Touchstone Exploration Inc.

Management's Discussion and Analysis

For the three and nine months ended September 30, 2022 and 2021

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As at and for the three and nine months ended September 30, 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 and nine months ended September 30, 2022 with comparisons to the three and nine months ended September 30, 2021 is dated November 9, 2022 and should be read in conjunction with the Company's unaudited interim condensed consolidated financial statements as at and for the three and nine months ended September 30, 2022 (the "interim financial statements"), as well as with the Company's audited consolidated financial statements as at and for the year ended December 31, 2021 (the "audited 2021 financial statements"). The interim financial statements have been prepared by Management in accordance with International Accounting Standard 34 "*Interim Financial Reporting*" using accounting policies consistent with International Financial Reporting Standards ("IFRS" or "GAAP") as issued by the International Accounting Standards Board. Accounting policies adopted by the Company are set out in the notes to the audited 2021 financial statements. This MD&A should also be read in conjunction with Touchstone's MD&A for the year ended December 31, 2021, as disclosure which is unchanged from December 31, 2021 may not be duplicated herein.

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 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 "*Advisory*" section herein which provides information on non-GAAP financial measures, forward-looking statements, 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 an oil 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 initially-in-place and an extensive inventory of oil 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 its core Trinidad portfolio, the Company 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 September 30, 2022	2021	% change	Nine months ended September 30, 2022	2021	% change
Operational						
Average daily production *(bbls/d)*						
Crude oil[1]	**1,272**	1,333	(5)	**1,362**	1,344	1
NGLs	**-**	-	-	**-**	3	(100)
Average daily production	**1,272**	1,333	(5)	**1,362**	1,347	1
Average realized prices[2] *($/bbl)*						
Crude oil	**84.85**	62.37	36	**88.80**	58.09	53
NGLs	**-**	-	-	**-**	46.32	(100)
Realized commodity price	**84.85**	62.37	36	**88.80**	58.06	53
Operating netback *($/bbl)*						
Realized commodity price[2]	**84.85**	62.37	36	**88.80**	58.06	53
Royalties[2]	**(29.14)**	(19.36)	51	**(30.97)**	(17.75)	74
Operating expenses[2]	**(18.16)**	(15.24)	19	**(17.60)**	(14.90)	18
Operating netback[2]	**37.55**	27.77	35	**40.23**	25.41	58
Financial *($000's except per share amounts)*						
Petroleum sales	**9,933**	7,650	30	**33,025**	21,356	55
Cash from operating activities	**3,092**	384	100	**6,941**	158	100
Funds flow from operations[2]	**290**	1,073	(73)	**2,849**	2,816	1
Net loss	**(778)**	(51)	100	**(1,276)**	(795)	61
Per share – basic and diluted	**(0.00)**	(0.00)	-	**(0.01)**	(0.00)	n/a
Exploration capital expenditures	**2,692**	7,542	(64)	**7,498**	17,160	(56)
Development capital expenditures	**207**	2,315	(91)	**1,323**	2,567	(48)
Capital expenditures[2]	**2,899**	9,857	(71)	**8,821**	19,727	(55)
Working capital deficit[2]				**4,537**	4,657	(3)
Principal long-term bank loan				**22,500**	7,125	100
Net debt[2] – end of period				**27,037**	11,782	100
Share Information *(000's)*						
Weighted average shares outstanding – basic and diluted	**212,647**	210,732	1	**211,898**	209,968	1
Outstanding shares – end of period				**213,113**	210,732	1

Notes:

(1) References to crude oil production volumes in the above table and elsewhere in this MD&A refer to light, medium and heavy crude oil product types as defined in National Instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities*. See the "*Product Type Disclosures*" advisory section of this MD&A for further information.

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

Third quarter 2022 highlights

- Produced quarterly average crude oil volumes of 1,272 bbls/d, representing a 10 percent decrease relative to the preceding quarter and a 5 percent decrease from the 1,333 bbls/d produced in the third quarter of 2021, as three key wells were down in the quarter.
- Realized petroleum sales of $9,933,000 from an average crude oil price of $84.85 per barrel compared to $7,650,000 from an average realized price of $62.37 per barrel in the comparative quarter of 2021.
- Generated an operating netback of $37.55 per barrel, a 17 percent decrease from the second quarter of 2022 and a 35 percent increase from $27.77 per barrel in the third quarter of 2021, with

the variances primarily attributed to movements in realized crude oil pricing.

- Recognized current income tax expenses of $1,381,000 in the quarter compared to $377,000 in the third quarter of 2021, driven by $1,173,000 in supplemental petroleum tax expenses based on our average realized oil price exceeding the $75.00 per barrel threshold in the period.
- Our funds flow from operations was $290,000 in the quarter compared to $1,073,000 in the prior year equivalent quarter, and our year to date funds flow from operations increased 1 percent from the same period of 2021.
- Recognized a net loss of $778,000 in the quarter compared to a net loss of $51,000 reported in the same period of 2021, principally driven by higher current income tax expenses.
- Capital investments of $2,899,000 primarily focused on facility and pipeline expenditures related to the Coho-1 natural gas facility and investments directed to the Cascadura natural gas and liquids facility.
- Exited the quarter with cash of $8,732,000, a working capital deficit of $4,537,000 and a $28,500,000 term credit facility balance, resulting in a net debt position of $27,037,000.

Our near-term development plan is strategically balanced between maintaining base crude oil production levels and bringing our Cascadura natural gas discovery onstream. Throughout 2022 we have been diligently investing funds in our Coho and Cascadura facilities, with Coho coming online in October 2022. Our priority is to bring Cascadura discovery onstream as soon as possible. As a result, September 30, 2022 cash and working capital balances have declined, and net debt has increased from year-end 2021 as we proceed with this strategy.

Operational Update

Coho

On October 10, 2022, we achieved first natural gas production from our Coho facility located on the Ortoire block, in which we have an 80 percent operating working interest. In conjunction with initial production, we sold the 2.7-kilometre, 6-inch gathering line tying in the Coho facility to the Baraka natural gas facility to The National Gas Company of Trinidad and Tobago Limited ("NGC") for net proceeds of $1,200,000.

Over 19 operational days in October, the Coho-1 well delivered average net October sales of 7.3 MMcf/d (approximately 1,212 boe/d) on a controlled choke. We will continue to optimize production from the well as conditions stabilize.

Cascadura

On August 16, 2022, we 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.

The CEC approved the construction of a multi-well surface production facility with a designed production capacity of 200 MMcf/d of natural gas, 5,000 bbls/d of associated liquids and 200 bbls/d of produced water, with a storage capacity of 8,800 barrels of liquids on the Cascadura A wellsite. 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 Ortoire block.

Work on the surface location is progressing, and components for the facility are being fabricated by local contractors and/or being imported in completed form. We are currently targeting completion of the facility by the end of the first quarter of 2023.

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. In addition, we entered into a long-term natural gas sales agreement with NGC related to all natural gas sales from our Ortoire property in December 2020.

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.

Lease operatorship agreements

Under our four LOAs (Coora-1, Coora-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 "*Contractual Obligations and Commitments*" for further information).

Private lease agreements

We may also negotiate private surface and subsurface lease arrangements with individual landowners. Lease terms are typically 35 years in duration and contain no minimum work obligations. We are operating under a number of Trinidad private lease agreements which have expired and are currently in the process of renewal. Based on legal opinions received, Touchstone is continuing to recognize petroleum 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 nine months ended September 30, 2022, production volumes produced under expired private lease agreements represented approximately 4.5 percent of our total production (2021 - 2.0 percent).

Results of Operations

Financial highlights

($000's except per share amounts)	**Three months ended September 30,**		% change	**Nine months ended September 30,**		% change
	2022	2021		**2022**	2021	
Net loss	**(778)**	(51)	100	**(1,276)**	(795)	61
Per share – basic and diluted	**(0.00)**	(0.00)	-	**(0.01)**	(0.00)	-
Cash from operating activities	**3,092**	384	100	**6,941**	158	100
Funds flow from operations	**290**	1,073	(73)	**2,849**	2,816	1

Net loss

We recorded a net loss of $778,000 ($0.00 per basic share) in the third quarter of 2022 compared to a net loss of $51,000 ($0.00 per basic share) in the prior year equivalent quarter. Compared to the third quarter of 2021, the year-over-year variance reflected an increase of $990,000 in operating netbacks, offset by increases in general and administration ("G&A"), finance, depletion and depreciation and income tax expenses.

Net loss for the nine months ended September 30, 2022 was $1,276,000 ($0.01 per basic share), representing a $481,000 increase from the $795,000 ($0.00 per basic share) net loss recognized in the corresponding 2021 period. Increases in realized pricing primarily led to a $5,613,000 increase in operating netbacks in comparison to the 2021 period, which was offset by increased G&A, term loan interest, depletion and depreciation, current income tax expenses and a $672,000 provision for oil spill reclamation costs due to vandalism.

The following table sets forth details of the change in net loss from the three and nine months ended September 30, 2021 to the three and nine months ended September 30, 2022.

