Touchstone Exploration Inc.

Management's Discussion and Analysis

For the three months and years ended December 31, 2022 and 2021

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As at and for the three months and years ended December 31, 2022 and 2021

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, 2022 with comparisons to the three months and year ended December 31, 2021 is dated March 23, 2023 and should be read in conjunction with the Company's audited consolidated financial statements as at and for the years ended December 31, 2022 and 2021 (the "audited financial statements") and our 2022 Annual Information Form. The audited financial statements have been prepared by Management in accordance with International Financial Reporting Standards ("IFRS" or "GAAP") as issued by the International Accounting Standards 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, oil and natural gas reserves, 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 is a petroleum and natural gas exploration and production company active in the Republic of Trinidad and Tobago ("Trinidad"). Touchstone is currently one of the largest independent onshore oil and natural gas producers in Trinidad, with assets in several large, high-quality reservoirs that have significant internally estimated total petroleum and natural gas initially-in-place and an extensive 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 symbol "TXP".

Touchstone's strategy is to leverage Canadian experience and capability to international onshore properties to create shareholder value. Outside of our core Trinidad portfolio, we will continue to examine opportunities in jurisdictions that have stable political and fiscal regimes coupled with large defined petroleum initially-in-place.

Financial and Operating Results Summary

	Three months ended December 31, 2022	2021	% change	Year ended December 31, 2022	2021	% change
Operational						
Average daily production						
Crude oil[1] *(bbls/d)*	**1,274**	1,336	(5)	**1,340**	1,342	-
NGLs[1] *(bbls/d)*	**-**	-	-	**-**	2	(100)
Crude oil and liquids *(bbls/d)*	**1,274**	1,336	(5)	**1,340**	1,344	-
Natural gas[1] *(Mcf/d)*	**5,729**	-	n/a	**1,444**	-	n/a
Average daily production *(boe/d)*[2]	**2,229**	1,336	67	**1,581**	1,344	18
Average realized prices[3]						
Crude oil[1] *($/bbl)*	**75.10**	66.81	12	**85.52**	60.28	42
NGLs[1] *($/bbl)*	**-**	-	-	**-**	46.32	(100)
Crude oil and liquids *($/bbl)*	**75.10**	66.81	12	**85.52**	60.25	42
Natural gas[1] *($/Mcf)*	**2.11**	-	n/a	**2.11**	-	n/a
Realized commodity price *($/boe)*[2]	**48.36**	66.81	(28)	**74.43**	60.25	24
Production mix *(% of production)*						
Crude oil and liquids	**57**	100		**85**	100	
Natural gas[1]	**43**	-		**15**	-	
Operating netback *($/boe)*[2]						
Realized commodity price[3]	**48.36**	66.81	(28)	**74.43**	60.25	24
Royalties[3]	**(15.24)**	(22.15)	(31)	**(25.37)**	(18.85)	35
Operating expenses[3]	**(12.07)**	(14.70)	(18)	**(15.64)**	(14.85)	5
Operating netback[3]	**21.05**	29.96	(30)	**33.42**	26.55	26
Financial *($000's except per share amounts)*						
Petroleum and natural gas sales	**9,919**	8,212	21	**42,944**	29,568	45
Cash (used in) from operating activities	**(1,189)**	1,406	n/a	**5,752**	1,611	100
Funds flow from operations[3]	**691**	1,309	(47)	**3,540**	4,172	(15)
Net (loss) earnings	**(1,921)**	6,514	n/a	**(3,197)**	5,719	n/a
Per share – basic and diluted	**(0.01)**	0.03	n/a	**(0.01)**	0.03	n/a
Exploration capital expenditures	**2,290**	2,946	(22)	**9,788**	20,106	(51)
Development capital expenditures	**219**	5,190	(96)	**1,542**	7,757	(80)
Capital expenditures[3]	**2,509**	8,136	(69)	**11,330**	27,863	(59)
Working capital surplus[3]				**(4,992)**	(6,925)	(28)
Principal long-term bank loan				**21,000**	27,000	(22)
Net debt[3] – end of period				**16,008**	20,075	(20)
Share Information *(000's)*						
Weighted average shares – basic	**217,106**	210,732	3	**213,211**	210,160	1
Weighted average shares – diluted	**217,106**	218,102	-	**213,211**	217,678	(2)
Outstanding shares – end of period				**233,037**	210,732	11

Notes:
(1) In the table above and elsewhere in this MD&A, references to "crude oil" refers to light and medium crude oil and heavy crude product types combined; references to "NGLs" refers to condensate; and references to "natural gas" refers to conventional natural gas, all as defined in National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101"). 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.

Fourth quarter 2022 financial and operational highlights

- Achieved initial natural gas production from our Coho-1 well, which produced average net volumes of 5.7 MMcf/d (955 boe/d) in the quarter and contributed $1,114,000 of net natural gas sales at an average realized price of $2.11/Mcf.
- Produced quarterly average crude oil volumes of 1,274 bbls/d, consistent with the preceding quarter and representing a 5 percent decrease from the 1,336 bbls/d produced in the fourth quarter of 2021, reflecting strategic capital allocated to our Ortoire natural gas facilities.
- Produced quarterly average volumes of 2,229 boe/d, a 67 percent increase relative to the 1,336 boe/d produced in the prior year equivalent quarter.
- Realized petroleum and natural gas sales of $9,919,000 compared to $8,212,000 in the prior year equivalent quarter, reflecting natural gas sales from Coho and a 12 percent increase in average crude oil pricing in the fourth quarter of 2022.
- Generated an operating netback of $4,319,000, representing a 17 percent increase from the prior year equivalent quarter. Operating netbacks were $21.05 per boe, a 30 percent decrease from the $29.96 per boe reported in the fourth quarter of 2021, attributed to natural gas volumes brought online in the quarter.
- Recognized current income tax expenses of $1,092,000 in the quarter compared to $208,000 in the fourth quarter of 2021, driven by $979,000 in supplemental petroleum tax ("SPT") expenses based on our average realized crude oil price exceeding the $75.00 per barrel threshold in the period.
- Reported funds flow from operations of $691,000 in the quarter compared to $1,309,000 in the prior year equivalent quarter, as a $637,000 increase in operating netbacks was offset by increased general and administration ("G&A"), term loan interest and current income tax expenses.
- Recognized a net loss of $1,921,000 ($0.01 per basic share) in the quarter compared to net earnings of $6,514,000 ($0.03 per basic and diluted share) reported in the same period of 2021, principally driven by impairment reversals recorded at year-end 2021.
- Our $2,509,000 in quarterly capital investments primarily focused on expenditures directed to the Cascadura natural gas and liquids facility.
- Following the December Canadian and United Kingdom private placements that raised net proceeds of $12,269,000, we exited the quarter with a cash balance of $16,335,000, a working capital surplus of $4,992,000 and a principal balance of $27,000,000 remaining on our term credit facility, resulting in a net debt position of $16,008,000.

Annual 2022 financial and operational highlights

- Commissioned and delivered natural gas from the Coho facility on October 10, 2022, representing the first onshore natural gas field to come onstream in Trinidad in 20 years.
- Reported average daily production volumes of 1,581 boe/d, reflecting an 18 percent increase from 2021. Relative to 2021, the 2022 annual increase was attributed incremental natural gas production from the Coho-1 well, as average 2022 crude oil and liquids production were consistent with 2021 levels.
- Generated funds flow from operations of $3,540,000 (2021 - $4,172,000) and an annual operating netback of $19,281,000 or $33.42 per boe (2021 - $13,031,000 and $26.55 per boe).
- Recognized a net loss of $3,197,000 ($0.01 per basic share) compared to net earnings of $5,719,000 ($0.03 per basic and diluted share) in 2021, primarily attributed to $6,323,000 in impairment reversals (net of tax) recognized in the prior year based on increased forecasted crude oil pricing.
- We executed an incident-free $11,330,000 capital program, primarily focused on completing the

Coho natural gas facility and progressing construction of the Cascadura natural gas and liquids facility. Cascadura operations commenced in October 2022 following receipt of all required regulatory approvals.

- 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.
- Responsible operations remained a top priority throughout 2022, as Touchstone had no lost time injuries and released its second sustainability report encompassing the 2021 year. We proactively responded to the June 2022 vandalism incident that resulted in a crude oil spill and are pleased to report that all reclamation efforts were completed in September 2022.

Recent highlights

- Net average natural gas volumes from Coho-1 were 900 boe/d and 864 boe/d in January 2023 and February 2023, respectively.
- Daily crude oil sales averaged 1,286 bbls/d in January 2023 with a realized price of $66.48 per barrel and averaged 1,341 bbls/d in February 2023 with a realized price of $67.14 per barrel.
- We safely reached budgeted total depth of our Royston-1X sidetrack well on the Ortoire block on February 24, 2023. The well has been cased, and we expect to commence production testing in late March 2023.
- The National Gas Company Of Trinidad and Tobago Limited ("NGC") notified us that they expect to be ready to receive first natural gas from the Cascadura facility on or about June 30, 2023. We remain on track to complete the Cascadura facility prior to this date to ensure production can commence as soon as NGC is in a position to receive first natural gas.
- In January 2023, we entered into an asset exchange agreement for certain onshore Trinidad assets with a privately held Trinidadian entity. Pursuant to the agreement, we agreed to swap our 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. The agreement remains subject to certain closing conditions, including receipt of applicable regulatory approvals and an extension of the Rio Claro licence.
- Our December 31, 2022 reserves evaluation was highlighted by an increase in gross proved developed producing reserves of 33 percent to 4,843 Mboe relative to the prior year. Gross proved ("1P") reserves decreased by 0.7% to 38,463 Mboe, and gross proved plus probable ("2P") reserves declined by 0.6 percent to 75,074 Mboe from December 31, 2021 despite no drilling performed in 2022. The reserves data is based on an independent reserve evaluation prepared by GLJ Ltd. ("GLJ") dated March 3, 2023 with an effective date of December 31, 2022 (the "Reserves Report").

Our near-term development plan is strategically balanced between maintaining base crude oil and Coho natural gas production levels and bringing our Cascadura natural gas discovery onstream. Throughout 2022, we prudently invested funds in our Coho and Cascadura facilities, with Coho coming online in October 2022. We continue to focus on financial discipline and value creation, and our immediate priority is to bring Cascadura discovery onstream. As a result, forecasted cash and working capital balances are expected to decline in the first half of 2023 as we proceed with this strategy.

Principal Properties and Licences

We operate Trinidad-based upstream petroleum and natural gas activities under state exploration and production licences with the Trinidad and Tobago Ministry of Energy and Energy Industries ("MEEI"), Lease Operatorship Agreements ("LOAs") with Heritage Petroleum Company Limited ("Heritage") and private subsurface and surface leases with individual landowners. The LOAs contain marketing arrangements, whereas any oil sold from MEEI licences and private agreements are marketed under a separate crude oil sales agreement with Heritage. We executed a long-term natural gas sales agreement with NGC related to all natural gas sales from our Ortoire property in December 2020.

A schedule of our core Trinidad property interests as of December 31, 2022 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	100	Lease Operatorship	469	469
WD-4	100	Lease Operatorship	700	700
WD-8	100	Lease Operatorship	650	650
Barrackpore(3)	100	Private	211	211
Fyzabad(3)	100	Crown and Private	564	564
Ortoire - Coho	80	Crown	1,317	1,054
Ortoire - Cascadura	80	Crown	2,377	1,902
San Francique(3)	100	Private	1,277	1,277
	92		**8,795**	**8,057**
Exploratory				
Ortoire	**80**	Crown	**41,037**	**32,830**
Total	**82**		**49,832**	**40,887**

Notes:
(1) "Gross" means acres in which the Company has an interest.
(2) "Net" means the Company's interest in the gross acres.
(3) Subsequent to year-end, Touchstone announced an asset swap agreement for the noted properties with a third-party Trinidadian private company. Refer to the "*Subsequent Event*" section of this MD&A for further details.

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 "*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 ten-year licence periods (refer to the "*Contractual Obligations and Commitments*" section herein for further information).

The following table sets forth information relating to our producing properties governed by LOAs as of December 31, 2022.

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)
Coora[4]	December 31, 2030[5]	15,284	3,125	4,896	13,255
WD-4	December 31, 2030[5]	17,651	2,787	5,124	4,501
WD-8	December 31, 2030[5]	15,345	2,525	4,807	4,506
Total		**48,280**	**8,437**	**14,827**	**22,262**

Notes:
(1) Represents the field's carrying value included in property, plant and equipment ("PP&E") as at December 31, 2022 including allocated overhead charges.
(2) December 31, 2022 assigned gross light and medium crude oil reserves are the Company's working interest share before deduction of royalties. Refer to the "*Advisories - Oil and Natural Gas Reserves*" section of this MD&A.
(3) Includes future estimates of minimum work obligations stipulated in the LOA as of December 31, 2022. Refer to the "*Contractual Obligations and Commitments* " section of this MD&A for further details.
(4) The Coora field is governed by the CO-1 and CO-2 LOAs.
(5) The LOAs may be extended for a further five-year term pending mutual agreement to minimum work commitments over the extended period.

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, 2022, production volumes produced under expired private lease agreements represented approximately 3.8 percent of our total production (2021 - 1.9 percent).

Crude oil 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 all crude oil produced by our wholly owned Trinidad subsidiary, Primera Oil and Gas Limited ("POGL"), from various 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. The price currently paid is Heritage's equity land blend indexed price, payable in US$. In January 2022, the parties executed a letter agreement to sell testing production volumes produced from the Royston-1 exploration well under similar terms and conditions.

Natural gas sales contract

On December 18, 2020, POGL and NGC executed a natural gas sales agreement for all future 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. Marketing of free liquids associated with future natural gas production on the Ortoire block is currently being negotiated under a separate arrangement.

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 March 2021, the parties amended the Ortoire Licence to extend the initial exploration period an additional nine months through July 31, 2021, during which we completed all required exploration minimum work commitments.

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. No acreage was surrendered in the Ortoire Licence second amendment.

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 well (Royston-1X) drilled in February 2023. Similar to the initial minimum work program, we will be responsible for 100 percent of the drilling, completion and testing costs for the three 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.

The following table sets forth Touchstone's aggregate Ortoire exploration and evaluation ("E&E") investments as of December 31, 2022 and 2021.

