels of oil equivalent. We use the industry-accepted standard conversion of six thousand cubic feet of natural gas to one barrel of oil (6 Mcf = 1 bbl). The 6:1 boe ratio is based on an energy equivalent conversion method primarily applicable at the burner tip. It does not represent a value equivalency at the wellhead and is not based on either energy content or current prices. While the boe ratio is useful for comparative measures and observing trends, it does not accurately reflect individual product values and might be misleading, particularly if used in isolation. As well, given that the value ratio, based on the current price of crude oil to natural gas, is significantly different from the 6:1 energy equivalency ratio, using a 6:1 conversion ratio may be misleading as an indication of value.

Product Type Disclosures

This MD&A includes references to crude oil, NGLs, natural gas, total production and average daily production volumes. Under NI 51-101, disclosure of production volumes should include segmentation by product type as defined in the instrument. In this MD&A, references to "crude oil" refer to "light crude oil and medium crude oil" and "heavy crude oil" combined product types; references to "NGLs" refer to condensate; and references to "natural gas" refer to the "conventional natural gas" product type, all as defined in the instrument. In addition, references to "crude oil and liquids" herein include crude oil and NGLs.

The Company's total and average production for the past eight quarters and the references to "crude oil", "NGLs" and "natural gas" reported in this MD&A consist of the following product types as defined in NI 51-101 using a conversion of 6 Mcf to 1 boe where applicable.

Three months ended	Dec. 31, 2023	Sept. 30, 2023	June 30, 2023	March 31, 2023	Dec. 31, 2022	Sept. 30, 2022	June 30, 2022	March 31, 2022
Production								
Light and medium crude oil *(bbls)*	**98,314**	103,048	96,050	108,722	111,114	110,467	122,778	117,253
Heavy crude oil *(bbls)*	**5,966**	5,831	6,270	6,918	6,126	6,592	6,434	8,372
Crude oil *(bbls)*	**104,280**	108,879	102,320	115,640	117,240	117,059	129,212	125,625
NGLs *(bbls)*	**57,183**	16,180	-	-	-	-	-	-
Crude oil and liquids *(bbls)*	**161,463**	125,059	102,320	115,640	117,240	117,059	129,212	125,625
Conventional natural gas *(Mcf)*	**3,725,201**	1,121,585	383,572	461,189	527,105	-	-	-
Total production *(boe)*	**782,330**	311,990	166,249	192,505	205,091	117,059	129,212	125,625
Average daily production								
Light and medium crude oil *(bbls/d)*	**1,068**	1,120	1,055	1,208	1,207	1,200	1,349	1,303
Heavy crude oil *(bbls/d)*	**65**	63	69	77	67	72	71	93
Crude oil *(bbls/d)*	**1,133**	1,183	1,124	1,285	1,274	1,272	1,420	1,396
NGLs *(bbls/d)*	**622**	176	-	-	-	-	-	-
Crude oil and liquids *(bbls/d)*	**1,755**	1,359	1,124	1,285	1,274	1,272	1,420	1,396
Conventional natural gas *(Mcf/d)*	**40,491**	12,191	4,215	5,124	5,729	-	-	-
Average daily production *(boe/d)*	**8,504**	3,391	1,827	2,139	2,229	1,272	1,420	1,396

The Company's total and average production for the years ended December 31, 2023 and 2022 and the references to "crude oil", "NGLs" and "natural gas" reported in this MD&A consist of the following product types as defined in NI 51-101 using a conversion of 6 Mcf to 1 boe where applicable.