($000's)	**Three months ended September 30,**	**Nine months ended September 30,**
Net loss – 2021	(51)	(795)
Cash items		
Funds flow from operations	**(783)**	**33**
Decommissioning expenditures	**69**	**119**
Cash variances	**(714)**	**152**
Non-cash items		
Gain on asset dispositions	**-**	**99**
Unrealized foreign exchange	**149**	**615**
Equity-based compensation	**(23)**	**(400)**
Depletion and depreciation	**(478)**	**(761)**
Impairment	**22**	**(139)**
Non-cash finance expenses	**(42)**	**(19)**
Deferred income tax	**359**	**(28)**
Non-cash variances	**(13)**	**(633)**
Net loss – 2022	**(778)**	**(1,276)**

Cash from operating activities

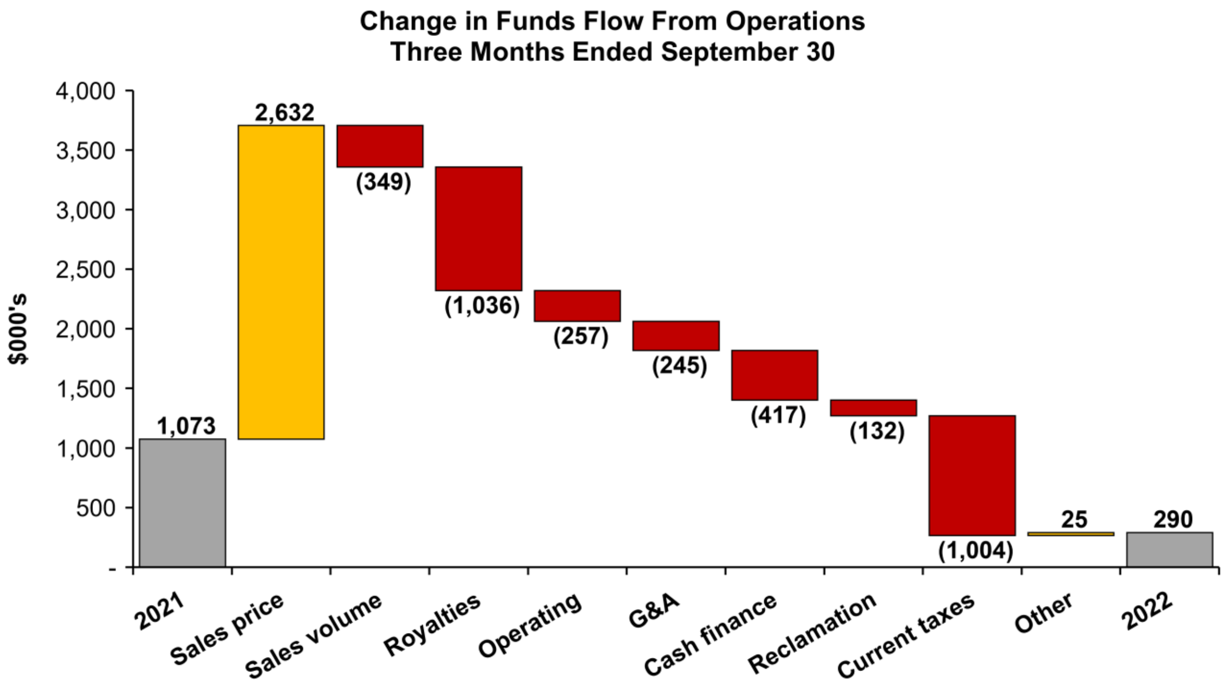
Details of the change in cash from operating activities from the three and nine months ended September 30, 2021 to the three and nine months ended September 30, 2022 are included in the table below.

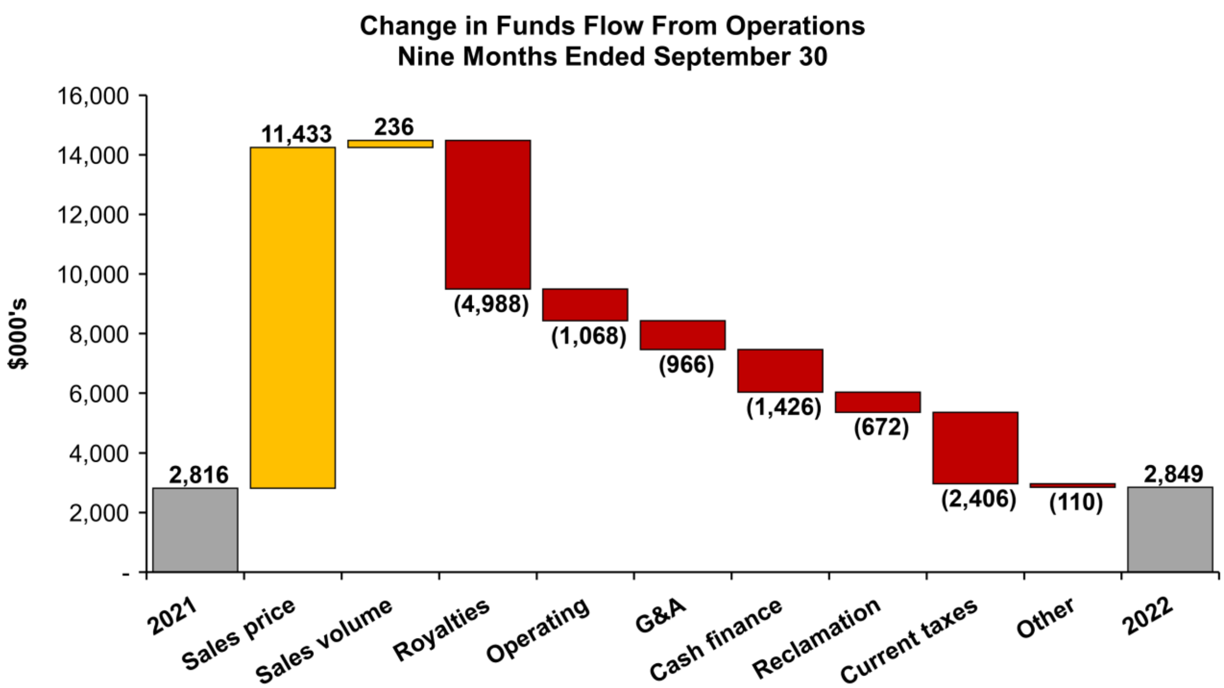
($000's)	**Three months ended September 30,**	**Nine months ended September 30,**
Cash from operating activities – 2021	384	158
Change in funds flow from operations	**(783)**	**33**
Net change in non-cash working capital	**3,491**	**6,750**
Cash from operating activities – 2022	**3,092**	**6,941**

Funds flow from operations

We generated funds flow from operations of $290,000 in the third quarter of 2022 compared to $1,073,000 recognized in the prior year comparative quarter. On a year-to-date basis, we reported funds flow from operations of $2,849,000 in 2022 versus $2,816,000 in the prior year equivalent period. Relative to the corresponding periods of 2021, the variances in 2022 primarily reflected elevated crude oil realized pricing which increased 2022 operating netbacks, offset by increased G&A, term loan interest, current income tax and reclamation expenses related to the aforementioned oil spill incident.

The following graphs summarizes the change in funds flow from operations from the three and nine months ended September 30, 2021 to the three and nine months ended September 30, 2022.





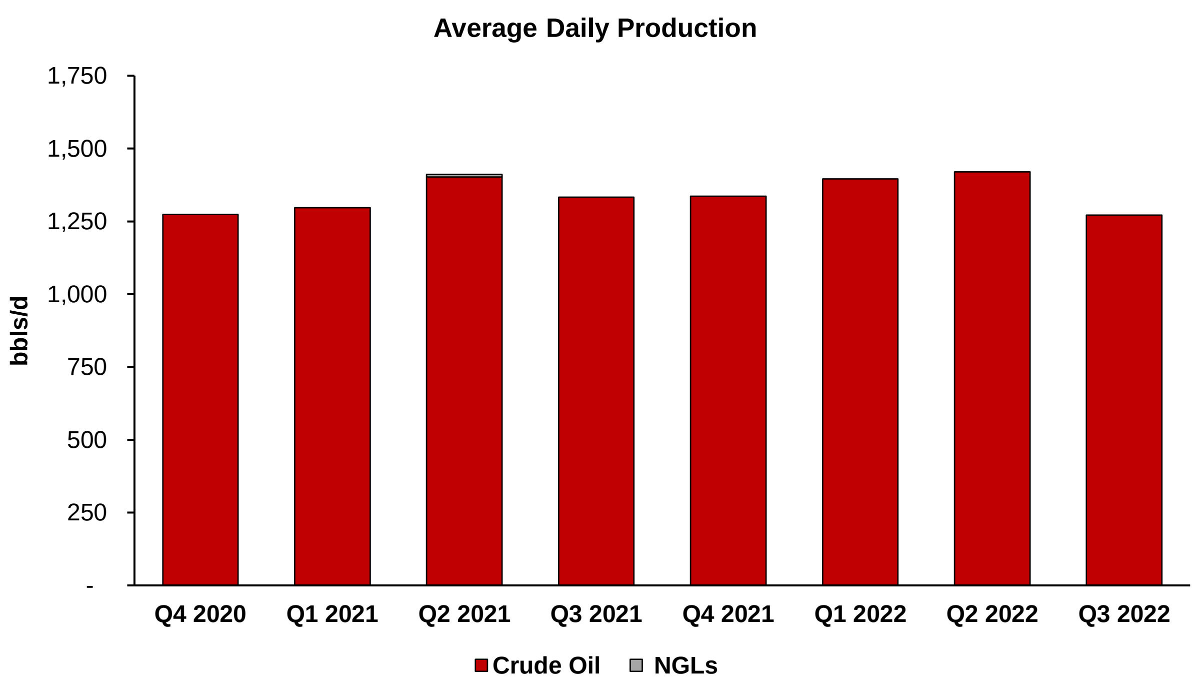
Production volumes

	Three months ended September 30, 2022	2021	% change	Nine months ended September 30, 2022	2021	% change
Production *(bbls)*						
Crude oil	**117,059**	122,649	(5)	**371,896**	366,982	1
NGLs	**-**	-	-	**-**	842	(100)
Total production	**117,059**	122,649	(5)	**371,896**	367,824	1
Average daily production *(bbls/d)*						
Crude oil	**1,272**	1,333	(5)	**1,362**	1,344	1
NGLs	**-**	-	-	**-**	3	(100)
Average daily production	**1,272**	1,333	(5)	**1,362**	1,347	1

Average production volumes of 1,272 bbls/d in the third quarter of 2022 decreased 5 percent from the 1,333 bbls/d produced in the prior year equivalent quarter, while year to date 2022 production volumes were consistent with production from the prior year equivalent period.

Our third quarter oil production decreased 10 percent from the second quarter of 2022, as three key wells were offline throughout the period. The wells have since been serviced, with October 2022 sales volumes averaging 1,304 bbls/d.