($000's)	**December 31, 2022**	**December 31, 2021**
Coho-1 drilling and testing(1)	**3,936**	3,768
Coho-1 facility and pipeline(1)(2)	**6,025**	2,092
Cascadura-1ST1 drilling and testing	**6,688**	6,538
Cascadura Deep-1 drilling and testing	**6,953**	7,048
Cascadura facility and pipeline	**3,973**	288
Cascadura environmental impact study	**389**	334
Chinook-1 drilling and testing	**8,888**	8,857
Royston-1 drilling	**11,394**	10,049
Seismic program	**3,174**	3,138
Drilling inventory	**1,538**	1,377
Ortoire Licence financial obligations	**4,465**	3,937
Other	**3,890**	3,334
Total Ortoire E&E investments	**61,313**	50,760
Less Coho amounts transferred to PP&E or disposed(1)(2)	**(9,961)**	-
Total E&E asset	**51,352**	50,760

Notes:
(1) Costs were transferred to PP&E upon initial natural gas production in October 2022 as disclosed below.
(2) The pipeline was sold to NGC upon initial production as disclosed below.

Touchstone has conducted successful exploration activities in three areas within the Ortoire Licence to date: Coho, Cascadura and Royston. The Chinook-1 well drilled in the second half of 2020 was considered non-commercial to produce.

Coho

Throughout 2022, we constructed the Coho natural gas sales facility and pipeline, with facility commissioning occurring in early October 2022. On October 10, 2022, we achieved first natural gas production from our Coho-1 well. Over 83 operational days, the well produced an average of 7.9 MMcf/d gross (6.35 MMcf/d net) and contributed $1,114,000 in net natural gas sales in the fourth quarter of 2022.

Upon first natural gas production, the Company transferred $7,915,000 in E&E costs related to the Coho area to PP&E. Immediately prior to transferring the asset to PP&E, Touchstone conducted an impairment test of the recoverable amounts of the asset and transferred the asset at its carrying amount, with no impairment expense recognized. Concurrent with initial natural gas production, Touchstone sold the gathering line tying in the Coho natural gas facility to the third-party natural gas processing facility to NGC for net proceeds of $1,200,000, with a loss of $846,000 recorded in connection with the transaction. The following table sets forth information relating to the Coho area as of December 31, 2022.

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	7,641	1,118	3,428	52

Notes:
(1) Represents the field's carrying value included in PP&E as at December 31, 2022 including allocated overhead charges.
(2) December 31, 2022 assigned gross conventional natural gas reserves are the Company's working interest share before deduction of royalties. Refer to the "*Advisories - Oil and Natural Gas Reserves*" and the "*Advisories - Oil and Natural Gas Measures*" sections of this MD&A.
(3) Includes future estimates of Ortoire licence financial obligations related to the Coho area as of December 31, 2022. Refer to the "*Contractual Obligations and Commitments* " section of this MD&A for further details.

Cascadura

Touchstone is currently constructing the Cascadura natural gas and liquids facility to meet the long-term production capabilities of the previously drilled Cascadura-1ST1 and Cascadura Deep-1 wells that were successfully evaluated. The Cascadura natural gas and liquids processing facility has been designed for a maximum gross capacity of approximately 200 MMcf/d of natural gas and 5,000 bbls/d of associated liquids (38,333 boe/d), with a storage capacity of 8,800 barrels of liquids on the Cascadura A surface location.

The Company received a Certificate of Environmental Clearance ("CEC") to conduct development operations within the Cascadura area of the Ortoire block from the Trinidad and Tobago Environmental Management Authority in August 2022, and construction of the facility commenced in October 2022. In addition to the facility, the CEC includes the drilling of eight wells at two well pads (Cascadura B and C) and the establishment of associated pipelines and infrastructure within the area. We are currently commencing construction of the Cascadura C surface location, which is expected to be the location of the first two Cascadura development wells.

Pursuant to the natural gas sales agreement, NGC is responsible to build a 1.7-kilometre pipeline connecting our Cascadura facility to their main sales pipeline. In February 2023, we were notified by NGC that they expect to be ready to receive first gas from the Cascadura facility on or about June 30, 2023. Touchstone is currently negotiating a marketing arrangement for the associated liquids from the Cascadura reservoir and expects to truck condensate to sales facilities until a long-term plan is in place.

The following table sets forth information relating to the Cascadura field as of December 31, 2022.

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	21,384	26,902	52,082	94

Notes:
(1) Represents the field's carrying value included in E&E assets as at December 31, 2022 including allocated overhead charges.
(2) December 31, 2022 assigned gross conventional natural gas and condensate reserves are the Company's working interest share before deduction of royalties. Refer to the "*Advisories - Oil and Natural Gas Reserves*" section of this MD&A.
(3) Includes future estimates of Ortoire licence financial obligations related to the Cascadura area as of December 31, 2022. Refer to the "*Contractual Obligations and Commitments* " section of this MD&A for further details.

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 total measured depth of 11,316 feet. Drilling samples and openhole wireline logs indicated that the well encountered a significant Herrera turbidite package with aggregate estimated thickness in excess of 1,660 feet. The Herrera turbidite section was identified at a measured depth of 9,558 feet, approximately 330 feet structurally higher than in the original Royston-1 well and penetrated approximately 310 feet of Herrera section below what was observed in Royston-1. The overall Herrera section drilled in Royston-1X is estimated to contain approximately 765 net feet of sand. Touchstone expects to commence completion and testing operations in late March 2023 which are anticipated to include multiple test intervals.

The following table sets forth information relating to the Royston area as of December 31, 2022.

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	To be determined[(3)]	17,814	1,280	3,520	-

Notes:
(1) Represents the field's carrying value included in E&E assets as at December 31, 2022 including allocated overhead charges.
(2) December 31, 2022 assigned gross light and medium crude oil reserves are the Company's working interest share before deduction of royalties. Refer to the "*Advisories - Oil and Natural Gas Reserves*" section of this MD&A. The reserves figures do not include any values for Royston-1X which was drilled subsequent to December 31, 2022.
(3) The Company has yet to finalize a field development plan to the MEEI for the Royston discovery and therefore no reservoir area has been defined.

Results of Operations

Financial highlights

($000's except per share amounts)	**Three months ended December 31,**		% change	**Year ended December 31,**		% change
	2022	2021		**2022**	2021	
Net (loss) earnings	**(1,921)**	6,514	n/a	**(3,197)**	5,719	n/a
Per share – basic and diluted	**(0.01)**	0.03	n/a	**(0.01)**	0.03	n/a
Cash (used in) from operating activities	**(1,189)**	1,406	n/a	**5,752**	1,611	100
Funds flow from operations	**691**	1,309	(47)	**3,540**	4,172	(15)

Net (loss) earnings

Touchstone recorded a net loss of $1,921,000 ($0.01 per basic share) in the fourth quarter of 2022 compared to net earnings of $6,514,000 ($0.03 per basic and diluted share) in the prior year equivalent quarter. Compared to the fourth quarter of 2021, the year-over-year variance was primarily attributed to $6,323,000 in impairment reversals (net of tax) recorded in the prior year period. In addition, 2022 fourth quarter funds flow from operations decreased by $618,000 relative to the prior year equivalent quarter, and we recorded an $846,000 loss from the sale of the Coho pipeline in the fourth quarter of 2022.

We recognized a net loss of $3,197,000 ($0.01 per basic share) in 2022 versus net earnings of $5,719,000 ($0.03 per basic and diluted share) in 2021. Compared to 2021, the annual variance was mainly a result of $6,323,000 in PP&E impairment reversals (net of tax) recorded in the prior year. Annual 2022 funds flow from operations decreased by $632,000 from 2021, and increased depletion and depreciation expenses, equity-based compensation expenses and the aforementioned loss recorded on the disposition of the Coho pipeline contributed to the annual variance.

The following table sets forth details of the change in net earnings (loss) from the three months and year ended December 31, 2021 to the three months and year ended December 31, 2022.

($000's)	**Three months ended December 31,**	**Year ended December 31,**
Net earnings – 2021	6,514	5,719
Cash items		
Funds flow from operations	**(618)**	**(632)**
Decommissioning expenditures	**2**	**121**
Cash variances	**(616)**	**(511)**
Non-cash items		
Loss on asset dispositions	**(846)**	**(747)**
Unrealized foreign exchange	**(615)**	**-**
Equity-based compensation	**(53)**	**(453)**
Depletion and depreciation	**(157)**	**(918)**
Impairment	**(13,730)**	**(13,869)**
Non-cash finance expenses	**90**	**118**
Deferred income tax	**7,492**	**7,464**
Non-cash variances	**(7,819)**	**(8,405)**
Net loss – 2022	**(1,921)**	**(3,197)**

Cash (used in) from operating activities

Details of the change in cash (used in) from operating activities from the three months and year ended December 31, 2021 to the three months and year ended December 31, 2022 are included in the table below.

($000's)	**Three months ended December 31,**	**Year ended December 31,**
Cash from operating activities – 2021	1,406	1,611
Change in funds flow from operations	**(618)**	**(632)**
Net change in non-cash working capital	**(1,977)**	**4,773**
Cash (used in) from operating activities – 2022	**(1,189)**	**5,752**

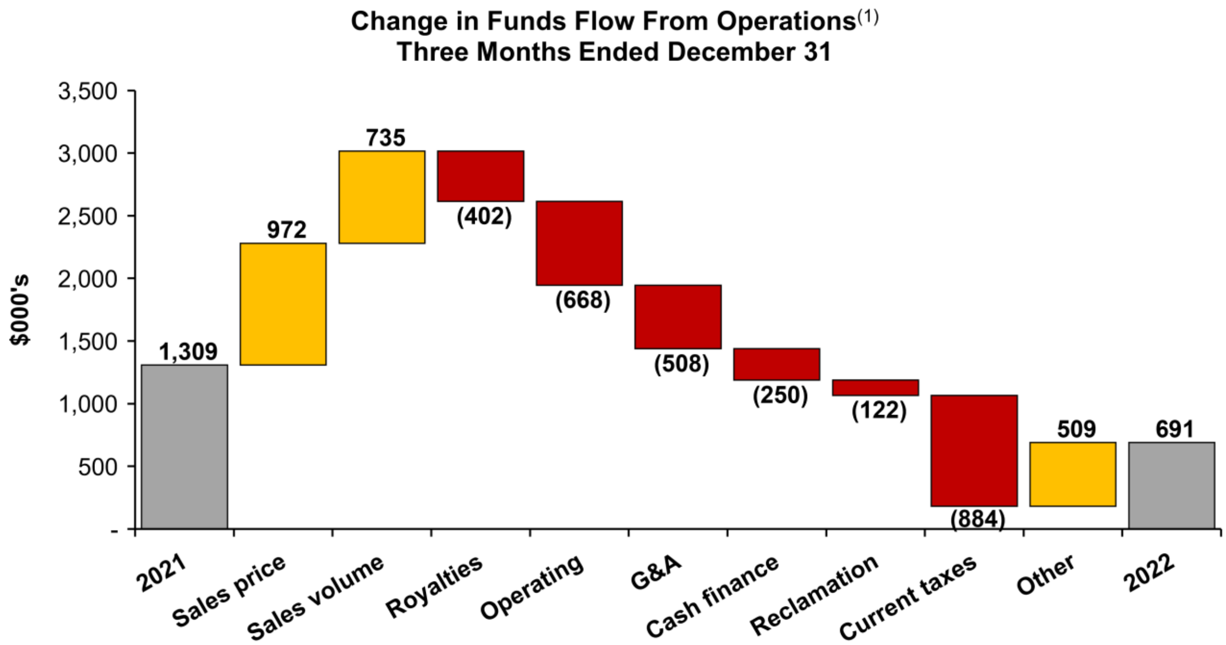
Funds flow from operations

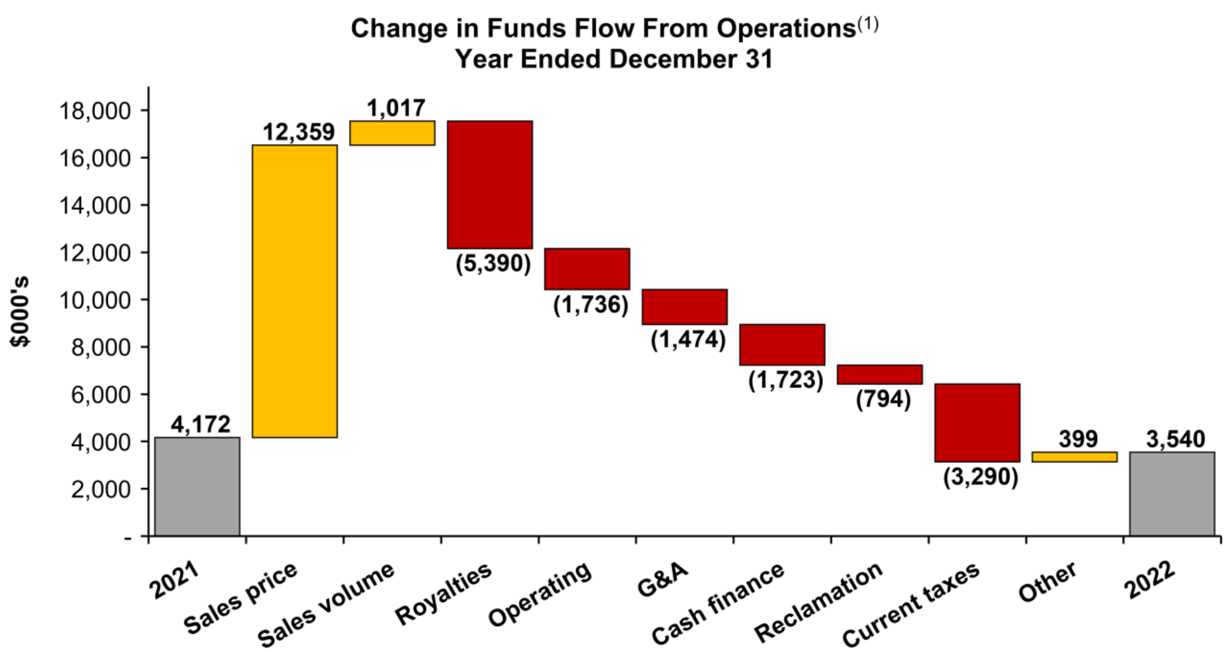
We generated funds flow from operations of $691,000 in the fourth quarter of 2022 compared to $1,309,000 in the prior year comparative quarter. In 2022 we achieved an operating netback increase of $637,000 in comparison to the prior year fourth quarter, reflecting an increase in realized crude oil pricing and incremental net natural gas sales volumes from the Coho-1 well, slightly offset by increases in royalties and operating costs. In relation to the fourth quarter of 2021, the increase in fourth quarter 2022 operating netbacks was fully offset by increases in G&A, term loan interest expenses and current income taxes reflecting an additional $979,000 in SPT charges due to elevated crude oil realized pricing.

