TransGlobe Energy
CORPORATION

TSX & AIM: TGL; NASDAQ: TGA
www.trans-globe.com

2020 ANNUAL REPORT

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MESSAGE TO THE SHAREHOLDERS

TransGlobe and the industry experienced a year of extreme volatility, requiring the Company to take thoughtful action to mitigate the pandemic-caused impact to oil demand and the subsequent deleterious effect to the Company, and further exacerbated by oil oversupply from the breakdown in OPEC+. While managing our balance sheet and preserving cash were key priorities in 2020, strategic focus was still dedicated towards value creation for the Company's shareholders. Securing approval for our Eastern Desert consolidation project was a key milestone achieved in 2020 and enables a project pipeline of Egypt cashflow accretive investments as the market recovers.

During the year, the Company repaid $15 million of the amount outstanding under its prepayment agreement with Mercuria, leaving $15.0 million outstanding at year end. The Company also repaid $1.5 million of the reserves-based lending facility with ATB Financial ("ATB"), leaving $6.6 million drawn at year end. The Company continues to be conservative with its debt structure, balancing working capital considerations against debt service costs and intends to continue that conservative approach into 2021. With the Mercuria agreement maturing in Q3'21 the Company is working to amend and extend the agreement to provide greater flexibility in its capital allocation decisions.

TransGlobe produced an average of 13,425 boe/d in 2020 and 12,384 boe/d during the fourth quarter. Egypt production was 11,147 bbls/d in 2020 (Q4-2020 – 10,268 bbls/d) and Canada production was 2,278 boe/d (Q4-2020 - 2,116 boe/d). Annual production was within our adjusted 2020 full-year guidance (13,300 - 13,800 boe/d). Corporate production increased by 2% in Q4-2020 over the previous quarter due to the completion of well interventions in Egypt, partially offset by a two week shut-in of certain wells in Canada due to repairs on a third-party pipeline. Production was down from the previous year due to a reduced capital program and deferred well interventions in Egypt, a consequence of the decisive action taken by management in the spring of 2020 in response to the sudden collapse of demand and impact to commodity prices due to worldwide government action to lock down economies in the face of the COVID-19 pandemic.

TransGlobe recorded a net loss of $77.4 million in 2020 compared to a net loss of $4.0 million in 2019. The net loss was inclusive of a non-cash impairment loss of $40.0 million on the Company's petroleum and natural gas ("PNG") assets and a non-cash impairment loss of $33.5 million on the Company's exploration and evaluation ("E&E") assets. The net loss was also inclusive of a $0.2 million unrealized derivative loss on commodity contracts (fair value adjustment on the Company's hedging contracts). Before impairment and the unrealized loss on derivative commodity contracts, TransGlobe had a net loss of $3.7 million for 2020.

The Company generated funds flow from operations of $30.4 million (2019 - $46.9 million) in 2020, $0.42 per share (2019 - $0.64 per share). We ended 2020 with positive working capital of $15.3 million (2019 - $32.2 million), including cash and cash equivalents of $34.5 million. The decrease in funds flow from operations is primarily due to lower commodity prices in 2020.

Health, Safety and the Environment were primary focus areas for the Company in 2020 as we continued to operate safely in both Egypt and Canada, successfully navigating the challenges presented by producing in an abnormal operating environment of reduced staffing and numerous work from home orders. Business continuity plans were successfully implemented in all our locations at the onset of the pandemic, and operations were able to continue as normal while following established Company, local and national COVID-19 protocols.

In early 2020, the Company implemented an 80% reduction to its 2020 capital program to focus only on those investments that were critical to HSE and value preservation during the low commodity price environment.

In Canada, the program consisted of one horizontal (multi-stage stimulated) well targeting the Cardium light oil resource in South Harmattan (the 100/13-16-029-03W5/0 well). Drilling commenced prior to the capital program reductions, however the well was not completed in 2020 in order to preserve the economic value of flush production that results from the initial phase of production from a horizontal well. Preparations have commenced to stimulate and equip this well in Q1-2021. This well offsets the successful 2-mile horizontal oil well 2-20 which has been producing continuously since the original tie-in in late November of 2019, other than for maintenance conducted on third-party facilities. This long-term production performance has further strengthened the Company's confidence in the potential of its South Harmattan acreage.

In Egypt, the Company drilled the HW-2A development oil well in the Eastern Desert at West Bakr at the beginning of the year before cutting all capital in the spring in response to the pandemic. During the fourth quarter, the Company resumed a reduced investment program where cash flow accretive well repair and maintenance activities were restarted while approvals to amend, extend and consolidate the Company's Eastern Desert concession agreements were obtained.

2P reserves at year end 2020 were down by 14% from 2019. The 5.7 MMboe of negative revisions for economic factors was due to a decrease in commodity price forecasts at year end 2020 compared to 2019. The majority of the economic revisions occurred in Canada on the liquids rich Ellerslie gas wells, where the liquids pricing was significantly lower year over year. 2P reserves were also reduced by 4.9 MMboe of production. This was only partially offset by 2.3 MMboe of positive technical revisions and 1.9 MMboe of extensions and improved recovery due to the curtailed capital program. The positive technical revisions were driven by improved production performance in Canada, while the extensions and improved recovery increases were related to the West Bakr field in the Eastern Desert of Egypt.

The Company decreased its inventoried crude oil as Egypt sales of 13,160 bbls/d exceeded production of 11,147 bbls/d in the year. TransGlobe ended 2020 with 227.9 Mbbls of inventoried entitlement crude oil (2019 - 964.5 Mbbls), which is ~1.5 months of entitlement crude oil production. The Company completed two direct crude sale shipments to third-parties through Mercuria Energy Trading S.A. ("Mercuria") and had direct sales of inventoried entitlement crude oil totaling 1,602.1 Mbbls to the Egyptian General Petroleum Company ("EGPC") during 2020. An additional 167.0 Mbbls of inventoried entitlement crude oil has been sold to EGPC in 2021 and the Company is scheduled to lift a cargo in Q2-2021.

In 2020, the Company undertook a significant analysis of operating costs in Canada and Egypt in order to identify all possible optimization opportunities to balance the reduction in capital investment. Overall operating expenses increased by approximately 65% to $12.43 per sold boe during 2020 (2019 - $7.52 per sold boe). This increase in operating expenses per sold boe was primarily due to higher manpower costs in Egypt as well as operating expenses related to the South Ghazalat concession which began operating in 2020, partially offset by a decrease in workovers and production handling fees in Egypt and overall lower operating expenses in Canada. Unit operating cost reductions in Egypt will continue to be a focus for TransGlobe in 2021.

The Company significantly reduced G&A costs by ~35% on an annualized basis through headcount reduction, universal salary rollbacks and reducing all discretionary expenditures. Gross G&A costs were $11.9 million in 2020 (2019 - $15.8 million), representing a 25% decrease from prior year.

Gross G&A per produced barrel decreased to $2.42 per boe from $2.70 per boe in 2019.

After a lengthy and constructive negotiation, TransGlobe announced a merged concession agreement with a 15-year primary term and improved Company economics in early December 2020. Ratification of the concession is anticipated in Q2-2021, and the February 1, 2020 effective date supports increased investment in advance of ratification.

The Company believes that it has arrived at a win-win amendment for both TransGlobe and EGPC. The efficiencies gained from the consolidation of TransGlobe's Eastern Desert concessions, along with the improved netbacks and extended term, are expected to provide the Company with the fiscal incentive and time to unlock meaningful additional reserves and production through the application of modern technology and optimization of infrastructure. This will also allow the Company to move forward with important ESG initiatives to improve its environmental footprint as well as continue to be a major employer in the Ras Gharib region for the foreseeable future.

TransGlobe intends to continue to manage the finances of the Company with a conservative approach and it is expected that, under a reasonable range of oil prices, the Company will be able to fund the equalization payments and a continuous capital investment program from existing resources and cash flows. In addition, as soon as practicable, direct returns to shareholders will be prioritized.

This Agreement is a critical first step in achieving TransGlobe's stated goal of becoming a leading independent Middle East/North Africa region cashflow-focused energy producer.

TransGlobe appreciates the commitment and vision of the leadership team at EGPC to extending the life of these mature oil fields and the Company looks forward to working closely with EGPC to realize the significant mutual benefits of this Merged Concession. In the immediate future TransGlobe will begin to plan for increased activities that should, in the near to medium term, arrest and reverse recent production declines.

Signed by:

"Randy C. Neely"

Randy C. Neely
President and Chief Executive Officer
March 12, 2021

FINANCIAL AND OPERATING RESULTS

(US$000s, except per share, price, volume amounts and % change)

	Three Months Ended December 31			Years Ended December 31		
Financial	**2020**	2019	% Change	**2020**	2019	% Change
Petroleum and natural gas sales	**50,989**	64,201	(21)	**188,771**	278,929	(32)
Petroleum and natural gas sales, net of royalties	**33,309**	28,473	17	**114,675**	140,096	(18)
Realized derivative (loss) gain on commodity contracts	**(6)**	(218)	97	**6,801**	(1,259)	640
Unrealized derivative loss on commodity contracts	**(941)**	(1,201)	(22)	**(180)**	(1,586)	89
Production and operating expense	**19,326**	15,119	28	**64,462**	50,626	27
Selling costs	**1,008**	638	58	**2,111**	1,287	64
General and administrative expense	**3,593**	3,868	(7)	**11,990**	16,611	(28)
Depletion, depreciation and amortization expense	**7,647**	8,764	(13)	**31,049**	34,948	(11)
Income tax expense	**3,408**	6,003	(43)	**13,530**	26,098	(48)
Cash flow generated by operating activities	**14,180**	23,740	(40)	**31,709**	44,836	(29)
Funds flow from operations[1]	**7,202**	3,171	127	**30,443**	46,871	(35)
Basic per share	**0.10**	0.04		**0.42**	0.65	
Diluted per share	**0.10**	0.04		**0.42**	0.65	
Net loss	**(2,855)**	(8,202)	(65)	**(77,397)**	(3,995)	1,837
Basic per share	**(0.04)**	(0.11)		**(1.07)**	(0.06)	
Diluted per share	**(0.04)**	(0.11)		**(1.07)**	(0.06)	
Capital expenditures	**255**	10,996	(98)	**7,498**	36,932	(80)
Dividends declared	**-**	-	-	**-**	5,078	(100)
Dividends declared per share	**-**	-		**-**	0.07	
Working capital	**15,349**	32,194	(52)	**15,349**	32,194	(52)
Long-term debt, including current portion	**21,464**	37,041	(42)	**21,464**	37,041	(42)
Common shares outstanding						
Basic (weighted average)	**72,542**	72,542	-	**72,542**	72,514	-
Diluted (weighted average)	**72,542**	72,542	-	**72,542**	72,514	-
Total assets	**201,147**	308,325	(35)	**201,147**	308,325	(35)
Operating						
Average production volumes (boe/d)	**12,384**	15,362	(19)	**13,425**	16,041	(16)
Average sales volumes (boe/d)	**15,712**	14,688	7	**15,437**	14,954	3
Inventory (Mbbls)	**227.9**	964.5	(76)	**227.9**	964.5	(76)
Average realized sales price ($/boe)	**35.27**	47.51	(26)	**33.41**	51.10	(35)
Production and operating expenses ($/boe)	**13.37**	11.19	19	**11.41**	9.28	23

[1] Funds flow from operations is a measure that represents cash generated from operating activities before changes in non-cash working capital and may not be comparable to measures used by other companies.

FINDING AND DEVELOPMENT COSTS/FINDING, DEVELOPMENT AND NET ACQUISITION COSTS

F&D costs are calculated as the aggregate of exploration costs, development costs and the change in estimated future development costs divided by the applicable reserve additions. FD&A costs incorporate acquisitions, net of any dispositions during the year. The Company expects to fund the development costs of the reserves through a combination of cash flow from operations, debt capacity, proceeds from property dispositions and, if necessary, the issuance of Common Shares.

Changes in forecasted future development capital ("FDC") occur annually as a result of development activities, acquisition and disposition activities and capital cost estimates that reflect the independent evaluator’s best estimate of what it will cost to bring the proved plus probable undeveloped reserves on production at that time. Undiscounted FDC for proved plus probable undeveloped reserves decreased $39.3 million compared to year end 2019, to total $82.1 million at year end 2020. The decrease in FDC is attributable to undeveloped locations no longer being economic under the January 1 2021 pricing forecast. December 31, 2020 FDC, reserves estimates and future net revenues do not include the impact of the merger of the Company’s three existing Eastern Desert concessions into a new modernized concession agreement. The new agreement will be reflected in the reserves report upon ratification.

Estimates of reserves and future net revenues have been made assuming the development of each property will occur, without regard to the likelihood of us obtaining funding for the development. There can be no guarantee that funds will be available or that we will allocate funding to develop all of the reserves attributed in the reserves evaluator's report. Failure to develop those reserves would have a negative impact on future cash flow from operations.

Interest and other costs of external funding are not included in the reserves and future net revenue estimates. These costs would reduce reserves and future net revenues depending upon the funding sources utilized. TransGlobe does not anticipate that interest or other funding costs would make development of any property uneconomic.

Proved

($000s, except volumes and $/boe amounts)	Three-Year Weighted-Average	2020	2019	2018
Total capital expenditures		**7,498**	36,932	40,706
Net change from previous year's future capital		**4,124**	(5,625)	(10,612)
		11,622	31,307	30,094
Reserve additions and revisions (Mboe)				
Exploration and development[1]		**2,277**	4,382	4,629
Total reserve additions (Mboe)		**2,277**	4,382	4,629
Average cost per boe				
F&D[2]	**6.47**	**5.10**	7.15	6.50
FD&A[2]	**6.47**	**5.10**	7.15	6.50

[1] The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year.

[2] Neither F&D costs nor FD&A costs have any standardized meaning under IFRS and therefore may not be comparable to similar measures used by other companies.

Proved Plus Probable

($000s, except volumes and $/boe amounts)	Three-Year Weighted-Average[3]	2020	2019	2018
Total capital expenditure		**7,498**	36,932	40,706
Net change from previous year's future capital		**(39,313)**	10,040	(16,100)
		(31,815)	46,972	24,606
Reserve additions and revisions (Mboe)				
Exploration and development[1]		**(1,526)**	7,090	3,465
Total reserve additions (Mboe)		**(1,526)**	7,090	3,465
Average cost per boe				
F&D[2]	**4.40**	**20.85**	6.63	7.10
FD&A[2]	**4.40**	**20.85**	6.63	7.10

[1] The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year.

[2] Neither F&D costs nor FD&A costs have any standardized meaning under IFRS and therefore may not be comparable to similar measures used by other companies.

[3] Three-year weighted average is impacted by negative 2P net revisions in 2020 and negative net change from 2019's future capital.

RECYCLE RATIO

Proved

	Three-Year Weighted-Average	2020	2019	2018
Netback ($/boe)[1]	**7.82**	**5.05**	7.92	10.69
Proved F&D costs ($/boe)[2]	**6.47**	**5.10**	7.15	6.50
Proved FD&A costs ($/boe)[2]	**6.47**	**5.10**	7.15	6.50
F&D Recycle ratio[3]	**1.21**	**0.99**	1.11	1.64
FD&A Recycle ratio[3]	**1.21**	**0.99**	1.11	1.64

[1] For the purpose of calculating the recycle ratio, Netback is defined as net earnings (loss) adjusted for non-cash items per boe of sales - see "Recycle Netback Calculation" section.

[2] Neither F&D costs nor FD&A costs have any standardized meaning under IFRS and therefore may not be comparable to similar measures used by other companies.

[3] Recycle ratio does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures used by other companies.

Proved Plus Probable

	Three-Year Weighted-Average[4]	2020	2019	2018
Netback ($/boe)[1]	**7.82**	**5.05**	7.92	10.69
Proved plus Probable F&D costs ($/boe)[2]	**4.40**	**20.85**	6.63	7.10
Proved plus Probable FD&A costs ($/boe)[2]	**4.40**	**20.85**	6.63	7.10
F&D Recycle ratio[3]	**1.78**	**0.24**	1.20	1.51
FD&A Recycle ratio[3]	**1.78**	**0.24**	1.20	1.51

[1] For the purpose of calculating the recycle ratio, Netback is defined as net earnings (loss) adjusted for non-cash items per boe of sales - see "Recycle Netback Calculation" section.

[2] Neither F&D costs nor FD&A costs have any standardized meaning under IFRS and therefore may not be comparable to similar measures used by other companies.

[3] Recycle ratio does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures used by other companies.

[4] Three-year weighted average is impacted by negative 2P net revisions in 2020 and negative net change from 2019's future capital.

The 2020 recycle ratio is positive as a result of positive recycle ratio netbacks in the year. The positive netbacks were primarily the result of lower royalties and taxes in 2020, offset by lower realized prices, higher selling costs and higher production and operating expenses during the year, combined with the Company completing two direct crude sale shipments to Mercuria and consistent monthly sales of inventoried entitlement crude oil to EGPC for a total of 2,506.5 Mbbls during 2020. Annual sales in excess of production resulted in an overall decrease in inventoried crude oil by 736.6 Mbbls from 2019.

The recycle ratio is calculated by dividing the recycle netback by the proved and proved plus probable finding and development costs on a per boe basis.

Recycle Netback Calculation

For the purpose of calculating the recycle ratio, netback is defined as net earnings (loss) adjusted for non-cash items per boe of sales.

($000s, except volumes and per boe amounts)	**2020**	2019	2018
Net earnings (loss)	**(77,397)**	(3,995)	15,677
Adjustments for non-cash items:			
Depletion, depreciation and amortization	**31,049**	34,948	34,291
Asset retirement obligation accretion	**259**	215	270
Share-based compensation	**857**	2,237	3,536
Amortization of deferred financing costs	**395**	368	360
Interest on lease obligations	**211**	250	-
Deferred lease inducement	**-**	-	(90)
Unrealized foreign exchange gain	**(62)**	(153)	(135)
Unrealized loss (gain) on financial instruments	**180**	1,586	(9,335)
Impairment loss	**73,495**	7,937	14,500
Asset retirement obligations settled	**(458)**	(46)	(300)
Gain on asset disposition	**-**	(114)	(207)
Recycle netback[1]	**28,529**	43,233	58,567
Sales volumes (Mboe)	**5,650**	5,458	5,480
Recycle netback per boe	**5.05**	7.92	10.69

[1] Recycle netback does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures used by other companies.

SUSTAINABILITY REPORT

TransGlobe Energy Corporation plans and executes its business activities with a strong sense of responsibility, and this has been reflected in a demonstrable track record of performance in Heath, Safety, Environment and Social Responsibility ("HSES").

While an integral part of its business, the transparency of the Company's performance reporting in these areas has lagged behind its reporting in other areas. In 2020 TransGlobe began to address this reporting variance by moving towards a Sustainability Accounting Standards Board ("SASB") compliant framework of reporting its sustainability performance, with the aim of fully compliant reporting by year end 2021.

As this is TransGlobe's first sustainability report, the Company has submitted 2019 performance metrics against SASB indicators, based on the data it has been able to collect and verify to date. The 2020 data collected is still being collated and verified at the time of this publication and will be published on our website once complete.

While TransGlobe is embarking on a transition to compliant sustainability reporting, the Company has developed principles to guide the way it operates and its ambitions for the future.

TransGlobe Energy Corporation Sustainability Statement

TransGlobe Energy Corporation recognizes the importance of executing its business activities in a responsible way, specifically acknowledging that its activities impact the communities within which it operates directly and the broader population at large.

TransGlobe Energy Corporation acknowledges that human activity has a climate change impact, and that carbon neutrality from human activity is a key international goal.

TransGlobe Energy Corporation is committed to measuring, reporting, and improving its operational footprint in five key areas of sustainability performance.

The Company will:

- execute operations in a socially responsible way, ensuring its local communities benefit from the way it invests and conducts its activities;
- work to understand the environmental impacts of its operations to: specifically carbon emissions intensity, water use, and air quality;
- minimise potential adverse impacts of its operations on the health and safety of its workforce and communities in which it operates;
- manage its business to a high standard of corporate conduct; and
- transparently report the sustainability performance of its business, moving to full compliance with SASB.

Signed by:

"Randy C. Neely"

Randy C. Neely
President and Chief Executive Officer
March 12, 2021

SUSTAINABILITY ACCOUNTING STANDARDS BOARD ("SASB")

This is the first year the Company has reported against SASB indicators.

The table below details TransGlobe's disclosures against the SASB standards and indicators for 2019, the first year for which verifiable data is available. The relevant standards have been selected on a materiality-driven basis, and the Company's response to the individual indicators outlines where in TransGlobe's public documents relevant information can be found, as well as any supplementary information.

TransGlobe is working on enhancing the breadth and depth of its reporting against the SASB framework over time, to include reporting against additional indicators. This report represents a best-efforts basis including the information and data available for 2019, with more information planned in subsequent editions.