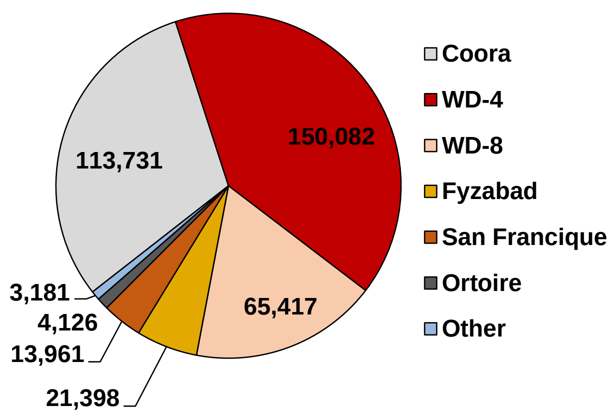
Our year to date 2022 production volumes increased 1 percent from the comparative period of 2021. 2022 production volumes from our three development wells drilled in the fourth quarter of 2021 contributed aggregate field estimated crude oil production of 122 bbls/d in the nine month period. In addition, we sold 4,126 net barrels of crude oil from our Royston-1 production test during the nine months ended September 30, 2022, representing an average of 15 bbls/d. The increases in current year production were partially offset by natural declines and reduced production from two properties that were disposed effective December 31, 2021, which contributed approximately 25 bbls/d of production in the 2021 year to date period.



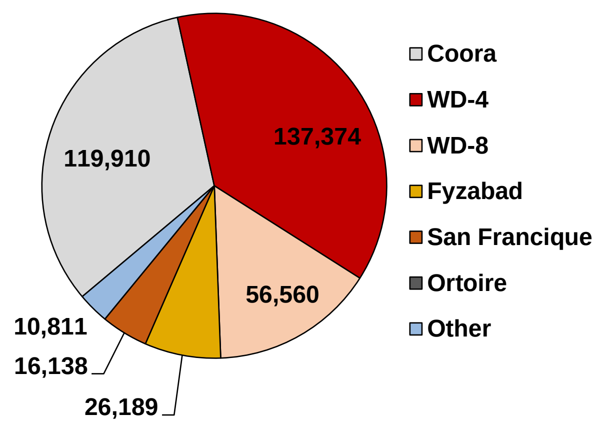
The following table and graphs summarize crude oil production by property during the three and nine months ended September 30, 2022 and 2021.

(bbls)	Three months ended September 30, 2022	2021	% change	Nine months ended September 30, 2022	2021	% change
Coora	**35,308**	39,373	(10)	**113,731**	119,910	(5)
WD-4	**47,919**	46,590	3	**150,082**	137,374	9
WD-8	**21,900**	19,793	11	**65,417**	56,560	16
Fyzabad	**6,592**	8,917	(26)	**21,398**	26,189	(18)
San Francique	**4,225**	4,690	(10)	**13,961**	16,138	(13)
Ortoire	**-**	-	-	**4,126**	-	n/a
Other	**1,115**	3,286	(66)	**3,181**	10,811	(71)
Crude oil production	**117,059**	122,649	(5)	**371,896**	366,982	1

Nine Months Ended September 30, 2022
(bbls)



Nine Months Ended September 30, 2021
(bbls)



Commodity prices

	Three months ended September 30, 2022	2021	% change	Nine months ended September 30, 2022	2021	% change
Avg. benchmark prices[(1)]						
Brent *($/bbl)*	**100.71**	73.51	37	**105.00**	67.89	55
WTI *($/bbl)*	**91.56**	70.56	30	**98.09**	64.82	51
Average realized prices[(2)]						
Crude oil *($/bbl)*	**84.85**	62.37	36	**88.80**	58.09	53
NGLs *($/bbl)*	**-**	-	-	**-**	46.32	(100)
Realized commodity price *($/bbl)*	**84.85**	62.37	36	**88.80**	58.06	53
Crude oil realized price discount as a % of Brent	**(15.7)**	(15.2)		**(15.4)**	(14.4)	
Crude oil realized price discount as a % of WTI	**(7.3)**	(11.6)		**(9.5)**	(10.4)	

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 "*Non-GAAP Financial Measures*" advisory section of this MD&A for further information.

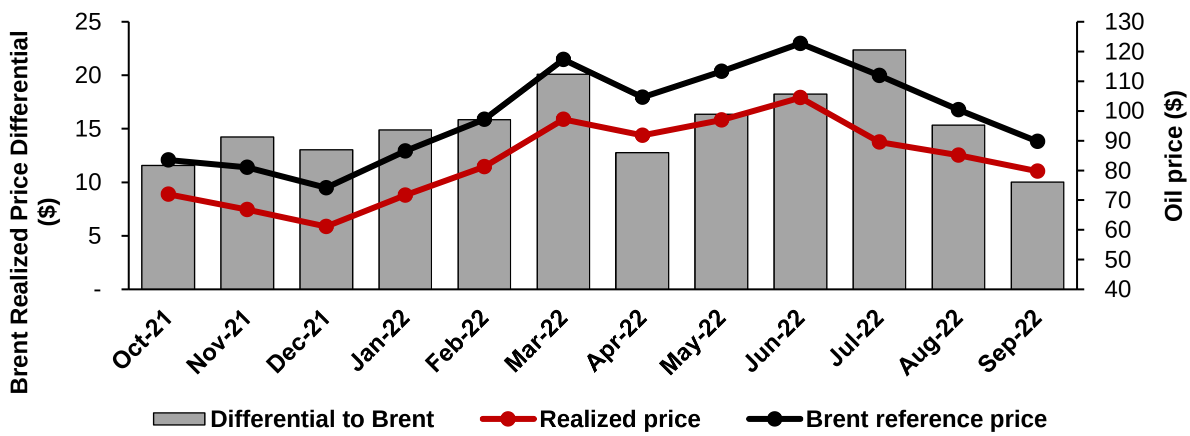
Our crude oil price received is based on quality differentials and international marketing arrangements and therefore are attributed to factors that are beyond our control. Our crude oil realized price is primarily driven by the Brent benchmark price, as Trinidad crude oil is exported for refining and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

Third quarter and year to date 2022 average Dated Brent benchmark pricing increased 37 and 55 percent in comparison to both prior year periods, respectively, due to many countries opening their economies by lifting their pandemic restrictions, the Russia invasion of Ukraine and the resulting sanctions applicable to Russia's businesses and commodities, and limited global incremental sources of oil supply. More recent price volatility has arisen due to uncertainty around global output capacity and recessionary concerns.

We realized an average price of $84.85 per barrel in the third quarter of 2022 compared to an average of $62.37 per barrel in the equivalent quarter of 2021. Relative to the third quarter of 2021, the 36 percent increase in 2022 was predominately driven by the aforementioned increase in Brent reference pricing.

On a year-to-date basis, we realized an average crude oil price of $88.80 per barrel in 2022, a 53 percent increase relative to the $58.06 per barrel price received during the nine months ended September 30, 2021. The increase from the 2021 period was attributed to a 55 percent increase in the average Brent reference price, slightly offset by a widening of the realized price differential in relation to Brent benchmark pricing from 14.4 percent to 15.4 percent.

Realized Oil Price and Differential to Brent



Petroleum sales

($000's)	Three months ended September 30, **2022**	2021	% change	Nine months ended September 30, **2022**	2021	% change
Crude oil	**9,933**	7,650	30	**33,025**	21,317	55
NGLs	**-**	-	-	**-**	39	(100)
Petroleum sales	**9,933**	7,650	30	**33,025**	21,356	55

We sell all produced crude oil volumes to Heritage, with title transferring at our various sales batteries. As at September 30, 2022, we held 4,286 barrels of crude oil inventory in comparison to 7,015 barrels as of December 31, 2021.

Petroleum sales in the third quarter of 2022 increased 30 percent to $9,933,000 from $7,650,000 in the third quarter of 2021. The $2,283,000 increase was a result of $2,632,000 from higher realized pricing, slightly offset by $349,000 from a decline in sales volumes. For the nine months ended September 30, 2022, petroleum sales were $33,025,000, representing a $11,669,000 or 55 percent increase from the $21,356,000 recognized in the equivalent 2021 period. The 2022 variance consisted of $11,433,000 from higher realized pricing and $236,000 attributed to elevated sales volumes.

Royalties

($000's unless otherwise stated)	Three months ended September 30, 2022	2021	% change	Nine months ended September 30, 2022	2021	% change
Crown royalties	**1,148**	873	32	**3,810**	2,423	57
Private royalties	**92**	79	16	**320**	236	36
Overriding royalties	**2,171**	1,423	53	**7,386**	3,869	91
Royalties	**3,411**	2,375	44	**11,516**	6,528	76
Per bbl(1)	**29.14**	19.36	51	**30.97**	17.75	74
As a % of petroleum sales(1)	**34.3**	31.0	11	**34.9**	30.6	14

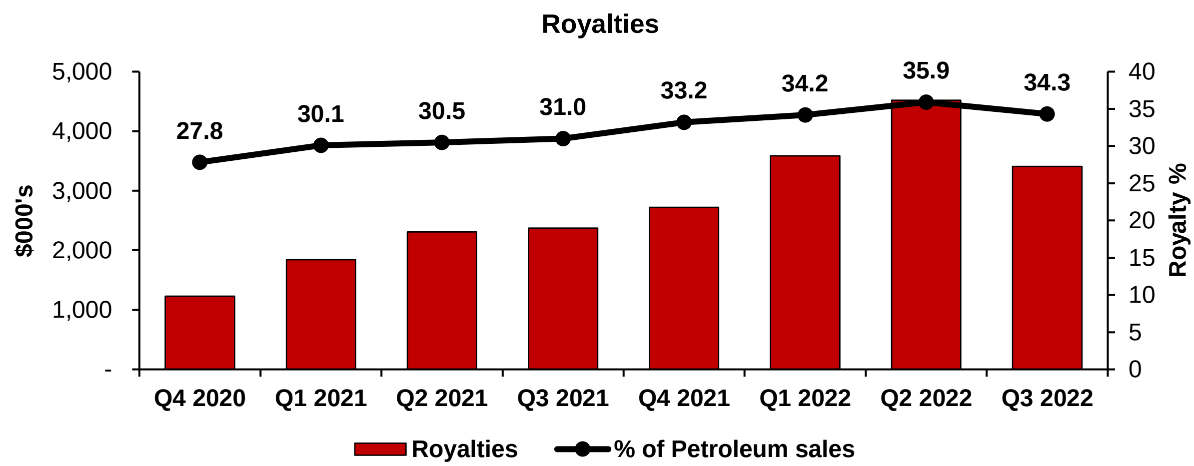
Note:
(1) Non-GAAP financial measure. See the "*Non-GAAP Financial Measures*" advisory section of this MD&A for further information.