During the year ended December 31, 2022, we generated funds flow from operations of $3,540,000, representing a $632,000 decrease relative to the $4,172,000 recognized in 2021. In comparison to 2021, increased 2022 SPT expenses, G&A expenses, term loan interest expenses from higher 2022 debt levels and $794,000 relating to oil spill reclamation costs due to vandalism were partially offset by an increase of

$6,250,000 in operating netbacks.

The following graphs summarizes the change in funds flow from operations from the three months and year ended December 31, 2021 to the three months and year ended December 31, 2022.





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

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, 2022.

	Assumption[(1)]	**Change** *(%)*	**Impact on annual net loss**[(2)] *($000's)*	**Impact on annual funds flow from operations**[(2)(3)] *($000's)*
Average realized crude oil price *($/bbl)*[(3)]	85.52	+10	**2,181**	**1,620**
Average realized crude oil price *($/bbl)*[(3)]	85.52	-10	**(1,122)**	**(860)**
Average daily production *(boe/d)*	1,581	±10	**2,238**	**1,703**
Operating expenses *($/boe)*[(3)]	15.64	±10	**(1,035)**	**(784)**

Notes:
(1) Assumptions are indicative of actual prices and volumes realized and actual results for the year ended December 31, 2022.
(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.

Production volumes

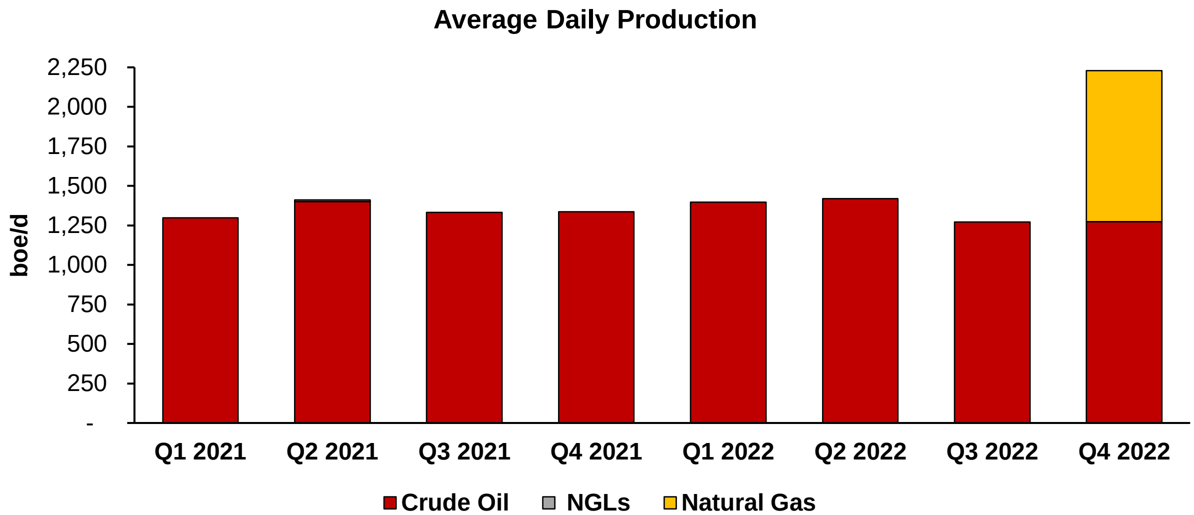
	Three months ended December 31,		% change	**Year ended December 31,**		% change
	2022	2021		**2022**	2021	
Production						
Crude oil *(bbls)*	**117,240**	122,917	(5)	**489,136**	489,899	-
NGLs *(bbls)*	**-**	-	-	**-**	842	(100)
Crude oil and liquids *(bbls)*	**117,240**	122,917	(5)	**489,136**	490,741	-
Natural gas *(Mcf)*	**527,105**	-	-	**527,105**	-	-
Total production *(boe)*	**205,091**	122,917	67	**576,987**	490,741	18
Average daily production						
Crude oil *(bbls/d)*	**1,274**	1,336	(5)	**1,340**	1,342	-
NGLs *(bbls/d)*	**-**	-	-	**-**	2	(100)
Crude oil and liquids *(bbls/d)*	**1,274**	1,336	(5)	**1,340**	1,344	-
Natural gas *(Mcf/d)*	**5,729**	-	-	**1,444**	-	-
Average daily production *(boe/d)*	**2,229**	1,336	67	**1,581**	1,344	18
Crude oil and liquids *(%)*	**57**	100		**85**	100	
Natural gas *(%)*	**43**	-		**15**	-	

Average crude oil production volumes of 1,274 bbls/d in the fourth quarter of 2022 decreased 5 percent from the 1,336 bbls/d produced in the prior year equivalent quarter, while annual 2022 crude oil production volumes were consistent with production from the prior year.

2022 annual production volumes from our three development wells drilled in the fourth quarter of 2021 contributed aggregate field estimated crude oil production of 103 bbls/d. In addition, we sold 4,274 net barrels of crude oil from our Royston-1 production test and 236 net barrels from our Coho-1 well in 2022, representing an aggregate average of 12 bbls/d. Increases in 2022 production were partially offset by natural declines and reduced production from two producing properties that were disposed effective December 31, 2021, which contributed approximately 25 bbls/d of production in the prior year.

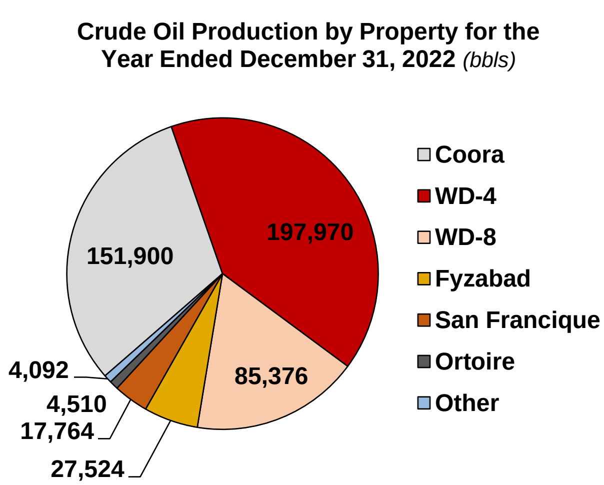
2021 annual NGL volumes represented nominal production from the Cascadura Deep-1 well test in April 2021.

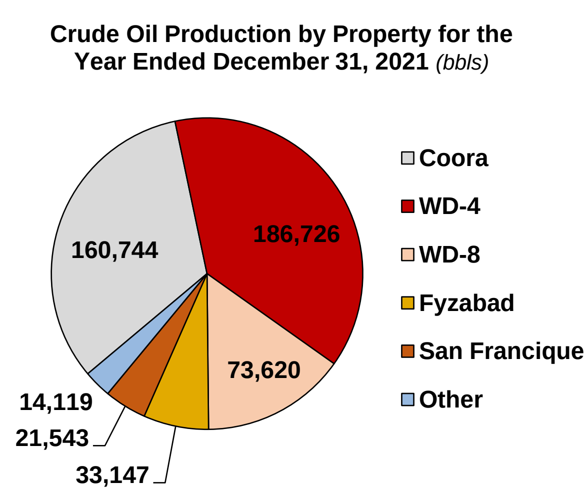
On October 10, 2022, we achieved first natural gas production from our Coho-1 well. Over 83 operational days, the well produced an average of 7.9 MMcf/d gross (6.35 MMcf/d net), and contributed average net production rates of 5.7 MMcf/d (approximately 955 boe/d) in the fourth quarter of 2022 and 1.4 MMcf/d (approximately 241 boe/d) in the 2022 year.



The following table and graphs summarize crude oil production by property during the three months and years ended December 31, 2022 and 2021.

(bbls)	Three months ended December 31, 2022	2021	% change	Year ended December 31, 2022	2021	% change
Coora	**38,169**	40,834	(7)	**151,900**	160,744	(6)
WD-4	**47,888**	49,352	(3)	**197,970**	186,726	6
WD-8	**19,959**	17,060	17	**85,376**	73,620	16
Fyzabad	**6,126**	6,958	(12)	**27,524**	33,147	(17)
San Francique	**3,803**	5,405	(30)	**17,764**	21,543	(18)
Ortoire	**384**	-	n/a	**4,510**	-	n/a
Other	**911**	3,308	(72)	**4,092**	14,119	(71)
Crude oil production	**117,240**	122,917	(5)	**489,136**	489,899	-





Commodity prices

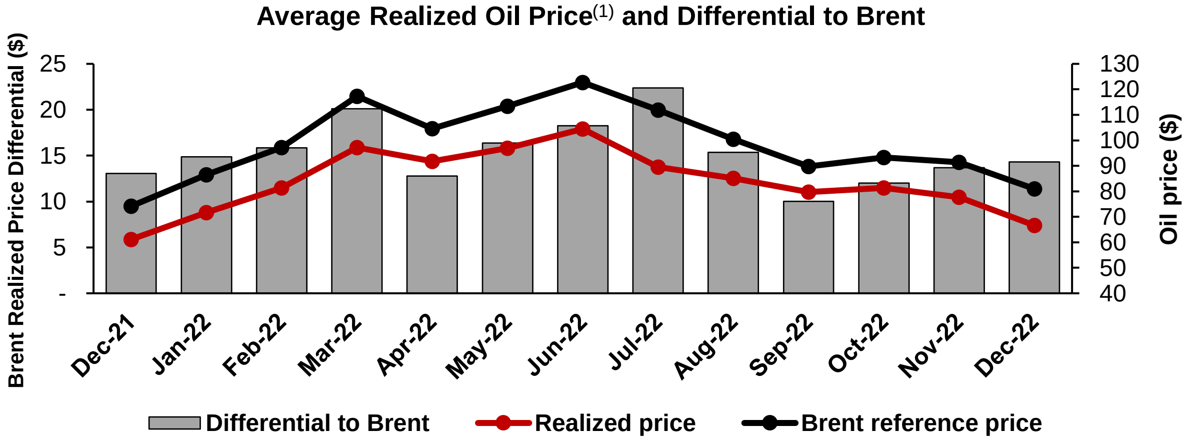
	Three months ended December 31, 2022	2021	% change	Year ended December 31, 2022	2021	% change
Avg. benchmark prices[(1)]						
Brent *($/bbl)*	**88.72**	79.61	11	**100.93**	70.86	42
WTI *($/bbl)*	**82.64**	77.19	7	**94.23**	67.92	39
Average realized prices[(2)]						
Crude oil *($/bbl)*	**75.10**	66.81	12	**85.52**	60.28	42
NGLs *($/bbl)*	**-**	-	-	**-**	46.32	(100)
Crude oil and liquids *($/bbl)*	**75.10**	66.81	12	**85.52**	60.25	42
Natural gas *($/Mcf)*	**2.11**	-	n/a	**2.11**	-	n/a
Realized commodity price *($/boe)*	**48.36**	66.81	(28)	**74.43**	60.25	24
Crude oil realized price discount as a % of Brent	**(15.4)**	(16.1)		**(15.3)**	(14.9)	
Crude oil realized price discount as a % of WTI	**(9.1)**	(13.4)		**(9.2)**	(11.2)	

Notes:
(1) Average of the daily closing spot prices for a given product over the specified time 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 price received is based on quality differentials and international marketing arrangements and therefore are attributed to factors that are beyond our control. Our crude oil realized price is primarily driven by the Brent benchmark price, as Trinidad crude oil is exported for refining and classified as waterborne crude.

Fourth quarter and annual 2022 average Dated Brent benchmark pricing increased 11 and 42 percent in comparison to both prior year periods, respectively. Crude oil pricing remains higher than pre-pandemic and prior year levels due to global concerns over crude oil supply, including the impacts from the continuing Russia-Ukraine military conflict. More recent price volatility has arisen due to uncertainty around global output capacity, sanctions and price caps on Russian output, reopening of economies previously shut down due to the novel coronavirus ("COVID-19") pandemic and inflation and recessionary concerns.

Average Realized Oil 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.

We realized an average crude oil price of $75.10 per barrel in the fourth quarter of 2022 compared to an average of $66.81 per barrel in the equivalent quarter of 2021. Relative to the fourth quarter of 2021, the

12 percent increase in 2022 was predominately driven by the aforementioned 11 percent increase in Brent reference pricing and a slight narrowing of our realized price differential in relation to Brent benchmark pricing.

In 2022 we realized an average crude oil price of $85.52, representing a 42 percent increase relative to the average $60.28 per barrel price received in 2021. The 2022 annual increase relative to 2021 was attributed to a 42 percent increase in the annual average Brent reference price.

In the fourth quarter of 2022 we commenced production from our Coho-1 well, which received an average price of $2.11 per Mcf. Touchstone is obligated to pay a $0.125 per Mcf processing fee to the third-party natural gas facility operator which was netted against natural gas sales in the fourth quarter of 2022.

Petroleum and natural gas sales

($000's unless otherwise stated)	Three months ended December 31,		% change	Year ended December 31,		% change
	2022	2021		**2022**	2021	
Crude oil	**8,805**	8,212	7	**41,830**	29,529	42
NGLs	**-**	-	-	**-**	39	(100)
Natural gas	**1,114**	-	n/a	**1,114**	-	n/a
Petroleum and natural gas sales	**9,919**	8,212	21	**42,944**	29,568	45
Crude oil and liquids *(%)*	**89**	100		**97**	100	
Natural gas *(%)*	**11**	-		**3**	-	

We sell all produced crude oil volumes to Heritage, with title transferring at our various sales batteries. As at December 31, 2022, we held 4,021 barrels of crude oil inventory in comparison to 7,043 barrels as of December 31, 2021.