Topic	Definition	Unit of Measure	SASB Metric	Egypt	Canada	Corporate
Greenhouse Gas Emissions	Gross Scope 1 GHG Emissions	Metric tons (t) CO_2-e	EM-EP-110a.1	207,981	11,071	219,052
	Gross Scope 1 GHG Intensity Rate	kg CO_2-e / production (BOE)	EM-EP-110a.1	41.6	13.4	37.6
	Gross Scope 1 Methane Emissions as a percentage of GHG Emissions	Percentage (%)	EM-EP-110a.1	83	21	80
	Percentage of Scope 1 GHG Emissions covered under emissions-limiting regulations	Percentage (%)	EM-EP-110a.1	0	100	5
	Gross Scope 1 GHG emissions from flared hydrocarbons	Metric tons (t) CO_2-e	EM-EP-110a.2	0	125	125
	Gross Scope 1 GHG emissions from other combustion	Metric tons (t) CO_2-e	EM-EP-110a.2	34,566	8,607	43,173
	Gross Scope 1 GHG emissions from process emissions	Metric tons (t) CO_2-e	EM-EP-110a.2	0	0	0
	Gross Scope 1 GHG emissions from other vented emissions	Metric tons (t) CO_2-e	EM-EP-110a.2	173,415	1,494	174,909
	Gross Scope 1 GHG emissions from fugitive emissions	Metric tons (t) CO_2-e	EM-EP-110a.2	tbd	845	tbd
	Discussion of long-term and short-term strategy or plan to manage Scope 1 emissions, emissions reduction targets, and an analysis of performance against those targets	Discussion and Analysis	EM-EP-110a.3	Strategy and plan to manage scope 1 emissions to be developed in 2021		
Air Quality	Nitrogen Oxide (NO) Emissions	Metric tons (t)	EM-EP-120a.1	637	71	708
	Sulfur Dioxide (SO2) Emissions	Metric tons (t)	EM-EP-120a.1	10.1	0.1	10.2
	Volatile Organic Compounds (VOCs) Emissions	Metric tons (t)	EM-EP-120a.1	3,810	65	3,876
	Particulate Matter (PM10) Emissions	Metric tons (t)	EM-EP-120a.1	9.8	0.6	10.4
Water Management	Total Fresh Water withdrawn	Thousand cubic meters (m^3)	EM-EP-140a.1	44.3	18.8	63.0

	Percentage of total fresh water withdrawn in regions with High or Extremely High Baseline Water Stress	Percentage (%)	EM-EP-140a.1	tbd		
	Total Fresh Water Consumed	Thousand cubic meters (m^3)	EM-EP-140a.1	44.3	18.8	63.0
	Percentage of total fresh water consumed in regions with High or Extremely High Baseline Water Stress	Percentage (%)	EM-EP-140a.1	tbd		
	Volume of produced water	Thousand cubic meters (m^3)	EM-EP-140a.2	2,827.2	7.4	2,834.6
	Volume of flowback generated	Thousand cubic meters (m^3)	EM-EP-140a.2	-	-	-
	Percentage of produced water and flowback discharged	Percentage (%)	EM-EP-140a.2	tbd		
	Percentage of produced water and flowback injected	Percentage (%)	EM-EP-140a.2	tbd		
	Percentage of produce water and flowback recycled	Percentage (%)	EM-EP-140a.2	0	0	0
	Hydrocarbon content in discharged water	Metric tons (t)	EM-EP-140a.2	0	0	0
	Percentage of hydraulically fractured wells for which there is public disclosure of all fracturing fluid chemicals used.	Percentage (%)	EM-EP-140a.3	0	0	0
	Percentage of hydraulic fracturing sites where ground or surface water deteriorated compared to a baseline	Percentage (%)	EM-EP-140a.4	0	0	0
Biodiversity Impacts	Number of hydrocarbon spills	Number	EM-EP-160a.2	51	0	51
	Aggregate volume of hydrocarbon spills	Barrels (bbls)	EM-EP-160a.2	tbd	0	tbd
	Volume of hydrocarbon spills in the Arctic	Barrels (bbls)	EM-EP-160a.2	0	0	0
	Volume of hydrocarbon spills impacting shorelines with ESI rankings 8-10	Barrels (bbls)	EM-EP-160a.2	0	0	0
	Volume of hydrocarbon spills recovered	Barrels (bbls)	EM-EP-160a.2	tbd	-	tbd
	Percentage of proved reserves in or near sites with protected conservation status or endangered species habitat	Percentage (%)	EM-EP-160a.3	0	0	0
	Description of environmental management policies and practices for active sites	Discussion and Analysis	EM-EP-160a.1	HSES Policy published on website and HSES Management System in place		

Security, Human Rights & Rights of Indigenous Peoples	Percentage of Proved reserves in or near areas of conflict	Percentage (%)	EM-EP-210a.1	0	0	0
	Percentage of Probable reserves in or near areas of conflict	Percentage (%)	EM-EP-210a.1	0	0	0
	Percentage of proved reserves in or near indigenous land	Percentage (%)	EM-EP-210a.2	0	tbd	0
	Percentage of probable reserves in or near indigenous land	Percentage (%)	EM-EP-210a.2	0	tbd	0
	Discussion of engagement processes and due diligence practices with respect to human rights, indigenous rights, and operation in areas of conflict	Discussion and Analysis	EM-EP-210a.3	Policy, process and practices to be developed in 2021		
Community Relations	Number of non-technical delays	Number	EM-EP-210b.2	0	0	0
	Duration of non-technical delays	Days	EM-EP-210b.2	0	0	0
	Discussion of process to manage risks and opportunities associated with community rights and interests	Discussion and Analysis	EM-EP-210b.1	HSES Policy published on website and HSES Management System in place		
Workforce Health & Safety	Total recordable incident rate (TRIR)	Rate per 200,000 hours (h)	EM-EP-320a.1	0.37	0	0.37
	Fatality Rate	Rate per 200,000 hours (h)	EM-EP-320a.1	0	0	0
	Near miss frequency rate (NMFR)	Rate per 200,000 hours (h)	EM-EP-320a.1	tbd	27	tbd
	Average hours of health, safety and emergency response training for fulltime employees	Hours (h)	EM-EP-320a.1	tbd		
	Average hours of health, safety and emergency response training for contract employees	Hours (h)	EM-EP-320a.1	tbd		
	Average hours of health, safety and emergency response training for short service employees	Hours (h)	EM-EP-320a.1	tbd		
	Discussion of management systems used to integrate a culture of safety throughout the exploration and production lifecycle	Discussion and Analysis	EM-EP-320a.2	HSES Policy published on website and HSES Management System in place		
Reserves Valuation & Capital Expenditures	Sensitivity of hydrocarbon reserve levels to future price projection scenarios that account for a price on carbon emissions	Million barrels (MMbbls),Million standard cubic feet (MMscf)	EM-EP-420a.1	tbd		

	Estimated carbon dioxide emissions embedded in proved hydrocarbon reserves	Metric tons (t) CO_2-e	EM-EP-420a.2	tbd		
	Amount invested in renewable energy	$USD	EM-EP-420a.3	0	0	0
	Revenue generated by renewable energy sales	$USD	EM-EP-420a.3	0	0	0
	Discussion of how price and demand for hydrocarbons and/or climate regulation influence the capital expenditure strategy for exploration, acquisition, and development of assets	Discussion and Analysis	EM-EP-420a.4	Policy and practice to be developed during 2021		
Business Ethics & Transparency	Percentage of proved reserves in countries that have the 20 lowest rankings in Transparency International's Corruption Perception Index	Percentage (%)	EM-EP-510a.1	0	0	0
	Percentage of probable reserves in countries that have the 20 lowest rankings in Transparency International's Corruption Perception Index	Percentage (%)	EM-EP-510a.1	0	0	0
	Description of the management system for prevention of corruption and bribery throughout the value chain	Discussion and Analysis	EM-EP-510a.2	Governance Charter, Code of Conduct for the Corporation, and Code of Conduct and Conflict of Interest Guidelines for Directors and Officers, and Whistleblower Protection Policy in place and published on website		
Management of the Legal & Regulatory Environment	Discussion of corporate positions related to government regulations and/or policy proposals that address environmental and social factors affecting the industry	Discussion and Analysis	EM-EP-530a.1	R&HSES committee annually reviews changes to national regulations and reporting requirements		
Critical Incident Risk Management	Process Safety Event (PSE) rates for Loss of Primary Containment (LOPC) of greater consequence (Tier 1)	Rate	EM-EP-540a.1	tbd		
	Description of the management systems used to identify and mitigate catastrophic and tail-end risks	Discussion and Analysis	EM-EP-540a.2	HSES Management System in place. Emergency management system active and exercised annually		

MANAGEMENT'S DISCUSSION AND ANALYSIS

March 12, 2021

The following discussion and analysis is management's opinion of TransGlobe Energy Corporation's ("TransGlobe" or the "Company") historical financial and operating results and should be read in conjunction with the message to shareholders and the audited consolidated financial statements of the Company for the years ended December 31, 2020 and 2019, together with the notes related thereto (the "Consolidated Financial Statements"). The Consolidated Financial Statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") in the currency of the United States, except otherwise noted. Additional information relating to the Company, including the Company's Annual Information Form, is on SEDAR at www.sedar.com. The Company's Annual Report on Form 40-F may be found on EDGAR at www.sec.gov.

READER ADVISORIES

Forward-Looking Statements

Certain statements or information contained herein may constitute forward-looking statements or information under applicable securities laws, including, but not limited to, management's assessment of future plans and operations, that TransGlobe will have the ability to develop its properties in the manner currently contemplated, the expected benefits to the Company of consolidating, amending and extending the Company's Eastern Desert PSCs (as defined herein), the ratification of the consolidation, amendment and extension of the Company's Eastern Desert PSCs, and other matters, anticipated changes to the Company's reserves and production, timing of directly marketed crude oil sales, drilling plans and the timing thereof, commodity price risk management strategies, adapting to the current political situation in Egypt, reserves estimates, management's expectation for results of operations for 2021, including expected 2021 average production, funds flow from operations, that TransGlobe will have the ability to pay down its debt and return money to its shareholders, the 2021 capital program for exploration and development, the timing and method of financing thereof, the Company's continued work with EGPC (as defined herein) regarding scheduling cargoes, anticipated reductions in year-end inventory, the availability of funds to meet current and foreseeable financial requirements at a reasonable cost, collection of accounts receivable from the Egyptian Government, the timing of liftings of crude oil produced from the Company's Egyptian operations, the terms of drilling commitments under the Egyptian Production Sharing Agreements and Production Sharing Concessions (collectively defined as "PSCs") and the method of funding such drilling commitments, the Company's beliefs regarding the reserves and production growth of its assets and the ability to grow with a stable production base, that TransGlobe will have the ability to steward capital and reduce costs, commodity prices and expected volatility thereof, and interest rates and the expected volatility thereof. 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.

Forward-looking statements or information relate to the Company's future events or performance. All statements other than statements of historical fact may be forward-looking statements or information. Such statements or information are often but not always identified by the use of words such as "seek", "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "project", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe", and similar expressions.

Forward-looking statements or information necessarily involve risks including, without limitation, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets, economic and political instability, volatility of commodity prices, currency fluctuations, fluctuations in operating expenses due to changes in inventory volumes, inability to pay down the Company's debt, inability to continue to work with the Egyptian General Petroleum Company ("EGPC") to schedule cargoes, the ratification of the consolidation, amendment and extension of the Company's Eastern Desert PSCs, imprecision of reserves estimates, environmental risks, competition from other producers, inability to retain drilling rigs and other services, incorrect assessment of the value of acquisitions, failure to realize the anticipated benefits of acquisitions, delays resulting from or inability to obtain required regulatory approvals, failure to collect the remaining accounts receivable balance from EGPC, the potential impacts of COVID-19 to the Company's business, operating results, cash flows and/or financial condition, ability to access sufficient capital from internal and external sources and the risks contained under "Risk Factors" in the Company's Annual Information Form which is available on www.sedar.com. The recovery and reserves estimates of the Company's reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Events or circumstances may cause actual results to differ materially from those predicted, as a result of the risk factors set out and other known and unknown risks, uncertainties, and other factors, many of which are beyond the control of the Company.

Forward-looking information and statements contained in this document include the payment of dividends, including the timing and amount thereof, and the Company's intention to declare and pay dividends in the future under its current dividend policy. Without limitation of the foregoing, future dividend payments, if any, and the level thereof is uncertain, as the Company's dividend policy and the funds available for the payment of dividends from time to time will be dependent upon, among other things, free cash flow, financial requirements for the Company's operations and the execution of its strategy, ongoing production maintenance, growth through acquisitions, fluctuations in working capital and the timing and amount of capital expenditures and anticipated business development capital, payment irregularity in Egypt, debt service requirements and other factors beyond the Company's control. Further, the ability of the Company to pay dividends will be subject to applicable laws (including the satisfaction of the liquidity and solvency tests contained in applicable corporate legislation) and contractual restrictions contained in the instruments governing its indebtedness.

In addition, forward-looking statements or information are based on a number of factors and assumptions which have been used to develop such statements and information in order to provide shareholders with a more complete perspective on the Company's future operations. Such statements and information may prove to be incorrect and readers are cautioned that such statements and information may not be appropriate for other purposes. Although the Company believes that the expectations reflected in such forward-looking statements or information are reasonable, undue reliance should not be placed on forward-looking statements or information because the Company can give no assurance that such expectations will prove to be correct. In addition to other factors and assumptions which may be identified herein, assumptions have been made regarding, among other things: the impact of increasing competition; the general stability of the economic and political environment in which the Company operates; the timely receipt of any required regulatory approvals; the ability of the Company to obtain qualified staff, equipment and services in a timely and cost efficient manner; drilling results; the ability of the operator of the projects which the Company has an interest in to operate the field in a safe,

efficient and effective manner; the ability of the Company to obtain financing on acceptable terms; field production rates and decline rates; the ability to replace and expand oil and natural gas reserves through acquisition, development and exploration; the timing and costs of pipeline, storage and facility construction and expansion and the ability of the Company to secure adequate product transportation; future commodity prices; the ability of the Company's derivative financial instruments to manage its exposure thereto; currency exchange and interest rates; the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which the Company operates; that the Company's ongoing work with the EGPC with respect to scheduling cargoes will continue be successful; the ratification of the consolidation, amendment and extension of the Company's Eastern Desert PSCs; the impact of potential litigation and claims on the Company; and the ability of the Company to successfully market and receive payment for its oil and natural gas products.

Readers are cautioned that the foregoing list is not exhaustive of all factors and assumptions which have been used. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements. 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 and U.S. securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com), EDGAR website (www.sec.gov) and on the Company's website (www.trans-globe.com).

Furthermore, the forward-looking statements or information contained herein are made as at the date hereof and the Company does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities laws.

The reader is further cautioned that the preparation of 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. Estimating reserves is also critical to several accounting estimates and requires judgments and decisions based upon available geological, geophysical, engineering and economic data. These estimates may change, having either a negative or positive effect on net earnings (loss) as further information becomes available, and as the economic environment changes.

This MD&A includes references to certain financial measures which are not specified, defined, or determined under IFRS and are therefore considered non-GAAP financial measures. These non-GAAP financial measures are unlikely to be comparable to similar financial measures presented by other issuers. For a full description of these non-GAAP financial measures and a reconciliation of these measures to their most directly comparable GAAP measures, please refer to "NON-GAAP FINANCIAL MEASURES".

All oil and natural gas reserves information contained in this document has been prepared and presented in accordance with National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities and the Canadian Oil and Gas Evaluation Handbook. The actual crude oil and natural gas reserves and future production will be greater than or less than the estimates provided in this document. The estimated future net revenue from the production of crude oil and natural gas reserves does not represent the fair market value of these reserves.

Mr. Ron Hornseth, B.Sc., General Manager - Canada for TransGlobe Energy Corporation, and a qualified person as defined in the Guidance Note for Mining, Oil and Gas Companies, June 2009, of the London Stock Exchange, has reviewed and approved the technical information contained in this report. Mr. Hornseth is a professional engineer who obtained a Bachelor of Science in Mechanical Engineering from the University of Alberta. He is a member of the Association of Professional Engineers and Geoscientists of Alberta ("APEGA") and the Society of Petroleum Engineers ("SPE") and has over 20 years' experience in oil and gas.

Natural gas volumes have been converted on the basis of six thousand cubic feet of natural gas to one barrel of oil equivalent. Barrels of oil equivalent ("boe") may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet to one barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

NON-GAAP FINANCIAL MEASURES

Funds flow from operations

This document contains the term "funds flow from operations", which should not be considered an alternative to or more meaningful than "cash flow from operating activities" as determined in accordance with IFRS. Funds flow from operations is a measure that represents cash generated from operating activities before changes in non-cash working capital. Management considers this a key measure as it demonstrates TransGlobe's ability to generate the cash flows necessary to fund future growth through capital investment. Funds flow from operations does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures used by other companies.

Reconciliation of funds flow from operations

($000s)	**2020**	2019
Cash flow generated by operating activities	**31,709**	44,836
Changes in non-cash working capital	**(1,266)**	2,035
Funds flow from operations[1]	**30,443**	46,871

[1] Funds flow from operations does not include interest costs. Interest expense is included in financing costs on the Consolidated Statements of (Loss) and Comprehensive (Loss). Cash interest paid is reported as a financing activity on the Consolidated Statements of Cash Flows.

Net debt-to-funds flow from operations ratio

Net debt-to-funds flow from operations is a measure that is used by management to set the amount of capital in proportion to risk. The Company's net debt-to-funds flow from operations ratio is computed as long-term debt, including the current portion, net of working capital, over funds flow from operations for the trailing twelve months. Net-debt-to-funds flow from operations does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures used by other companies.

Reconciliation of net debt-to-funds flow from operations ratio

($000s)	**2020**	2019
Long-term debt	**6,567**	37,041
Current assets	**(53,864)**	(65,786)
Current liabilities	**38,515**	33,592
Net debt	**(8,782)**	4,847
Funds flow from operations	**30,443**	46,871
Net debt-to-funds flow from operations	**(0.29)**	0.10

Netback

Netback is a measure of operating results and is computed as sales net of royalties (all government interests, net of income taxes), production and operating expenses, current taxes and selling costs. The Company's netbacks include sales and associated costs of production from inventoried crude oil sold during the period. Royalties and taxes associated with inventoried crude oil are recognized in the financial statements at the time of production. As a result, netbacks fluctuate depending on the timing of entitlement crude oil sales. Management believes that netback is a useful supplemental measure to analyze operating performance and provide an indication of the results generated by the Company's principal business activities prior to the consideration of other income and expenses. Netback does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures used by other companies.

MANAGEMENT STRATEGY AND OUTLOOK

The 2021 outlook provides information as to management's expectation for results of operations for 2021. Readers are cautioned that the 2021 outlook may not be appropriate for other purposes. The Company's expected results are sensitive to fluctuations in the business environment in the jurisdictions that the Company operates in, and may vary accordingly. **This outlook contains forward-looking statements that should be read in conjunction with the Company's disclosure under "Forward-Looking Statements", outlined on the first page of this Management's Discussion and Analysis ("MD&A").**

2021 Outlook

The 2021 production outlook for the Company is provided as a range to reflect timing and performance contingencies.

Global reaction to the spread of COVID-19 and the related economic fallout has created significant volatility, uncertainty, and turmoil in the oil and gas industry. Oil demand significantly deteriorated as a result of the pandemic and corresponding preventative measures taken globally to mitigate the spread of the virus. While market conditions have recently improved, the Company may record lower per boe results in 2021 due to these events which may continue to negatively affect TransGlobe's business.

TransGlobe maintains a strong balance sheet with modest debt and is the operator across all of its producing assets, which gives the Company significant capital flexibility and a high degree of discretion in its forward investment program. The Company intends to use all available tools to minimize balance sheet risk and position itself for future success.

With $15.0 million owed to Mercuria Energy Trading SA ("Mercuria") and $6.6 million owed to ATB Financial ("ATB"), TransGlobe is in compliance with its debt covenants. During 2020, the Company repaid $15.0 million on the prepayment facility with Mercuria and $1.5 million to ATB. The Company exited 2020 with $34.5 million cash on hand. TransGlobe is actively engaged with Mercuria on an amendment and extension to the facility currently maturing in September, 2021.

As announced in early December, 2020, the Company reached an agreement with the Egyptian General Petroleum Company ("EGPC") to merge its three existing Eastern Desert concessions with a 15-year primary term and improved Company economics. Ratification of the concession is anticipated in Q2-2021, and the February 1, 2020 effective date for the improved concession terms supports increased investment in advance of ratification. Subject to ratification, the Company will pay EGPC a signature bonus and an equalization payment in installments. An initial equalization payment of $15.0 million and signature bonus of $1.0 million are due on ratification, with five further annual equalization payments of $10.0 million each being made over five years (beginning February 1, 2022 until February 1, 2026). The Company will also have minimum financial work commitments of $50.0 million per each five-year period of the primary development term, commencing on the February 1, 2020 effective date.

With the approval of the agreement to merge the Eastern Desert concessions and recent commodity price improvements, the Company has moved forward to re-start investment in Egypt and also in Canada to support growth plans in both countries. The Company's recently announced 2021 capital program of $27.2 million (before capitalized G&A) includes $16.6 million for Egypt and $10.6 million for Canada. The 2021 plan was prepared to focus on value accretive projects within its portfolio, maximize free cash flow to direct at future value growth opportunities and to increase the Company's production base.

Total corporate production is expected to range between 12.0 and 13.0 Mboe/d (mid-point of 12.5 Mboe/d) for 2021 with a 93% weighting to oil and liquids. Egypt oil production is expected to range between 9.7 and 10.5 Mbbls/d (mid-point of 10.1 Mbbls/d) in 2021. Canadian production is expected to range between 2.3 and 2.5 Mboe/d (mid-point of 2.4 Mboe/d) in 2021. The 2021 mid-point production guidance broken out by product type is summarized below:

Mid-point production guidance	Egypt	Canada	Total
Light and medium crude oil (bbls/d)	791	800	1,591
Heavy crude oil (bbls/d)	9,309	-	9,309
Conventional natural gas (Mcf/d)	-	4,800	4,800
Associated natural gas liquids (bbls/d)	-	800	800
Total (boe/d)	**10,100**	**2,400**	**12,500**

The Company has and will continue to monitor its economic thresholds for shutting-in production in Canada. In Egypt, the Company continues to carry out economic reviews to determine whether offline production should be brought back on or if well interventions should be carried out. If oil prices return to the lows in Q2 of 2020, the Company may choose to shut-in uneconomic production and 2021 production guidance could be negatively impacted.

Funds flow from operations in any given period is dependent upon the timing and market price of crude oil sales in Egypt. Because these factors are difficult to accurately predict, the Company has not provided funds flow from operations guidance for 2021. Funds flow from operations and inventory levels in Egypt may fluctuate significantly from quarter to quarter due to the timing of crude oil sales.

The below chart provides a comparison of well netbacks in the Company's Egyptian and Canadian assets under multiple price sensitivities. The Egyptian netbacks reflect the existing PSC terms in the Eastern Desert and do not reflect the potential netbacks once ratification occurs to merge the Eastern Desert PSCs. A typical Cardium well produces both oil and natural gas/NGLs. The price of each commodity varies significantly, therefore the below chart presents the netback of each revenue stream separately.