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

We operate under LOAs with Heritage on our Coora-1, Coora-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 sales were 34.3 percent in the third quarter of 2022 compared to 31.0 percent in the prior year third quarter. For the nine months ended September 30, 2022, royalties represented 34.9 percent of petroleum sales compared to 30.6 percent in the prior year equivalent period. The year-over-year variances reflected an increase in realized crude oil pricing received in each period of 2022 compared to 2021.



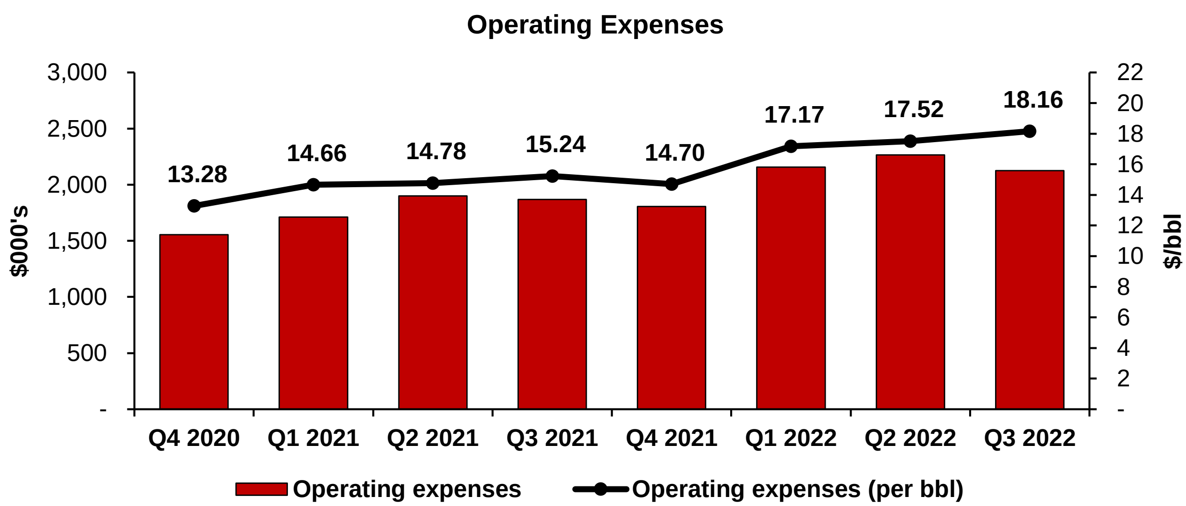
Operating expenses

($000's except per bbl amounts)	Three months ended September 30, 2022	2021	% change	Nine months ended September 30, 2022	2021	% change
Operating expenses	**2,126**	1,869	14	**6,547**	5,479	19
Per bbl(1)	**18.16**	15.24	19	**17.60**	14.90	18

Note:
(1) Non-GAAP financial measure. See the "*Non-GAAP Financial Measures*" advisory 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. Third quarter and year to date 2022 operating costs increased 14 percent and 19 percent from the corresponding 2021 periods, respectively. Relative to the prior year comparative periods, 2022 operating expenses reflected increases in employee headcount and salaries, well servicing and maintenance activity costs, and produced water transportation costs.

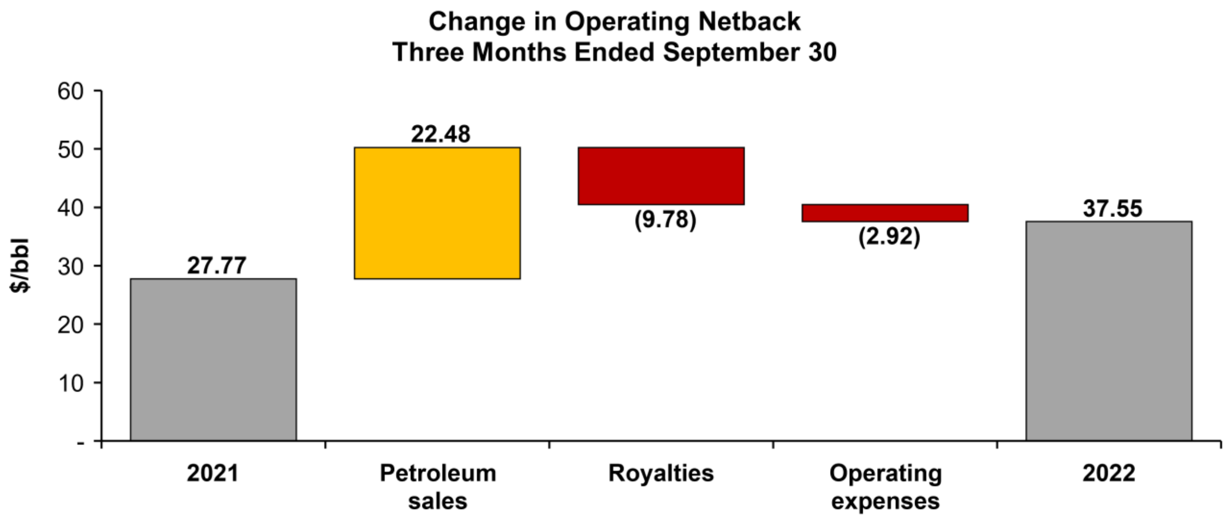
2022 third quarter operating expenses were $18.16 per barrel, representing a 19 percent increase from the $15.24 per barrel reported in the third quarter of 2021 based on elevated operating expenses and decreased 2022 crude oil production volumes. Year to date 2022 operating expenses per barrel increased 18 percent from the equivalent 2021 period, attributed to a 19 percent increase in operating expenditures.

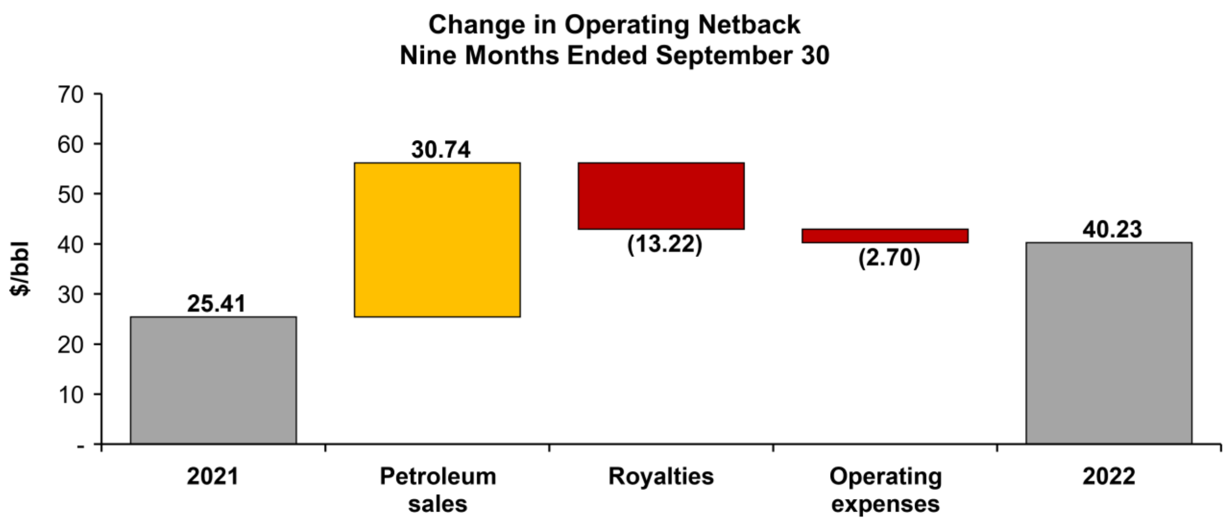


Operating netback

	Three months ended September 30, 2022	2021	% change	Nine months ended September 30, 2022	2021	% change
($000's)						
Petroleum sales	**9,933**	7,650	30	**33,025**	21,356	55
Royalties	**(3,411)**	(2,375)	44	**(11,516)**	(6,528)	76
Operating expenses	**(2,126)**	(1,869)	14	**(6,547)**	(5,479)	19
Operating netback(1)	**4,396**	3,406	29	**14,962**	9,349	60
($/bbl)						
Realized commodity price(1)	**84.85**	62.37	36	**88.80**	58.06	53
Royalties(1)	**(29.14)**	(19.36)	51	**(30.97)**	(17.75)	74
Operating expenses(1)	**(18.16)**	(15.24)	19	**(17.60)**	(14.90)	18
Operating netback(1)	**37.55**	27.77	35	**40.23**	25.41	58

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





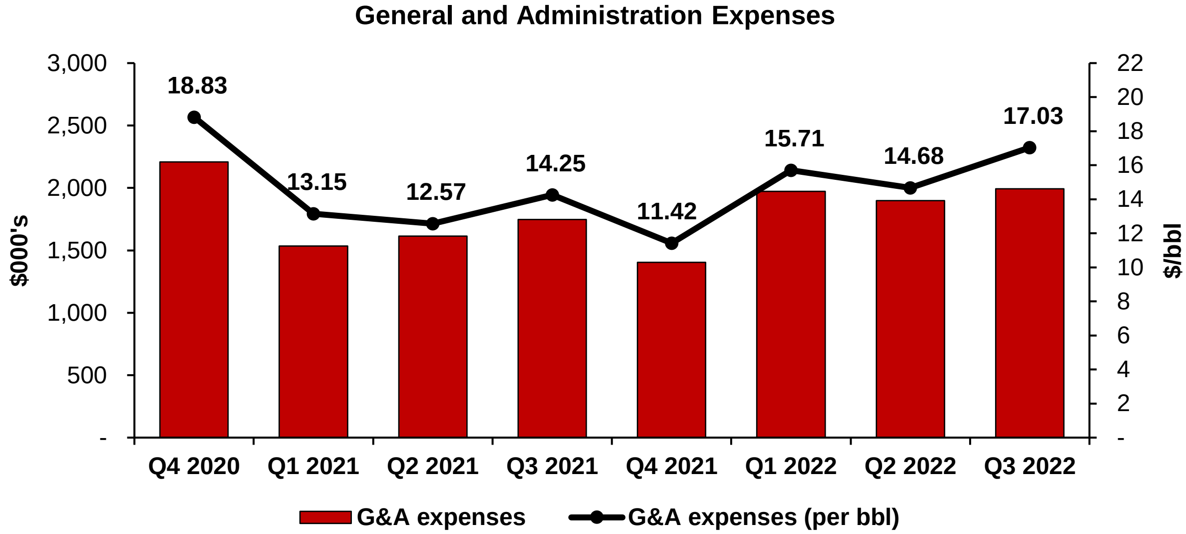
General and administration expenses

($000's except per bbl amounts)	Three months ended September 30, 2022	Three months ended September 30, 2021	% change	Nine months ended September 30, 2022	Nine months ended September 30, 2021	% change
Gross G&A expenses	**2,247**	1,993	13	**6,594**	5,673	16
Capitalized G&A expenses	**(254)**	(245)	4	**(731)**	(776)	(6)
G&A expenses	**1,993**	1,748	14	**5,863**	4,897	20
Per bbl[(1)]	**17.03**	14.25	20	**15.77**	13.31	18

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

The increase in gross G&A expenses in the third quarter and year to date 2022 periods compared to the same periods in 2021 was primarily attributed to increases in employee headcount and salaries, insurance, information technology, legal and travel expenses to Trinidad based on the easing of health restrictions in 2022. Further, $133,000 and $410,000 were recognized during the three and nine months ended September 30, 2022, respectively, relating to security costs for the third-party drilling rig that has been idle throughout 2022.