Petroleum and natural gas sales in the fourth quarter of 2022 increased 21 percent to $9,919,000 from $8,212,000 in the fourth quarter of 2021. In the fourth quarter of 2022, we commenced production from our Coho-1 well, which contributed natural gas sales of $1,114,000. Compared to the fourth quarter of 2021, fourth quarter 2022 crude oil sales increased by $593,000. The increase consisted of $972,000 attributed to higher realized pricing, partially offset by a $379,000 decline in sales volumes.

2022 petroleum and natural gas sales were $42,944,000, representing a $13,376,000 or 45 percent increase from the $29,568,000 recognized in 2021. $1,114,000 of the variance was attributed from initial natural gas sales from the Coho-1 well brought onstream in October 2022. The remaining $12,262,000 variance relative to 2021 was attributed to crude oil and liquids sales, with $12,359,000 reflecting higher realized pricing, slightly offset by $97,000 from reduced 2022 sales volumes.

Other revenue

We recorded $42,000 of other revenue during the year ended December 31, 2022, which primarily consisted of consideration for selling crude oil on behalf of a third-party operator (2021 - $40,000).

Royalties

($000's unless otherwise stated)	Three months ended December 31,		% change	Year ended December 31,		% change
	2022	2021		**2022**	2021	
Crown royalties	**1,184**	949	25	**4,994**	3,372	48
Private royalties	**81**	101	(20)	**401**	337	19
Overriding royalties	**1,860**	1,673	11	**9,246**	5,542	67
Royalties	**3,125**	2,723	15	**14,641**	9,251	58

($000's unless otherwise stated)	Three months ended December 31, 2022	2021	% change	Year ended December 31, 2022	2021	% change
Per boe[(1)]	**15.24**	22.15	(31)	**25.37**	18.85	35
As a % of petroleum and natural gas sales[(1)]	**31.5**	33.2	(5)	**34.1**	31.3	9

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

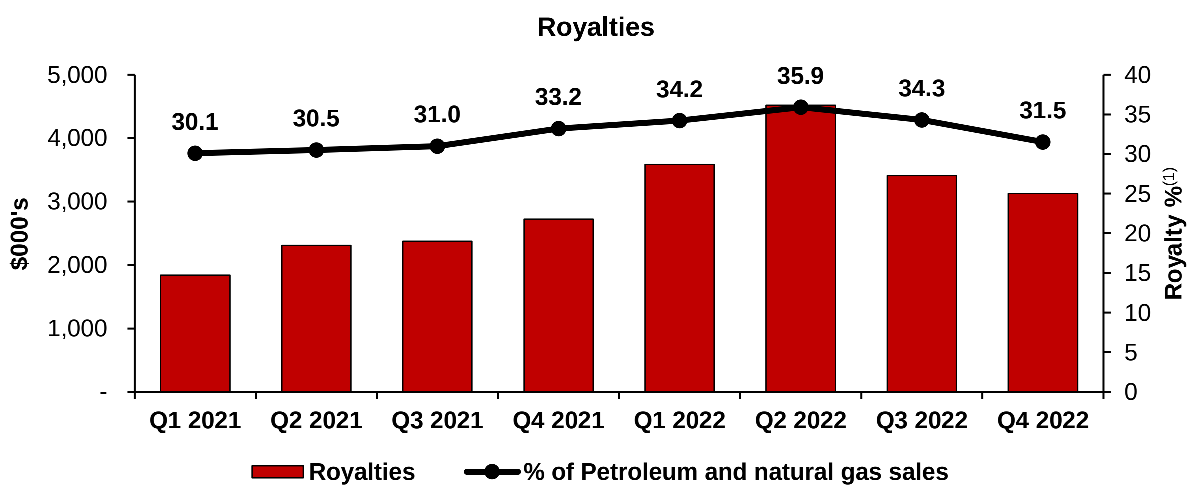
Touchstone is obligated to pay a crown royalty rate of 12.5 percent on all petroleum and natural gas production under MEEI and Heritage licences. For private leases, the Company incurs private royalties between 10 and 12.5 percent of crude oil sales.

We operate under LOAs with Heritage on our CO-1, CO-2, WD-4 and WD-8 blocks, which in addition to crown royalties 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**
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

Royalties as a percentage of petroleum and natural gas sales were 31.5 percent in the fourth quarter of 2022 compared to 33.2 percent in the prior year equivalent quarter. The 2022 decrease in relation to 2021 was mainly a result of Coho natural gas production brought onstream in the fourth quarter of 2022, which is only subject to the 12.5 percent crown royalty.

In 2022, Touchstone's average effective royalty rate was 34.1 percent compared to 31.3 percent in 2021. Relative to 2021, the increase in our effective royalty rate was predominantly from increased ORR, as the sliding scale royalty expense is correlated to higher realized crude oil pricing as noted in the table above.



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, **2022**	2021	% change	Year ended December 31, **2022**	2021	% change
Operating expenses	**2,475**	1,807	37	**9,022**	7,286	24
Per boe(1)	**12.07**	14.70	(18)	**15.64**	14.85	5

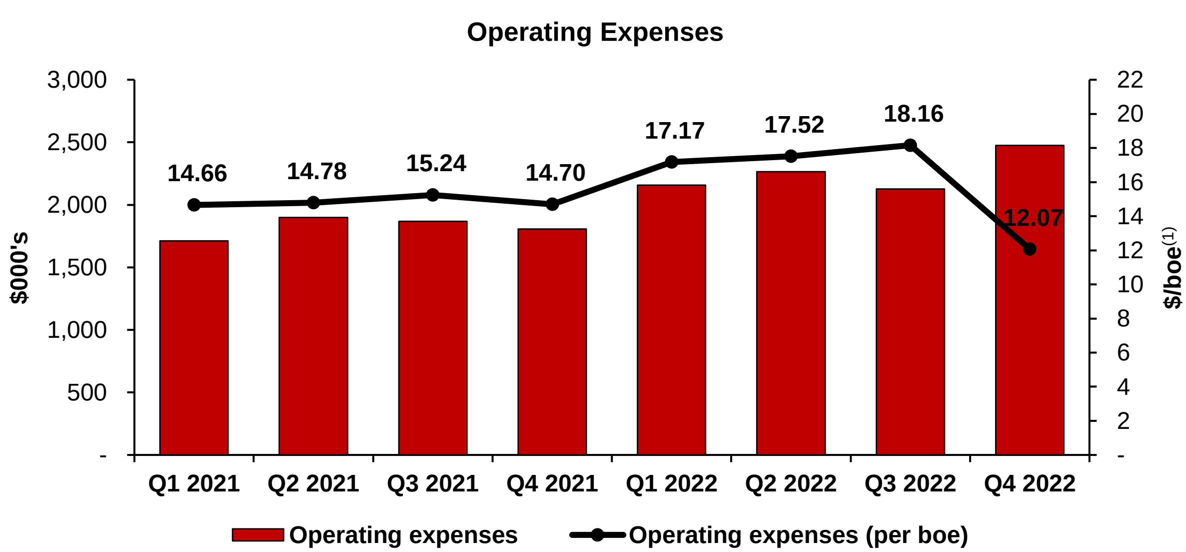
Note:
(1) Non-GAAP financial measure. See the "*Advisories - Non-GAAP Financial Measures*" section of this MD&A for further information.

Operating expenses include all periodic lease, field-level and transportation expenses and directly attributable employee salaries and benefits.

Fourth quarter and annual 2022 operating expenses increased 37 percent and 24 percent from the corresponding 2021 periods, respectively. Relative to the prior year comparative periods, 2022 operating expenses reflected increases in employee headcount and related compensation expenses, well servicing and maintenance activity costs, produced water transportation costs and the impact of inflationary pressures on other cost categories. In addition, the Coho-1 well contributed an incremental $297,000 in operating costs during the three months and year ended December 31, 2022.

2022 fourth quarter operating expenses were $12.07 per boe, representing an 18 percent decrease from the $14.70 per boe reported in the prior year equivalent period. The per unit decrease in comparison to the fourth quarter of 2021 was attributed to incremental Coho-1 well production that averaged operating expenses of $0.56/Mcf ($1.45 per boe) in in the fourth quarter of 2022. Operating costs related to crude oil and liquids production averaged approximately $18.58 per barrel in the fourth quarter of 2022 versus $14.70 per barrel in the prior year equivalent quarter, based on elevated operating expenses and decreased fourth quarter 2022 crude oil production volumes.

Annual 2022 operating expenses averaged $15.64 per boe, a 5 percent increase from $14.85 per boe in 2021. 2022 crude oil and liquids production averaged operating expenses of $17.84 per barrel in comparison to $14.85 per barrel in the prior year, based on increased 2022 operating expenditures over consistent production volumes. Incremental annual 2022 Coho-1 operating costs averaged $0.51 per boe, leading to a per unit Company annual average of $15.64 per boe.

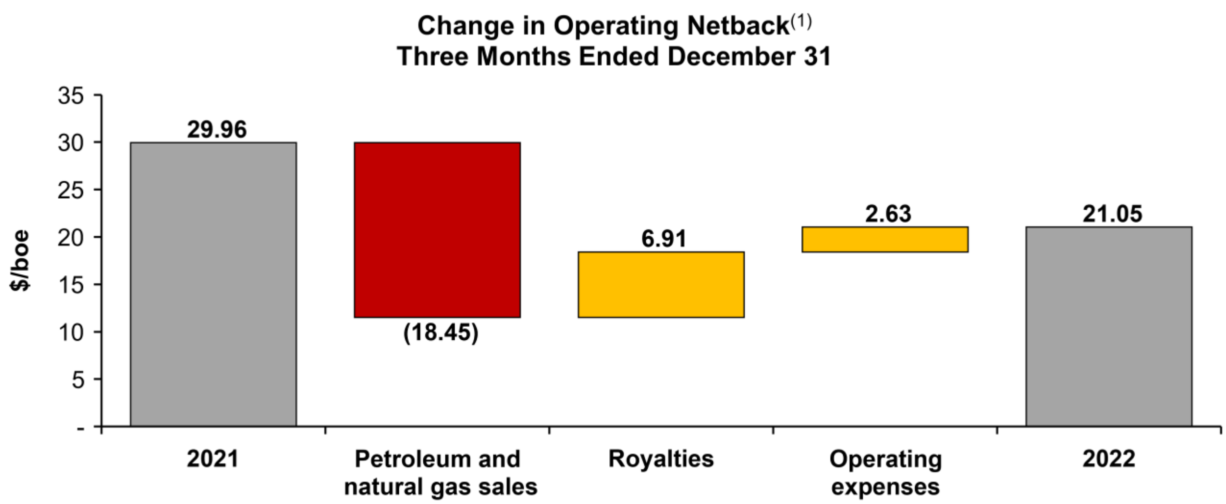


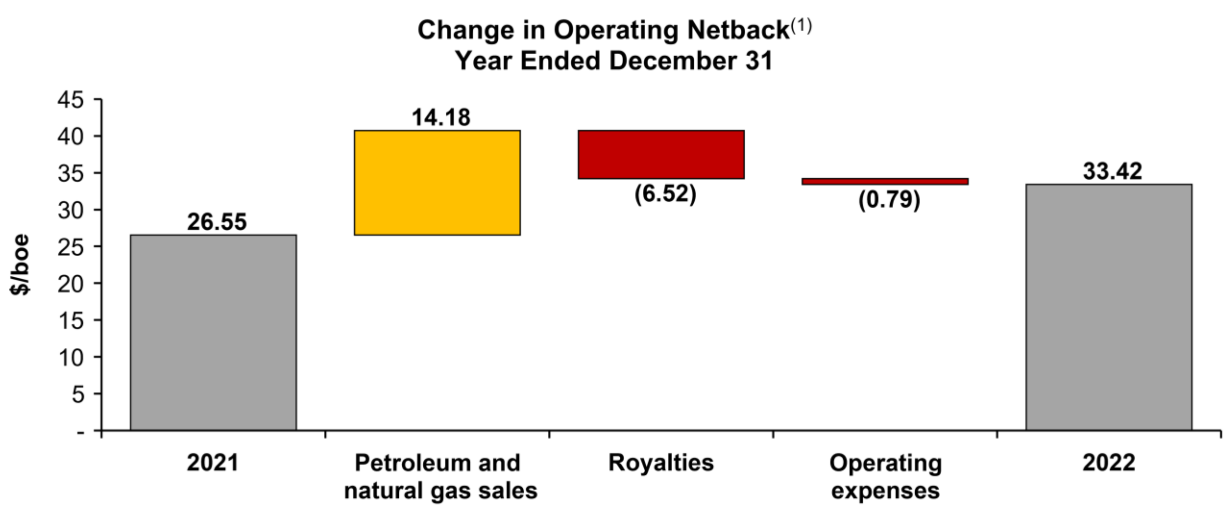
Note:
(1) Non-GAAP financial measure. See the "*Advisories - Non-GAAP Financial Measures*" section of this MD&A for further information.