	Year ended December 31,		%
	2023	2022	change
Production			
Light and medium crude oil *(bbls)*	**406,134**	461,612	(12)
Heavy crude oil *(bbls)*	**24,985**	27,524	(9)
Crude oil *(bbls)*	**431,119**	489,136	(12)
NGLs *(bbls)*	**73,363**	-	n/a
Crude oil and liquids *(bbls)*	**504,482**	489,136	3
Conventional natural gas *(Mcf)*	**5,691,547**	527,105	100
Total production *(boe)*	**1,453,073**	576,987	100
Average daily production			
Light and medium crude oil *(bbls/d)*	**1,113**	1,265	(12)
Heavy crude oil *(bbls/d)*	**68**	75	(9)
Crude oil *(bbls/d)*	**1,181**	1,340	(12)
NGLs *(bbls/d)*	**201**	-	n/a
Crude oil and liquids *(bbls/d)*	**1,382**	1,340	3
Conventional natural gas *(Mcf/d)*	**15,593**	1,444	100
Average daily production *(boe/d)*	**3,981**	1,581	100

References to Touchstone

For convenience, references in this document to the "Company", "we", "us", "our", and "its" may, where applicable, refer only to Touchstone.

Abbreviations

The following is a list of abbreviations that may be used in this MD&A:

Oil and natural gas measurement		Other	
bbl(s)	barrel(s)	AIM	AIM market of the London Stock Exchange plc
bbls/d	barrels per day	Brent	Dated Brent
Mbbls	thousand barrels	C$	Canadian dollar
Mcf	thousand cubic feet	NGL(s)	Natural gas liquid(s)
Mcf/d	thousand cubic feet per day	TSX	Toronto Stock Exchange
MMcf	million cubic feet	TT$	Trinidad and Tobago dollar
MMcf/d	million cubic feet per day	WTI	Western Texas Intermediate
MMBtu	million British Thermal Units	$ or US$	United States dollar
boe	barrels of oil equivalent	£	Pounds sterling
boe/d	barrels of oil equivalent per day		
Mboe	thousand barrels of oil equivalent		

Additional Information

Additional information related to Touchstone and factors that could affect our operations and financial results are included with reports on file with the Canadian securities regulatory authorities, including the audited financial statements and our 2023 AIF dated March 20, 2024, all of which can be accessed online on our SEDAR+ profile (www.sedarplus.ca) and on our website (www.touchstoneexploration.com).

Corporate Information

Directors
John D. Wright
Chair of the Board

Jenny Alfandary
Paul R. Baay
Priya Marajh
Kenneth R. McKinnon
Peter Nicol
Beverley Smith
Stanley T. Smith
Harrie Vredenburg

Corporate Secretary
Thomas E. Valentine

Officers and Senior Executives
Paul R. Baay
President and Chief Executive Officer

Scott Budau
Chief Financial Officer

James Shipka
Chief Operating Officer

Brian Hollingshead
Vice President Engineering and Business Development

Alex Sanchez
Vice President Production and Environment

Cayle Sorge
Vice President Finance

Head Office
Touchstone Exploration Inc.
4100, 350 7th Avenue SW
Calgary, Alberta, Canada
T2P 3N9

Registered Office
3700, 400 3rd Avenue SW
Calgary, Alberta, Canada
T2P 4H2

Operating Offices
Touchstone Exploration (Trinidad) Ltd.
30 Forest Reserve Road
Fyzabad, Trinidad, W.I.

Primera Oil and Gas Limited
14 Sydney Street
Rio Claro, Trinidad, W.I.

Stock Exchange Listings
Toronto Stock Exchange
London Stock Exchange AIM
Symbol: TXP

Banker
Republic Bank Limited
Port of Spain, Trinidad, W.I.

Auditor
KPMG LLP
Calgary, Alberta, Canada

Reserves Evaluator
GLJ Ltd.
Calgary, Alberta, Canada

Legal Counsel
Norton Rose Fulbright LLP
Calgary, Alberta, Canada
London, United Kingdom

Transfer Agent and Registrar
Odyssey Trust Company
Calgary, Alberta, Canada

Link Group
London, United Kingdom

UK Nominated Advisor and Joint Broker
Shore Capital
London, United Kingdom

UK Joint Broker
Canaccord Genuity
London, United Kingdom

UK Public Relations
FTI Consulting
London, United Kingdom