Third quarter 2022 G&A expenses were $17.03 per barrel, representing a 20 percent increase from the $14.25 per barrel reported in the third quarter of 2021 based on higher net G&A costs and lower 2022 production volumes. Year to date 2022 G&A expenses per barrel increased 18 percent from the equivalent 2021 period, mainly attributed to increased net G&A expenditures.



Net finance expenses

($000's except per bbl amounts)	Three months ended September 30, **2022**	2021	% change	Nine months ended September 30, **2022**	2021	% change
Lease liability interest expense	**12**	5	100	**138**	14	100
Term loan interest expense	**583**	148	100	**1,761**	442	100
Accretion on term loan	**10**	19	(47)	**57**	51	12
Production liability revaluation loss	**20**	5	100	**139**	135	3
Accretion on decommissioning liabilities	**48**	66	(27)	**168**	206	(18)
Other	**19**	(10)	n/a	**(11)**	(41)	(73)
Net finance expenses	**692**	233	100	**2,252**	807	100
Cash net finance expenses	**580**	163	100	**1,889**	463	100
Non-cash net finance expenses	**112**	70	60	**363**	344	38
Net finance expenses	**692**	233	100	**2,252**	807	100
Per bbl(1)	**5.91**	1.90	100	**6.06**	2.19	100

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

Net finance expenses in the third quarter of 2022 were $692,000 compared to $233,000 recognized in the same period of 2021. For the nine months ended September 30, 2022, net finance expenses were $2,252,000, representing a $1,445,000 increase from the $807,000 recognized in the prior year comparative period, with cash finance expenses increasing by $1,426,000 from the comparative 2021 period.

Compared to 2021, lease liability interest expenses increased during the nine months ended September 30, 2022, reflecting increased lease liability carrying values. Refer to "*Liquidity and Capital Resources - Other liabilities*" for further details.

Relative to the equivalent periods of 2021, 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 $29.9 million drawn throughout the nine months ended September 30, 2022 compared to an average of $7.5 million drawn throughout the 2021 equivalent period. Refer to "*Liquidity and Capital Resources - Term loan*" for further details.

Production liability revaluation 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 "*Liquidity and Capital Resources - Other liabilities*" 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 a Trinidad and Tobago dollar functional currency. 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 September 30,**		% change	**Nine months ended September 30,**		% change
	2022	2021		**2022**	2021	
US$:C$ avg. FX rate[1]	**1.305**	1.259	4	**1.283**	1.251	3
US$:TT$ avg. FX rate[2]	**6.754**	6.757	-	**6.755**	6.757	-
	September 30, 2022	June 30, 2022		**September 30, 2022**	December 31, 2021	
US$:C$ closing FX rate[1]	**1.383**	1.288	7	**1.383**	1.264	9
US$:TT$ closing FX rate[2]	**6.733**	6.753	-	**6.733**	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 "*Market Risk Management - Foreign currency risk*").

During the three and nine months ended September 30, 2022, the C$ depreciated 4 percent and 3 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 during the three and nine months ended September 30, 2022 and 2021. In aggregate, we recorded foreign exchange gains of $285,000 and $481,000 during the three and nine months ended September 30, 2022, respectively (2021 - gain of $48,000 and loss of $148,000). 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 7 percent weaker on September 30, 2022 versus June 30, 2022 and 9 percent weaker in comparison to December 31, 2021. In comparison to the US$, the TT$ remained consistent over the corresponding periods. We recognized foreign currency translation losses of $450,000 and $317,000 during the three and nine months ended September 30, 2022, respectively (2021 - loss of $228,000 and aggregate gain of $42,000).

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.

Share options	**Number of share options**	**Weighted average exercise price** *(C$)*
Outstanding, January 1, 2021	9,552,434	0.34
Granted	3,013,000	1.70
Exercised	(1,332,100)	0.22
Issued and outstanding, December 31, 2021	**11,233,334**	**0.72**
Granted	3,257,000	1.44
Exercised	(2,381,099)	0.21
Forfeited	(261,800)	1.47
Issued and outstanding, September 30, 2022	**11,847,435**	**1.00**
Exercisable, September 30, 2022	**5,677,440**	**0.57**

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 September 30, 2022, our outstanding share options represented 5.6 percent of our outstanding common shares (December 31, 2021 - 5.3 percent).

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 September 30,**		% change	**Nine months ended September 30,**		% change
	2022	2021		**2022**	2021	
Gross equity-based compensation	**421**	381	10	**1,223**	728	68
Capitalized equity-based compensation	**(93)**	(76)	22	**(252)**	(157)	61
Equity-based compensation	**328**	305	8	**971**	571	70

For the three and nine months ended September 30, 2022, Touchstone recorded equity-based compensation of $328,000 and $971,000, respectively (2021 - $305,000 and $571,000). 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 10 "*Shareholders' Capital*" of our interim financial statements.

Depletion and depreciation expense

($000's except per bbl amounts)	Three months ended September 30, **2022**	2021	% change	Nine months ended September 30, **2022**	2021	% change
Depletion expense	**837**	703	19	**2,621**	2,230	18
Depreciation expense	**367**	23	100	**488**	118	100
Depletion and depreciation expense	**1,204**	726	66	**3,109**	2,348	32
Depletion expense per bbl[(1)]	**7.15**	5.73	25	**7.05**	6.06	16

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

Depletion expense associated with our producing petroleum assets included in property, plant and equipment ("PP&E") increased on an absolute and a per barrel basis in the third quarter and year-to-date periods of 2022 compared to the 2021 comparative periods. The year-over-year increase in depletion predominately reflected increased carrying values from petroleum asset PP&E impairment reversals recognized in the fourth quarter of 2021. Depletion expenses will fluctuate based on the amount and type of capital spending, the recognition or reversal of PP&E impairments, the quantity of reserves added and production volumes. Depletion rates are calculated on proved plus probable reserves, considering the future development costs to produce the reserves.

Assets in the exploration and evaluation ("E&E") phase are not amortized. Depreciation expense is recorded on corporate assets on a declining balance basis, and right-of-use ("ROU") assets are depreciated over their estimated useful lives on a straight-line basis. The increases in depreciation expense reported during the three and nine months ended September 30, 2022 relative to the equivalent 2021 periods was reflective of higher net asset carrying values associated with capitalized drilling rig mobilization costs, corporate PP&E expenditures and increased ROU assets as a result of increased lease liability carrying values. Refer to "*Liquidity and Capital Resources - Other liabilities*" for further details.

Impairment

E&E asset impairment

During the three and nine months ended September 30, 2022, we recognized E&E asset impairments of $10,000 and $181,000 related to non-core exploration properties, respectively (2021 - $32,000 and $42,000). The impairments were predominately related to writing down well decommissioning assets based on changes in 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 is currently discussing investment alternatives with the MEEI, which may include licence relinquishment.

As of September 30, 2022, we identified no indicators of impairment relating to our Ortoire cash-generating unit, which had a carrying value of $59,093,000 representing the full E&E asset balance on the interim consolidated statement of financial position (December 31, 2021 - $50,760,000).

PP&E impairment

On September 30, 2022, we evaluated our petroleum assets included in PP&E for indicators of any potential impairment or reversal. As a result of these assessments, no indicators were identified.

Other expenses

($000's except per bbl amounts)	**Three months ended September 30,**		% change	**Nine months ended September 30,**		% change
	2022	2021		**2022**	2021	
Other expenses	**132**	-	n/a	**672**	-	n/a
Per bbl(1)	**1.13**	-	n/a	**1.81**	-	n/a

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

For the three and nine months ended September 30, 2022, the Company incurred $132,000 and $672,000 in expenses related to an oil spill that occurred as a result of vandalism in June 2022, respectively. The Company is in the process of submitting 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 ("SPT") 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 liquids volumes. Actual rates vary based on the average realized selling prices of crude oil and liquids in the applicable quarter. For the 2021 and 2022 calendar years, 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. 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.