Operating netback

	Three months ended December 31, 2022	2021	% change	Year ended December 31, 2022	2021	% change
($000's)						
Petroleum and natural gas sales	**9,919**	8,212	21	**42,944**	29,568	45
Royalties	**(3,125)**	(2,723)	15	**(14,641)**	(9,251)	58
Operating expenses	**(2,475)**	(1,807)	37	**(9,022)**	(7,286)	24
Operating netback[(1)]	**4,319**	3,682	17	**19,281**	13,031	48
($/boe)						
Realized commodity price[(1)]	**48.36**	66.81	(28)	**74.43**	60.25	24
Royalties[(1)]	**(15.24)**	(22.15)	(31)	**(25.37)**	(18.85)	35
Operating expenses[(1)]	**(12.07)**	(14.70)	(18)	**(15.64)**	(14.85)	5
Operating netback[(1)]	**21.05**	29.96	(30)	**33.42**	26.55	26

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 expenses

($000's except per boe amounts)	**Three months ended December 31,**		% change	**Year ended December 31,**		% change
	2022	2021		**2022**	2021	
Gross G&A expenses	**2,268**	1,812	25	**8,862**	7,485	18
Capitalized G&A expenses	**(356)**	(408)	(13)	**(1,087)**	(1,184)	(8)
G&A expenses	**1,912**	1,404	36	**7,775**	6,301	23
Per boe(1)	**9.32**	11.42	(18)	**13.48**	12.84	5

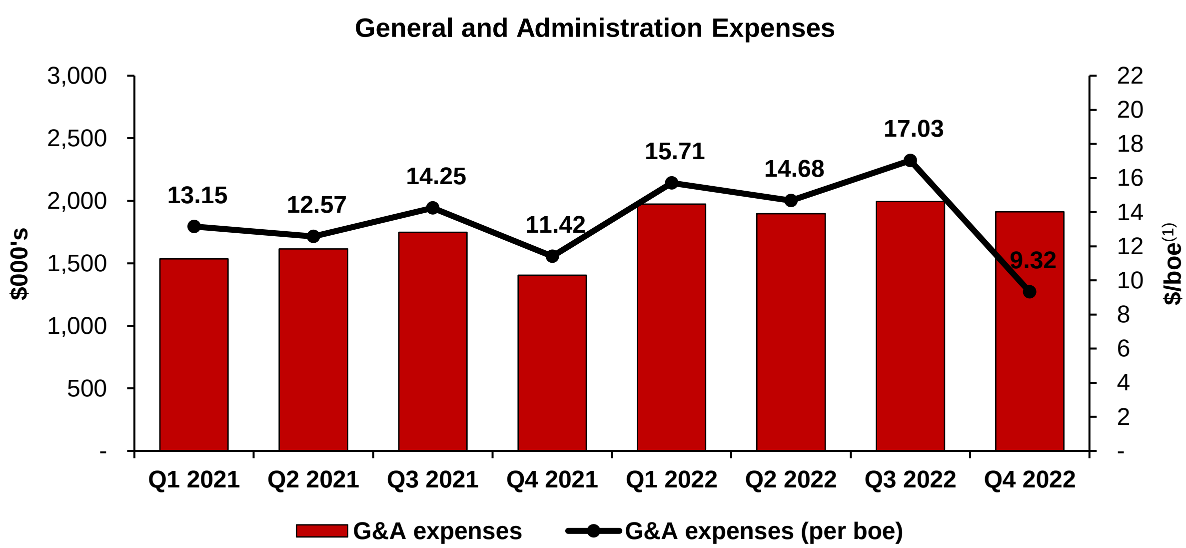
Note:
(1) Non-GAAP financial measure. See the "*Advisories - Non-GAAP Financial Measures*" section of this MD&A for further information.

Gross G&A expenses in the fourth quarter and 2022 were $2,268,000 and $8,862,000 representing increases of 25 percent and 18 percent from the prior year comparative periods, respectively. The variances were primarily from increases in employee headcount and related salary and benefit expenses, insurance, information technology, legal and travel expenses to Trinidad and the United Kingdom based on the easing of health restrictions in 2022. An additional $131,000 and $541,000 were recognized during the fourth quarter and annual 2022 period, respectively, relating to security expenses for a contracted third-party drilling rig that remained idle throughout 2022.

Decreases in capitalized G&A as a percentage of gross G&A in the fourth quarter and the 2022 year in relation to the prior year comparative periods were predominantly from decreased employee hours allocated to capital projects given Touchstone drilled no wells in 2022 versus 3.8 net wells in 2021.

Fourth quarter 2022 G&A expenses were $9.32 per boe, representing an 18 percent decrease from the $11.42 per boe reported in the fourth quarter of 2021. Increases in 2022 net G&A expenses in relation to the prior year fourth quarter were fully offset by a 67 percent increase in production volumes.

Annual 2022 G&A expenses per boe increased 5 percent from 2021, reflecting the aforementioned 23 percent increase in net G&A expenditures slightly offset from an 18 percent increase in production volumes.



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, 2022	2021	% change	Year ended December 31, 2022	2021	% change
Finance lease interest income	**(12)**	(18)	(33)	**(63)**	(65)	(3)
Lease liability interest	**53**	67	(21)	**242**	81	100
Term loan interest	**555**	292	90	**2,316**	734	100
Term loan revaluation loss	**-**	279	(100)	**-**	279	(100)
Accretion on term loan	**9**	(6)	n/a	**66**	45	47
Production liability revaluation loss (gain)	**101**	(52)	n/a	**240**	83	100
Accretion on decommissioning liabilities	**54**	67	(19)	**222**	273	(19)
Other	**30**	1	100	**19**	7	100
Net finance expenses	**790**	630	25	**3,042**	1,437	100
Cash net finance expenses	**592**	342	73	**2,481**	758	100
Non-cash net finance expenses	**198**	288	(31)	**561**	679	(17)
Net finance expenses	**790**	630	25	**3,042**	1,437	100
Per boe(1)	**3.85**	5.13	(25)	**5.27**	2.93	80

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 2022 were $790,000 compared to $630,000 recognized in the same period of 2021. During the year ended December 31, 2022, net finance expenses were $3,042,000, representing a $1,605,000 increase from the $1,437,000 recognized in the prior year comparative period, with cash finance expenses increasing by $1,723,000 from 2021.

Compared to 2021, lease liability interest expenses increased during the year ended December 31, 2022, reflecting a full year of lease liability interest expense for the third-party drilling rig which commenced operating in the fourth quarter of 2021. Refer to the "*Liquidity and Capital Resources - Other liabilities*" section of this MD&A for further details.

Relative to the equivalent periods of 2022, the increase in cash finance costs in 2022 were primarily attributed to increases in term loan interest expense. Elevated 2022 term loan interest expense was a function of increased average principal balances outstanding in 2022, with an average of $29.4 million drawn throughout 2022 compared to an average of $10.7 million drawn throughout 2021. The term credit facility was amended and restated in December 2021, with our lender providing a $10 million increase in the principal balance to $30 million. In connection with this 2021 term loan modification, we recognized a $279,000 non-cash loss on revaluation during the three months year ended December 31, 2021. Refer to the "*Liquidity and Capital Resources - Term loan*" section herein for further details.

Production liability revaluation gains or losses are recognized as a result of a change in the production royalty obligation estimated by the Company at each reporting period in connection with its former term loan. Refer to the "*Liquidity and Capital Resources - Other liabilities*" section of this MD&A for further information.

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 below.

Applicable FX rates	Three months ended December 31, 2022	2021	% change	Year ended December 31, 2022	2021	% change
US$:C$ avg. FX rate(1)	**1.358**	1.261	8	**1.302**	1.254	4
US$:TT$ avg. FX rate(2)	**6.749**	6.759	-	**6.754**	6.757	-
	December 31, 2022	September 30, 2022		**December 31, 2022**	December 31, 2021	
US$:C$ closing FX rate(1)	**1.357**	1.383	(2)	**1.357**	1.264	7
US$:TT$ closing FX rate(2)	**6.742**	6.733	-	**6.742**	6.763	-

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 fourth quarter and year ended December 31, 2022, the C$ depreciated 8 percent and 4 percent relative to the US$ in comparison to the corresponding average rates observed in the 2021 equivalent periods, respectively. Relative to the US$, the TT$ remained range bound throughout 2022. In aggregate, we recorded a foreign exchange loss of $148,000 and a foreign exchange gain of $333,000 during the fourth quarter and year ended December 31, 2022, respectively (2021 - losses of $37,000 and $185,000). 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 2 percent stronger on December 31, 2022 versus September 30, 2022 and 7 percent weaker in comparison to December 31, 2021. In comparison to the US$, the TT$ remained consistent over the corresponding periods. We recognized a foreign currency translation gain of $19,000 and aggregate loss of $298,000 during the fourth quarter and year ended December 31, 2022, respectively (2021 - gains of $70,000 and $112,000).

Equity-based awards

We have a share option plan pursuant to which options to purchase common shares of the Company may be granted by the Board of Directors ("Board") to our directors, officers, employees and consultants. The exercise price of each share option may not be less than the volume weighted average trading price per common share on the TSX for the five consecutive trading days ending on the last trading day preceding the grant date. Equity-based compensation expense is recognized as the options vest. Unless otherwise determined by the Board, vesting typically occurs one third on each of the next three anniversaries of the grant date as recipients render continuous service to the Company, and the share options typically expire five years from the date of the grant.

The maximum number of common shares issuable on the exercise of outstanding share options at any time is limited to 10 percent of our issued and outstanding common shares. As of December 31, 2022, we had 11,928,435 shares options outstanding, which represented 5.1 percent of our outstanding common shares (2021 - 11,233,334 options and 5.3 percent, respectively).

The following table sets forth equity compensation expenses recorded in relation to our equity compensation plan for the periods indicated.

($000's)	Three months ended December 31, 2022	2021	% change	Year ended December 31, 2022	2021	% change
Gross equity-based compensation	**431**	394	9	**1,654**	1,122	47
Capitalized equity-based compensation	**(61)**	(77)	(21)	**(313)**	(234)	34
Equity-based compensation	**370**	317	17	**1,341**	888	51

For the three months and year ended December 31, 2022, we recorded equity-based compensation of $370,000 and $1,341,000, respectively (2021 - $317,000 and $888,000). The increases in 2022 equity-based compensation and capitalized equity-based compensation compared to the same periods of 2021 were primarily attributable to increases in the fair value of our annual equity-based awards granted in May 2021 and April 2022 based on our higher common share price versus previously granted awards.

Further information regarding our equity compensation plan 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, 2022	2021	% change	Year ended December 31, 2022	2021	% change
Depletion expense	**1,134**	737	54	**3,755**	2,967	27
Depreciation expense	**90**	330	(73)	**578**	448	29
Depletion and depreciation expense	**1,224**	1,067	15	**4,333**	3,415	27
Depletion expense per boe(1)	**5.53**	6.00	(8)	**6.51**	6.05	8

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, 2022, $71,638,000 in future development costs were included in development asset cost bases for depletion calculation purposes (2021 - $62,637,000).

In comparison to the fourth quarter of 2021, fourth quarter 2022 depletion increased 54 percent on an absolute basis and decreased 8 percent on a per boe basis. The $397,000 increase in fourth quarter 2022 depletion expenses in relation to the same period of 2021 was predominately related to incremental production from Coho-1 while the decrease on a per boe basis was attributed to a 67 percent increase in production volumes. 2022 annual depletion expenses increased by 27 percent and 8 percent on a unit of production basis in comparison to 2021. The annual increase in depletion predominately reflected increased carrying values from development PP&E impairment reversals recognized in the fourth quarter of 2021.

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. Depreciation expense decreased by $240,000 in the fourth quarter of 2022 in comparison to the 2021 equivalent period, reflecting a decrease in the carrying value of drilling rig mobilization expenses. The increase in depreciation expense reported in 2022 relative to 2021 was reflective of a full year of depreciation recorded on fourth quarter 2021 corporate PP&E expenditures.

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, and the test may be conducted for a cash-generating unit ("CGU") where an asset does not generate cash inflows that are largely independent of those from other assets. 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 reversals on each reporting date.

E&E asset impairment

During the three months and year ended December 31, 2022, we recognized E&E asset impairment expenses of $14,000 and $195,000 related to non-core exploration properties, respectively (2021 - $70,000 and $112,000). The impairment charges predominately reflected licence financial obligations and writing down related decommissioning assets based on updates in long-term inflation estimates that increased the corresponding decommissioning liabilities related to our non-core properties that were previously fully impaired.

Our 16.2 percent non-operated working interest in the Cory Moruga licence continues to have an estimated recoverable value of $nil, and the operator of the licence has entered into a sale and purchase agreement for the asset with a third-party.

As of December 31, 2022, we identified no indicators of impairment relating to our Ortoire CGU, which had a carrying value of $51,352,000 representing the full E&E asset balance on the consolidated balance sheet (2021 - $50,760,000).

PP&E impairment

PP&E impairment reversal by CGU for the specified periods are disclosed in the following table.

CGU *($000's)*	**Three months ended December 31,**		% change	**Year ended December 31,**		% change
	2022	2021		**2022**	2021	
Coora	**-**	(5,596)		**-**	(5,596)	
WD-4	**-**	(4,060)		**-**	(4,060)	
WD-8	**-**	(4,130)		**-**	(4,130)	
PP&E impairment reversal	**-**	(13,786)	(100)	**-**	(13,786)	(100)

On December 31, 2022, we evaluated our development assets included in PP&E for indicators of any potential impairment or reversal. As a result of these assessments, no indicators were identified.

We identified indicators of impairment reversal on December 31, 2021 for our Coora, WD-4 and WD-8 CGUs and performed impairment tests to estimate the recoverable amount of each of these CGUs. As a result, we recorded an aggregate impairment reversal of $13,786,000 related to these CGUs for the year ended December 31, 2021. Indicators of impairment reversal were identified as a result of an increase in forecast crude oil prices compared to December 31, 2020, as well as increases in field and drilling activities performed in 2021.

As future commodity prices remain volatile, impairments or impairment reversals could be recorded in future periods. Estimating the recoverable amounts of our E&E and PP&E CGUs involves several assumptions and estimates which are subject to estimation uncertainty, as well as a significant degree of judgement. Changes in any of the key judgements, such as a revision in reserves, changes to forecasted production, changes in forecast 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 years ended December 31, 2022 and 2021 and their related measurement uncertainty is included in Note 8 "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
	2022	2021		**2022**	2021	
Other expenses	**122**	-	n/a	**794**	-	n/a
Per boe(1)	**0.59**	-	n/a	**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. Touchstone is finalizing an insurance claim through our general and pollution liability policy and has a $250,000 deductible for all pollution claims.

Income taxes

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 produced 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. For quarterly average prices greater than $90.00, the SPT rate is 18 percent plus 0.2 percent per $1.00 above $90.00. The tax base for the calculation of SPT is crude oil and liquids sales less related royalties paid, less 25 percent investment tax credits on mature oilfields for allowable tangible and intangible capital expenditures incurred in the applicable fiscal quarter. Effective January 1, 2023, the investment tax credits increased from 25 percent to 30 percent on approved capital expenditures. 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 (tangible and intangible) are amortized on a five-year straight-line basis.