Netback sensitivity					
Benchmark crude oil price ($/bbl)[1]	30.00	40.00	50.00	60.00	70.00
Benchmark natural gas price ($/Mcf)[2]	1.97	2.05	2.13	2.20	2.28
Netback ($/boe)					
Egypt - crude oil[3]	(4.80)	(0.70)	3.40	7.20	9.50
Canada - crude oil[4]	13.80	22.40	30.20	37.60	45.10
Canada - natural gas and NGLs[4]	2.40	4.50	6.40	8.20	10.00

1 Benchmark Egypt crude oil price is Dated Brent; benchmark Canada crude oil price is WTI.

2 Benchmark natural gas price is AECO.

3 Egypt assumptions: using anticipated 2021 Egypt production profile, Gharib Blend price differential estimate of $5.00/bbl applied consistently at all price points, concession differentials of 4%, 5% and 5% applied to WG/WB/NWG, respectively, operating costs estimated at ~$15.20/bbl, pre-concession merger ratification terms, and maximum cost recovery resulting from accumulated cost pools.

4 Canada assumptions: using anticipated 2020 Canada production profile, Edmonton Light price differential estimate of C$5.00/bbl, Edmonton Light to Harmattan discount of C$2.50/bbl, operating costs estimated at ~C$7.00/boe, NGL mixture price at 45% of Edmonton Light, and takes into consideration Canadian tax pools.

2021 Capital Budget

The Company's 2021 capital program of $27.2 million (before capitalized G&A) includes $16.6 million for Egypt and $10.6 million for Canada. The 2021 plan was prepared to focus on value accretive projects within its portfolio, maximize free cash flow to direct at future growth opportunities and to increase the Company's production base. The 2021 drilling program includes 12 Egypt wells and 3 Canadian Cardium wells in South Harmattan.

Egypt

As announced in early December, 2020, the Company reached an agreement with the Egyptian General Petroleum Company ("EGPC") to merge its three existing concessions with a 15-year primary term and improved Company economics. Ratification of the concession is anticipated in Q2-2021 and the February 1, 2020 effective date for the improved concession terms supports increased investment in parallel with ratification.

The $16.6 million Egypt program is entirely allocated to development activities. The primary focus of the 2021 Egypt plan is to accelerate the exploitation of the Company's Eastern Desert acreage with the aim of increasing oil production, while evaluating and increasing production from the more prospective lower Bahariya reservoir on the South Ghazalat development lease in the Western Desert.

The 2021 development program is principally focused on the Eastern Desert and includes: nine development wells in West Bakr (three in H and six in K pools), one Red Bed appraisal well in the NW Gharib 3X pool, two development wells targeting Arta Nukhul reservoir in West Gharib, two recompletions in West Bark, two recompletions in West Gharib, three conversions to water injectors in West Gharib, and development & maintenance projects in the Eastern Desert (West Bakr, NW Gharib and West Gharib). A recompletion of the SGZ-6X well to the more prospective lower Bahariya reservoir is also planned.

Egypt production is expected to average between 9.7 and 10.5 Mboe/d for the year and achieve an exit rate in the range of 10.4 to 10.7 Mboe/d.

Canada

The $10.6 million Canada program consists of drilling three (three net) horizontal wells and completing one (one net) standing well, all targeting the Cardium light oil resource at Harmattan, with additional maintenance/ development capital. The Cardium drilling program in 2021 consists of one 2-mile and two 1-mile development wells in South Harmattan. The one 2-mile horizontal well drilled, but not completed, in South Harmattan in 2020 will also be stimulated, equipped, and brought into production.

Canada production is expected to average between 2.3 and 2.5 Mboe/d for the year and achieve an exit rate in the range of 3.1 to 3.3 Mboe/d.

The approved 2021 capital program is summarized in the following table:

	TransGlobe 2021 Capital ($MM)				**Gross Well Count**		
	Development		**Exploration**		**Drilling**		
Concession	**Wells**	**Other[1]**	**Wells**	**Total[2]**	**Development**	**Exploration**	**Total**
West Gharib	1.1	2.0	-	**3.1**	2	-	**2**
West Bakr	9.3	0.5	-	**9.8**	9	-	**9**
NW Gharib	0.9	-	-	**0.9**	1	-	**1**
South Ghazalat	-	0.3	-	**0.3**	-	-	**-**
Egypt	**11.3**	**5.3**	**-**	**16.6**	**12**	**-**	**12**
Canada	**9.0**	**1.6**	**-**	**10.6**	**3**	**-**	**3**
2021 Total	**20.3**	**6.9**	**-**	**27.2**	**15**	**-**	**15**
Splits (%)	100%		0%	100%	100%	0%	100%

[1] Other includes completions, workovers, recompletions and equipping.

SELECTED ANNUAL INFORMATION

($000s, except per share amounts, price and volumes)	**2020**	% Change	2019	% Change	2018
Operations					
Average production volumes					
Crude oil (bbls/d)	**11,858**	(18)	14,527	14	12,708
NGLs (bbls/d)	**785**	35	582	(25)	780
Natural gas (Mcf/d)	**4,686**	(16)	5,594	(2)	5,707
Total (boe/d)	**13,425**	(16)	16,041	11	14,439
Average sales volumes					
Crude oil (bbls/d)	**13,871**	3	13,441	1	13,282
NGLs (bbls/d)	**785**	35	582	(25)	780
Natural gas (Mcf/d)	**4,686**	(16)	5,594	(2)	5,707
Total (boe/d)	**15,437**	3	14,954	-	15,013
Average realized sales prices					
Crude oil ($/bbl)	**35.80**	(35)	55.31	(7)	59.57
NGLs ($/bbl)	**14.59**	(36)	22.93	(16)	27.17
Natural gas ($/Mcf)	**1.64**	24	1.32	5	1.26
Total oil equivalent ($/boe)	**33.41**	(35)	51.10	(6)	54.59
Inventory (Mbbls)	**227.9**	(76)	964.5	70	568.1
Petroleum and natural gas sales	**188,771**	(32)	278,929	(7)	299,144
Petroleum and natural gas sales, net of royalties	**114,675**	(18)	140,096	(21)	176,227
Cash flow generated by operating activities	**31,709**	(29)	44,836	(35)	69,192
Funds flow from operations[1]	**30,443**	(35)	46,871	(26)	63,282
Funds flow from operations per share:					
Basic	**0.42**		0.65		0.87
Diluted	**0.42**		0.65		0.86
Net (loss) earnings	**(77,397)**	1,837	(3,995)	(125)	15,677
Net (loss) earnings per share:					
Basic	**(1.07)**		(0.06)		0.22
Diluted	**(1.07)**		(0.06)		0.22
Capital expenditures	**7,498**	(80)	36,932	(9)	40,706
Dividends declared	**-**	-	5,078	101	2,527
Dividends declared per share	**-**	-	0.070	100	0.035
Total assets	**201,147**	(35)	308,325	(3)	318,296
Cash and cash equivalents	**34,510**	4	33,251	(36)	51,705
Working capital	**15,349**	(52)	32,194	(37)	50,987
Total long-term debt, including current portion	**21,464**	(42)	37,041	(29)	52,355
Net debt-to-funds flow from operations ratio[2]	**0.20**		0.10		0.02
Reserves					
Total proved (MMboe)[3]	**22.8**	(10)	25.4	(6)	26.9
Total proved plus probable (MMboe)[3]	**38.9**	(14)	45.3	3	44.1

[1] Funds flow from operations (before finance costs) is a measure that represents cash generated from operating activities before changes in non-cash working capital and may not be comparable to measures used by other companies. See "Non-GAAP Financial Measures".

[2] Net debt-to-funds flow from operations ratio is a measure that represents total long-term debt (including the current portion) net of working capital, over funds flow from operations for the trailing 12 months and may not be comparable to measures used by other companies. See "Non-GAAP Financial Measures".

[3] As determined by the Company's 2020, 2019 & 2018 independent reserves evaluator, GLJ Ltd. ("GLJ"), in their reports dated February 9, 2021, February 4, 2020 and January 22, 2019 with effective dates of December 31, 2020, December 31, 2019 and December 31, 2018. The reports of GLJ have been prepared in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook prepared jointly by The Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society), as amended from time to time and National Instrument 51-101.

In 2020 compared with 2019, TransGlobe:

- Reported a 16% decrease in production volumes compared to 2019. In Egypt, the decrease was primarily attributable to the curtailed 2020 capital program, deferred well interventions and natural declines;
- Ended 2020 with inventoried crude oil of 227.9 Mbbls, a decrease of 736.6 Mbbls over inventoried crude oil levels at December 31, 2019, primarily due to annual sales volumes exceeding production volumes;
- Reported positive funds flow from operations of $30.4 million (2019 - $46.9 million). The decrease in funds flow from operations from 2019 is primarily due lower production and lower commodity prices;
- Petroleum and natural gas sales decreased by 32%, primarily due to a 35% decrease in average realized sales prices;
- Reported a net loss of $77.4 million (2019 - net loss of $4.0 million) inclusive of a $0.2 million unrealized derivative loss on commodity contracts and a combined $73.5 million non-cash impairment loss on the Company's petroleum and natural gas ("PNG") and exploration and evaluation ("E&E") assets;
- Ended the year with positive working capital of $15.3 million, including $34.5 million in cash and cash equivalents as at December 31, 2020;
- Spent $7.5 million on capital expenditures, funded entirely from cash flow from operations and cash on hand; and
- Repaid $16.5 million of long-term debt with cash on hand.

SELECTED QUARTERLY FINANCIAL INFORMATION

	2020				2019			
($000s, except per share amounts, price and volumes)	**Q-4**	Q-3	Q-2	Q-1	Q-4	Q-3	Q-2	Q-1
Operations								
Average production volumes								
Crude oil (bbls/d)	**10,886**	10,473	12,696	13,404	13,739	14,416	15,451	14,510
NGLs (bbls/d)	**755**	798	826	761	735	585	533	470
Natural gas (Mcf/d)	**4,454**	4,633	4,665	4,996	5,331	5,652	5,733	5,663
Total (boe/d)	**12,384**	12,044	14,300	14,997	15,362	15,943	16,940	15,924
Average sales volumes								
Crude oil (bbls/d)	**14,215**	9,110	10,865	21,341	13,065	12,595	14,484	13,633
NGLs (bbls/d)	**755**	798	826	761	735	585	533	470
Natural gas (Mcf/d)	**4,454**	4,633	4,665	4,996	5,331	5,652	5,733	5,663
Total (boe/d)	**15,712**	10,680	12,470	22,934	14,688	14,122	15,973	15,047
Average realized sales prices								
Crude oil ($/bbl)	**37.40**	37.14	23.40	40.47	51.61	54.33	60.29	54.51
NGLs ($/bbl)	**18.96**	15.65	11.43	12.49	18.81	19.75	24.55	31.80
Natural gas ($/Mcf)	**1.85**	1.80	1.31	1.61	1.81	0.70	0.89	1.94
Total oil equivalent ($/boe)	**35.27**	33.63	21.63	38.42	47.51	49.56	55.81	51.11
Inventory (Mbbls)	**227.9**	534.0	408.7	242.1	964.5	902.6	735.0	647.0
Petroleum and natural gas sales	**50,989**	33,046	24,549	80,187	64,201	64,388	81,123	69,217
Petroleum and natural gas sales, net of royalties	**33,309**	16,740	11,392	53,234	28,473	31,200	43,071	37,352
Cash flow generated by (used in) operating activities	**14,180**	(3,349)	24,551	(3,672)	23,740	12,042	22,125	(13,071)
Funds flow from operations[1]	**7,202**	323	(2,764)	25,683	3,171	9,429	19,116	15,155
Basic per share	**0.10**	-	(0.03)	0.35	0.04	0.13	0.26	0.21
Diluted per share	**0.10**	-	(0.03)	0.35	0.04	0.13	0.26	0.21
Net (loss) earnings	**(2,855)**	(5,957)	(13,367)	(55,218)	(8,202)	2,967	10,046	(8,806)
Basic per share	**(0.04)**	(0.08)	(0.19)	(0.76)	(0.11)	0.04	0.14	(0.12)
Diluted per share	**(0.04)**	(0.08)	(0.19)	(0.76)	(0.11)	0.04	0.14	(0.12)
Capital expenditures	**254**	437	1,229	5,577	10,996	9,292	8,097	8,547
Dividends declared	**-**	-	-	-	-	2,539	-	2,539
Dividends declared per share	**-**	-	-	-	-	0.035	-	0.035
Total assets	**201,147**	205,583	221,347	241,219	308,325	312,654	315,999	308,113
Cash and cash equivalents	**34,510**	27,065	34,837	23,830	33,251	24,444	34,125	24,735
Working capital	**15,349**	12,708	35,112	53,294	32,194	47,150	54,078	43,600
Total long-term debt, including current portion	**21,464**	25,946	27,071	36,591	37,041	41,726	48,109	47,687
Net debt-to-funds flow from operations ratio[2]	**0.69**	1.25	(0.23)	(0.29)	0.10	(0.10)	(0.10)	0.05

[1] Funds flow from operations (before finance costs) is a measure that represents cash generated from operating activities before changes in non-cash working capital and may not be comparable to measures used by other companies. See "Non-GAAP Financial Measures".

[2] Net debt-to-funds flow from operations ratio is a measure that represents total long-term debt (including the current portion) net of working capital over funds flow from operations from the trailing 12 months and may not be comparable to measures used by other companies. See "Non-GAAP Financial Measures".

During the fourth quarter of 2020, TransGlobe:

- Reported a 19% decrease in production volumes compared to Q4-2019, primarily due to the curtailed 2020 capital program, deferred well interventions in Egypt and natural declines.
- Sold one cargo of TransGlobe's entitlement crude oil of 452.3 Mbbls during the quarter and ended the year with crude oil inventory of 227.9 Mbbls;
- Reported positive funds flow from operations of $7.2 million;
- Petroleum and natural gas sales decreased by 21% compared to Q4-2019, primarily due to a 26% decrease in realized prices;
- Reported a net loss of $2.9 million, inclusive of a $0.9 million unrealized derivative loss on commodity contracts;
- Spent $0.3 million on capital expenditures, funded entirely from cash flows from operations and cash on hand; and
- Repaid $5.0 million of long-term debt with cash on hand.

BUSINESS ENVIRONMENT

The Company's financial results are influenced by fluctuations in commodity prices, including price differentials. The following table shows select market benchmark prices and foreign exchange rates:

Average reference prices and exchange rates	2020	2019
Crude oil		
Dated Brent average oil price ($/bbl)	**41.76**	64.36
Edmonton Sweet index ($/bbl)	**34.04**	52.11
Natural gas		
AECO ($/MMBtu)	**1.68**	1.29
US/Canadian Dollar average exchange rate	**1.34**	1.33

In 2020, the average price of Dated Brent oil was 35% lower than in 2019. Egypt production is priced based on Dated Brent, less a quality differential and is shared with the Egyptian government through PSCs. When the price of oil increases, it takes fewer barrels to recover costs (cost oil or cost recovery barrels) which are assigned 100% to the Company. The PSCs provide for cost recovery per quarter up to a maximum percentage of total production. Timing differences often exist between the Company's recognition of costs and their recovery as the Company accounts for costs on an accrual basis, whereas cost recovery is determined on a cash basis. If the eligible cost recovery is less than the maximum defined cost recovery, the difference is defined as "excess". In Egypt, depending on the PSCs, the Contractor's share of excess ranges between 0% and 30%. If the eligible cost recovery exceeds the maximum allowed percentage, the unclaimed cost recovery is carried forward to the next quarter. Typically maximum cost oil ranges from 25% to 30% in Egypt. The balance of the production after maximum cost recovery is shared with the government (profit oil). Depending on the contract, the Egyptian government receives 70% to 86% of the profit oil. Production sharing splits are set in each contract for the life of the contract. Typically the government's share of profit oil increases when production exceeds pre-set production levels in the respective contracts. During times of high oil prices, the Company receives less cost oil and may receive more production-sharing oil. During times of lower oil prices, the Company receives more cost oil and may receive less profit oil. For reporting purposes, the Company records the government's share of production as royalties and taxes (all taxes are paid out of the government's share of production) which will increase during times of rising oil prices and decrease in times of declining oil prices. If oil prices are sufficiently low and the Gharib Blend/Dated Brent differential is high, the cost oil portion may not be sufficient to cover operating costs and capital costs, or even operating costs alone. When this occurs, the non-recovered costs accumulate in the Company's cost pools and are available to be offset against future cost oil during the term of the PSCs and any eligible extension periods.

EGPC owns the storage and export facilities where the Company's production is delivered and the Company requires EGPC cooperation and approval to schedule liftings. Once liftings occur, the Company incurs a 30-day collection cycle on liftings as a result of direct marketing to third-party international buyers. Depending on the Company's assessment of the credit of crude oil cargo buyers, they may be required to post irrevocable letters of credit to support the sales prior to the cargo liftings.

TransGlobe pays royalties to the Alberta provincial government and landowners in accordance with the established royalty regime. In Alberta, Crown royalty rates are based on reference commodity prices, production levels and well depths, and are offset by certain incentive programs in place to promote drilling activity by reducing overall royalty expense.

In 2020, the average price of Edmonton Sweet Index oil (expressed in US$) was 35% lower than in 2019. In 2020, the average price of AECO natural gas increased by 30% compared to 2019.

OPERATING RESULTS AND NETBACK

Daily Volumes, Working Interest before Royalties

Production Volumes

	2020	2019
Egypt crude oil (bbls/d)	**11,147**	13,713
Canada crude oil (bbls/d)	**711**	814
Canada NGLs (bbls/d)	**785**	582
Canada natural gas (Mcf/d)	**4,686**	5,594
Total Company (boe/d)	**13,425**	16,041

Sales Volumes (excludes volumes held as inventory)

	2020	2019
Egypt crude oil (bbls/d)	**13,160**	12,627
Canada crude oil (bbls/d)	**711**	814
Canada NGLs (bbls/d)	**785**	582
Canada natural gas (Mcf/d)	**4,686**	5,594
Total Company (boe/d)	**15,437**	14,954

Netback

Consolidated netback

	2020		2019	
($000s, except per boe amounts)	**$**	**$/boe**	$	$/boe
Petroleum and natural gas sales	**188,771**	**33.41**	278,929	51.10
Royalties[2]	**74,096**	**13.11**	138,833	25.44
Current taxes[2]	**13,530**	**2.39**	26,098	4.78
Production and operating expenses	**64,462**	**11.41**	50,626	9.28
Selling costs	**2,111**	**0.37**	1,287	0.24
Netback[1]	**34,572**	**6.13**	62,085	11.36

[1] The Company achieved the netbacks above on sold barrels of oil equivalent for the year ended December 31, 2020 and December 31, 2019 (these figures do not include TransGlobe's Egypt entitlement crude oil held as inventory at December 31, 2020).

[2] Royalties and taxes are settled at the time of production. Fluctuations in royalty and tax costs per bbl are due to timing differences between the production and sale of the Company's entitlement crude oil.

Egypt

	2020		2019	
($000s, except per boe amounts)	**$**	**$/boe**	$	$/boe
Oil sales	**173,086**	**35.94**	256,193	55.59
Royalties[2]	**71,741**	**14.89**	136,616	29.64
Current taxes[2]	**13,530**	**2.81**	26,098	5.66
Production and operating expenses	**58,305**	**12.11**	43,252	9.38
Selling costs	**2,111**	**0.44**	1,287	0.28
Netback[1]	**27,399**	**5.69**	48,940	10.63

[1] The Company achieved the netbacks above on sold barrels of oil equivalent for the year ended December 31, 2020 and December 31, 2019 (these figures do not include TransGlobe's Egypt entitlement crude oil held as inventory at December 31, 2020).

[2] Royalties and taxes are settled at the time of production. Fluctuations in royalty and tax costs per bbl are due to timing differences between the production and sale of the Company's entitlement crude oil.

Netback per barrel in Egypt decreased by 46% in 2020 compared to 2019. The decrease was due to a 35% lower realized oil price, 57% higher selling costs and 29% higher production and operating expenses.

Royalties and taxes as a percentage of revenue were 49% in 2020 (2019 - 64%). Royalties and taxes are settled on a production basis, therefore, the correlation of royalties and taxes to oil sales fluctuates depending on the timing of entitlement oil sales. If sales volumes had been equal to production volumes during the year, royalties and taxes as a percentage of revenue would have been 58% (2019 - 58%). In periods when the Company sells less than its entitlement production, royalties and taxes as a percentage of revenue will be higher than the terms set out in the PSCs. In periods when the Company sells more than its entitlement production, royalties and taxes as a percentage of revenue will be lower than the terms set out in the PSCs. The relative decrease, from 64% in 2019 to 49% in 2020, was due to sales outpacing production in 2020, partially offset by Q1-2020 excess cost oil in the West Bakr concession. Excess cost oil occurs when the current costs and historic cost amortization, permissible within the PSC, are less than the proportion of cost oil value. In the case of West Bakr, 100% of excess cost oil belongs to EGPC, which effectively increases the royalty burden.

In Egypt, the average selling price for the year ended December 31, 2020 was $35.94/bbl (2019 - $55.59/bbl), which was $5.82/bbl lower (2019 - $8.77/bbl lower) than the average Dated Brent oil price of $41.76/bbl for 2020 (2019 - $64.36/bbl). The difference between the average selling price and Dated Brent is due to a gravity/quality adjustment and is also impacted by the specific timing of direct sales.

In Egypt, production and operating expenses fluctuate periodically due to changes in inventory volumes as a portion of costs are capitalized and expensed when sold. Production and operating expenses increased by 35% ($15.1 million) in 2020 compared with 2019. The increase was primarily related to a decrease in crude oil inventory through sales to both EGPC and Mercuria, where operating costs previously capitalized to inventory were expensed in the period of sale ($14.0 million). The increase was also caused by higher manpower costs as well as operating expenses related to the South Ghazalat concession which began operating in 2020, partially offset by a decrease in workovers and production handling fees. The increase in production and operating expenses per barrel from $9.38/bbl in 2019 to $12.11/bbl in 2020 was due to a 19% decrease in production primarily attributed to the curtailed 2020 capital program, deferred well interventions and natural declines.