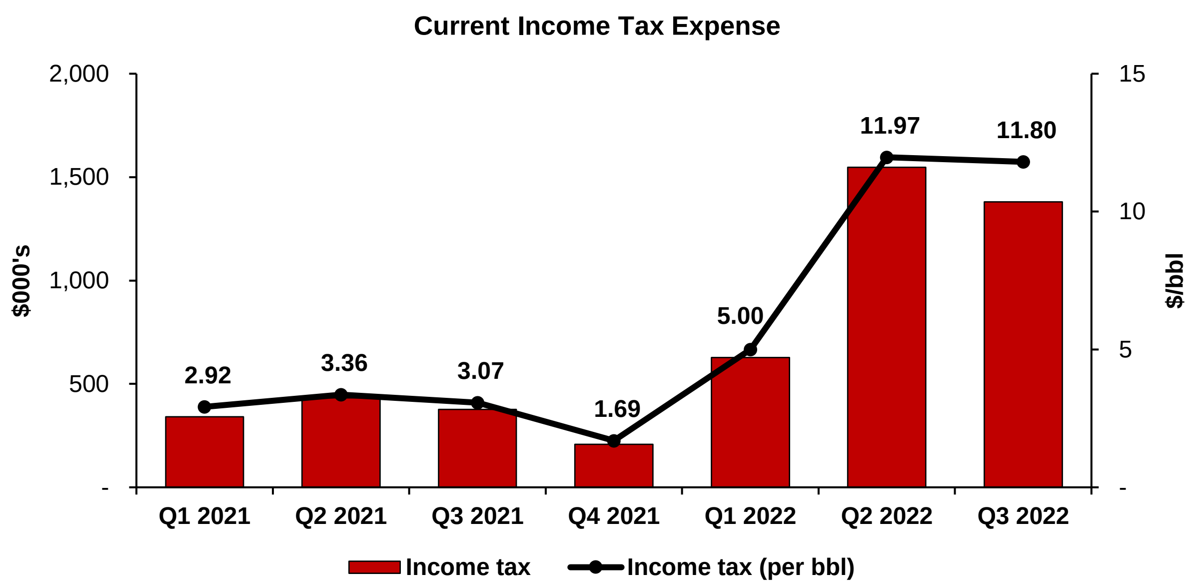
Our Trinidad oilfield service subsidiary, which primarily leases oilfield service equipment to third-party contractors for use in our exploration and production subsidiaries, is subject to the greater of a 30 percent corporate income tax calculated on net taxable profits or a 0.6 percent business levy 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 bbl amounts)	Three months ended September 30, 2022	2021	% change	Nine months ended September 30, 2022	2021	% change
SPT	**1,173**	-	n/a	**2,443**	-	n/a
PPT	**122**	248	(51)	**702**	759	(8)
UL	**48**	99	(52)	**281**	303	(7)
Business levy	**6**	5	20	**21**	16	31
GFL	**32**	25	28	**109**	72	51
Current income tax expenses	**1,381**	377	100	**3,556**	1,150	100
Per bbl[(1)]	**11.80**	3.07	100	**9.56**	3.13	100

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

In the third quarter of 2022, we recognized $1,381,000 of current income tax expenses compared to $377,000 in the third quarter of 2021. On a year-to-date basis, we reported an aggregate $3,556,000 in current income tax expenses in 2022 versus $1,150,000 in the prior year comparative period. 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 2022.



During the three and nine months ended September 30, 2022, we recognized a deferred income tax recovery of $271,000 and an aggregate deferred income tax expense of $265,000, respectively (2021 – expenses of $88,000 and $237,000). Our $14,844,000 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 tax bases as at September 30, 2022 (December 31, 2021 - $14,450,000). The deferred income tax balance remained in a liability position mainly from the discrepancy between the carrying values and the tax values of the Company's petroleum assets included in PP&E.

Further information regarding our current and deferred income taxes is included in Note 9 "*Income Taxes*" of our interim 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 September 30,**		% change	**Nine months ended September 30,**		% change
	2022	2021		**2022**	2021	
Licence financial obligations	**176**	175	1	**519**	775	(33)
Geological and seismic	**-**	775	(100)	**-**	2,438	(100)
Drilling, completions and well testing	**288**	5,946	(95)	**1,310**	12,232	(89)
Equipment and facilities	**1,667**	237	100	**4,328**	700	100
Capitalized G&A	**180**	169	7	**498**	555	(10)
Other	**381**	240	59	**843**	460	83
E&E asset expenditures	**2,692**	7,542	(64)	**7,498**	17,160	(56)

During the three and nine months ended September 30, 2022, we invested $2,692,000 and $7,498,000 in E&E assets, respectively. The investments primarily focused on facility and pipeline expenditures related to the Coho-1 natural gas facility, investments for the Cascadura natural gas and liquids facility and Royston-1 production testing operations completed in the first quarter of 2022.

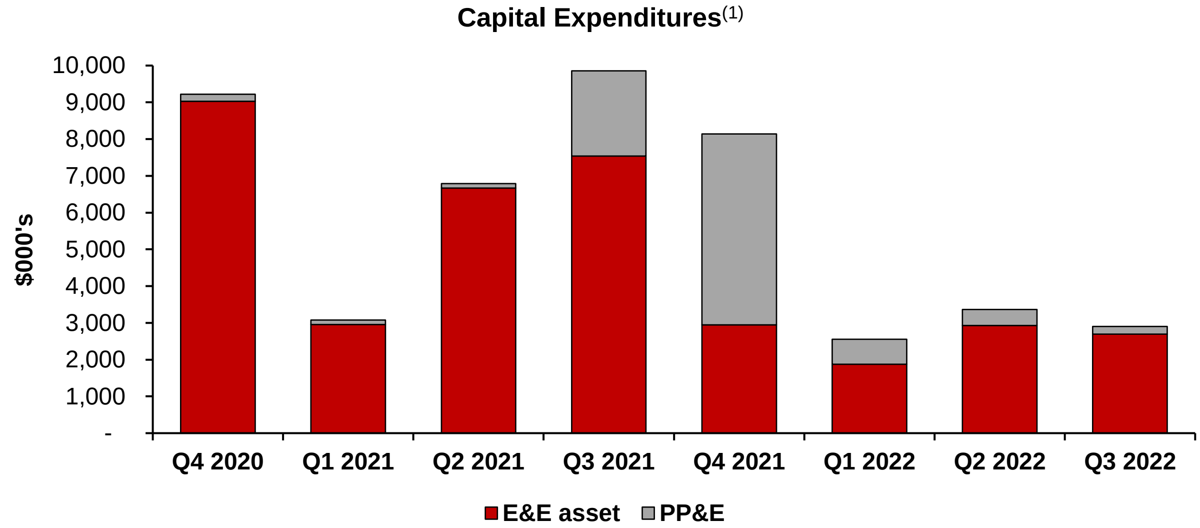
Third quarter and year to date 2021 Ortoire exploration expenditures were $7,542,000 and $17,160,000 respectively. We invested in drilling and road construction expenditures relating to the Royston-1 well in the third quarter of 2021 and conducted Cascadura Deep-1 and Chinook-1 well testing operations during the September 30, 2021 year to date period. Further capital investments were directed toward the Coho-1 pipeline and production facility and the Royston area seismic program that was completed in July 2021.

PP&E expenditures

($000's)	**Three months ended September 30,**		% change	**Nine months ended September 30,**		% change
	2022	2021		**2022**	2021	
Drilling and completions	**110**	2,197	(95)	**1,008**	2,293	(56)
Capitalized G&A	**74**	76	(3)	**233**	221	5
Corporate and other	**23**	42	(45)	**82**	53	55
PP&E expenditures	**207**	2,315	(91)	**1,323**	2,567	(48)

Third quarter and year to date 2022 PP&E expenditures were $207,000 and $1,323,000, 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 Coora-1 drilling locations.

For the three and nine months ended September 30, 2021, PP&E expenditures were $2,315,000 and $2,567,000, respectively. Third quarter 2021 drilling and completion expenditures were related to capitalized drilling rig mobilization fees and inventory purchases for the Company's three well drilling program completed in the fourth quarter of 2021.



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

PP&E 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 nine months ended September 30, 2022. The Palo Seco disposition remains subject to standard regulatory approvals.

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 or reclaim a property, the time frame in which such costs will be incurred, historical well production and annual inflation factors.

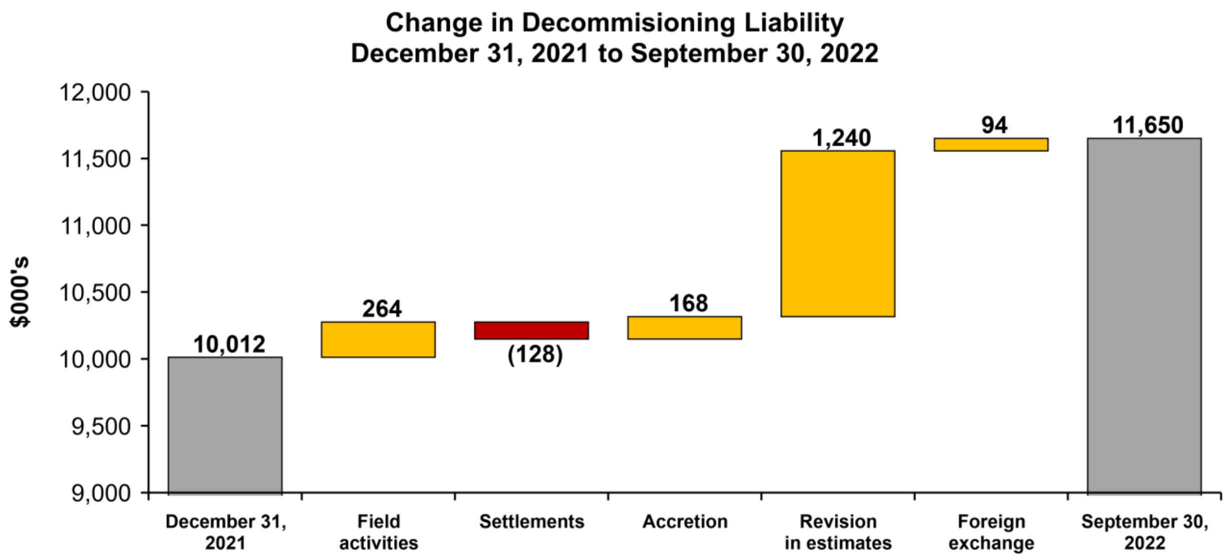
Pursuant to production and exploration licences with the MEEI, we are obligated to remit $0.25 per barrel sold into an escrow account in the name of the MEEI. The payments are used as a contingency fund for remediation of pollution arising from petroleum operations conducted under the relevant licence 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 statements of financial position 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 statements of financial position.

As of September 30, 2022, we reported $1,374,000 of accrued or paid contributions into MEEI and Heritage abandonment funds as long-term abandonment fund assets (December 31, 2021 - $1,278,000). At September 30, 2022, our estimated decommissioning liability balance was $11,650,000 compared to $10,012,000 at December 31, 2021. The increase in the decommissioning liability was primarily attributed to an increase in the estimated long-term inflation rate from 1.6 percent as of December 31, 2021 to 2.7 percent at September 30, 2022. Further, $48,000 and $168,000 of accretion expenses were recognized during the three and nine months ended September 30, 2022 to reflect the increase in decommissioning liabilities associated with the passage of time, respectively (2021 - $66,000 and $206,000).