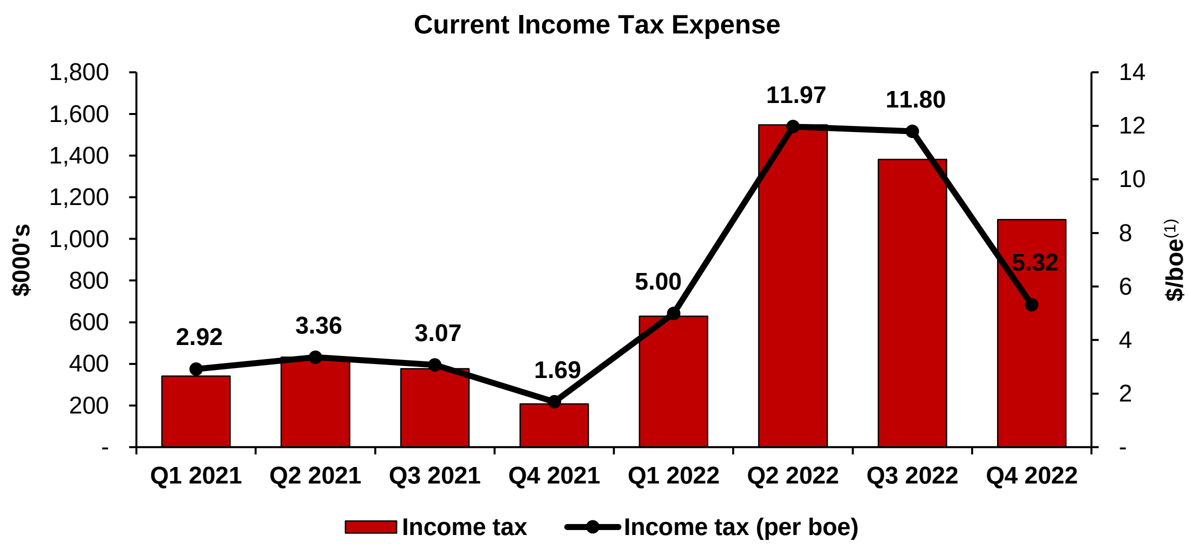
Our Trinidad oilfield service subsidiary, which primarily leases oilfield service equipment to third-party contractors for use in our exploration and production subsidiaries, is subject to the greater of a 30 percent corporate income tax calculated on net taxable profits or a 0.6 percent business levy 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
	2022	2021		**2022**	2021	
SPT	**979**	-	n/a	**3,422**	-	n/a
PPT	**53**	124	(57)	**755**	883	(14)
UL	**22**	51	(57)	**303**	354	(14)
Business levy	**3**	4	(25)	**24**	20	20
GFL	**35**	29	21	**144**	101	43
Current income tax expenses	**1,092**	208	100	**4,648**	1,358	100
Per boe[(1)]	**5.32**	1.69	100	**8.06**	2.77	100

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

In the fourth quarter of 2022, we recognized $1,092,000 of current income tax expenses compared to $208,000 in the fourth quarter of 2021. On an annual basis, we reported an aggregate $4,648,000 in current income tax expenses in 2022 versus $1,358,000 in the prior year. The 2022 increases relative to 2021 were primarily attributed to SPT, as crude oil realized pricing averaged above the $75.00 per barrel SPT threshold throughout every quarter of 2022.



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, 2022, we recognized deferred income tax recoveries of $266,000 and $1,000, respectively (2021 - expenses of $7,226,000 and $7,463,000). The variance in deferred income tax expense on a quarterly and annual 2022 basis compared to the same periods of 2021 were primarily reflective of PP&E impairment reversals recognized in the fourth quarter of 2021, which increased PP&E financial statement carrying values and increased the corresponding deferred income tax liability balance.

Our $14,557,000 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, 2022 (2021 - $14,450,000). 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.

Tax regulations and legislation and interpretations thereof in the various jurisdictions in which we operate are continually changing. As a result, there are generally a number of tax matters under review, and we believe that the provision for income taxes is adequate. Further information regarding our current and deferred income taxes is included in Note 15 "*Income Taxes*" of our audited financial statements.

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. Our 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
	2022	2021		**2022**	2021	
Licence financial obligations	**69**	281	(75)	**588**	1,056	(44)
Geological and seismic	**-**	-	n/a	**-**	2,438	(100)
Drilling, completions and well testing	**(157)**	2,063	n/a	**1,153**	14,295	(92)
Equipment and facilities	**1,873**	99	100	**6,201**	799	100
Capitalized G&A	**200**	280	(29)	**698**	835	(16)
Other	**305**	223	37	**1,148**	683	68
E&E asset expenditures	**2,290**	2,946	(22)	**9,788**	20,106	(51)

Fourth quarter and annual 2022 expenditures on our Ortoire E&E asset 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 production testing operations completed in the first quarter of 2022 (refer to the "*Ortoire Operations*" section of this MD&A for further information).

Fourth quarter and annual 2021 Ortoire E&E asset investments were $2,946,000 and $20,106,000, respectively. 2021 Ortoire expenditures included conducting production testing operations on the Chinook-1 and Cascadura Deep-1 wells drilled in the second half of 2020, completing the Royston area 22-kilometre seismic program, and drilling and initiating production testing of the Royston-1 exploration well.

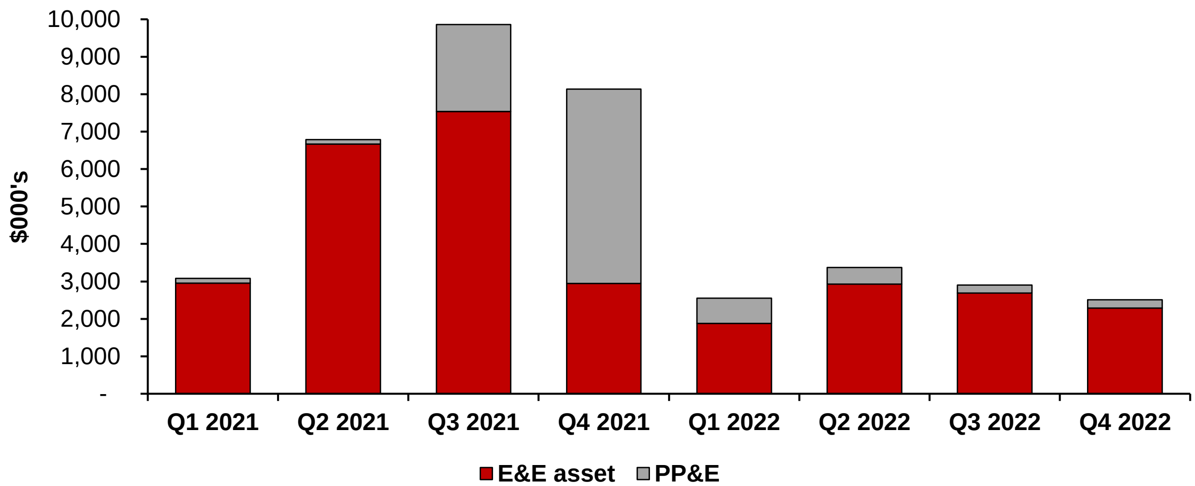
PP&E expenditures

($000's)	**Three months ended December 31,**		% change	**Year ended December 31,**		% change
	2022	2021		**2022**	2021	
Drilling and completions	**51**	4,264	(99)	**1,059**	5,108	(79)
Drilling rig mobilization	**-**	401	(100)	**-**	1,850	(100)
Capitalized G&A	**156**	128	22	**389**	349	11
Corporate and other	**12**	397	(97)	**94**	450	(79)
PP&E expenditures	**219**	5,190	(96)	**1,542**	7,757	(80)

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. Touchstone drilled no development wells in 2022.

For the three months and year ended December 31, 2021, PP&E expenditures were $5,190,000 and $7,757,000, respectively. In the fourth quarter of 2021, we drilled three (gross and net) wells on our LOA properties. In addition, an aggregate $1,850,000 was incurred in 2021 for costs to mobilize a third-party drilling rig to Trinidad. 2021 corporate asset expenditures included investments related to the Rio Claro office in Trinidad and information technology upgrades.

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 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 gain of $85,000 recorded during the year ended December 31, 2022. The Palo Seco disposition remains conditional upon standard regulatory approvals which are proceeding. Further information regarding property dispositions is included in Note 7 "Property, Plant and Equipment" of our audited financial statements.

In conjunction with initial Coho production, 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 loss of $846,000 was recorded in connection with the transaction and included in net loss on asset dispositions in the statement of comprehensive income during the year ended December 31, 2022.

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 or 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, 2022, we reported $1,446,000 of accrued or paid contributions into MEEI and Heritage abandonment funds as long-term abandonment fund assets (2021 - $1,278,000).

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.

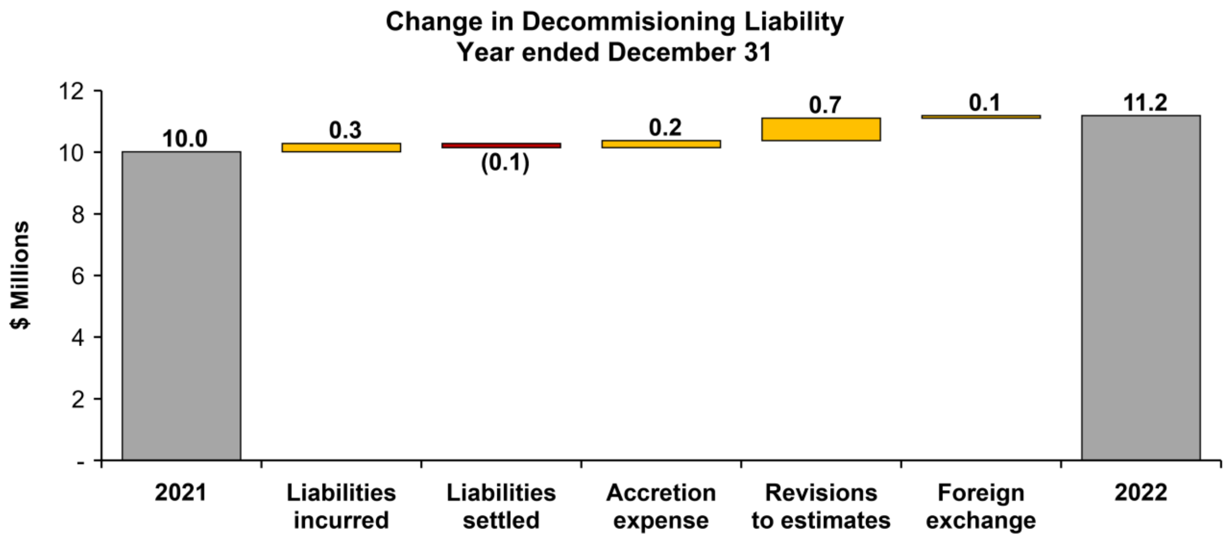
Touchstone is responsible for all site restoration, well abandonment costs and removal of infrastructure and facilities used in petroleum operations conducted on our private production and exploration agreements.

We estimated the net present value of the cash flows required to settle our decommissioning liabilities to be $11,182,000 as at December 31, 2022 (2021 - $10,012,000). The estimate included assumptions in respect of actual costs to abandon wells or reclaim a property, the time frame in which such costs will be incurred, historical well production and annual inflation factors. December 31, 2022 decommissioning liabilities were estimated using a weighted average long-term risk-free rate of 5.3 percent and a long-term inflation rate of 2.4 percent (2021 - 5.3 percent and 1.6 percent, respectively).

$54,000 and $222,000 of accretion expenses were recognized during the three months and year ended December 31, 2022 to reflect the increase in decommissioning liabilities associated with the passage of time, respectively (2021 - $67,000 and $273,000).

Decommissioning liability details as of December 31, 2022, 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)*
736.6	3.8	14,285	17,920	11,182



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.

Finance Leases

Effective March 1, 2021, we entered into separate three-year arrangements to lease our oilfield service rigs and swabbing units to two third-party contractors for aggregate proceeds of approximately $1,120,000. Principal payments commenced in March 2021, and we continue to hold title to the assets until all principal payments have been collected. The lease arrangements were classified as finance leases, as substantially all of the risks and rewards incidental to ownership of the underlying assets are held by the lessees. As of December 31, 2022, our aggregate finance lease receivable balance was $534,000, of which $457,000 was included in long-term other assets on the consolidated balance sheet (2021 - $738,000 and $647,000, respectively). Further information regarding finance lease receivables is included in Note 9 "*Other Assets* " of our audited financial statements.

Liquidity and Capital Resources

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 long-term 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 activities and profitable growth activities will be financed with a combination of funds flow from operations and other sources of capital. We use shareholders' equity and term debt as our primary sources of capital.

Touchstone completed Canadian and United Kingdom based private placements in December 2022 to provide funding for our Royston-1X exploration well drilled in February 2023, a future Cascadura development well and for working capital purposes. In aggregate, net proceeds of $12,269,000 were raised by way of issuing 19,924,400 common shares at a price of C$0.90 (54.5 pence sterling) per common share.

As at December 31, 2022, we had a cash balance of $16,335,000, a working capital surplus of $4,992,000 and a principal balance of $27,000,000 remaining on our term credit facility.

The following table summarizes our changes in cash for the periods specified.

($000's)	Three months ended December 31, 2022	2021	% change	Year ended December 31, 2022	2021	% change
Net cash from (used in):						
Operating activities	**(1,189)**	1,406	(100)	**5,752**	1,611	100
Investing activities	**(1,734)**	(9,943)	(83)	**(16,476)**	(29,391)	(44)
Financing activities	**10,714**	21,051	(49)	**9,052**	21,082	(57)
Change in cash	**7,791**	12,514	(38)	**(1,672)**	(6,698)	(75)
Cash, beginning of period	**8,732**	5,004		**17,936**	24,281	
Impact of FX on cash balances	**(188)**	418	n/a	**71**	353	(80)
Cash, end of period	**16,335**	17,936	(9)	**16,335**	17,936	(9)

Our year-end 2022 cash balance declined in comparison to December 31, 2021 based on an increase in cash generated from operating activities and a reduction in cash used in investing activities, fully offset by decreases in cash from financing activities. Year-end 2022 cash and working capital balances moderately declined from 2021 levels, attributable to ongoing investments directed toward our Ortoire block and $3,000,000 in principal payments made on our term credit facility, partially offset by the December 2022 private placement that raised net proceeds of $12,269,000.

Our near-term development plan is strategically balanced between maintaining base crude oil and natural gas production levels, bringing our Cascadura discovery onstream and investing in future Ortoire development and exploratory activities. We will continue to take a measured approach to future developmental and exploration drilling in an effort to manage financial liquidity while proceeding with this plan. We expect 2023 cash levels and working capital balances to decline in the short-term as we drilled the Royston-1X exploration well subsequent to year-end and as we continue to proceed to invest in our Cascadura natural gas and liquids facility in anticipation of future production and cash flows therefrom.