Canada

	2020		2019	
($000s, except per boe amounts)	**$**	**$/boe**	$	$/boe
Crude oil sales	**8,679**	**33.36**	15,159	51.02
Natural gas sales	**2,815**	**9.85**	2,705	7.95
NGL sales	**4,191**	**14.59**	4,872	22.93
Total sales	**15,685**	**18.82**	22,736	26.75
Royalties	**2,355**	**2.83**	2,217	2.61
Production and operating expenses	**6,157**	**7.39**	7,374	8.68
Netback	**7,173**	**8.60**	13,145	15.46

Netbacks per boe in Canada decreased by 44% in 2020 compared with 2019. The decrease is mainly due to a 30% lower realized sales price and an 8% increase in royalties, partially offset by a 15% decrease in production and operating expenses.

In 2020, the Company's Canadian operations incurred $0.1 million higher royalty costs than in 2019. The increase in royalties was primarily due to an increase in mineral taxes. Mineral taxes are an annual tax on PNG productive mineral rights on freehold properties payable to the Crown. A further increase in royalties was caused by a decrease in Gas Cost Allowance ("GCA") rebates received in 2020 compared to 2019. Royalties amounted to 15% of petroleum and natural gas sales revenue during 2020 compared to 10% during the prior year. TransGlobe pays royalties to the Alberta provincial government and landowners in accordance with an established royalty regime. In Alberta, Crown royalty rates are based on reference commodity prices, production levels and well depths, and are offset by certain incentive programs in place to promote drilling activity by reducing overall royalty expense.

Production and operating expenses decreased by 15% compared with 2019. The decrease was primarily due to a decrease in transportation costs.

GENERAL AND ADMINISTRATIVE EXPENSES ("G&A")

	2020		2019	
($000s, except per boe amounts)	**$**	**$/boe**	$	$/boe
Gross G&A	**11,893**	**2.10**	15,784	2.89
Stock-based compensation	**857**	**0.15**	2,237	0.41
Capitalized G&A and overhead recoveries	**(760)**	**(0.13)**	(1,410)	(0.26)
Net G&A	**11,990**	**2.12**	16,611	3.04

G&A (gross) decreased by 25% in 2020 compared with 2019. This decrease was primarily due to lower salaries, short term incentive payments, business development costs, reduced corporate travel and professional fees, partially offset by non-recurring restructuring charges.

Stock-based compensation expense decreased by 62% in 2020 compared to 2019. This decrease is primarily due to a decrease in the Company's average share price in 2020 and the associated revaluation of the Company's potential obligations.

Capitalized G&A decreased by 46% from the prior year due to reduced capital activity in 2020 due to the COVID-19 pandemic.

FINANCE COSTS

	Years Ended December 31	
($000s)	**2020**	2019
Interest on long-term debt	**1,597**	3,211
Interest on borrowing base facility	**317**	427
Amortization of deferred financing costs	**395**	368
Interest on lease obligations	**211**	250
Finance costs	**2,520**	4,256
Interest paid	**1,918**	3,664

Finance costs decreased to $2.5 million in 2020 from $4.3 million in 2019. This decrease was due to a lower balance of long-term debt and decreases to LIBOR and ATB Prime rates.

As at December 31, 2020, the Company had a prepayment agreement with Mercuria Energy Trading S.A. ("Mercuria") that allows for a revolving balance of up to $75.0 million, of which $15.0 million is outstanding. During 2020, the Company made repayments of $15.0 million on this prepayment balance.

As at December 31, 2019 the Company had in place a revolving Canadian reserves-based lending facility with ATB totaling C$25.0 million ($19.2 million). As at June 30, 2020, the ATB facility was renewed for C$15.0 million ($11.0 million), of which C$8.3 million ($6.6 million) was drawn (December 31, 2019 - C$9.8 million/$7.5 million). The facility bears interest at a rate of either ATB Prime or CDOR (Canadian Dollar Offered Rate) plus applicable margins that vary from 2.25% to 4.25% (December 31, 2019: 1.25% to 3.25%) depending on the company's net debt to trailing cash flow ratio. There were no other changes to the key terms of the agreement from December 31, 2019. During the year ended December 31, 2020, the Company repaid C$2.0 million ($1.5 million) and drew C$0.5 million ($0.4 million) on the revolving facility.

The prepayment agreement and reserves-based lending facility are subject to certain covenants, the details of which are outlined in Note 18 to the Company's Consolidated Financial Statements. The Company was in compliance with its covenants as at December 31, 2020. Refer to the related description of TransGlobe's debt included in the December 31, 2020 Consolidated Financial Statements.

DEPLETION, DEPRECIATION AND AMORTIZATION ("DD&A")

	2020		2019	
($000s, except per boe amounts)	**$**	**$/boe**	$	$/boe
Egypt[1]	**22,927**	**4.76**	26,345	5.72
Canada	**7,320**	**8.78**	7,790	9.17
Corporate	**802**	**-**	813	-
Total	**31,049**	**5.50**	34,948	6.40

[1] Egypt DD&A per barrel is calculated on a sales basis for the years ended December 31, 2020 and December 31, 2019 (these figures do not include TransGlobe's Egypt entitlement barrels held as inventory at December 31, 2020).

In Egypt, gross DD&A fluctuates periodically due to changes in inventory volumes as the DD&A per barrel associated with capitalized inventory barrels is also capitalized and subsequently expensed when sold. During 2020 DD&A decreased by 13% ($3.4 million) for the year ended December 31, 2020, compared to 2019. This decrease was primarily due to a lower depletable base from Q1-2020 impairment losses and a decrease in production, partially offset by a decrease in crude oil inventory during the first quarter of 2020.

In Canada, gross DD&A decreased by 6% ($0.4 million) during the year ended December 31, 2020, compared to 2019. The decrease was primarily attributable to a lower depletable base from impairment losses recognized in the first quarter of 2020 and a decrease in production.

IMPAIRMENT LOSS

The disruption to the oil and gas industry experienced during the first quarter of 2020 and the resulting downward pressure on commodity prices led to an assessment of impairment indicators present on both the Company's petroleum and natural gas ("PNG") and exploration and evaluation ("E&E") assets that required it to perform an assessment of the recoverability of these assets as at March 31, 2020.

The Company recorded a non-cash impairment loss of $40.0 million on its PNG assets during the first quarter of 2020. This was comprised of a $24.7 million impairment loss on the West Gharib concession, a $6.6 million impairment loss on the West Bakr concession, a $4.6 million impairment loss on the North West Gharib concession and a $4.1 million impairment loss on the Canadian assets. These impairment losses were recorded to reduce the carrying value of these PNG assets to their projected recoverable amounts, which was $23.8 million in West Gharib, $55.0 million in West Bakr, $nil in North West Gharib and $60.0 million in Canada. No further impairment losses were recognized in 2020.

The Company also recorded an impairment loss of $33.5 million on its E&E assets during the first quarter of 2020. This was comprised of a $29.5 million impairment loss on the South Ghazalat concession and a $4.0 million impairment loss on the North West Gharib concession. The impairment loss recognized on these two concessions represented the entire E&E asset balances in the concessions. The E&E impairment losses were taken after consideration of the scale of exploration results compared to investments to date and consideration of the uncertainly of the timing of additional exploration activities in these areas given the current economic environment.

If market conditions deteriorate, including crude oil prices declining and remaining at low levels for a sustained period of time, TransGlobe may record further asset impairments in the future. Alternatively, if both near-term and long-term commodity prices have a strong recovery from current levels and outlook, the possibility exists for a value recovery in the future.

In 2019, the Company was unsuccessful in its attempts to secure military approval to access its desired drilling location in South Alamein. Based on the 2017 well results in the Boraq area, the limited commerciality of the original Boraq 2 discovery (2009) and continued access restrictions in the eastern area of the concession; the Company fully impaired the remaining carrying value of South Alamein of $8.3 million and relinquished the concession in 2019. During the third quarter of 2019, the Company received a final settlement report from EGPC regarding the relinquished North West Sitra concession. The final settlement report resulted in a reduction of the original impairment loss recognized by $0.4 million**.**

CAPITAL EXPENDITURES

($000s)	**2020**	2019
Egypt	**5,256**	27,239
Canada	**2,067**	9,525
Corporate	**175**	168
Total	**7,498**	36,932

Capital expenditures in 2020 were $7.5 million (2019 - $36.9 million).

In Egypt, the Company incurred $5.3 million in capital expenditures during 2020 primarily associated with drilling and completing one development oil well and performing four recompletions.

In Canada, the Company incurred $2.1 million in capital expenditures during 2020 associated with drilling one horizontal Cardium oil well in the Harmattan area.

OUTSTANDING SHARE DATA

As at December 31, 2020 and March 12, 2021, the Company had 72,542,071 common shares issued and outstanding and 4,589,042 stock options issued and outstanding, of which 2,797,168 were exercisable in accordance with their terms into an equal number of common shares of the Company.

LIQUIDITY AND CAPITAL RESOURCES

Liquidity describes a company's ability to access cash. Companies operating in the upstream oil and gas industry require sufficient cash in order to fund capital programs that maintain and increase production and reserves, to acquire strategic oil and gas assets, to repay current liabilities and debt and ultimately to provide a return to shareholders. TransGlobe's capital programs are funded by existing working capital and cash provided from operating activities. The Company's cash flow from operations varies significantly from quarter to quarter, depending on the timing of oil sales from cargoes lifted in Egypt, and these fluctuations in cash flow impact the Company's liquidity. TransGlobe's management will continue to steward capital and focus on cost reductions in order to maintain balance sheet strength through the current volatile oil price environment.

Funding for the Company's capital expenditures is provided by cash flows from operations and cash on hand. The Company expects to fund its 2021 exploration and development program through the use of working capital and cash flow from operations. Fluctuations in commodity prices, product demand, foreign exchange rates, interest rates and various other risks may impact capital resources and capital expenditures.

Working capital is the amount by which current assets exceed current liabilities. As at December 31, 2020, the Company had a working capital surplus of $15.3 million (December 31, 2019 - $32.2 million). The decrease in working capital is primarily due to the $15.0 million outstanding balance of the Mercuria prepayment agreement being reclassified as current during the year, a decrease in cash resulting from repayments on long-term debt, payments on accounts payable during the year, a decrease in crude oil inventory due to increased sales to EGPC in 2020, partially offset by a decrease in accounts payable.

As at December 31, 2020, the Company's cash equivalents balance consisted of short-term deposits with an original term to maturity at purchase of one month or less. All of the Company's cash and cash equivalents are on deposit with high credit-quality financial institutions.

Over the past 10 years, the Company experienced delays in the collection of accounts receivable from EGPC. The length of delay peaked in 2013, returned to historical delays of up to six months in 2017, and has since fluctuated within an acceptable range. As at December 31, 2020, amounts owing from EGPC were $6.0 million. The Company considers there to be minimal credit risk associated with amounts receivable from EGPC.

In Egypt, the Company completed a second crude oil sale in Q4-2020 for total proceeds of $16.2 million, which were collected in December 2020. The Company incurs a 30-day collection cycle on sales to third-party international buyers. Depending on the Company's assessment of the credit of crude oil purchasers, they may be required to post irrevocable letters of credit to support the sales prior to the cargo lifting. As at December 31, 2020, the Company held 227.9 Mbbls of entitlement oil as inventory.

As at December 31, 2020, the Company had $86.0 million of revolving credit facilities with $21.5 million drawn and $64.5 million available. The Company has a prepayment agreement with Mercuria that allows for a revolving balance of up to $75.0 million, of which $15.0 million was drawn and outstanding as at December 31, 2020. During 2020, the Company repaid $15.0 million of this prepayment agreement. The Company also has a revolving Canadian reserves-based lending facility with ATB that was renewed and reduced as at June 30, 2020 from C$25.0 million ($19.2 million) to C$15.0 million ($11.0 million). The reduction in the ATB facility is a result of lower forecasted commodity prices and the associated impact on asset value. During 2020, the Company repaid C$2.0 million ($1.5 million) and had drawings of $C0.5 million ($0.4 million) on this facility, leaving C$8.3 million ($6.6 million) drawn and outstanding.

The Company actively monitors its liquidity to ensure that cash flows, credit facilities and working capital are adequate to support these financial liabilities, as well as the Company's capital programs.

To date, the Company has experienced no difficulties with transferring funds abroad (see "Risks and Uncertainties").

PRODUCT INVENTORY

Product inventory consists of the Company's Egypt entitlement crude oil barrels, which are valued at the lower of cost or net realizable value. Cost includes operating expenses and depletion associated with the unsold entitlement crude oil as determined on a concession by concession basis. All oil produced is delivered to EGPC facilities. EGPC owns the storage and export facilities from where the Company's product inventory is sold. The Company requires EGPC cooperation to schedule liftings and works with EGPC on a continuous basis to schedule cargoes. Crude oil inventory levels fluctuate from quarter to quarter depending on EGPC approvals, as well as the timing and size of cargoes in Egypt. As at December 31, 2020, the Company had 227.9 Mbbls of entitlement crude oil stored as inventory, which represents approximately one and a half months of entitlement oil production. Since the Company began directly marketing its oil on January 1, 2015, crude oil inventory levels have both increased and decreased from year to year. These fluctuations in crude oil inventory levels impact the Company's financial condition, financial performance and cash flows.

(Mbbls)	**Years Ended December 31, 2020**	Year Ended December 31, 2019
Product inventory, beginning of year	**964.5**	568.1
TransGlobe entitlement production	**1,769.9**	2,170.0
Crude oil sales	**(2,506.5)**	(1,773.6)
Product inventory, end of year	**227.9**	964.5

Inventory reconciliation

The following table summarizes the operating expenses and depletion capitalization in unsold entitlement crude oil inventory.

	Years Ended December 31, 2020	Year Ended December 31, 2019
Production and operating expenses ($/bbl)	**22.29**	12.82
Depletion ($/bbl)	**3.29**	5.34
Unit cost of inventory ($/bbl)	**25.57**	18.16
Product inventory, end of year (Mbbls)	**227.9**	964.5
Product inventory, end of year ($000s)	**5,828**	17,516

COMMITMENTS AND CONTINGENCIES

As part of its principal business, the Company entered into arrangements and incurred obligations that will impact the Company's future operations and liquidity. The principal commitments of the Company are as follows:

			Payment Due by Period[1,2]			
($000s)	Recognized in Financial Statements	Contractual Cash Flows	Less than 1 year	1-3 years	4-5 years	More than 5 years
Accounts payable and accrued liabilities	Yes-Liability	21,667	21,667	-	-	-
Long-term debt[3]	Yes-Liability	21,567	15,000	6,567	-	-
Lease obligations[4]	Yes-Liability	2,243	1,760	483	-	-
Drilling commitment	No	1,000	-	1,000	-	-
Other long-term liabilities	Yes-Liability	544	-	544	-	-
Derivative commodity contracts	Yes-Liability	398	398	-	-	-
Equipment and facility leases (short-term)[5]	No	21	21	-	-	-
Total		**47,440**	**38,846**	**8,594**	**-**	**-**

1 Payments exclude ongoing operating costs, finance costs and payments made to settle derivatives.
2 Payments denominated in foreign currencies have been translated at December 31, 2020 exchange rates.
3 Excludes deferred financing costs of $0.1 million.
4 These amounts include the notional principal and interest payments.
5 Equipment leases include one facility contract.

Pursuant to the approved South Ghazalat development lease, the Company is committed to drill one exploration well during the initial four year period of the 20 year development lease. The Company has issued a production guarantee in the amount of $1.0 million which will be released when the commitment well has been drilled.

In the normal course of its operations, the Company may be subject to litigation and claims. Although it is not possible to estimate the extent of potential costs, if any, management believes that the ultimate resolution of such contingencies would not have a material adverse impact on the results of operations, financial position or liquidity of the Company.

The Company is not aware of any material provisions or other contingent liabilities as at December 31, 2020.

ASSET RETIREMENT OBLIGATION

As at December 31, 2020, TransGlobe had an asset retirement obligation ("ARO") of $13.0 million (December 31, 2019 - $13.6 million) for the future abandonment and reclamation costs of the Canadian assets. The estimated ARO liability includes assumptions of actual costs to abandon and/or reclaim wells and facilities, the time frame in which such costs will be incurred, as well as inflation factors in order to calculate the undiscounted total future liability. TransGlobe calculated the present value of the obligations using a discount rate of 2.00% (December 31, 2019- rates between 1.68% and 1.76%) to reflect the market assessment of the time value of money as well as risks specific to liabilities that have not been included in the cash flow estimates. The inflation rate used in determining the cash flow estimate was 2% per annum (December 31, 2019 - 2%).

In Egypt, under model concession agreements and the Fuel Material Law, liabilities in respect of decommissioning movable and immovable assets (other than wells) passes to the Egyptian Government through the transfer of ownership from the contractor to the government under the cost recovery process. While the current risk to the Company of becoming liable for decommissioning liabilities in Egypt is low, future changes to legislation could result in decommissioning liabilities in Egypt. Any increase in Egyptian decommissioning liabilities could adversely affect the Company's financial condition.

In relation to petroleum wells, under good oilfield practices, the contractor is responsible for decommissioning non-producing wells under a decommissioning plan approved by EGPC during the life of the concession agreement. If EGPC agrees that a producing well is not economic, then the contractor will be responsible for decommissioning the well under an EGPC approved decommissioning plan. EGPC, at its own discretion, may not require a well to be decommissioned if it wants to preserve the ability to use the well for other purposes. As EGPC has discretion on decommissioning wells, there is a risk that the Company could incur well decommissioning costs. In accordance with the respective concession agreements, expenses approved by EGPC are recoverable through the cost recovery mechanism.

As at December 31, 2020 there is no ARO associated with the Egypt PSCs.

DERIVATIVE COMMODITY CONTRACTS

The nature of TransGlobe's operations exposes it to fluctuations in commodity prices, interest rates and foreign currency exchange rates. TransGlobe monitors and when appropriate, uses derivative financial instruments to manage its exposure to these fluctuations. All transactions of this nature entered into by TransGlobe are related to an underlying financial position or to future crude oil and natural gas production. TransGlobe does not use derivative financial instruments for speculative purposes. TransGlobe has elected not to designate any of its derivative financial instruments as accounting hedges and thus accounts for changes in fair value in net earnings (loss) at each reporting period. TransGlobe has not obtained collateral or other security to support its financial derivatives as management reviews the creditworthiness of its counterparties prior to entering into derivative contracts. The derivative financial instruments are initiated within the guidelines of the Company's corporate hedging policy. This includes linking all derivatives to specific assets and liabilities on the balance sheet or to specific firm commitments or forecasted transactions.

In conjunction with the prepayment agreement, discussed further in the "Liquidity and Capital Resources" section of this MD&A, TransGlobe also entered into a marketing contract with Mercuria to market nine million barrels of TransGlobe's Egypt entitlement crude oil production. The pricing of the crude oil sales is based on market prices at the time of sale.

The following table summarizes TransGlobe's outstanding derivative commodity contract positions as at December 31, 2020, the fair values of which have been presented on the Consolidated Balance Sheet:

Financial Brent crude oil contracts

Period Hedged	Contract	Remaining Volume (bbl)	Monthly Volume (bbl)	Bought Put US$/bbl	Sold Call US$/bbl	Sold Put US$/bbl
Jan 2021 - Jun 2021	3-Way Collar	300,000	50,000	48.00	53.25	40.00

Financial AECO natural gas contracts

Period Hedged	Contract	Remaining Volume (GJ)	Daily Volume (GJ)	Swap C$/GJ
Jan 2021 - Dec 2021	Swap	1,387,000	3,800	2.76

Subsequent to year-end, the Company entered into the following Brent crude oil derivative commodity contract position:

Period Hedged	Contract	Remaining Volume (bbl)	Monthly Volume (bbl)	Bought Put US$/bbl	Sold Call US$/bbl	Sold Put US$/bbl
Feb 2021 - Dec 2021	3-Way Collar	550,000	50,000	50.00	60.00	40.00

RISKS AND UNCERTAINTIES

TransGlobe's results are affected by a variety of business risks and uncertainties in the international petroleum industry. Many of these risks are not within the control of management, however, the Company has adopted several strategies to reduce and minimize the effects of these risks:

The COVID-19 pandemic and continued low commodity price environment resulting from decreased demand and oversupply to the market could negatively affect the Company's operating results in 2021. The future impacts of the global repercussions of these factors on the Company's business or operating and financial results are unpredictable and cannot be identified with certainty at this time. There is no assurance that these factors will not have a material adverse impact on TransGlobe or the results of its operations. The extent of the impact, if any, will depend on developments beyond the Company's control, including actions taken by governments, financial institutions, monetary policy authorities, and public health authorities to contain and respond to public health concerns and general economic conditions as a result of the pandemic.

TransGlobe will continue to actively monitor the situation and may take further actions to adapt to these conditions. TransGlobe cannot be certain of the potential effects any such actions may have on the business or operating and financial results in future periods.

Financial risk

Financial risk is the risk of loss or lost opportunity resulting from financial management and market conditions that could have a positive or negative impact on TransGlobe.

The Company actively manages its cash position and maintains credit facilities to ensure it has sufficient available funds to meet current and foreseeable financial requirements at a reasonable cost. Management believes that future cash flow from operations, working capital and availability under existing credit facilities will be adequate to support these financial liabilities and its capital programs.

The political changes that have created financial instability in Egypt since 2011 could present challenges to the Company if the issues re-emerge in future years. Future instability could reduce the Company's ability to access debt, capital and banking markets. To mitigate potential financial risk factors, the Company maintains a strong liquidity position. Management regularly evaluates operational and financial risk strategies and continues to monitor the 2021 capital budget and the Company's long-term plans. In January 2015, TransGlobe began direct sales of Eastern Desert entitlement production to international buyers. The Company anticipates that direct sales will continue to reduce financial risk in future periods.

Market risk

Market risk is the risk or uncertainty arising from possible market price movements and the associated impact on the future performance of the business. The market price movements that the Company is exposed to include commodity prices, foreign currency exchange rates and interest rates, all of which could have a positive or negative impact on TransGlobe.

Commodity price risk

The Company's operational results and financial condition are partially dependent on the commodity prices received for its production of oil, natural gas and NGLs.