Decommissioning liability details as of September 30, 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	9.8	14,301	18,265	11,650



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 8 "*Decommissioning Liabilities*" of our interim 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 September 30, 2022, our aggregate finance lease receivable balance was $613,000, of which $516,000 was included in long-term other assets on the consolidated statement of financial position (December 31, 2021 - $738,000 and $647,000, respectively).

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.

As at September 30, 2022, we had a cash balance of $8,732,000, a working capital deficit of $4,537,000 and $28,500,000 drawn on our term credit facility. The following table summarizes our changes in cash for the periods specified.

($000's)	**Three months ended September 30,**		% change	**Nine months ended September 30,**		% change
	2022	2021		**2022**	2021	
Net cash from (used in):						
Operating activities	**3,092**	384	100	**6,941**	158	100
Investing activities	**(2,090)**	(6,633)	(68)	**(14,742)**	(19,448)	(24)
Financing activities	**(1,856)**	(54)	100	**(1,662)**	78	n/a
Change in cash	**(854)**	(6,303)	(86)	**(9,463)**	(19,212)	(51)
Cash, beginning of period	**9,425**	11,214		**17,936**	24,281	
Impact of FX on cash balances	**161**	93	73	**259**	(65)	n/a
Cash, end of period	**8,732**	5,004	75	**8,732**	5,004	75

Our change in cash balances in the third quarter and year to date September 30, 2022 has decreased in comparison to the corresponding prior year periods, primarily based on increases in cash generated from operating activities and reductions in cash used in investing activities, partially offset by cash used in financing activities as we repaid $1.5 million of our term loan principal balance in September 2022. Current year cash and working capital balances have declined, and net debt has increased from 2021 as we invested in our Coho pipeline and natural gas facility which came online in October 2022 and continued to proceed to invest in our Cascadura natural gas and liquids facility in anticipation of future production.

Our near-term development plan is strategically balanced between maintaining base crude oil production levels, bringing our Cascadura natural gas and associated liquids discovery onstream and investing in future Ortoire exploratory and development 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.

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 total managed capital ratio. Our strategy is to utilize more equity than debt, thereby targeting net debt to total 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**	**September 30, 2022**	December 31, 2021
Current assets		**(17,489)**	(27,856)
Current liabilities		**22,026**	20,931
Working capital deficit (surplus)(1)		**4,537**	(6,925)
Principal long-term balance of term loan		**22,500**	27,000
Net debt(1)		**27,037**	20,075
Shareholders' equity		**67,582**	67,558
Managed capital(1)		**94,619**	87,633
Trailing twelve-month funds flow from operations(2)		**4,140**	4,107
Net debt to funds flow from operations ratio(1)	**at or < 2.0 times**	**6.53**	4.89
Net debt to managed capital ratio(1)	**< 0.4 times**	**0.29**	0.23

Notes:
(1) Non-GAAP financial measure. See the "*Non-GAAP Financial Measures*" advisory section of this MD&A for further information.
(2) Trailing twelve-month funds flow from operations as at September 30, 2022 includes the sum of funds flow from operations for the nine months ended September 30, 2022 and the October 1 through December 31, 2021 interim period.

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 the fourth quarter of 2022 as our Coho-1 well is currently onstream, and we forecast to achieve and 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, September 30, 2022 and December 31, 2021.

	November 9, 2022	**September 30, 2022**	December 31, 2021
Common shares outstanding	**213,112,826**	**213,112,826**	210,731,727
Share options outstanding	**11,928,435**	**11,847,435**	11,233,334
Fully diluted common shares	**225,041,261**	**224,960,261**	221,965,061

Further information regarding our shareholders' capital and equity-based compensation plan is included in "*Results of Operations - Equity-based awards*" herein and in Note 10 "*Shareholders' Capital*" of our interim 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 twelve 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 (the "Retired 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.

We made our first quarterly principal payment of $1.5 million on September 15, 2022. Nineteen equal and consecutive quarterly principal payments of $1.5 million remain 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, Primera Oil and Gas Limited. The agreement contains industry standard representations and warranties, undertakings, events of default, and financial covenants, which will be tested on an annual basis commencing with the year ended December 31, 2022.

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 of September 30, 2022, the term loan balance was $28,453,000 of which $6,000,000 was classified as current on the consolidated statement of financial position (December 31, 2021 - $29,896,000 and $3,000,000 respectively).

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 $1,079,000 of cash as long-term restricted as at September 30, 2022 (December 31, 2021 - $1,178,000).

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.

Other liabilities

Lease liabilities

The Company is a party to lease arrangements for a drilling rig, office space and office equipment. As of September 30, 2022, we recognized $2,264,000 in aggregate lease liabilities on our consolidated statement of financial position, of which $1,355,000 was classified as long-term (December 31, 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, with the Company recognizing a $2,479,000 lease liability and associated ROU asset. During the initial year of the contract, we used the drilling rig for 56 days, which resulted in an aggregate $472,000 standby payment to the counterparty in August and September 2022.

Production liability

In connection with the Retired Term Loan, we granted our former lender a production payment equal to 1.33 percent of petroleum sales from Trinidad land holdings, payable quarterly through October 31, 2023. Upon repayment of the Retired Term Loan, the parties entered into an amended production payment agreement to continue the obligation under its previous terms and conditions.

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 and nine months ended September 30, 2022, we recognized losses of $20,000 and $139,000 on revaluation of the liability predominately from the strengthening of strip crude oil pricing from December 31, 2021, respectively (2021 - losses of $5,000 and $135,000). At September 30, 2022, our estimated production liability balance was $832,000, of which $344,000 was classified as long-term and included in other liabilities on the consolidated statement of financial position (December 31, 2021 - $1,211,000 and $908,000, respectively).

Contractual Obligations and Commitments

We have 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 September 30, 2022.

($000's)		**Estimated payments due by year**			
	Total	**2022**	**2023**	**2024**	**Thereafter**
Operating agreement commitments					
Coora blocks	**13,927**	4,875	92	2,733	6,227
WD-4 block	**4,821**	10	42	1,401	3,368
WD-8 block	**4,825**	9	75	1,398	3,343
Fyzabad block	**834**	27	76	78	653
Cory Moruga exploration block	**1,224**	25	99	105	995
Ortoire exploration block	**24,474**	130	6,947	7,276	10,121
Office and equipment leases	**848**	113	423	94	218
Minimum payments	**50,953**	**5,189**	**7,754**	**13,085**	**24,925**

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 2022. The Company has notified Heritage its intent to defer the development drilling commitments to 2023.

As of December 31, 2021, we completed all of our minimum work commitment obligations pursuant to our Ortoire block exploration and production licence. In March 2022, we were notified that the Trinidad government approved an extension to the exploration period of the licence to July 31, 2026. The licence amendment has been approved by the Trinidad and Tobago government and is awaiting formal execution. Upon execution, we will be required to drill three exploration wells prior to the end of the amended term which are included in the table above.

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 production. Commodity prices have fluctuated widely in recent years due to global and regional factors including supply and demand fundamentals, the novel coronavirus ("COVID-19") pandemic, the Russia-Ukraine 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. Consequently, any changes in crude oil pricing could affect our cash flow from operations, the value of our properties, the level of capital expenditures and our ability to meet financial obligations as they come due.

In addition, we entered into a long-term fixed price natural gas sales agreement in 2020 with NGC, which contains options for price negotiations on each fifth anniversary of the initial 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 future natural gas sales prices will result in a reduction of the Company's cash flow from operations and financial position.

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

We had no commodity financial contracts in place as of the date hereof or during the three and nine months ended September 30, 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.

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. As we primarily operate in Trinidad, fluctuations in the exchange rate between the TT$ and the US$ could have a significant effect on financial results. Although the sales prices of crude oil are determined by reference to US$ denominated benchmark prices, the majority of the invoices for such sales are paid in TT$, exposing the Company to foreign exchange risk. To mitigate this risk, we attempt to match revenues received in TT$ by entering into contracts denominated and payable in TT$ when possible. We also attempt to limit our exposure to foreign currency risk through collecting and paying foreign currency denominated balances in a timely fashion. In addition, we have US$ denominated debt and related interest payments. These risks are mitigated by the fact that the TT$ is informally pegged to the US$. Touchstone does not hedge its foreign currency risk.

Touchstone has further foreign exchange exposure on cash balances denominated in Canadian dollars and pounds sterling, on head office costs and our production liability denominated in Canadian dollars, 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 also have a material effect on our reporting results (refer to "*Results of Operations - Foreign exchange and foreign currency translation*").

Credit risk

Credit risk is the risk of a counterparty failing to meet its obligations in accordance with the agreed upon 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 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 $1,508,000 as of September 30, 2022, as we collected approximately $3,952,000 in past due amounts in 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 aging of our accounts receivable is disclosed in the following table for the specified periods.

($000's)	**September 30, 2022**	December 31, 2021
Not past due	**3,636**	3,181
Past due (greater than 90 days)	**2,857**	4,365
Accounts receivable	**6,493**	7,546

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 "*Finance Leases*"). Further details relating to our financial assets and credit risk can be found in Note 3 "*Financial Assets and Credit Risk*" of our interim 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 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 September 30, 2022.

($000's)	**Recognized in financial statements**	**Undiscounted cash outflows**	**Financial maturity by period**		
			Less than 1 year	**1 to 3 years**	**Thereafter**
Accounts payable and accrued liabilities	Yes – liability	**10,791**	10,791	-	-
Income taxes payable	Yes – liability	**2,164**	2,164	-	-
Lease liabilities	Yes – liability	**2,641**	1,102	1,178	361
Term loan principal	Yes – liability	**28,500**	6,000	12,000	10,500
Term loan interest	No – recognized as incurred	**5,500**	2,041	2,669	790
Production liability	Yes – liability	**1,213**	694	519	-
Financial liabilities		**50,809**	**22,792**	**16,366**	**11,651**

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.

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 "*Contractual Obligations and Commitments*" herein.