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, 2022	December 31, 2021
Current assets		**(26,415)**	(27,856)
Current liabilities		**21,423**	20,931
Working capital deficit (surplus)(1)		**(4,992)**	(6,925)
Principal long-term balance of term loan		**21,000**	27,000
Net debt(1)		**16,008**	20,075
Shareholders' equity		**78,380**	67,558
Managed capital(1)		**94,388**	87,633
Annual funds flow from operations(1)		**3,540**	4,172
Net debt to funds flow from operations ratio(1)	At or < 2.0 times	**4.52**	4.81
Net debt to managed capital ratio(1)	< 0.4 times	**0.17**	0.23

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

Our net debt to funds flow from operations ratio has exceeded our target based on continuing facility capital expenditures required to bring our natural gas discoveries onstream. We expect funds flow from operations to increase in 2023 as our Coho-1 well remains onstream, and we forecast to achieve and will strive to maintain our capital management targets when our Cascadura wells are onstream at optimized production rates.

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 share options as at the date of this MD&A, December 31, 2022 and 2021.

	March 23, 2023	**December 31, 2022**	December 31, 2021
Common shares outstanding	**233,037,226**	**233,037,226**	210,731,727
Share options outstanding	**11,928,435**	**11,928,435**	11,233,334
Fully diluted common shares	**244,965,661**	**244,965,661**	221,965,061

Relative to 2021, our common shares increased in 2022 as a result of 1,332,100 share options exercised which were originally granted in accordance with our equity-based compensation plan and an aggregate 19,924,400 common shares issued from the aforementioned December 2022 private placements.

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

Term loan

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. The term credit facility arrangement is a senior secured syndicated loan, with Republic Bank Limited acting as initial lender, arranger and administrative agent.

On closing, we withdrew $15 million to satisfy our obligations relating to prepaying our former C$20 million Canadian-based term loan. On December 21, 2021, the parties entered into an amended and restated loan agreement providing for a $10 million increase in the principal balance to $30 million. The amendment did not amend any other terms of the prior term loan agreement. Effective December 30, 2021, we withdrew an additional $15 million on the credit facility, resulting in the full principal balance of $30 million outstanding.

The term loan bears a fixed interest rate of 7.85 percent per annum, compounded and payable quarterly. Prepayments are permitted with a one percent penalty and a 30-day notice period, and no penalty shall apply on principal repayments after three years. The term 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 its wholly owned Trinidadian subsidiary, POGL. Twenty equal and consecutive quarterly principal payments of $1.5 million commenced on September 15, 2022.

As at December 31, 2022, the principal balance outstanding was $27 million, as we made two scheduled principal payments of $1.5 million each on September 15 and December 15, 2022. Eighteen equal and consecutive quarterly principal payments of $1.5 million remain outstanding.

For financial reporting purposes, the term loan and its modification were initially measured at fair value and subsequently measured at amortised cost, with the aggregate associated financing fees unwound using the effective interest rate method to the face value at maturity. As at December 31, 2022, the term loan balance was $26,962,000 of which $6,000,000 was classified as current on the consolidated balance sheet (2021 - $29,896,000 and $3,000,000, respectively).

The term loan agreement contains industry standard representations and warranties, undertakings, events of default, and financial covenants tested on an annual basis commencing with results for the year ended December 31, 2022. Pursuant to the term loan arrangement, a failure of any covenant constitutes an event of default. Upon an event of default, 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, 2022, the first period where such covenants were tested.

Financial covenant description	**Limit**	**Year ended December 31, 2022**
Net senior funded debt(1) to trailing annual EBITDA(2)	Less than 2.50	**0.89**
Net senior funded debt to book value of equity(3)	Less than 0.70	**0.10**
Debt service coverage(4)	Equal to or greater than 2.50	**3.56**

Notes:
(1) Net senior funded debt is defined as all obligations for senior secured and unsecured borrowed money which bears interest less restricted and unrestricted cash balances.
(2) EBITDA is defined 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 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 means the ratio of trailing annual EBITDA plus restricted and unrestricted cash balances to the total of term loan interest expense due for the future annual period and scheduled principal payments in respect of outstanding term loan principal for the future annual period.

As at December 31, 2022, the Company was compliant with all covenants provided for in the credit facility.

At all times, we must maintain a cash reserves balance of not less than the equivalent of two subsequent quarterly interest payments. Accordingly, Touchstone classified $1,021,000 of cash as long-term restricted on the consolidated balance sheet as at December 31, 2022 (2021 - $1,178,000).

Further information regarding the term loan is included in Note 12 "*Term Loan*" of our audited financial statements, and copies of the credit facility agreement and amendments may be accessed through our profile on SEDAR (www.sedar.com).

Other liabilities

Lease liabilities

The Company is a party to lease arrangements for a drilling rig, office space and office equipment. As of December 31, 2022, we recognized $2,255,000 in aggregate lease liabilities, of which $1,373,000 was classified as long-term on the consolidated balance sheet (2021 - $2,648,000 and $2,265,000, respectively).

In March 2021, we entered into a minimum three-year drilling services contract with a third party to supply a North American based drilling rig to Trinidad in 2021. Pursuant to the arrangement, we are required to utilize the rig for a minimum of 120 days per annum over the initial three-year term. The drilling rig commenced operations in October 2021. During the initial year of the contract, we used the drilling rig for 55 days, which resulted in an aggregate $520,000 standby payment to the counterparty during the year ended December 31, 2022.

Further information regarding our lease obligations is included in Note 11 "*Lease Liabilities* " of our audited financial statements.

Production liability

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 is revalued at each reporting period based on changes to internally forecasted petroleum and natural gas production and forward product pricing and is thus subject to variability. During the three months and year ended December 31, 2022, we recognized losses of $101,000 and $240,000 on revaluation of the liability predominately from the strengthening of strip crude oil pricing from December 31, 2021, respectively (2021 - gain of $52,000 and aggregate loss of $83,000). As at December 31, 2022, our estimated production liability balance was $816,000, of which $nil was classified as long-term and included in other liabilities on the consolidated balance sheet (2021 - $1,211,000 and $908,000, respectively).

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 for office space and motor vehicles. The following table outlines our estimated minimum contractual payments as at December 31, 2022.

($000's)		**Estimated payments due by year**			
	Total	**2023**	**2024**	**2025**	**Thereafter**
Operating agreement commitments					
Coora blocks	**13,255**	4,887	2,566	2,635	3,167
WD-4 block	**4,501**	40	1,316	1,353	1,792
WD-8 block	**4,506**	72	1,313	1,349	1,772
Fyzabad block	**713**	76	78	79	480
Cory Moruga exploration block	**1,200**	99	105	110	886
Ortoire exploration block	**19,090**	4,964	6,394	6,565	1,167
Office and equipment leases	**908**	480	131	154	143
Minimum payments	**44,173**	**10,618**	**11,903**	**12,245**	**9,407**

Under the terms of our Heritage operating agreements, we are required to fulfill minimum work obligations on an annual basis over the specific licence term. With respect to these obligations, we have four development wells and three heavy workover commitments to perform in 2023.

In 2022, we were granted an extension to the exploration phase of the Ortoire Licence to July 31, 2026, and we are obligated to drill three exploration wells prior to the end of the amended licence term, with one well drilled (Royston-1X) in February 2023.

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, natural gas and NGL production. We have entered into 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, the COVID-19 pandemic, the ongoing Russia-Ukraine military conflict, inventory levels, weather, economic and geopolitical factors. Further, our realized crude oil price is based on quality differentials and international marketing arrangements and therefore are attributed to factors that are beyond our control.

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 predominantly 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.

We maintain a risk management strategy to protect our cash from operations from the volatility of crude oil and liquids prices. Our strategy focuses on the periodic use of puts, costless collars, swaps or fixed price contracts to limit exposure to fluctuations in crude oil prices while allowing for participation in crude oil price increases.

We had no commodity financial management contracts in place as of the date hereof or during the years ended December 31, 2022 and 2021. We 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 "*Results of Operations - 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 and liquids 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 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 (refer to the "*Results of Operations - Foreign exchange and foreign currency* *translation*" section of this MD&A for further information).

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. Touchstone has established credit policies and controls designed to mitigate the risk of default or non-payment with respect to petroleum and natural gas sales and financial derivative transactions. However, we are exposed to sole purchaser risk in Trinidad as Heritage is the sole purchaser of crude oil and liquids and NGC is the sole purchaser of Ortoire natural gas production.

In addition, the Company historically has aged accounts receivables owing for Trinidad-based value added taxes ("VAT"). In comparison to December 31, 2021, our past due VAT accounts receivable balance decreased by $1,329,000 as of December 31, 2022, as we collected approximately $3,947,000 in past due amounts in 2022 and $1,696,000 subsequent to December 31, 2022. 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, 2022.

Composition	Counterparty	Balance due *($000's)*	Balance due *(%)*	Accounts receivable aging	
				Current *($000's)*	Over 90 days *($000's)*
Crude oil and NGL sales	Heritage	**1,845**	**25**	1,845	-
Natural gas sales	NGC	**558**	**7**	558	-
Joint interest billings	Heritage	**478**	**6**	478	-
VAT	Trinidad government	**4,190**	**56**	749	3,441
Finance leases	Third-party lessees	**77**	**1**	77	-
Other	Various	**339**	**5**	291	48
Accounts receivable		**7,487**	**100**	**3,998**	**3,489**

We have further credit risk associated with our finance lease receivable balances. We have determined that the associated credit risk is negligible, as the assets are secured by the underlying equipment, with ownership transferring to the counterparties subsequent to receipt of the final lease payments (refer to the "*Finance Leases*" section herein for further information). Further details relating to our financial assets and credit risk can be found in Note 5 "*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. We believe that future cash flows will be adequate to meet 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 potential 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 flow.

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 will continue to manage our capital expenditures to reflect current financial resources in the interest of sustaining long-term viability. The following table sets forth estimated undiscounted cash outflows and financial maturities of our financial liabilities as at December 31, 2022.

($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	**11,039**	11,039	-	-
Income taxes payable	Yes – liability	**1,014**	1,014	-	-
Lease liabilities	Yes – liability	**2,581**	1,055	1,258	268
Term loan principal	Yes – liability	**27,000**	6,000	12,000	9,000
Term loan interest	No – recognized as incurred	**4,946**	1,923	2,434	589
Production liability	Yes – liability	**816**	816	-	-
Financial liabilities		**47,396**	**21,847**	**15,692**	**9,857**

Notes:

(1) The undiscounted cash outflows equal their financial statement carrying values, with the exception of lease liabilities and term loan principal.

(2) Excludes the current portion of lease liabilities and other liabilities.

We actively monitor our liquidity to ensure that cash flows, potential credit facility capacity and working capital are adequate to support these 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, 2022, $89,000 and $204,000 in legal fees and disbursements charged by Norton Rose Fulbright Canada LLP were incurred, respectively (2021 - $34,000 and $81,000). $44,000 was included in accounts payable and accrued liabilities as at December 31, 2022 (2021 - $24,000).

Further, our Trinidad-based director is a member of the board of directors of a private Trinidad engineering services company that provides oilfield supplies to Touchstone. For the three months and year ended December 31, 2022, $21,000 and $41,000 in products were purchased, respectively (2021 - $nil and $10,000). As at December 31, 2022, $16,000 was included in accounts payable and accrued liabilities (2021 - $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 share option plan. Key management personnel compensation paid or payable during the years ended December 31, 2022 and 2021 are disclosed below.

($000's)	**Year ended December 31,**	
	2022	2021
Salaries and benefits included in G&A expenses	**1,094**	1,048
Director fees included in G&A expenses	**395**	363
Equity-based compensation	**1,034**	661
Capitalized salaries, benefits and equity-based compensation	**306**	279
Key management compensation	**2,829**	2,351

The 2022 increase in key management compensation compared to 2021 was primarily attributable to increases in equity-based compensation, as the fair value of equity-based awards granted in 2021 and 2022 increased based on higher Company share prices versus previously granted awards.

The compensation paid to our non-executive directors during the year ended December 31, 2022 is set forth in the following table.

Director *($000's)*	**Fees earned**	**Equity-based compensation**	**All other compensation**	**Total compensation**
Jenny Alfandary(1)	23	14	-	**37**
Priya Marajh(1)	23	13	-	**36**
Kenneth R. McKinnon	50	80	8	**138**
Peter Nicol	48	74	8	**130**
Beverley Smith	48	63	8	**119**
Stanley T. Smith	50	77	8	**135**
Thomas E. Valentine(2)	46	80	8	**134**
Harrie Vredenburg	46	65	8	**119**
John D. Wright	61	83	8	**152**
Director compensation	**395**	**549**	**56**	**1,000**

Notes:
(1) Appointed to the Board on July 11, 2022.
(2) Retired from the Board effective July 11, 2022 and continued to serve as the Company's Corporate Secretary.

Subsequent Event

In January 2023, POGL entered into an Asset Exchange Agreement for the exchange of certain onshore Trinidad assets with a privately held Trinidadian entity. 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. The agreement remains subject to certain closing conditions, including receipt of applicable regulatory approvals and an extension of the Rio Claro Exploration and Production (Public Petroleum Rights) Licence.

Changes in Accounting Policies Including Initial Adoption

There were no changes in accounting policies during the year ended December 31, 2022 that had a material effect on the reported comprehensive income (loss) or net assets of the Company.

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 comprehensive income (loss) or net assets of the Company.

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 4 "*Use of Estimates, Judgements and Assumptions*" of our audited financial statements.

The Company has hired individuals 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 in order 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 2022 Annual Information Form dated March 23, 2023, which can be found on our SEDAR profile (www.sedar.com) 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 subject 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.

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.

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. In 2020, COVID-19, as well as other factors, resulted in the deepest drop in crude oil prices that global markets have seen since 1991. The extent to which Touchstone's operational and financial results continue to be affected by COVID-19 will depend on whether, and to what extent, actions are taken by businesses and governments in response to any resurgence of the pandemic and the speed and effectiveness of responses to combat any such resurgence of the virus.

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 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. 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 commodity price volatility. Refer to the "*Market Risk Management - Commodity price risk*" section herein for further information.

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 in order to protect the environment, our employees and consultants, and the general public.

These environmental laws and regulations impose certain costs and risks on the Company, and there remain some uncertainty with regard to 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.

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. Furthermore, we may be subject to specific project risks that may be required to process and market our Cascadura conventional natural gas and condensate reserves.