Any movement in commodity prices would have an effect on the Company's financial condition which could result in the delay or cancellation of drilling, development or construction programs, all of which could have a material adverse impact on the Company. The Company uses financial derivative contracts from time to time, as deemed necessary, to manage fluctuations in commodity prices in the normal course of operations. The

use of derivative instruments is governed under formal policies and is subject to limits established by the Board of Directors.

Foreign currency exchange risk

As the Company's business is conducted primarily in U.S. dollars and its financial instruments are primarily denominated in U.S. dollars, the Company's exposure to foreign currency exchange risk relates primarily to certain cash and cash equivalents, accounts receivable, long-term debt, lease obligations and accounts payable and accrued liabilities denominated in Canadian dollars. When assessing the potential impact of foreign currency exchange risk, the Company believes that 10% volatility is a reasonable measure. The Company estimates that a 10% increase in the value of the Canadian dollar against the U.S. dollar would increase net loss for the year ended December 31, 2020 by approximately $0.5 million and conversely, a 10% decrease in the value of the Canadian dollar against the U.S. dollar would decrease net loss by $0.5 million for the same period.

The Company is also exposed to foreign currency exchange risk on cash balances denominated in Egyptian pounds. Some collections of accounts receivable from the Egyptian Government are received in Egyptian pounds, and while the Company is generally able to spend the Egyptian pounds received on accounts payable, there remains foreign currency exchange risk exposure on Egyptian pound cash balances. Using month-end cash balances converted at month-end foreign exchange rates, the average Egyptian pound cash balance for 2020 was $3.0 million (2019 - $2.3 million) in equivalent U.S. dollars. The Company estimates that a 10% increase in the value of the Egyptian pound against the U.S. dollar would increase net loss for the year ended December 31, 2020 by approximately $0.3 million and conversely a 10% decrease in the value of the Egyptian pound against the U.S. dollar would decrease net loss by $0.3 million for the same period. The Company does not currently utilize derivative instruments to manage foreign currency exchange risk.

The Company maintains nominal balances of British Pounds sterling to pay in-country costs incurred in operating its London office. Foreign exchange risk on these funds is not considered material.

Interest rate risk

Fluctuations in interest rates could result in a significant change in the amount the Company pays to service variable interest debt. No derivative contracts were entered into during 2020 to mitigate interest rate risk. When assessing interest rate risk applicable to the Company's variable interest debt the Company believes 1% volatility is a reasonable measure. The effect of interest rates increasing by 1% would increase the Company's net loss, for the year ended December 31, 2020, by $0.3 million and conversely, the effect of interest rates decreasing by 1% would decrease the Company's net loss, for the year ended December 31, 2019, by $0.3 million.

Credit risk

Credit risk is the risk of loss if counterparties do not fulfill their contractual obligations. The Company's exposure to credit risk primarily relates to cash equivalents and accounts receivable, the majority of which are in respect of oil and gas operations. The Company is currently, and may in the future, be exposed to third-party credit risk through its contractual arrangements with its current or future joint interest partners, marketers of its petroleum production and other parties, including the government of Egypt. Significant changes in the oil and gas industry, including fluctuations in commodity prices and economic conditions, environmental regulations, government policy, royalty rates and other geopolitical factors, could adversely affect the Company's ability to realize the full value of its accounts receivable. The Company has historically had significant receivables outstanding from the Government of Egypt. In the past, the timing of payments on these receivables from the Government of Egypt were longer than the industry standard. Despite these factors, the Company expects to collect these receivables in full, though there can be no assurance that this will occur. In the event the Government of Egypt fails to meet its obligations, or other third-party creditors fail to meet their obligations to the Company, such failures could individually or in the aggregate have a material adverse effect on the Company, its cash flow from operating activities and its ability to conduct its ongoing capital expenditure program. The Company has not experienced any material credit loss in the collection of accounts receivable to date.

TransGlobe entered into a joint marketing arrangement with EGPC in December 2014. In January 2015, TransGlobe began direct sales of Eastern Desert entitlement production to international buyers. Buyers may be required to post irrevocable letters of credit to support the sales prior to the cargo liftings. The Company anticipates that direct sales will continue to reduce credit risk in future periods.

Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. Liquidity describes a company's ability to access cash. Companies operating in the upstream oil and gas industry require sufficient cash to fund capital programs necessary to maintain and increase production and proved reserves, to acquire strategic oil and gas assets and to repay debt.

The Company actively maintains its credit facilities to ensure it has sufficient available funds to meet current and foreseeable financial requirements at a reasonable cost. Management believes that future cash flows from operations, working capital and availability under existing credit facilities will be adequate to support these financial liabilities and its capital programs. All of the payments received from the lifting and sale of the Company's entitlement crude oil are deposited directly to its accounts held in London, England.

Crude oil inventory levels fluctuate from quarter to quarter depending on the timing and size of tanker liftings in Egypt. Since the Company began directly marketing its oil on January 1, 2015, both increases and decreases in crude oil inventory levels have been experienced from quarter to quarter. During 2019 there was a steady increase in crude oil inventory levels, as production outpaced sales. Throughout 2020 crude inventory levels decreased as sales exceeded production. These fluctuations in crude oil inventory levels impact the Company's financial condition, financial performance and cash flows.

To date, the Company has experienced no difficulties with transferring funds abroad.

Operational risk

The Company’s future success largely depends on its ability to exploit its current reserves base and to find, develop or acquire additional oil reserves that are economically recoverable. Failure to acquire, discover or develop these additional reserves will have an impact on cash flows of the Company. To mitigate these operational risks, as part of its capital approval process, the Company applies rigorous geological, geophysical and engineering analysis to each prospect. The Company utilizes its in-house expertise for all international and domestic ventures or employs and contracts professionals to handle each aspect of the Company’s business. The Company retains independent reserves evaluators to determine year-end Company reserves and estimated future net revenues.

The Company also mitigates operational risks by maintaining a comprehensive insurance program according to customary industry practice, but cannot fully insure against all risks.

Safety, environmental, social and regulatory risk

To mitigate safety, environmental and social risks, TransGlobe conducts its operations in accordance with the Company's Health, Safety, Environmental, and Social Responsibility Policy to ensure compliance with government regulations and guidelines. Monitoring and reporting programs for environmental health and safety performance in day-to-day operations, as well as inspections and assessments, are designed to provide assurance that environmental and regulatory standards are met. Security risks are managed through security procedures designed to protect TransGlobe's personnel and assets. The Company has a Whistleblower Protection Policy which protects employees if they raise any concerns regarding TransGlobe's operations, accounting or internal control matters.

Regulatory and legal risks are identified and monitored by TransGlobe's corporate team and external legal professionals to ensure that the Company continues to comply with laws and regulations.

Political risk

TransGlobe operates in countries with political, economic and social systems, which subject the Company to a number of risks that are not within the control of the Company. These risks may include, among others, currency restrictions and exchange rate fluctuations, loss of revenue and property and equipment as a result of expropriation, nationalization, war, insurrection and geopolitical and other political risks, increases in taxes and governmental royalties, changes in laws and policies governing operations of companies, economic and legal sanctions and other uncertainties arising from foreign and domestic governments.

Egypt experienced significant political changes over the past ten years and while this had an impact on the efficient operations of the government in general, business processes and the Company’s operations generally proceeded as normal. The current government has added stability in the Egyptian political landscape; however, the possibility of future political changes exists. Future political changes could have a material adverse impact on the Company's operations.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements in accordance with IFRS requires that management make appropriate decisions with respect to the selection of accounting policies and in formulating estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. The following is included in the MD&A to aid the reader in assessing the critical accounting policies and practices of the Company. The information will also aid in assessing the likelihood of materially different results being reported depending on management's assumptions and changes in prevailing conditions which affect the application of these policies and practices. Significant accounting policies are disclosed in Note 3 of the Consolidated Financial Statements, and critical judgements and accounting estimates are disclosed in Note 4.

Oil and gas reserves

TransGlobe's proved and probable oil and gas reserves are evaluated and reported on by independent reserves evaluators to the Reserves, Health, Safety, Environment and Social Responsibility Committee comprised of a majority of independent directors. The estimation of reserves is a subjective process. Forecasts are based on engineering data, projected future rates of production, estimated commodity price forecasts and the timing of future expenditures, all of which are subject to numerous uncertainties and various interpretations. The Company expects that its estimates of reserves will change to reflect updated information. Reserves estimates can be revised upward or downward based on the results of future drilling, testing, production levels and economics of recovery based on cash flow forecasts.

Production sharing concessions

International operations conducted pursuant to PSCs are reflected in the Consolidated Financial Statements based on the Company's working interest in such operations. Under the PSCs, the Company and other non-governmental partners pay all operating and capital costs for exploring and developing the concessions. Each PSC establishes specific terms for the Company to recover these costs and to share in the production sharing oil. Cost recovery oil is determined in accordance with a formula that is generally limited to a specified percentage of production during each quarter. Production sharing oil is that portion of production remaining after cost recovery oil and is shared between the joint interest partners and the government of each country, varying with the level of production. Production sharing oil that is attributable to the government includes an amount in respect of all income taxes payable by the Company under the laws of the respective country. Revenue represents the Company's share and is recorded net of royalty payments to government and other mineral interest owners. For the Company's international operations; all government interests, except for income taxes, are considered royalty payments. The Company's revenue also includes the recovery of costs paid on behalf of foreign governments in international locations.

DISCLOSURE CONTROLS AND PROCEDURES

As of December 31, 2020, an evaluation was carried out, under the supervision and with the participation of the Company's management including the Chief Executive Officer and Chief Financial Officer, on the effectiveness of the Company's disclosure controls and procedures as defined in Rule 13a-15 under the U.S. Securities Exchange Act of 1934, as amended (the "Exchange Act") and as defined in Canada by National Instrument 52-109, Certification of Disclosure in Issuers' Annual and Interim Filings. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that as of the end of the fiscal year, the design and operation of these disclosure controls and procedures were effective to ensure that all information required to be disclosed by the Company in its annual filings is recorded, processed, summarized and reported within the specified time periods.

Disclosure controls and procedures are defined as controls and other procedures of an issuer that are designed to provide reasonable assurance that information required to be disclosed by the issuer in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in the securities legislation and include controls and procedures designed to ensure that information required to be disclosed by an issuer in its annual filings, interim filings or other reports filed or submitted under securities legislation is accumulated and communicated to the issuer's management, including its certifying officers, as appropriate to allow timely decisions regarding required disclosure.

INTERNAL CONTROLS OVER FINANCIAL REPORTING

TransGlobe's management designed and implemented internal controls over financial reporting, as defined under National Instrument 52-109 *Certification of Disclosure in Issuers' Annual and Interim Filings*, of the Canadian Securities Administrators and as defined in Rule 13a-15 under the Exchange Act. Internal controls over financial reporting is a process designed under the supervision of the Chief Executive Officer and the Chief Financial Officer and effected by the Board of Directors, management and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS as issued by the IASB. Due to its inherent limitations, internal controls over financial reporting may not prevent or detect misstatements on a timely basis. A system of internal controls over financial reporting, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the internal controls over financial reporting are met. Also, projections of any evaluation of the effectiveness of internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with policies or procedures may deteriorate.

Management has assessed the effectiveness of the Company's internal control over financial reporting based on the Committee of Sponsoring Organizations of the Treadway Commission framework on *Internal Control - Integrated Framework (2013)*. Based on this assessment, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2020. No changes were made to the Company's internal controls over financial reporting during the year ended December 31, 2020 that have materially affected, or are reasonably likely to materially affect, the internal controls over financial reporting.

MANAGEMENT'S REPORT

Management's Responsibility for Financial Statements

The Consolidated Financial Statements of TransGlobe Energy Corporation were prepared by management within acceptable limits of materiality and are in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board. Management is responsible for ensuring that the financial and operating information presented in this annual report is consistent with that shown in the Consolidated Financial Statements.

The Consolidated Financial Statements have been prepared by management in accordance with the accounting policies as described in the notes to the Consolidated Financial Statements. Timely release of financial information sometimes necessitates the use of estimates when transactions affecting the current accounting period cannot be finalized until future periods. When necessary, such estimates are based on informed judgments made by management.

To ensure the integrity of the Consolidated Financial Statements, we carefully select and train qualified personnel. We also ensure our organizational structure provides appropriate delegation of authority and division of responsibilities. Our policies and procedures are communicated throughout the organization and include a written Code of Conduct that applies to all employees, including the Chief Executive Officer and Chief Financial Officer.

BDO Canada LLP, an independent registered public accounting firm appointed by the shareholders, has conducted an examination of the corporate and accounting records in order to express their opinion on the Consolidated Financial Statements. The Audit Committee, consisting of three independent directors, has met with representatives of BDO Canada LLP and management in order to determine if management has fulfilled its responsibilities in the preparation of the Consolidated Financial Statements. The Board of Directors has approved the Consolidated Financial Statements.

Management's Report on Internal Controls over Financial Reporting

Management has designed and maintains an appropriate system of internal controls to provide reasonable assurance that all assets are safeguarded and financial records are properly maintained to facilitate the preparation of Consolidated Financial Statements for reporting purposes. Management's evaluation concluded that the internal controls over financial reporting were effective as of December 31, 2020.

Signed by:

"Randy C. Neely"

Randy C. Neely
President & Chief Executive Officer

"Edward D. Ok"

Edward D. Ok
Vice President, Finance & Chief Financial Officer

March 12, 2021

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of TransGlobe Energy Corporation and its subsidiaries (the "Company") as of December 31, 2020, the related consolidated statements of loss and comprehensive loss, changes in shareholders' equity, and cash flows for the year ended December 31, 2020, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2020, and the results of its operations and its cash flows for the year ended December 31, 2020, in conformity with International Financial Reporting Standards as issued by the International Accounting Standards Board.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's consolidated financial statements based on our audit. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal controls over financial reporting. As part of our audit we are required to obtain an understanding of internal controls over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal controls over financial reporting. Accordingly, we express no such opinion.

Our audit included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audit also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audit provides a reasonable basis for our opinion.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that: (i) relates to accounts or disclosures that are material to the consolidated financial statements and (ii) involved especially challenging, subjective, or complex judgments. The communication of the critical audit matter does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

The impact of estimates of proved plus probable oil, natural gas and natural gas liquids reserves on petroleum and natural gas assets

As described in Note 14 to the Consolidated Financial Statements, the Company has a balance in Petroleum and natural gas assets of $140,059 (000's) at December 31, 2020 and depletion, depreciation, and amortization ("DD&A") expense of $24,786 (000's) for the year ended December 31, 2020. Additionally, an impairment loss of $40,036 (000's) was recorded during the year ended December 31, 2020. The process of estimating oil and gas reserves is complex and involves decisions and assumptions in evaluating the available geological, geophysical, engineering and economic data. The accuracy of the Company's reserves estimates is a function of the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions, and the judgment of the management and 3rd party reserves engineers preparing the estimate. The determination of the present value of the reserves estimates requires both management and the 3rd party reserves engineers to make significant estimations and assumptions related pricing, differentials, volume, operating costs, division of interest, taxes, future development costs, and discount rate. The Company's oil and natural gas reserves estimates directly impact (1) oil and natural gas properties, (2) depreciation, depletion, and amortization and (3) the assessment of impairment of oil and natural gas properties. As disclosed by management, any significant variance in these assumptions could materially affect the estimated quantities and present value of their reserves.

The cost of petroleum and natural gas assets comprise the purchase or construction costs, and any costs directly attributable to bring the asset into operation, including qualifying exploration and evaluation ("E&E") costs. Petroleum and natural gas assets are measured at cost less accumulated depletion, depreciation and amortization, and accumulated impairment losses.

We identified the impact of estimates of proved plus probable oil, natural gas and natural gas liquids reserves on petroleum and natural gas assets as a critical audit matter. Certain inputs and assumptions required to estimate volumes and future net revenues of proved plus probable reserves, involve a high degree of subjectivity which could have a significant impact on the measurement of depletion expense and impairment.

Our audit procedures included the following, among others:

- We obtained an understanding of internal controls over the Company's estimation of proved plus probable reserves quantities and related future net cash flows;
- We evaluated the independence, objectivity, and professional qualifications of the Company's reserves engineers, made inquiries of those specialists regarding the process followed and judgments made to estimate the Company's proved plus probable reserves volumes, and read the reserves report prepared by the Company's specialists;
- We evaluated the reasonableness of management's key inputs and assumptions used to determine proved plus probable reserves volumes and other cash flow inputs and assumptions including:
    - Internal communications to management and the Board of Directors.
    - Permits and approval for expenditures.
    - Agree significant inputs to source documentation where available.
    - Assess inputs for reasonableness based on review of corroborative evidence.
    - Applied analytical procedures to the reserves report forecasted production by comparing to historical actual results, and to the prior year reserves report.
    - Compared the estimated pricing differentials used in the reserves report to realized prices related to revenue transactions recorded in the current year and examined contractual support for the pricing differentials.
- We evaluated management's estimated future oil and natural gas prices by:
    - Understanding the methodology used by management for developing future prices and comparing the estimated prices to an independently determined range of prices.
    - Comparing management's estimates to published forward pricing indices and third-party industry sources.
- Engaged our fair value specialist to review the appropriateness of discounts rates used in the impairment models.

Chartered Professional Accountants

We have served as the Company's auditor since 2020.

/s/ BDO Canada LLP

Calgary, Alberta

March 12, 2021

Consolidated Statements of Loss and Comprehensive Loss

(Expressed in thousands of U.S. Dollars, except per share amounts)

	Notes	Years Ended December 31 2020	2019
REVENUE			
Petroleum and natural gas sales, net of royalties	26	**114,675**	140,096
Finance revenue	7	**106**	471
Other revenue	6	**641**	-
		115,422	140,567
EXPENSES			
Production and operating	11,26	**64,462**	50,626
Selling costs	8	**2,111**	1,287
General and administrative		**11,990**	16,611
Foreign exchange loss (gain)		**24**	(147)
Finance costs	7	**2,520**	4,256
Depletion, depreciation and amortization	14	**31,049**	34,948
Asset retirement obligation accretion	15	**259**	215
(Gain) loss on financial instruments	5	**(6,621)**	2,845
Impairment loss	13,14	**73,495**	7,937
Gain on disposition of assets		**-**	(114)
		179,289	118,464
(Loss) earnings before income taxes		**(63,867)**	22,103
Income tax expense - current	12	**13,530**	26,098
NET LOSS		**(77,397)**	(3,995)
OTHER COMPREHENSIVE INCOME			
Currency translation adjustments		**766**	2,073
COMPREHENSIVE LOSS		**(76,631)**	(1,922)
Net loss per share	22		
Basic		**(1.07)**	(0.06)
Diluted		**(1.07)**	(0.06)

See accompanying notes to the Consolidated Financial Statements

Consolidated Balance Sheets

(Expressed in thousands of U.S. Dollars)

	Notes	**As at December 31, 2020**	As at December 31, 2019
ASSETS			
Current			
Cash and cash equivalents	9	**34,510**	33,251
Accounts receivable	5,10	**9,996**	10,681
Prepaids and other		**3,530**	4,338
Product inventory	11	**5,828**	17,516
		53,864	65,786
Non-Current			
Intangible exploration and evaluation assets	13	**584**	33,706
Property and equipment			
Petroleum and natural gas assets	14	**140,059**	196,150
Other	14	**2,917**	4,296
Deferred taxes	12	**3,723**	8,387
		201,147	308,325
LIABILITIES			
Current			
Accounts payable and accrued liabilities	17	**21,667**	32,156
Derivative commodity contracts	5	**398**	217
Current portion of lease obligations	16	**1,553**	1,219
Current portion of long-term debt	18	**14,897**	-
		38,515	33,592
Non-Current			
Long-term debt	18	**6,567**	37,041
Asset retirement obligations	15	**13,042**	13,612
Other long-term liabilities		**544**	614
Lease obligations	16	**461**	589
Deferred taxes	12	**3,723**	8,387
		62,852	93,835
SHAREHOLDERS' EQUITY			
Share capital	20	**152,805**	152,805
Accumulated other comprehensive income		**1,900**	1,134
Contributed surplus	21	**25,109**	24,673
(Deficit) Retained earnings		**(41,519)**	35,878
		138,295	214,490
		201,147	308,325

Commitments and Contingencies (Note 19)

See accompanying notes to the Consolidated Financial Statements

Approved on behalf of the Board of Directors

Signed by:

"Randy C. Neely"

Randy C. Neely
President & CEO
Director

"Steven Sinclair"

Steven Sinclair
Audit Committee Chair
Director

Consolidated Statements of Changes in Shareholders' Equity

(Expressed in thousands of U.S. Dollars)

	Notes	Years Ended December 31 2020	2019
Share Capital			
Balance, beginning of year	20	**152,805**	152,084
Stock options exercised	20	**-**	547
Transfer from contributed surplus on exercise of options	20	**-**	174
Balance, end of year		**152,805**	152,805
Accumulated Other Comprehensive Income			
Balance, beginning of year		**1,134**	(939)
Currency translation adjustment		**766**	2,073
Balance, end of year		**1,900**	1,134
Contributed Surplus			
Balance, beginning of year		**24,673**	24,195
Share-based compensation expense	21	**436**	652
Transfer to share capital on exercise of options	20	**-**	(174)
Balance, end of year		**25,109**	24,673
(Deficit) Retained Earnings			
Balance, beginning of year		**35,878**	44,951
Net loss		**(77,397)**	(3,995)
Dividends	23	**-**	(5,078)
Balance, end of year		**(41,519)**	35,878

See accompanying notes to the Consolidated Financial Statements

Consolidated Statements of Cash Flows

(Expressed in thousands of U.S. Dollars)

	Notes	Years Ended December 31 2020	2019
OPERATING			
Net loss		**(77,397)**	(3,995)
Adjustments for:			
Depletion, depreciation and amortization	14	**31,049**	34,948
Asset retirement obligation accretion	15	**259**	215
Impairment loss	13,14	**73,495**	7,937
Share-based compensation	21	**857**	2,237
Finance costs	7	**2,520**	4,256
Unrealized loss on financial instruments	5	**180**	1,586
Unrealized gain on foreign currency translation		**(62)**	(153)
Gain on asset disposition		**-**	(114)
Asset retirement obligations settled	15	**(458)**	(46)
Changes in non-cash working capital	27	**1,266**	(2,035)
Net cash generated by operating activities		**31,709**	44,836
INVESTING			
Additions to intangible exploration and evaluation assets	13	**(337)**	(5,377)
Additions to petroleum and natural gas assets	14	**(6,726)**	(30,626)
Additions to other assets	14	**(435)**	(929)
Proceeds from asset dispositions		**-**	114
Changes in non-cash working capital	27	**(3,544)**	(291)
Net cash used in investing activities		**(11,042)**	(37,109)
FINANCING			
Issue of common shares for cash	20	**-**	547
Interest paid	7	**(1,918)**	(3,664)
Increase in long-term debt	18	**406**	476
Payments on lease obligations	16	**(1,703)**	(1,945)
Repayments of long-term debt	18	**(16,504)**	(16,523)
Dividends paid	23	**-**	(5,078)
Changes in non-cash working capital	27	**161**	(200)
Net cash used in financing activities		**(19,558)**	(26,387)
Currency translation differences relating to cash and cash equivalents		**150**	206
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS		**1,259**	(18,454)
CASH AND CASH EQUIVALENTS, BEGINNING OF YEAR		**33,251**	51,705
CASH AND CASH EQUIVALENTS, END OF YEAR		**34,510**	33,251

See accompanying notes to the Consolidated Financial Statements

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

As at and for the years ended December 31, 2020 and December 31, 2019

(All amounts expressed in U.S. Dollars, except as otherwise noted)

1. CORPORATE INFORMATION

TransGlobe Energy Corporation ("TransGlobe" or the "Company") and its subsidiaries are engaged in oil and natural gas exploration, development and production, and the acquisition of oil and natural gas properties. The Company's shares are traded on the Toronto Stock Exchange ("TSX"), the London Stock Exchange's Alternative Investment Market ("AIM") and the Capital Market of the NASDAQ Stock Market ("NASDAQ"). TransGlobe is incorporated in Alberta, Canada and the address of its principal place of business is Suite 900, 444 – 5th Avenue SW, Calgary, Alberta, Canada, T2P 2T8.