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 and nine months ended September 30, 2022, $51,000 and $115,000 in legal fees and disbursements charged by Norton Rose Fulbright Canada LLP were incurred, respectively (2021 - $4,000 and $47,000). $49,000 was included in accounts payable and accrued liabilities as at September 30, 2022 (2021 - $4,000).

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 and nine months ended September 30, 2022, $12,000 and $20,000 in products were purchased, respectively (2021 - $3,000 and $10,000). As at September 30, 2022, $12,000 was included in accounts payable and accrued liabilities (2021 - $3,000).

Changes in Accounting Policies Including Initial Adoption

There were no changes in accounting policies during the three and nine months ended September 30, 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.

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.

The COVID-19 pandemic and subsequent measures intended to limit the outbreak contributed to significant declines and volatility in global financial markets. Although health measures have eased which positively impacted both demand for oil and benchmark commodity pricing, the timing of a full economic recovery remains uncertain, partially as a result of a possible rise in variants of the virus. In addition, the Russia-Ukraine conflict has raised global concerns over oil and natural gas supply and significantly increased benchmark commodity prices and inflationary pressures on global markets. Crude oil demand and improved benchmark pricing have remained strong in 2022, but the potential for volatility remains amid ongoing inflation and recessionary fears. To the extent known, Management has incorporated the impacts of COVID-19 and the resulting economic recovery as well as implications from the Russia-Ukraine conflict in its estimates and assumptions as of September 30, 2022.

A full list of the significant estimates and judgements made by Management in the preparation of our interim financial statements and our audited 2021 financial statements is included in Note 4 "*Use of Estimates, Judgements and Assumptions*" of our audited 2021 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.

Control Environment

Touchstone is required to comply with National Instrument 52-109 - *Certification of Disclosure in Issuers' Annual and Interim Filings*. The certification of interim filings for the interim period ended September 30, 2022 requires that Touchstone discloses in the interim MD&A any changes in the Company's internal controls over financial reporting that occurred during the period that have materially affected, or were reasonably likely to materially affect, Touchstone's internal controls over financial reporting. Touchstone confirms that no such changes were identified in the Company's internal controls over financial reporting during the period beginning on July 1, 2022 and ending on September 30, 2022.

Business Risks

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.

Please refer to our 2021 Annual Information Form dated March 25, 2022 for a full understanding of risks that affect Touchstone, which can be found on our SEDAR profile (www.sedar.com) and website (www.touchstoneexploration.com). Refer to the "*Forward-Looking Statements*" advisory section in this MD&A for additional information regarding the risks to which Touchstone and our business operations are subject to.

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	Sept. 30, 2022	June 30, 2022	March 31, 2022	Dec. 31, 2021	Sept. 30, 2021	June 30, 2021	March 31, 2021	Dec. 31, 2020
Operational								
Average daily production *(bbls/d)*	1,272	1,420	1,396	1,336	1,333	1,411	1,297	1,274
Net wells drilled	-	-	-	3.0	0.8	-	-	1.6
Realized commodity price[(1)] *($/bbl)*	84.85	97.48	83.55	66.81	62.37	59.06	52.43	37.66
Operating netback[(1)] *($/bbl)*	37.55	44.99	37.83	29.96	27.77	26.30	21.98	13.90
Financial *($000's except per share amounts)*								
Petroleum sales	9,933	12,596	10,496	8,212	7,650	7,586	6,120	4,414
Cash from (used in) operating activities	3,092	3,516	333	1,388	384	1,008	(1,234)	167
Funds flow from (used in) operations	290	1,133	1,426	1,291	1,073	1,205	538	(736)
Net (loss) earnings	(778)	(262)	(236)	6,514	(51)	(284)	(460)	1,655
Per share – basic and diluted	(0.00)	(0.00)	(0.00)	0.03	(0.00)	(0.00)	(0.00)	0.01
E&E asset expenditures	2,692	2,932	1,874	2,946	7,542	6,664	2,954	9,031
PP&E expenditures	207	436	680	5,190	2,315	125	127	186
Capital expenditures[(1)]	2,899	3,368	2,554	8,136	9,857	6,789	3,081	9,217
Working capital deficit (surplus)[(1)]	4,537	(346)	(4,259)	(6,925)	4,657	(4,671)	(10,552)	(12,933)
Principal long-term bank loan	22,500	24,000	25,500	27,000	7,125	7,500	7,500	7,500
Net debt (surplus)[(1)] – end of period	27,037	23,654	21,241	20,075	11,782	2,829	(3,052)	(5,433)

Three months ended	Sept. 30, 2022	June 30, 2022	March 31, 2022	Dec. 31, 2021	Sept. 30, 2021	June 30, 2021	March 31, 2021	Dec. 31, 2020
Share Information *(000's)*								
Weighted average – basic	212,647	212,204	210,823	210,732	210,732	209,757	209,400	197,686
Weighted average – diluted	212,647	212,204	210,823	218,102	210,732	209,757	209,400	206,072
Outstanding shares – end of period	213,113	212,275	211,164	210,732	210,732	210,732	209,400	209,400

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

The oil and natural gas exploration and production 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 also 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 flow generated from operations and access to capital markets.

The following significant items impacted our unaudited financial and operating results over the past eight fiscal quarters:

- 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.

- Touchstone completed a private placement that resulted in net proceeds of $28.4 million in the fourth quarter of 2020. As a result, we prepaid $7.5 million of our term loan balance and increased E&E asset capital expenditures in the quarter, ending the quarter with a net surplus of $5.4 million. Predominately based on increased crude oil future pricing, net impairment reversals of $7.8 million were recorded. The impairment reversals, which were partially offset by related $3.9 million deferred income tax expenses, contributed to the Company recognizing net earnings of $1.7 million in the quarter.

Advisory

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 sales. Operating netback per barrel is a non-GAAP ratio calculated by dividing the operating netback by total production volumes for the period. 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.

($000's unless otherwise stated)	**Three months ended September 30,**		**Nine months ended September 30,**	
	2022	2021	**2022**	2021
Petroleum sales	**9,933**	7,650	**33,025**	21,356
Royalties	**(3,411)**	(2,375)	**(11,516)**	(6,528)
Operating expenses	**(2,126)**	(1,869)	**(6,547)**	(5,479)
Operating netback	**4,396**	3,406	**14,962**	9,349
Production *(bbls)*	**117,059**	122,649	**371,896**	367,824
Operating netback *($/bbl)*	**37.55**	27.77	**40.23**	25.41

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 flows 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 September 30,**		**Nine months ended September 30,**	
	2022	2021	**2022**	2021
E&E asset expenditures	**2,692**	7,542	**7,498**	17,160
PP&E expenditures	**207**	2,315	**1,323**	2,567
Capital expenditures	**2,899**	9,857	**8,821**	19,727

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 as current assets minus current liabilities as they appear on the consolidated statements of financial position. 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)	**September 30, 2022**	December 31, 2021	September 30, 2021
Current assets	**(17,489)**	(27,856)	(14,097)
Current liabilities	**22,026**	20,931	18,754
Working capital deficit (surplus)	**4,537**	(6,925)	4,657
Principal long-term balance of term loan	**22,500**	27,000	7,125
Net debt	**27,037**	20,075	11,782

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

($000's)	**September 30, 2022**	December 31, 2021	September 30, 2021
Total liabilities	**72,672**	75,462	44,340
Lease liabilities	**(1,355)**	(2,265)	(294)
Other liabilities	**(344)**	(908)	(1,111)
Decommissioning liabilities	**(11,650)**	(10,012)	(10,105)
Deferred income tax liability	**(14,844)**	(14,450)	(7,224)
Variance of carrying value and principal value of term loan	**47**	104	273
Current assets	**(17,489)**	(27,856)	(14,097)
Net debt	**27,037**	20,075	11,782

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 barrel - is comprised of petroleum sales as determined in accordance with IFRS, divided by the Company's total production volumes for the period.

Royalties per barrel - 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 sales - is comprised of royalties as determined in accordance with IFRS, divided by petroleum sales as determined in accordance with IFRS.

Operating expenses per barrel - 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 barrel - 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 barrel - 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 barrel - 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 barrel - 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 barrel - 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:

- the Company's business and operational strategies, including targeted jurisdictions and technologies used to execute its strategies;
- financial condition and outlook and results of operations, including expectations of future growth;
- future demand for the Company's petroleum and natural gas products and economic activity in general;
- the Company's future capital expenditure programs, including the anticipated timing of completion, allocation and costs thereof and the method of funding;
- the Company's estimated timing of development, ultimate production and production rates from its Ortoire wells;
- current and future crude oil, natural gas and NGL production levels and estimated field production levels;
- the performance characteristics of the Company's oil and natural gas properties;
- expectations regarding the ability of the Company to raise capital and to continually add to reserves through exploration, acquisitions and development;
- 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;
- the Company's expectations regarding its 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 amendments;
- access to third-party facilities and infrastructure;
- expected levels of 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;

- the Company's risk management strategy and the future use of commodity derivatives to manage commodity price risk;
- the Company's foreign currency risk strategy and the ability to reverse unrealized foreign exchange gains and losses in the future;
- the Company's credit risk assumptions and the Company's expectation to receive past due VAT amounts from the Trinidad government;
- the Company's future liquidity and future sources of liquidity and its expectation to settle all current and future financial liabilities;
- the Company's future compliance with its 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, including receiving regulatory approvals related thereto;
- 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 Company making an insurance claim related to reclamation costs incurred from the oil spill and its future ability to receive potential funds therefrom;
- 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 crude oil 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, 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 net earnings (loss), as further information becomes available and as the economic environment or other factors change.

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

Under National Instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities*, disclosure of production volumes should include segmentation by product type as defined in the instrument. In this MD&A, references to "crude oil" refer to "light crude oil and medium crude oil" and "heavy crude oil" product types. The Company's reported crude oil production is a mix of light and medium crude oil and heavy crude oil for which there is not a precise breakdown given Touchstone's oil sales volumes typically represent blends of more than one type of crude oil. In this MD&A, references to "natural gas" mean "conventional natural gas" as defined in the instrument.

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 2021 financial statements and our 2021 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

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Priya Marajh
Kenneth R. McKinnon
Peter Nicol
Beverley Smith
Stanley T. Smith
Harrie Vredenburg

Officers and Senior Executives
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President and Chief Executive Officer

Scott Budau
Chief Financial Officer

James Shipka
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