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.

Sole purchasers and ability to market

We are exposed to sole purchaser risk in Trinidad as Heritage is the sole purchaser of crude oil 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.

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 forecast 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 - Oil and Natural Gas Reserves*" section herein for further information.

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.

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 licence 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 "*Principal Properties and Licences"* section herein for further information.

Selected Quarterly Information and Trends

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

Three months ended	**Dec. 31, 2022**	**Sept. 30, 2022**	**June 30, 2022**	**March 31, 2022**	**Dec. 31, 2021**	**Sept. 30, 2021**	**June 30, 2021**	**March 31, 2021**
Operational								
Average daily production *(boe/d)*	**1,274**	1,272	1,420	1,396	1,336	1,333	1,411	1,297
Net wells drilled	**-**	-	-	-	3.0	0.8	-	-
Realized commodity price(1) *($/boe)*	**48.36**	84.85	97.48	83.55	66.81	62.37	59.06	52.43
Operating netback(1) *($/boe)*	**21.05**	37.55	44.99	37.83	29.96	27.77	26.30	21.98
Financial *($000's except per share amounts)*								
Petroleum and natural gas sales	**9,919**	9,933	12,596	10,496	8,212	7,650	7,586	6,120
Cash from (used in) operating activities	**(1,189)**	3,092	3,516	333	1,406	404	1,029	(1,228)
Funds flow from operations	**691**	290	1,133	1,426	1,309	1,093	1,226	544
Net (loss) earnings	**(1,921)**	(778)	(262)	(236)	6,514	(51)	(284)	(460)
Per share – basic and diluted	**(0.01)**	(0.00)	(0.00)	(0.00)	0.03	(0.00)	(0.00)	(0.00)
E&E asset expenditures	**2,290**	2,692	2,932	1,874	2,946	7,542	6,664	2,954
PP&E expenditures	**219**	207	436	680	5,190	2,315	125	127
Capital expenditures(1)	**2,509**	2,899	3,368	2,554	8,136	9,857	6,789	3,081
Working capital (surplus) deficit(1)	**(4,992)**	4,537	(346)	(4,259)	(6,925)	4,657	(4,671)	(10,552)
Principal long-term bank loan	**21,000**	22,500	24,000	25,500	27,000	7,125	7,500	7,500
Net debt (surplus)(1) – end of period	**16,008**	27,037	23,654	21,241	20,075	11,782	2,829	(3,052)
Share Information *(000's)*								
Weighted average – basic	**217,106**	212,647	212,204	210,823	210,732	210,732	209,757	209,400
Weighted average – diluted	**217,106**	212,647	212,204	210,823	218,102	210,732	209,757	209,400
Outstanding shares – end of period	**233,037**	213,113	212,275	211,164	210,732	210,732	210,732	209,400

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 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:

- In the fourth quarter of 2022, we generated $0.7 million in 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, Touchstone 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, Touchstone 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, which were directed at completing the Coho-1 pipeline and sales facility and proceeding with the Cascadura development facility, resulting in a 14 percent increase in net debt from the second quarter of 2022.
- We generated $1.1 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 an aggregate $3.4 million in capital expenditures. As a result, net debt increased by $2.4 million or 11 percent from the prior quarter.
- Touchstone generated $1.4 million in funds flow from operations in the first quarter of 2022, as production and realized pricing increased by 4 percent and 25 percent from the fourth quarter of 2021, respectively. Capital expenditures of $2.6 million led to an increase in net debt of $1.2 million from the preceding quarter.
- We recorded $1.3 million in funds flow from operations in the fourth quarter of 2021, as production was consistent and realized crude oil pricing increased by 7 percent from the prior quarter. We increased our net debt by $8.3 million from the third quarter of 2021, as $8.1 million was invested in exploration and development drilling activities. Further, we increased our term loan balance from $20 million to $30 million and withdrew the remaining $15 million available balance on December 30, 2021. Net impairment reversals of $13.7 million and the associated deferred income tax expense of $7.2 million led to net earnings of $6.5 million reported in the quarter.
- In the third quarter of 2021, we maintained base crude oil production levels and generated $1.1 million in funds flow from operations. Capital expenditures increased from the prior quarter, as we drilled an exploration well and incurred rig mobilization and inventory costs for our fourth quarter 2021 development drilling program. The increased capital activity in the quarter led to a $9 million increase in net debt from the second quarter of 2021.
- We generated $1.2 million in funds flow from operations in the second quarter of 2021, reflecting 13 percent and 8 percent increases in realized crude oil pricing and production from the first quarter of 2021, respectively. Ortoire E&E investment was $6.7 million, resulting in a net debt balance of $2.8 million.
- In the first quarter of 2021, Touchstone reported $0.5 million in funds flow from operations predominantly from increased production and realized pricing from the fourth quarter of 2020. We proceeded with our Ortoire exploration activities, incurring a total of $3.1 million in capital expenditures. As a result, net surplus decreased by $2.4 million from the fourth quarter of 2020.

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, 2022. 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, 2022 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, 2022. There were no changes during the three months and year ended December 31, 2022 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.

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.

If applicable, the Company also discloses operating netback both prior to realized gains or losses on derivatives and after the impacts of derivatives are included. Realized gains or losses represent the portion of risk management contracts that have settled in cash during the period, and disclosing this impact provides Management and investors with transparent measures that reflect how the Company's risk management program can affect netback metrics.

The following table presents the computation of operating netback for the periods indicated.

($000's unless otherwise stated)	**Three months ended December 31,**		**Year ended December 31,**	
	2022	2021	**2022**	2021
Petroleum and natural gas sales	**9,919**	8,212	**42,944**	29,568
Royalties	**(3,125)**	(2,723)	**(14,641)**	(9,251)
Operating expenses	**(2,475)**	(1,807)	**(9,022)**	(7,286)
Operating netback	**4,319**	3,682	**19,281**	13,031
Production *(boe)*	**205,091**	122,917	**576,987**	490,741
Operating netback *($/boe)*	**21.05**	29.96	**33.42**	26.55

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.

($000's)	**Three months ended December 31,**		**Year ended December 31,**	
	2022	2021	**2022**	2021
E&E asset expenditures	**2,290**	2,946	**9,788**	20,106
PP&E expenditures	**219**	5,190	**1,542**	7,757
Capital expenditures	**2,509**	8,136	**11,330**	27,863

Working capital, net debt, net debt to funds flow from operations ratio, managed capital and net debt to managed capital ratio

Touchstone closely monitors its capital structure with a 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 and net debt 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.

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

($000's)	**December 31, 2022**	December 31, 2021
Current assets	**(26,415)**	(27,856)
Current liabilities	**21,423**	20,931
Working capital surplus	**(4,992)**	(6,925)
Principal long-term balance of term loan	**21,000**	27,000
Net debt	**16,008**	20,075

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

($000's)	**December 31, 2022**	December 31, 2021
Total liabilities	**69,497**	75,462
Lease liabilities	**(1,373)**	(2,265)
Other liabilities	**-**	(908)
Decommissioning liabilities	**(11,182)**	(10,012)
Deferred income tax liability	**(14,557)**	(14,450)
Variance of carrying value and principal value of term loan	**38**	104
Current assets	**(26,415)**	(27,856)
Net debt	**16,008**	20,075

The Company's forward net debt to funds flow from operations ratio is the desired target Touchstone strives to achieve and maintain in a normalized commodity price environment. This ratio may increase at certain times as a result of increased capital expenditures or low commodity prices.

Management defines managed capital as the sum of net debt and shareholders' equity. The Company's forward 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 disclosed 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.

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 "expects", "plans", "anticipates", "believes", "intends", "estimates", "projects", "potential" 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 and operational strategies, including targeted jurisdictions and technologies used to execute its strategies;
- financial condition and outlook and results of operations, including future liquidity and financial capacity and expectations of future growth, including expectations of increases in future production and cash flows therefrom;
- future demand for the Company's petroleum and natural gas products and economic activity in general;
- the magnitude of and ability to recover petroleum and natural gas reserves;
- the quantity and estimated future net revenue from petroleum and natural gas reserves and the projections of market prices and costs;
- the quality and quantity of prospective hydrocarbon accumulations on untested wells based on internal interpretations of wireline logs;
- 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;
- estimated timing of development, ultimate production and production rates from its Ortoire wells;
- current and future crude oil and liquids and natural gas production levels and estimated field production levels;
- the performance characteristics of the Company's petroleum and natural gas properties;
- future development and exploration activities to be undertaken in various areas and timing thereof, including future cash flows to be derived therefrom and 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 renewal or formal execution of certain contracts;
- expectations regarding the Company's ability to obtain contract extensions or 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 and exploration and production licence renewals or amendments;
- access to third-party facilities and infrastructure;
- expected levels of royalties, operating expenses, G&A expenses, net finance 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 ability to reverse non-financial asset impairment losses in the future;
- the foreign currency risk strategies of the Company and the benefits to be derived therefrom, and the Company's ability to reverse unrealized foreign exchange gains and losses 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 term loan covenants and its ability to make future scheduled interest and principal payments;
- estimated amounts of the Company's future obligations in connection with its production liability and its ability to make such future scheduled payments;
- the potential of future acquisitions or dispositions and receiving regulatory approvals and closing previously announced transactions;
- general economic and political developments in Trinidad and globally;
- estimated amounts, timing and the anticipated sources of funding for the Company's decommissioning liabilities;
- the future ability to receive proceeds from the Company's insurance claim related to reclamation costs incurred from the June 2022 oil spill;
- effect of business and environmental risks on the Company; and
- the statements under "*Significant Accounting Estimates, Judgements and Assumptions*".

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 general economic conditions in Canada, the United Kingdom and Trinidad, the impact of significant volatility in market prices for crude oil and liquids, the impact (and duration thereof) of the ongoing military actions between Russia and Ukraine and related sanctions on crude oil and liquids prices, 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 petroleum 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 under the Company's profile on SEDAR (www.sedar.com).

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.

Statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment, based on certain estimates and assumptions that the reserves described can be profitably produced in the future.

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 information 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.

Oil and Natural Gas Reserves

Touchstone's year-end crude oil, conventional natural gas and condensate 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 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, 2022 are included in the Company's 2022 Annual Information Form dated March 23, 2023, which can be accessed online on the Company's SEDAR profile (www.sedar.com) or the Company's website (www.touchstoneexploration.com).

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. The estimates of reserves for individual properties disclosed herein may not reflect the same confidence levels as estimates of reserves for all properties, due to the effects of aggregation.

"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.

Oil and Natural Gas Measures

Where applicable, natural gas has been converted to barrels of oil equivalent based on six thousand cubic feet to one barrel of oil. The barrel of oil equivalent rate is based on an energy equivalent conversion method primarily applicable at the burner tip, and given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different than the energy equivalency of the 6:1 conversion ratio, utilizing the 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" refers to "light crude oil and medium crude oil" and "heavy crude oil" combined product types; references to "NGLs" refers to condensate; and references to "natural gas" refers to the "conventional natural gas" product type, all as defined in the instrument.

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, 2022	Sept. 30, 2022	June 30, 2022	March 31, 2022	Dec. 31, 2021	Sept. 30, 2021	June 30, 2021	March 31, 2021
Production								
Light and medium crude oil *(bbls)*	**111,114**	110,467	122,778	117,253	113,724	111,725	115,487	106,683
Heavy crude oil *(bbls)*	**6,126**	6,592	6,434	8,372	9,193	10,924	12,116	10,047
Crude oil *(bbls)*	**117,240**	117,059	129,212	125,625	122,917	122,649	127,603	116,730
NGLs - condensate *(bbls)*	**-**	-	-	-	-	-	842	-
Conventional natural gas *(Mcf)*	**527,105**	-	-	-	-	-	-	-
Total production *(boe)*	**205,091**	117,059	129,212	125,625	122,917	122,649	128,445	116,730
Average daily production								
Light and medium crude oil *(bbls/d)*	**1,207**	1,200	1,349	1,303	1,236	1,214	1,269	1,185
Heavy crude oil *(bbls/d)*	**67**	72	71	93	100	119	133	112
Crude oil *(bbls/d)*	**1,274**	1,272	1,420	1,396	1,336	1,333	1,402	1,297
NGLs - condensate *(bbls/d)*	**-**	-	-	-	-	-	9	-
Conventional natural gas *(Mcf/d)*	**5,729**	-	-	-	-	-	-	-
Average daily production *(boe/d)*	**2,229**	1,272	1,420	1,396	1,336	1,333	1,411	1,297

The Company's total and average production for the years ended December 31, 2022 and 2021 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,		%
	2022	2021	change
Production			
Light and medium crude oil *(bbls)*	**461,612**	447,619	3
Heavy crude oil *(bbls)*	**27,524**	42,280	(35)
Crude oil *(bbls)*	**489,136**	489,899	-
NGLs - condensate *(bbls)*	**-**	842	(100)
Conventional natural gas *(Mcf)*	**527,105**	-	n/a
Total production *(boe)*	**576,987**	490,741	18
Average daily production			
Light and medium crude oil *(bbls/d)*	**1,265**	1,226	3
Heavy crude oil *(bbls/d)*	**75**	116	(35)
Crude oil *(bbls/d)*	**1,340**	1,342	-
NGLs - condensate *(bbls/d)*	**-**	2	(100)
Conventional natural gas *(Mcf/d)*	**1,444**	-	n/a
Average daily production *(boe/d)*	**1,581**	1,344	18

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

bbl(s)	barrel(s)
bbls/d	barrels per day
Mbbls	thousand barrels
Mcf	thousand cubic feet
Mcf/d	thousand cubic feet per day
MMcf	million cubic feet
MMcf/d	million cubic feet per day
MMBtu	million British Thermal Units
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
Mboe	thousand barrels of oil equivalent

Other

AIM	AIM market of the London Stock Exchange plc
Brent	Dated Brent
C$	Canadian dollar
NGL(s)	Natural gas liquid(s)
TSX	Toronto Stock Exchange
TT$	Trinidad and Tobago dollar
WTI	Western Texas Intermediate
$ or US$	United States dollar
£	Pounds sterling

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 interim financial statements, the audited 2022 financial statements and our 2022 Annual Information Form, which can be accessed online under our SEDAR profile at www.sedar.com or from our website at 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

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T2P 3N9

Registered Office
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Operating Offices
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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
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