2. BASIS OF PREPARATION

The Consolidated Financial Statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board. The accounting policies used in the preparation of the Consolidated Financial Statements are described in Note 3 *Significant Accounting Policies*.

The Company prepared the Consolidated Financial Statements on a going concern basis, which contemplates the realization of assets and liabilities in the normal course of business as they become due. Accordingly, the Consolidated Financial Statements have been prepared on a historical cost basis, except for cash and cash equivalents, derivative commodity contracts and other long-term liabilities that have been measured at fair value. The method used to measure fair value is discussed further in Notes 3 and 5.

The Consolidated Financial Statements are presented and expressed in United States dollars ("US$"), unless otherwise noted. All references to $ are to United States dollars and references to C$ are to Canadian dollars.

The Consolidated Financial Statements were authorized for issue by the Board of Directors on March 11, 2021.

3. SIGNIFICANT ACCOUNTING POLICIES

The accounting policies set out below have been applied consistently to all subsidiaries and periods presented in these Consolidated Financial Statements.

Basis of consolidation

The Consolidated Financial Statements include the financial statements of the Company and its wholly-owned, controlled subsidiaries. Control exists when the Company has the power to govern the financial and operating policies of an entity, it is exposed to or has rights to variable returns associated with its involvement in the entity, and it has the ability to use that power to influence the amount of returns it is exposed to or has rights to. In assessing control, potential voting rights need to be considered. All subsidiaries of the Company are wholly-owned by the parent company, TransGlobe Energy Corporation.

All intra-company transactions, balances, income and expenses, unrealized gains and losses are eliminated on consolidation.

Foreign currency translation

The Consolidated Financial Statements are presented in U.S. dollars. The Company's functional currency is the Canadian dollar, and the functional currency of all subsidiaries is the U.S. dollar. Foreign currency translations include the translation of foreign currency transactions and translation of the Canadian operations.

Foreign currency translations occur when translating transactions in foreign currencies to the applicable functional currency of TransGlobe Energy Corporation and its subsidiaries. Gains and losses from foreign currency transactions are recorded as foreign exchange gains or losses. Foreign currency transaction translations occur as follows:

- Income and expenses are translated at the prevailing rates on the date of the transaction
- Non-monetary assets or liabilities are carried at the prevailing rates on the date of the transaction
- Monetary items are translated at the prevailing rates at the balance sheet date

Translation gains and losses occur when translating the financial statements of non-U.S. functional currency operations to the U.S. dollar. These translation gains and losses are recorded as currency translation adjustments and presented as other comprehensive income on the Consolidated Statements of Earnings (Loss) and Comprehensive Income (Loss). Translations occur as follows:

- Income and expenses are translated at the date of the transaction
- Assets and liabilities are translated at the prevailing rates on the balance sheet date

Cash and cash equivalents

Cash and cash equivalents include cash and short-term investments that mature within one month of the date of their purchase.

Financial instruments

Financial instruments are measured at fair value on initial recognition. Measurement in subsequent periods depends on the classification of the financial instrument:

- Fair value through profit or loss - subsequently carried at fair value with changes recognized in net earnings (loss). Financial instruments under this classification include cash and cash equivalents, and derivative commodity contracts; and
- Amortized cost - subsequently carried at amortized cost using the effective interest method. Financial instruments under this classification include accounts receivable, accounts payable and accrued liabilities and long-term debt.

The Company enters into certain financial derivative contracts from time to time in order to reduce its exposure to market risks from fluctuations in commodity prices. These instruments are not used for trading or speculative purposes. The Company does not designate financial derivative contracts as effective accounting hedges, and thus does not apply hedge accounting, even though the Company considers all commodity contracts to be economic hedges. As a result, the Company's policy is to classify all financial derivative contracts at fair value through profit or loss and to record them on the Consolidated Balance Sheet at fair value with a corresponding gain or loss in net earnings (loss). Attributable transaction costs are recognized in net earnings (loss) when incurred. The estimated fair value of all derivative instruments is based on quoted market prices and/or third-party market indications and forecasts.

Embedded derivatives are derivatives embedded in a host contract. They are recorded separately from the host contract when their economic characteristics and risks are not closely related to those of the host contract; when the terms of the embedded derivatives are the same as those of a freestanding derivative; and when the combined contract is not measured at fair value through profit or loss.

Refer to Note 5 for the classification and measurement of these financial instruments.

Share capital

Common shares are classified as equity. Incremental costs directly attributable to the issue of common shares are recognized as a deduction from equity. Repurchase of the Company's own equity instruments is recognized and deducted directly in equity. No gain or loss is recognized in profit or loss on the purchase, sale, issue or cancellation of the Company's own equity instruments.

Leases

A contract is, or contains, a lease if the contract provides the right to control the use of an identified asset for a period of time in exchange for consideration. A lease obligation is recognized at the commencement of the lease term measured as the present value of the lease payments not already paid at that date. Interest expense is recognized on the lease obligations using the effective interest rate method and net payments are applied against the lease obligation. At the commencement date, a corresponding right-of-use asset is recognized at the amount of the lease obligation, adjusted for lease incentives received and initial direct costs. Depreciation is recognized on the right-of-use asset over the lease term.

Property and equipment and intangible exploration and evaluation assets

Exploration and evaluation assets

Exploration and evaluation ("E&E") costs related to each license/prospect are initially capitalized within "intangible exploration and evaluation assets". Such E&E costs may include costs of license acquisition, technical services and studies, seismic acquisition, exploration drilling and testing, directly attributable expenses, including remuneration of production personnel and supervisory management, and the projected costs of retiring the assets (if any), but do not include pre-licensing costs incurred prior to having obtained the legal rights to explore an area, which are expensed directly to net earnings (loss) as they are incurred and presented as exploration expenses on the Consolidated Statements of Earnings (Loss) and Comprehensive Income (Loss).

Intangible exploration and evaluation assets are not depleted. They are carried forward until technical feasibility and commercial viability of extracting a mineral resource is determined, at which point they are transferred to petroleum and natural gas ("PNG") assets. The technical feasibility and commercial viability is considered to be determined when proved and/or probable reserves are determined to exist or they can be empirically supported with actual production data or conclusive formation tests.

Petroleum and natural gas assets

PNG assets and other assets are recognized at cost less accumulated depletion, depreciation and amortization, and accumulated impairment losses. The initial cost of an asset comprises its purchase price or construction cost, any costs directly attributable to bringing the asset into operation, including qualifying E&E costs on reclassification from intangible exploration and evaluation assets, and for qualifying assets, where applicable, borrowing costs. When significant parts of an item of property and equipment have different useful lives, they are accounted for as separate items.

Gains and losses on disposal of items of property and equipment, including oil and natural gas interests, are determined by comparing the proceeds from disposal with the carrying amount of property and equipment and are recognized in net earnings (loss) immediately.

Subsequent costs

Costs incurred subsequent to the determination of technical feasibility and commercial viability and the costs of replacing parts of property and equipment are recognized as petroleum properties or other assets only when they increase the future economic benefits embodied in the specific asset to which they relate. All other expenditures are recognized in profit or loss as incurred. Such capitalized property and equipment generally represent costs incurred in developing proved and/or probable reserves and bringing in or enhancing production from such reserves, and are accumulated on a well, field or geotechnical area basis, together with the discounted value of estimated future costs of asset retirement obligations.

When components of PNG assets are replaced, disposed of or no longer in use, the carrying amount is derecognized. The costs of the day-to-day servicing of property, plant and equipment are recognized in net earnings (loss) as incurred.

Depletion, depreciation and amortization

The depletion, depreciation and amortization of PNG assets and other assets are recognized in net earnings (loss).

The net carrying value of the PNG assets included in petroleum properties is depleted using the unit of production method by reference to the ratio of production to the related proved plus probable reserves using estimated future prices and costs. Costs subject to depletion include estimated future development costs necessary to bring those reserves into production. These estimates are reviewed by independent reserves engineers at least annually and determined in accordance with National Instrument 51-101 *Standards of Disclosure of Oil and Gas Activities*. Natural gas reserves and production are converted at the energy equivalent of six thousand cubic feet to one barrel of oil.

Furniture and fixtures are depreciated at declining balance rates of 20% to 30%, whereas vehicles and leasehold improvements are depreciated on a straight-line basis over their estimated useful lives.

Depreciation methods, useful lives and residual values are reviewed at each reporting date.

Product inventory

Product inventory consists of the Company's unsold Egypt entitlement crude oil barrels, valued at the lower of cost, using the first-in, first-out method, or net realizable value. Cost includes operating expenses and depletion associated with the entitlement crude oil barrels as determined on a concession by concession basis.

Impairment

Financial assets carried at amortized cost

At each reporting date, the Company assesses whether there is objective evidence that a financial asset carried at amortized cost is impaired. If such evidence exists, the Company recognizes an impairment loss in net earnings (loss). Impairment losses are reversed in subsequent periods if the impairment loss decrease can be related objectively to an event occurring after the impairment was recognized.

An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount, and the present value of the estimated future cash flows discounted at the original effective interest rate. Individually significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics.

Non-financial assets

At each reporting date, the carrying amounts of the Company’s non-financial assets are reviewed to determine whether there is an indication of impairment, except for E&E assets, which are reviewed when circumstances indicate impairment may exist. If there is an indication of impairment, the asset's recoverable amount is estimated and compared to its carrying value.

For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generate cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets (the cash-generating unit). The recoverable amount of an asset or a cash-generating unit ("CGU") is the greater of its value in use and its fair value less costs to sell. The Company’s CGUs are not larger than a segment. In assessing both fair value less costs to sell and value in use, the estimated future cash flows are discounted to their present value using a discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in net earnings (loss).

For PNG assets, fair value less costs to sell and value in use is generally computed by reference to the present value of the future cash flows expected to be derived from production of proved plus probable reserves.

E&E assets are tested for impairment when they are transferred to petroleum properties and also if facts and circumstances suggest that the carrying amount of E&E assets may exceed the recoverable amount. Impairment indicators are evaluated at a CGU level. Indication of impairment includes:

1. Expiry or impending expiry of lease with no expectation of renewal;
2. Lack of budget or plans for substantive expenditures on further E&E;
3. Cessation of E&E activities due to a lack of commercially viable discoveries; and
4. Carrying amounts of E&E assets are unlikely to be recovered in full from a successful development project.

Impairment losses recognized in prior periods are assessed at each reporting date for indication that the loss has decreased or no longer exists. An impairment loss may be reversed if there has been a change in the estimates used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depletion and depreciation or amortization, if no impairment loss had been recognized.

Share-based payment transactions

Equity-settled transactions

The cost of equity-settled transactions with employees is measured by reference to the fair value at the date at which equity instruments are granted and is recognized as an expense over the vesting period, which ends on the date on which the relevant employees become fully entitled to the award. Fair value is determined by using the lattice-based trinomial option pricing model. An estimated forfeiture rate is taken into consideration when assigning a fair value to options granted such that no expense is recognized for awards that do not ultimately vest.

At each financial reporting date before vesting, the cumulative expense is calculated, which represents the extent to which the vesting period has expired and management's best estimate of the number of equity instruments that will ultimately vest. The movement in cumulative expense since the previous financial reporting date is recognized in net earnings (loss), with a corresponding entry in contributed surplus in equity.

When the terms of an equity-settled award are modified or a new award is designated as replacing a canceled or settled award, the cost based on the original award terms continues to be recognized over the remainder of the new vesting period for the incremental fair value of any modification, based on the difference between the fair value of the original award and the fair value of the modified award, both as measured on the date of the modification. No reduction is recognized if this difference is negative.

Cash-settled transactions

The expense related to the share units granted under these plans is measured at fair value using the lattice-based trinomial pricing model and is recognized over the vesting period, with a corresponding liability recognized on the Consolidated Balance Sheet.

The grant date fair value of cash-settled units granted to employees is recognized as compensation expense within general and administrative expenses, with a corresponding increase in accounts payable, accrued liabilities and other long-term liabilities over the period that the employees become unconditionally entitled to the units. The amount recognized as an expense is adjusted to reflect the actual number of units for which the related service and non-market vesting conditions are met. Until the liability is ultimately settled, it is re-measured at each reporting date with changes to fair value recognized in net earnings (loss).

Provisions and asset retirement obligations

A provision is recognized if, as a result of a past event, the Company has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a rate that reflects current market assessments of the time value of money and the risks specific to the liability. Provisions are not recognized for future operating losses.

The Company provides for asset retirement obligations on all of its Canadian operations based on current legislation and industry operating practices. The estimated present value of the asset retirement obligation is recorded as a long-term liability, with a corresponding increase in the carrying amount of the related asset. This increase is depleted with the related depletion unit and is allocated to a CGU for impairment testing. The liability is increased each reporting period to reflect the passage of time with a corresponding charge to accretion expense. The asset retirement obligation can also increase or decrease due to changes in the estimated timing of cash flows, changes in the discount rate and/or changes in the original estimated undiscounted costs. Increases or decreases in the obligation will result in a corresponding change in the carrying amount of the related asset. Actual costs incurred upon settlement of the asset retirement obligation are charged against the asset retirement obligation to the extent of the liability recorded. Asset retirement obligations are measured at each reporting period to reflect the discount rates in effect at that time. On an annual basis, the Company reviews its estimates of the expected costs to reclaim the net interest in its wells and facilities. Resulting changes are accounted for prospectively as a change in estimate.

In accordance with all of the Company's Production Sharing Agreements and Production Sharing Concessions (collectively defined as "PSCs"), the Company does not, at any time, hold title to the lands on which it operates. In Egypt, under model concession agreements and the Fuel Material Law, liabilities in respect of decommissioning movable and immovable assets (other than wells) passes to the Egyptian Government through the transfer of ownership from the contractor to the government under the cost recovery process.

In relation to petroleum wells, under good oilfield practices, the contractor is responsible for decommissioning non-producing wells under a decommissioning plan approved by the Egyptian General Petroleum Company ("EGPC") during the life of the concession agreement. If EGPC agrees that a producing well is not economic, then the contractor will be responsible for decommissioning the well under an EGPC approved decommissioning plan. EGPC, at its own discretion, may not require a well to be decommissioned if it wants to preserve the ability to use the well for other purposes. In accordance with the respective concession agreements, expenses approved by EGPC are recoverable through the cost recovery mechanism.

As at December 31, 2020 there is no ARO associated with the Egypt PSCs.

Revenue recognition

The Company's revenue is derived exclusively from contracts with customers, except for immaterial amounts related to interest and other income. Royalties are considered to be part of the price of the sale transaction and are therefore presented as a reduction to revenue. Revenue associated with the sale of crude oil, natural gas and natural gas liquids ("NGLs") is measured based on the consideration specified in contracts with customers. Revenue from contracts with customers is recognized when the Company satisfies a performance obligation by transferring a good or service to a customer. A good or service is transferred when the customer obtains control of the good or service. The transfer of control of oil, natural gas and NGLs usually coincides with title passing to the customer and the customer taking physical possession. TransGlobe mainly satisfies its performance obligations at a point in time and the amounts of revenue recognized relating to performance obligations satisfied over time are not significant.

Revenues associated with the sales of the Company's crude oil in Egypt are recognized by reference to actual volumes sold and quoted market prices in active markets (Dated Brent), adjusted according to specific terms and conditions as applicable per the sales contracts. Revenue is measured at the fair value of the consideration received or receivable. For reporting purposes, the Company records the government's share of production as royalties and taxes as all royalties and taxes are paid out of the government's share of production.

Revenues from the sale of crude oil, natural gas, condensate and NGLs in Canada are recognized by reference to actual volumes delivered at contracted delivery points and prices. Prices are determined by reference to quoted market prices in active markets (crude oil - NYMEX WTI, natural gas - AECO C, condensate - NYMEX WTI, and NGLs - various based on product), adjusted according to specific terms and conditions applicable per the sales contracts. Revenues are recognized prior to the deduction of transportation costs. Revenues are measured at the fair value of the consideration received. TransGlobe pays royalties to the Alberta provincial government and other mineral rights owners in accordance with the established royalty regime.

Revenue segregated by product type and geographical market is disclosed in Note 26.

Finance revenue and costs

Finance revenue comprises interest income on funds invested. Interest income is recognized as it accrues in net earnings (loss), using the effective interest method.

Finance costs comprise interest expense on borrowings.

Borrowing costs incurred for qualifying assets are capitalized during the period of time that is required to complete and prepare the assets for their intended use or sale. Qualifying assets are comprised of those significant assets that require a period greater than one year to be available for their intended use. All other borrowing costs are recognized in net earnings (loss).

Income tax

Income tax expense is comprised of current and deferred tax. TransGlobe is subject to income taxes based on the tax legislation of each respective country in which TransGlobe conducts business.

Current tax

Current tax assets and liabilities for the current and prior periods are measured as the amount expected to be recovered from or paid to the taxation authorities. The tax rates and tax laws used to compute the amount are those that are enacted or substantively enacted by the date of the Consolidated Financial Statements.

The Company's contractual arrangements in Egypt stipulate that income taxes are paid by the government out of its entitlement share of production sharing oil. Such amounts are included in current income tax expense at the statutory rate in effect at the time of production.

Deferred tax

The Company determines the amount of deferred income tax assets and liabilities based on the difference between the carrying amounts of the assets and liabilities reported for financial accounting purposes from those reported for tax. Deferred income tax assets and liabilities are measured using the substantively enacted tax rates expected to apply to taxable income in the years in which the temporary differences are expected to be recovered or settled. Deferred income tax assets are recognized to the extent it is probable the Company will have sufficient future taxable earnings available against which the unused tax losses can be utilized.

Joint arrangements

A joint arrangement involves joint control and offers joint ownership by the Company and other joint interest partners of the financial and operating policies, and of the assets associated with the arrangement. Joint arrangements are classified into one of two categories: joint operations or joint ventures.

A joint operation is a joint arrangement whereby the Company and the other parties that have joint control of the arrangement have rights to the assets and obligations for the liabilities relating to the arrangement. Parties involved in joint operations must recognize in relation to their interests in the joint operation their proportionate share of the revenues, expenses, assets and liabilities. A joint venture is a joint arrangement whereby the Company and the other parties that have joint control of the arrangement have rights to the net assets of the arrangement. Parties involved in joint ventures must recognize their interests in joint ventures as investments and must account for that investment using the equity method.

In Canada, the Company conducts some of its oil and gas production activities through joint operations and the Consolidated Financial Statements reflect only the Company's proportionate interest in such activities. Joint control exists for contractual agreements governing TransGlobe's assets whereby TransGlobe has less than 100% working interest, all of the partners have control of the arrangement collectively, and spending on the project requires the unanimous consent of all parties that collectively control the arrangement and share the associated risks. TransGlobe does not have any joint arrangements that are individually material to the Company or that are structured through joint venture arrangements.

In Egypt, joint arrangements in which the Company is involved are conducted pursuant to PSCs. Given the nature and contractual terms associated with the PSCs, the Company has determined that it has rights to the assets and obligations for the liabilities in all of its joint arrangements and that there are no joint arrangements where the Company has rights to the net assets. Accordingly, all joint arrangements have been classified as joint operations, and the Company has recognized its share of all revenues, expenses, assets and liabilities in accordance with the PSCs in the Consolidated Financial Statements.

4. CRITICAL JUDGMENTS AND ACCOUNTING ESTIMATES

Timely preparation of financial statements in conformity with IFRS as issued by the International Accounting Standards Board requires that management make estimates and assumptions and use judgments that affect the application of accounting policies and the reported amounts of assets, liabilities, revenues and expenses. Such estimates primarily relate to unsettled transactions and events as of the date of the Consolidated Financial Statements. Accordingly, actual results may differ from estimated amounts as future confirming events occur. The effect of these estimates, assumptions and the use of judgments are explained throughout the notes to the Consolidated Financial Statements. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future years affected.

The COVID-19 pandemic and continued volatile commodity price environment resulting from decreased demand and potential oversupply to the market has negatively impacted operating results in 2020 and could further impact operating results in 2021. The results of the economic downturn and any potential resulting impact to the Company have been considered in management's estimates at the year-end; however, there could be a further prospective material impact in future periods.

The key sources of estimation uncertainty that have a significant risk of causing a material adjustment to the carrying amounts of assets and liabilities are discussed below.

Recoverability of asset carrying values

The recoverability of PNG asset carrying values are assessed at the CGU level. Determination of what constitutes a CGU is subject to management judgment of the lowest level at which there are identifiable cash inflows that are largely independent of the cash inflows of other groups of assets or properties. The factors used by TransGlobe to determine CGUs may vary by country due to unique operating and geographic circumstances in each country. In general, TransGlobe assesses the following factors in determining whether a group of assets generate largely independent cash inflows:

- geographic proximity of the assets within a group to one another;
- geographic proximity of the group of assets to other groups of assets; and
- homogeneity of the production from the group of assets and the sharing of infrastructure used to process and/or transport production.

In Egypt, each PSC is considered a separate CGU. In Canada, CGUs are determined by regional geography and one CGU has been identified. The asset composition of a CGU can directly impact the recoverability of the assets included therein. In assessing the recoverability of the Company's petroleum properties, each CGU's carrying value is compared to its recoverable amount, defined as the greater of its fair value less costs to sell and value-in-use. As at December 31, 2020 and December 31, 2019, the recoverable amounts of the Company's CGUs were estimated as their fair value less costs to sell based on the net present value of the after-tax cash flows from the oil and natural gas reserves of each CGU based on reserves estimated by the Company's independent reserves evaluator.

Key input estimates used in the determination of cash flows from oil and natural gas reserves include the following:

- Reserves - There are numerous uncertainties inherent in estimating oil and gas reserves. An external reserves engineering report which incorporates a full evaluation of reserves is prepared on an annual basis with internal reserves updates completed at each quarterly period. Estimating reserves is highly complex, requiring many judgments including forward price estimates, production costs, and recovery rates based on available geological, geophysical, engineering and economic data. Changes in these judgments may have a material impact on the estimated reserves. These estimates may change, resulting in either negative or positive impacts on net earnings (loss) as further information becomes available and as the economic environment changes.
- Commodity prices - Forward price estimates of crude oil and natural gas prices are incorporated into the determination of expected future net cash flows. Commodity prices have fluctuated significantly in recent years due to global and regional factors including supply and demand fundamentals, inventory levels, foreign exchange rates, economic, and geopolitical factors.
- Discount rate - The discount rate used to determine the net present value of future cash flows is based on the Company's estimated weighted average cost of capital. Changes in the economic environment could change the Company's weighted average cost of capital.

Impairment tests were carried out at December 31, 2020 and were based on fair value less costs to sell calculations, using estimated after-tax cash discounted cash flows on proved plus probable reserves. The Company used discount rates based on a calculated cost of capital of 15% in Egypt and 11% in Canada along with the following commodity price estimates:

	Egypt[1]	Canada[1]						
	Brent Blend Crude Oil	WTI Oil	AECO Gas	Edmonton Pentane	Edmonton Butane	Edmonton Propane	Spec Ethane	Exchange Rate
Year	$/Bbl	$/Bbl	$C/Mcf	$C/Bbl	$C/Bbl	$C/Bbl	$C/Bbl	USD/CAD
2021	50.75	48.00	2.72	60.65	27.75	19.43	8.62	0.775
2022	55.00	51.50	2.67	65.36	36.47	24.31	8.45	0.765
2023	58.50	54.50	2.60	70.07	41.48	25.53	8.22	0.760
2024	61.79	57.79	2.60	74.72	44.29	27.26	8.22	0.760
2025	62.95	58.95	2.65	76.25	45.29	27.87	8.39	0.760
2026	64.13	60.13	2.71	77.80	46.30	28.49	8.58	0.760
2027	65.33	61.33	2.76	79.38	47.32	29.12	8.76	0.760
2028	66.56	62.56	2.81	81.00	48.37	29.77	8.94	0.760
2029	67.81	63.81	2.87	82.64	49.44	30.43	9.13	0.760
2030	69.17	65.09	2.92	84.30	50.43	31.03	9.31	0.760
Thereafter[2]	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	0.760

[1] GLJ Ltd. ("GLJ") price forecasts, effective January 1, 2021.

[2] Percentage change represents the increase in each year after 2030 to the end of the reserves life.

Depletion of petroleum properties

Reserves and resources are used in the units of production calculation for depletion, depreciation and amortization. Depletion of petroleum properties is calculated based on total proved plus probable reserves as well as estimated future development costs associated with these reserves as determined by the Company's independent reserves evaluator. See above for discussion of estimates and judgments involved in reserves estimation.

Income taxes

Related assets and liabilities are recognized for the estimated tax consequences between amounts included in the Consolidated Financial Statements and their tax base using substantively enacted future income tax rates. Timing of future revenue streams and future capital spending changes can affect the timing of any temporary differences, and accordingly affect the amount of the deferred tax asset or liability calculated at a point in time. Tax interpretations, regulations and legislation in the various jurisdictions in which TransGlobe and its subsidiaries operate are subject to change and interpretation. Such changes can affect the timing of the reversal of temporary tax differences, the tax rates in effect when such differences reverse and TransGlobe's ability to use tax losses and other tax pools in the future. The Company's income tax filings are subject to audit by taxation authorities in different jurisdictions and the results of such audits may increase or decrease the tax liability. The determination of current and deferred tax amounts recognized in the Consolidated Financial Statements are based on management's assessment of the tax positions, which includes consideration of their technical merits, communications with tax authorities and management's view of the most likely outcome. These differences could materially impact net earnings (loss).

Financial instruments

The fair values of financial instruments are estimated based upon market and third-party inputs. These estimates are subject to change with fluctuations in commodity prices, interest rates, foreign currency exchange rates and estimates of non-performance risk.

Share-based payments

The fair value estimates of equity-settled and cash-settled share-based payment awards depend on certain assumptions including share price volatility, risk-free interest rate, the term of the awards, and the forfeiture rate which, by their nature, are subject to measurement uncertainty.

Asset retirement obligations

The provision for site restoration and abandonment in Canada is based on current legal and constructive requirements, technology, price levels and expected plans for remediation. Actual costs and cash outflows can differ from estimates because of changes in laws and regulations, public expectations, market conditions, discovery and analysis of site conditions and changes in technology.

Recoverability of accounts receivable

The recoverability of accounts receivable due from EGPC is assessed to determine the carrying value of accounts receivable on the Company's Consolidated Balance Sheets. Management judgment is required in performing the recoverability assessment. No material credit losses have been experienced to date, and the Company expects to collect the accounts receivable balance in full.

E&E Assets

Management uses judgment to determine whether a sufficient amount of economically recoverable reserves have been discovered. This requires estimates of the quantity and realizable value of a discovery. E&E assets are subject to ongoing technical, commercial and management review to confirm the continued intent to establish the technical feasibility and commercial viability of the discovery.

Leases

Management uses judgement to determine the incremental borrowing rate and lease term related to the application of IFRS 16. Incremental borrowing rates are based on judgments including economic environment, term, currency, and the underlying risk inherent to the asset. The carrying amount of the right-of-use assets, lease obligations, and the resulting interest and depletion and depreciation expense, may differ due to changes in the market conditions and lease term. Lease terms are based on assumptions regarding extension terms that allow for operational flexibility and future market conditions.

5. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Fair values of financial instruments

Financial instruments include cash and cash equivalents, accounts receivable, derivative commodity contracts, accounts payable and accrued liabilities, lease obligations and long-term debt.

The Company has classified its cash and cash equivalents and derivative commodity contracts as fair value through profit or loss. Both are measured at fair value with subsequent changes recognized through net earnings (loss). Accounts receivable are classified as assets at amortized cost; accounts payable and accrued liabilities, lease obligations and long-term debt are classified as liabilities at amortized cost, all of which are measured initially at fair value, and subsequently at amortized cost. Transaction costs attributable to financial instruments carried at amortized cost are included in the initial measurement of the financial instrument and are subsequently amortized using the effective interest rate method.

Carrying value and fair value of financial assets and liabilities are summarized as follows:

	December 31, 2020		December 31, 2019	
Classification ($000s)	**Carrying Value**	**Fair Value**	Carrying Value	Fair Value
Financial assets at fair value through profit or loss	**34,510**	**34,510**	33,251	33,251
Financial assets at amortized cost	**9,996**	**9,996**	10,681	10,681
Financial liabilities at fair value through profit or loss	**398**	**398**	217	217
Financial liabilities at amortized cost	**45,145**	**45,248**	69,197	69,695

Assets and liabilities as at December 31, 2020 that are measured at fair value are classified into levels reflecting the method used to make the measurements. Fair values of assets and liabilities included in Level 1 are determined by reference to quoted prices in active markets for identical assets and liabilities. Assets and liabilities in Level 2 include valuations using inputs other than quoted prices for which all significant inputs are observable, either directly or indirectly. Level 3 valuations are based on inputs that are unobservable and significant to the overall fair value measurement.

The Company's cash and cash equivalents and derivative commodity contracts are assessed on the fair value hierarchy described above. TransGlobe's cash and cash equivalents are classified as Level 1. Derivative commodity contracts are classified as Level 2. Assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement within the fair value hierarchy level. There were no transfers between levels in the fair value hierarchy in the period.

Derivative commodity contracts

The nature of TransGlobe's operations exposes it to fluctuations in commodity prices, interest rates and foreign currency exchange rates. TransGlobe monitors and, when appropriate, uses derivative financial instruments to manage its exposure to these fluctuations. All transactions of this nature entered into by TransGlobe are related to an underlying financial position or to future crude oil and natural gas production. TransGlobe does not use derivative financial instruments for speculative purposes. TransGlobe has elected not to designate any of its derivative financial instruments as accounting hedges and thus accounts for changes in fair value in net earnings (loss) at each reporting period. TransGlobe has not obtained collateral or other security to support its financial derivatives as management reviews the creditworthiness of its counterparties prior to entering into derivative contracts. The derivative financial instruments are initiated within the guidelines of the Company's corporate hedging policy. This includes linking all derivatives to specific assets and liabilities on the balance sheet or to specific firm commitments or forecasted transactions.

In conjunction with the prepayment agreement (see Note 18), TransGlobe entered into a marketing contract with Mercuria Energy Trading SA ("Mercuria") to market nine million barrels of TransGlobe's Egyptian entitlement oil production. The pricing of the crude oil sales will be based on market prices at the time of sale.

The following table summarizes TransGlobe's outstanding derivative commodity contract positions as at December 31, 2020, the fair values of which have been presented on the Consolidated Balance Sheet:

Financial Brent crude oil contracts

Period Hedged	Contract	Remaining Volume (bbl)	Monthly Volume (bbl)	Bought Put US$/bbl	Sold Call US$/bbl	Sold Put US$/bbl
Jan 2021 - Jun 2021	3-Way Collar	300,000	50,000	48.00	53.25	40.00

Financial AECO natural gas contracts

Period Hedged	Contract	Remaining Volume (GJ)	Daily Volume (GJ)	Swap C$/GJ
Jan 2021 - Dec 2021	Swap	1,387,000	3,800	2.76

Subsequent to year-end, the Company entered into the following Brent crude oil derivative commodity contract position:

Period Hedged	Contract	Remaining Volume (bbl)	Monthly Volume (bbl)	Bought Put US$/bbl	Sold Call US$/bbl	Sold Put US$/bbl
Feb 2021 - Dec 2021	3-Way Collar	550,000	50,000	50.00	60.00	40.00

The gains and losses on financial instruments for 2020 and 2019 are comprised as follows:

	Years Ended December 31	
($000s)	**2020**	2019
Realized derivative (gain) loss during the year	**(6,801)**	1,259
Unrealized derivative loss on commodity contracts outstanding at year end	**180**	1,586
(Gain) loss on financial instruments	**(6,621)**	2,845

Overview of Risk Management

The Company's activities expose it to a variety of financial risks that arise as a result of its exploration, development, production and financing activities:

- Credit risk
- Market risk
- Liquidity risk

The Board of Directors and Audit Committee oversee management's establishment and execution of the Company's risk management framework. Management has implemented and monitors compliance with risk management policies. The Company's risk management policies are established to identify and analyze the risks faced by the Company, to set appropriate risk limits and controls, and to monitor risks and adherence to market conditions and the Company's activities.

Credit risk

Credit risk is the risk of financial loss if a customer or counterparty to a financial instrument fails to fulfill their contractual obligations. The Company's exposure to credit risk primarily relates to cash equivalents and accounts receivable, the majority of which are in respect of oil and natural gas operations. The Company generally extends unsecured credit to these parties and therefore the collection of these amounts may be affected by changes in economic or other conditions. The Company has not experienced any material credit losses in its cash investments or in the collection of accounts receivable to date.

TransGlobe's accounts receivable related to the Canadian operations are with customers and joint interest partners in the petroleum and natural gas industry, and are subject to normal industry credit risks. Receivables from petroleum and natural gas marketers are normally collected in due course. The Company currently sells its production to several purchasers under standard industry sale and payment terms. Purchasers of TransGlobe's natural gas, crude oil and natural gas liquids are subject to a periodic internal credit review to minimize the risk of non-payment. The Company has continued to closely monitor and reassess the creditworthiness of its counterparties, including financial institutions.

Trade and other receivables are analyzed in the table below.

($000s)	**December 31, 2020**	December 31, 2019
Neither impaired nor past due	**6,542**	3,636
Not impaired and past due in the following period:		
Within 30 days	**2,255**	226
31-60 days	**34**	131
61-90 days	**510**	5,672
Over 90 days	**655**	1,016
Accounts receivable	**9,996**	10,681

The Company completed two direct crude sale shipments in Egypt to third-party buyers during 2020 and 2019. Depending on the Company's assessment of the credit of crude purchasers, they may be required to post irrevocable letters of credit to support the sales prior to the cargo liftings. During 2020, the Company also completed monthly sales of inventoried entitlement crude oil to EGPC for a total of 1,602.1 mbbls with total proceeds of $65.3 million. As at December 31, 2020, $6.0 million (December 31, 2019 – $5.7 million) of the total accounts receivable balance of $10.0 million (December 31, 2019 - $10.7 million) is due from EGPC. All accounts receivable are in good standing and collection is not considered to be at risk.

The Company manages its credit risk on cash equivalents by investing only in term deposits with reputable banking institutions.

Market risk

Market risk is the risk or uncertainty arising from possible market price movements and the associated impact on future performance of the business. The market price movements that the Company is exposed to include commodity prices, foreign currency exchange rates and interest rates, all of which could adversely affect the value of the Company’s financial assets, liabilities and financial results.

Commodity price risk

The Company’s operational results and financial condition are partially dependent on the commodity prices received for its production of oil, natural gas and NGLs. The Company is exposed to commodity price risk on its derivative assets and liabilities which are used as part of the Company's risk management program to mitigate the effects of changes in commodity prices on future cash flows. While transactions of this nature relate to forecasted future petroleum and natural gas production, TransGlobe does not designate these derivative assets and liabilities as accounting hedges. As such, changes in commodity prices impact the fair value of derivative instruments and the corresponding gains or losses on derivative instruments. The estimated fair value of unrealized commodity contracts is reported on the Consolidated Balance Sheets, with any change in the unrealized positions recorded to net earnings (loss). The Company assesses these instruments on the fair value hierarchy and has classified the determination of fair value of these instruments as Level 2, as the fair values of these transactions are based on an approximation of the amounts that would have been received from counterparties to settle the transactions outstanding as at the date of the Consolidated Balance Sheets with reference to forward prices and market values provided by independent sources. The actual amounts realized may differ from these estimates.

Foreign currency exchange risk

As the Company’s business is conducted primarily in U.S. dollars and its financial instruments are primarily denominated in U.S. dollars, the Company’s exposure to foreign currency exchange risk relates primarily to certain cash and cash equivalents, accounts receivable, long-term debt, lease obligations and accounts payable and accrued liabilities denominated in Canadian dollars. When assessing the potential impact of foreign currency exchange risk, the Company believes that 10% volatility is a reasonable measure. The Company estimates that a 10% increase in the value of the Canadian dollar against the U.S. dollar would increase net loss for the year ended December 31, 2020 by approximately $0.5 million and conversely, a 10% decrease in the value of the Canadian dollar against the U.S. dollar would decrease net loss by $0.5 million for the same period. The Company does not utilize derivative instruments to manage this risk.

The Company is also exposed to foreign currency exchange risk on cash balances denominated in Egyptian pounds. Some collections of accounts receivable from the Egyptian Government are received in Egyptian pounds, and while the Company is generally able to spend the Egyptian pounds received on accounts payable denominated in Egyptian pounds, there remains foreign currency exchange risk exposure on Egyptian pound cash balances. Using month-end cash balances converted at month-end foreign exchange rates, the average Egyptian pound cash balance for 2020 was $3.0 million (2019 - $2.3 million) in equivalent U.S. dollars. The Company estimates that a 10% increase in the value of the Egyptian pound against the U.S. dollar would increase net loss for the year ended December 31, 2020 by approximately $0.3 million and conversely a 10% decrease in the value of the Egyptian pound against the U.S. dollar would decrease net loss by $0.3 million for the same period. The Company does not currently utilize derivative instruments to manage foreign currency exchange risk.

The Company maintains nominal balances of British Pounds sterling to pay in-country costs incurred in operating its London office. Foreign exchange risk on these funds is not considered material.

Interest rate risk

Fluctuations in interest rates could result in a significant change in the amount the Company pays to service variable interest debt. No derivative contracts were entered into during 2020 to mitigate interest rate risk. When assessing interest rate risk applicable to the Company’s variable interest debt, the Company believes 1% volatility is a reasonable measure. The effect of interest rates increasing by 1% would increase the Company’s net loss, for the year ended December 31, 2020, by $0.3 million and conversely, the effect of interest rates decreasing by 1% would decrease the Company’s net loss, for the year ended December 31, 2020, by $0.3 million.

Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. Liquidity describes a company’s ability to access cash. Companies operating in the upstream oil and gas industry require sufficient cash in order to fund capital programs necessary to maintain and increase production and proved reserves, to acquire strategic oil and gas assets and to repay debt.

The Company actively maintains credit facilities to ensure it has sufficient available funds to meet current and foreseeable financial requirements at a reasonable cost. The following are the contractual maturities of financial liabilities at December 31, 2020:

			Payment Due by Period[1,2]			
($000s)	Recognized in Financial Statements	Contractual Cash Flows	Less than 1 year	1-3 years	4-5 years	More than 5 years
Accounts payable and accrued liabilities	Yes-Liability	21,667	21,667	-	-	-
Long-term debt[3]	Yes-Liability	21,567	15,000	6,567	-	-
Lease obligations[4]	Yes-Liability	2,243	1,760	483	-	-
Drilling commitment	No	1,000	-	1,000	-	-
Other long-term liabilities	Yes-Liability	544	-	544	-	-
Derivative commodity contracts	Yes-Liability	398	398	-	-	-
Equipment and facility leases (short-term)[5]	No	21	21	-	-	-
Total		**47,440**	**38,846**	**8,594**	**-**	**-**

[1] Payments exclude ongoing operating costs, and finance costs.
[2] Payments denominated in foreign currencies have been translated at December 31, 2020 exchange rates.
[3] Excludes deferred financing costs of $0.1 million.
[4] These amounts include the notional principal and interest payments.
[5] Equipment leases include one facility contract.

As at December 31, 2020, the Company had $86.0 million of revolving credit facilities with $21.5 million drawn and $64.5 million available. The Company has a prepayment agreement with Mercuria that allows for a revolving balance of up to $75.0 million, of which $15.0 million was drawn and outstanding as at December 31, 2020. During 2020, the Company repaid $15.0 million on this prepayment facility (See Note 18). The Company also has a revolving Canadian reserves-based lending facility with ATB that was renewed and reduced as at June 30, 2020 from C$25.0 million ($19.2 million) to C$15.0 million ($11.0 million). The reduction in the ATB facility is a result of lower forecasted commodity prices and the associated impact on asset value. During 2020, the Company repaid C$2.0 million ($1.5 million) and had drawings of C$0.5 million ($0.4 million) on this facility, leaving C$8.3 million ($6.6 million) drawn and outstanding (See Note 18).

The Company actively monitors its liquidity to ensure that its cash flows, credit facilities and working capital are adequate to support these financial liabilities, as well as the Company's capital programs.

To date, the Company has experienced no difficulties with transferring funds abroad.

Capital disclosures

The Company's objective when managing capital is to ensure the Company will have the financial capacity, liquidity and flexibility to fund the ongoing exploration and development of its petroleum assets. The Company's financial objectives and strategy have remained substantially unchanged over the last two completed fiscal years. These objectives and strategy are reviewed on an annual basis. The Company was subject to financial covenants with the prepayment agreement and the reserves-based lending facility as at December 31, 2020 and 2019. The Company was in compliance with all financial covenants at December 31, 2020 and 2019.

The Company defines and computes its capital as follows:

($000s)	**2020**	2019
Long-term debt, including the current portion (net of unamortized transaction costs)	**21,464**	37,041
Current assets	**(53,864)**	(65,786)
Current liabilities, excluding the current portion of long-term debt	**23,618**	33,592
Net debt obligations	**(8,782)**	4,847
Shareholders' equity	**138,295**	214,490
Total capital	**129,513**	219,337

6. OTHER REVENUE

Other revenue includes funding received under the Government of Canada's Emergency Wage Subsidy (CEWS) program and the Alberta Site Rehabilitation Program (ASRP). Government grants are recognized when the Company has reasonable assurance that it has complied with the relevant conditions of the grant and that it will be received.

7. FINANCE REVENUE AND COSTS

Finance revenue relates to interest earned on the Company's bank account balances and term deposits.

Finance costs recognized in net earnings (loss) were as follows:

	Years Ended December 31	
($000s)	**2020**	2019
Interest on long-term debt	**1,597**	3,211
Interest on borrowing base facility	**317**	427
Amortization of deferred financing costs	**395**	368
Interest on lease obligations	**211**	250
Finance costs	**2,520**	4,256
Interest paid	**1,918**	3,664

8. SELLING COSTS

Selling costs include transportation and marketing costs associated with the sale of the Company's Egyptian crude oil production to third-party buyers and EGPC. The Company completed two direct crude oil sales to third-party buyers during the year ended December 31, 2020 (2019 - two). The Company also completed monthly sales of inventoried entitlement crude oil to EGPC in 2020. The Company completed two sales of inventoried entitlement crude oil to EGPC in 2019.

9. CASH AND CASH EQUIVALENTS

The following table reconciles TransGlobe's cash and cash equivalents:

($000s)	**December 31, 2020**	December 31, 2019
Cash	**34,510**	12,251
Cash equivalents	**-**	21,000
Cash and cash equivalents	**34,510**	33,251

As at December 31, 2020 the Company's cash equivalents balance consisted of short-term deposits with an original term to maturity at purchase of three months or less. All of the Company's cash and cash equivalents are on deposit with high credit-quality financial institutions.

10. ACCOUNTS RECEIVABLE

Accounts receivable are comprised principally of amounts owed from EGPC. There were no amounts due from related parties and no loans to management or employees as at December 31, 2020 or December 31, 2019.

11. PRODUCT INVENTORY

Product inventory consists of the Company's entitlement crude oil barrels in Egypt, which are valued at the lower of cost or net realizable value. Costs include operating expenses and depletion associated with crude oil entitlement barrels and are determined on a concession by concession basis. These amounts are initially capitalized and expensed when sold.

As at December 31, 2020, the Company held 227.9 Mbbls of crude oil in inventory valued at approximately $25.57/bbl (December 31, 2019 – 964.5 mbbls valued at approximately $18.16/bbl). During 2020, product inventory of $11.7 million was expensed (2019 - $8.8 million capitalized).

12. INCOME TAXES

The Company's deferred income tax assets and liabilities are as follows:

($000s)	**2020**	2019
Deferred income tax asset and liability, beginning of year	**-**	-
Expenses related to the origination and reversal of temporary differences for:		
Property and equipment	**(25,507)**	(377)
Non-capital losses carried forward	**(4,459)**	304
Long-term liabilities	**-**	—
Share issue expenses	**-**	—
Changes in unrecognized tax benefits	**29,967**	73
Deferred income tax expense recognized in net earnings (loss)	**3,723**	8,387
Deferred income tax recovery recognized in net earnings (loss)	**(3,723)**	(8,387)
Deferred income tax asset, end of year	**3,723**	8,387
Deferred income tax liability, end of year	**(3,723)**	(8,387)

The Company has non-capital losses of $117.0 million (2019 - $97.6 million) that expire between 2027 and 2040. A deferred tax asset of $3.7 million (2019 - $8.4 million) was recognized in respect of unused tax losses in West Gharib. The Company has an additional $42.5 million (2019 - $16.8 million) in unrecognized tax benefits arising in foreign jurisdictions.

Current income taxes represent income taxes incurred and paid under the laws of Egypt pursuant to the PSCs on the West Gharib, West Bakr, NW Gharib and South Ghazalat concessions.

Income taxes vary from the amount that would be computed by applying the average Canadian statutory income tax rate of 24% (2019 – 26.5%) to income before taxes as follows:

($000s)	2020	2019
Income taxes calculated at the Canadian statutory rate	**(15,328)**	5,857
Increases (decreases) in income taxes resulting from:		
Non-deductible expenses	**5,260**	(2,206)
Changes in unrecognized tax benefits	**29,966**	73
Effect of tax rates in foreign jurisdictions[1]	**(6,562)**	18,804
Changes in tax rates and other	**194**	3,570
Income tax expense - current	**13,530**	26,098

[1] The statutory tax rate in Egypt is 40.55%.

The Company's consolidated effective income tax rate for 2020 was 21.2% (2019 – 118.1%).

13. INTANGIBLE EXPLORATION AND EVALUATION ASSETS

The following table reconciles the changes in TransGlobe's exploration and evaluation assets:

($000s)	2020	2019
Balance, beginning of year	**33,706**	36,266
Additions to exploration and evaluation assets	**337**	5,377
Impairment loss	**(33,459)**	(7,937)
Balance, end of year	**584**	33,706

The disruption experienced by the industry, related to the effects caused by the COVID-19 pandemic, which began during the first quarter of 2020 resulted in the Company identifying indicators of impairment on its intangible exploration and evaluation ("E&E") assets as at March 31, 2020. Further consideration was given to the scale of exploration results compared to investments to date and consideration of the uncertainty of the timing of additional exploration activities in these areas given the current economic environment.

For the year ended December 31, 2020, the Company recorded a non-cash impairment loss of $33.5 million on its exploration and evaluation assets, which included a $29.5 million impairment loss on the South Ghazalat concession and a $4.0 million impairment loss on the North West Gharib concession. The impairment loss recognized represented the entire E&E asset balance in the two concessions.

For the year ended December 31, 2019, the Company recorded a non-cash impairment loss of $7.9 million on its exploration and evaluation assets, which included an $8.3 million impairment loss on the South Alamein concession and $0.4 million of impairment recovery on the North West Sitra concession. In 2019, the Company was unsuccessful in its attempts to secure military approval to access its desired drilling location in South Alamein. Based on the 2017 well results in the Boraq area, the limited commerciality of the original Boraq 2 discovery (2009) and continued access restrictions in the eastern area of the concession; the Company fully impaired the remaining carrying value of South Alamein of $8.3 million and relinquished the concession in 2019. During the third quarter of 2019, the Company received a final settlement report from EGPC regarding the relinquished North West Sitra concession. The final settlement report resulted in a reduction of the original impairment loss recognized by $0.4 million.

Exploration and evaluation assets as at December 31, 2020 includes $0.6 million in Canada (December 31, 2019-$0.5 million), $nil in South Ghazalat (December 31, 2019- $29.2 million) and $nil in North West Gharib (December 31, 2019- $4.0 million).

14. PROPERTY AND EQUIPMENT

The following table reconciles the changes in TransGlobe's property and equipment assets:

($000s)	PNG Assets	Other Assets	Total
Cost			
Balance at December 31, 2018	679,905	16,111	696,016
Increase in right-of-use assets	1,275	2,227	3,502
Additions	30,626	929	31,555
Change in estimate for asset retirement obligations	746	-	746
Balance at December 31, 2019	712,552	19,267	731,819
Increase in right-of-use assets	1,650	49	1,699
Additions	6,726	435	7,161
Change in estimate for asset retirement obligations (Note 15)	(624)	-	(624)
Balance at December 31, 2020	**720,304**	**19,751**	**740,055**
Accumulated depreciation, depletion, amortization and impairment losses			
Balance at December 31, 2018	483,272	13,032	496,304
Depletion, depreciation and amortization for the year[1]	35,136	1,939	37,075
Balance at December 31, 2019	518,408	14,971	533,379
Depletion, depreciation and amortization for the year[1]	24,786	1,863	26,649
Impairment loss	40,036	-	40,036
Balance at December 31, 2020	**583,230**	**16,834**	**600,064**
Foreign Exchange			
Balance at December 31, 2018	(1,370)	-	(1,370)
Currency translation adjustments	3,376	-	3,376
Balance at December 31, 2019	2,006	-	2,006
Currency translation adjustments	979	-	979
Balance at December 31, 2020	**2,985**	**-**	**2,985**
Net book value			
At December 31, 2019	196,150	4,296	200,446
At December 31, 2020	**140,059**	**2,917**	**142,976**

[1] Depletion, depreciation and amortization for the period includes amounts capitalized to product inventory for barrels produced but not sold in the period.

The collapse in commodity prices during the first quarter of 2020 and the resulting impact to the Company resulted in an increase in the market capitalization deficit from December 31, 2019 which led the Company to conclude there were indicators of impairment present on its petroleum and natural gas ("PNG") assets as at March 31, 2020.

Impairment tests were carried out at March 31, 2020 on all of its cash-generating units ("CGU") and were based on fair value less costs to sell calculations (fair value hierarchy Level 3), using estimated after-tax cash discounted cash flows on proved plus probable reserves. The Company used discount rates based on a calculated cost of capital of 15% in Egypt and 11% in Canada along with the following commodity price estimates:

	Egypt[1]	Canada[1]						
	Brent Blend Crude Oil	WTI Oil	AECO Gas	Edmonton Pentane	Edmonton Butane	Edmonton Propane	Spec Ethane	Exchange Rate
Year	**$/Bbl**	**$/Bbl**	**$C/Mcf**	**$C/Bbl**	**$C/Bbl**	**$C/Bbl**	**$C/Bbl**	**USD/CAD**
2020	34.00	30.00	1.95	37.47	21.23	9.61	5.99	0.720
2021	45.50	41.00	2.25	52.05	33.08	19.18	7.01	0.730
2022	52.50	47.50	2.35	61.56	39.52	25.41	7.36	0.735
2023	57.50	52.50	2.45	68.92	45.57	28.89	7.71	0.740
2024	62.50	57.50	2.55	75.84	50.99	32.32	8.05	0.745
2025	62.95	58.95	2.65	77.27	52.02	32.97	8.39	0.750
2026	64.13	60.13	2.70	78.84	53.14	33.68	8.57	0.750
2027	65.33	61.33	2.76	80.44	54.27	34.40	8.76	0.750
2028	66.56	62.56	2.81	82.08	55.44	35.14	8.94	0.750
2029	67.81	63.81	2.87	83.75	56.62	35.89	9.13	0.750
Thereafter[2]	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	0.750

[1] GLJ Ltd. ("GLJ") price forecasts, effective April 1, 2020.

[2] Percentage change represents the increase in each year after 2030 to the end of the reserves life.

The following are the results of the Q1-2020 impairment tests completed and sensitivity impacts of a 1% increase in discount rate and a 5% decrease in pricing on the impairment tests completed:

CGU	Impairment	1% increase in discount rate	5% decrease in pricing
West Gharib	24,769	917	5,536
West Bakr	6,610	1,400	5,171
North West Gharib	4,596	-	-
Canada	4,061	4,844	5,416
Total	**40,036**	**7,161**	**16,123**

The impairment losses above were recorded in Q1-2020 to reduce the carrying value of these PNG assets to their recoverable amounts, which was $23.8 million in West Gharib, $55.0 million in West Bakr, $nil in North West Gharib and $60.0 million in Canada as at March 31, 2020.

At December 31, 2020, the Company's market capitalization was less than its net asset value. This was identified as an indicator of impairment and as a result, the Company completed impairment tests on all of its CGUs in accordance with IAS 36. It was determined that the carrying amounts of the CGUs did not exceed their fair value less costs to sell.

Neither a 1% increase in the discount rate, nor a 5% decrease in the forward price estimates used in the impairment assessments would result in an impairment loss on the West Gharib, West Bakr or Canadian CGUs. The North West Gharib CGU was not assessed for impairment at December 31, 2020 as it was fully impaired as at March 31, 2020.

The following table discloses the carrying amount and depreciation charge for right-of-use assets by the class of underlying asset as at and for the year ended December 31, 2020:

($000s)	PNG Assets	Other Assets	Total
Net book value at January 1, 2019[1]	1,275	2,082	3,357
Increase in right-of-use assets	-	145	145
Depreciation for the year	(901)	(942)	(1,843)
Net book value at December 31, 2019	374	1,285	1,659
Increase in right-of-use assets	1,650	49	1,699
Depreciation for the year	(581)	(937)	(1,518)
Net book value at December 31, 2020	**1,443**	**397**	**1,840**

[1] The Company adopted IFRS 16 *Leases* on January 1, 2019 using the modified retrospective approach.

15. ASSET RETIREMENT OBLIGATION

The following table reconciles the change in TransGlobe's asset retirement obligation:

($000s)	2020	2019
Balance, beginning of year	**13,612**	12,113
Changes in estimates for asset retirement obligations and additional obligations recognized	**(624)**	746
Obligations settled	**(458)**	(46)
Asset retirement obligation accretion	**259**	215
Effect of movements in foreign exchange rates	**253**	584
Balance, end of year	**13,042**	13,612

As at December 31, 2020, the entire asset retirement obligation balance relates to the Company's Canadian operations. TransGlobe has estimated the net present value of its asset retirement obligation to be $13.0 million as at December 31, 2020 (2019 - $13.6 million) based on a total undiscounted future liability of $18.5 million (2019 - $18.9 million). These payments are expected to be made between 2021 and 2066. TransGlobe calculated the present value of the obligations using a discount rate of 2.00% (2019 – 1.68% and 1.76%) to reflect the market assessment of the time value of money as well as risks specific to liabilities that have not been included in the cash flow estimates. The inflation rate used in determining the cash flow estimate was 2% per annum (2019 – 2% per annum).

As at December 31, 2020 there is no ARO associated with the Egypt production sharing concessions.

16. LEASE OBLIGATIONS

The following table reconciles TransGlobe's lease obligations:

($000s)	At December 31, 2020	December 31, 2019
Less than 1 year	**1,760**	1,479
1 - 3 years	**434**	631
Total lease payments	**2,194**	2,110
Amounts representing interest	**180**	302
Present value of net lease payments	**2,014**	1,808
Current portion of lease obligations	**1,553**	1,219
Non-current portion of lease obligations	**461**	589

During the year ended December 31, 2020, the Company spent $0.2 million (2019 - $0.3 million) on interest expense and paid a total cash outflow

of $1.7 million (2019 - $1.9 million) relating to lease obligations.

17. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

Accounts payable and accrued liabilities are comprised of current trade payables and accrued expenses due to third-parties. There were no amounts due to related parties as at December 31, 2020 or December 31, 2019.

18. LONG-TERM DEBT

The following table reconciles the changes in TransGlobe's long-term debt, including the current portion:

($000s)	**2020**	2019
Balance, beginning of year	**37,041**	52,355
Draws on revolving credit facility	**406**	476
Repayment of long-term debt	**(16,504)**	(16,523)
Amortization of deferred financing costs	**395**	368
Effects of movements in foreign exchange rates	**126**	365
Balance, end of year	**21,464**	37,041
Current portion of long-term debt	**(14,897)**	-
Non-current portion of long-term debt	**6,567**	37,041

The Company's interest-bearing loans and borrowings are measured at amortized cost.

Based on the Company's current forecast of future production and prices the estimated future debt payments on long-term debt as of December 31, 2020 are as follows:

($000s)	**Prepayment Agreement[1]**	**Reserves Based Lending Facility**	**Total**
2021	15,000	-	15,000
2022	-	6,567	6,567
	15,000	**6,567**	**21,567**

[1] Excludes deferred financing costs of $0.1 million.

Prepayment Agreement

($000s)	**As at December 31, 2020**	As at December 31, 2019
Prepayment agreement - amount drawn	**15,000**	30,000
Deferred financing costs	**(103)**	(498)
	14,897	29,502

On February 10, 2017, the Company completed a $75 million crude oil prepayment agreement between its wholly-owned subsidiary, TransGlobe Petroleum International Inc. ("TPI") and Mercuria.

TPI's obligations under the prepayment agreement are guaranteed by the Company and the subsidiaries of TPI (the "Guarantors"). The obligations of TPI and the Guarantors will be supported by, among other things, a pledge of equity held by the Company in TPI and a pledge of equity held by TPI in its subsidiaries. The funding arrangement has a term of four years, maturing September 30, 2021. Effective March 31, 2020 the Company received a six month extension on the prepayment agreement. Advances bear interest at a rate of LIBOR plus 6.0%. The funding arrangement is revolving with each advance to be satisfied through the delivery of crude oil to Mercuria. Further advances become available upon delivery of crude oil to Mercuria up to a maximum of $75.0 million and subject to compliance with the other terms and conditions of the prepayment agreement. The prepayment agreement was initially recognized at fair value, net of financing costs, and has subsequently been measured at amortized cost. Financing costs of $1.5 million are being amortized over the term of the prepayment agreement using the effective interest rate method.

The Company is subject to certain financial covenants in accordance with the terms of the prepayment agreement. These covenants are tested on June 30 and December 31 of each year for the life of the prepayment agreement. The financial covenants include financial measures defined within the prepayment agreement that are not defined under IFRS. These financial measures are defined by the prepayment agreement as follows:

- the ratio of the Company's total consolidated indebtedness (calculated by including any outstanding letters of credit or bank guarantees and adding back any cash held by the Company on a consolidated basis) on each financial covenant test date to the Company's consolidated net cash generated by (used in) operating activities (where net cash generated includes the fair market value of crude oil inventory held as at the financial covenant test date) for the trailing 12 month period ending on that financial covenant test date will not exceed 4.00:1.00. The ratio as at December 31, 2020 is (0.32):1.00 (2019 - 0.04:1.00);
- the ratio of Current Assets of the Company on a consolidated basis (calculated, in the case of crude oil inventory, by adjusting the value to market value) to Current Liabilities of the Company on a consolidated basis on each financial covenant test date will not be less than 1.00:1.00. The ratio as at December 31, 2020 is 1.47:1.00 (2019 - 2.92:1.00); and
- the ratio of the parent's non-consolidated asset value to the aggregate amount of indebtedness outstanding under the advance documents on each financial covenant test date will not be less than 2.00:3.00. The ratio as at December 31, 2020 is 18.21:3.00 (2019 - 11.50:3.00).

As at December 31, 2020 and 2019, the Company was in compliance with all the financial covenants under the prepayment agreement.
The Company is also subject to a cover ratio provision. The cover ratio, defined as the value of the Company's Egyptian forecasted entitlement crude oil production on a forward 12-month basis to the prepayment service obligations, must not be less than 1.25:1.00. Prepayment service obligations include the principal outstanding of the advances at the time and any costs, fees, expenses, interest and other amounts outstanding or forecasted to be due during the applicable prepayment period. In the event the cover ratio falls below 1.25:1.00, TransGlobe must:

- reimburse in cash the relevant portion of the advances such that the cover ratio becomes equal to or greater than 1.25:1.00; and/or
- amend the initial commercial contract to extend its duration and amend the maturity date under the agreement.

The cover ratio as at December 31, 2020 is 5.08:1.00 (2019 - 2.73:1.00); the Company is in compliance with the cover ratio provision under the prepayment agreement.

Reserves-Based Lending Facility

($000s)	**December 31, 2020**	December 31, 2019
Reserves-based lending facility - amount drawn	**6,567**	7,539

As at December 31, 2019 the Company had in place a revolving Canadian reserves-based lending facility with ATB totaling C$25.0 million ($19.2 million). As at June 30, 2020, the ATB facility was renewed for C$15.0 million ($11.0 million), of which C$8.3 million ($6.6 million) was drawn (December 31, 2019 - C$9.8 million/$7.5 million). There were no other changes to the key terms of the agreement from December 31, 2019. During the year ended December 31, 2020, the Company repaid C$2.0 million ($1.5 million) and drew C$0.5 million ($0.4 million) on the revolving facility.

The facility borrowing base is re-calculated no less frequently than on a semi-annual basis of May 31 and November 30 of each year, or as requested by the lender. Lender shall notify the Company of each change in the amount of the borrowing base. In the event that the lender re-calculates the borrowing base to be an amount that is less than the borrowings outstanding under the facility, the Company shall repay the difference between such borrowings outstanding and the new borrowing base within 45 days of receiving notice of the new borrowing base.

The Company may request an extension of the term date by no later than 90 days prior to the then-current term date, and the lender may in its sole discretion agree to extend the term date for a further period of 364 days. Unless extended, before May 29, 2021, any unutilized amount of the facility will be canceled, and the amount of the facility will be reduced to the aggregate borrowings outstanding on that date. The balance of all amounts owing under the facility are due and payable in full on the date falling one year after the term date. If no extension is granted by the lender, the amounts owing pursuant to the facility are due at the maturity date. The facility bears interest at a rate of either ATB Prime or CDOR (Canadian Dollar Offered Rate) plus applicable margins that vary from 2.25% to 4.25% (December 31, 2019: 1.25% to 3.25%) depending on the company's net debt to trailing cash flow ratio. The revolving reserve-based lending facility was initially recognized at fair value, net of financing costs, and has subsequently been measured at amortized cost. Financing costs of $0.1 million were amortized over the initial term of the agreement using the effective interest rate method. The Company is subject to certain financial covenants in accordance with the terms of the agreement. These financial measures are defined by the agreement as follows:

- the Company shall not permit the working capital ratio (calculated as current assets plus any undrawn availability under the facility, to current liabilities less any amount drawn under the facility) to fall below 1.00:1.00. The working capital ratio as at December 31, 2020 is 2.82:1.00 (2019 - 1.08:1.00); and
- the Company shall not permit the ratio of net debt to trailing cash flows as at the end of any fiscal quarter to exceed 3.00:1.00. According to the agreement net debt is, as of the end of any fiscal quarter and as determined in accordance with IFRS on a non-consolidated basis, and without duplication, an amount equal to the amount of total debt less current assets. Trailing cash flow is defined as the two most recently completed fiscal quarters, annualized. The net debt to trailing cash flows ratio as at December 31, 2020 is 0.53:1.00 (2019 - 0.76:1.00).

As at December 31, 2020 and 2019, the Company was in compliance with all the financial covenants under the reserves-based lending facility.

19. COMMITMENTS AND CONTINGENCIES

As part of its normal business, the Company entered into arrangements and incurred obligations that will impact the Company's future operations and liquidity. The principal commitments of the Company are as follows:

			Payment Due by Period[1,2]			
($000s)	**Recognized in Financial Statements**	**Contractual Cash Flows**	**Less than 1 year**	**1-3 years**	**4-5 years**	**More than 5 years**
Accounts payable and accrued liabilities	Yes-Liability	21,667	21,667	-	-	-
Long-term debt[3]	Yes-Liability	21,567	15,000	6,567	-	-
Lease obligations[4]	Yes-Liability	2,243	1,760	483	-	-
Drilling commitment	No	1,000	-	1,000	-	-
Other long-term liabilities	Yes-Liability	544	-	544	-	-
Derivative commodity contracts	Yes-Liability	398	398	-	-	-
Equipment and facility leases (short-term)[5]	No	21	21	-	-	-
Total		**47,440**	**38,846**	**8,594**	**-**	**-**

[1] Payments exclude ongoing operating costs, and finance costs.
[2] Payments denominated in foreign currencies have been translated at December 31, 2020 exchange rates.
[3] Excludes deferred financing costs of $0.1 million.
[4] These amounts include the notional principal and interest payments.
[5] Equipment leases include one facility contract.

Pursuant to the approved South Ghazalat development lease, the Company is committed to drill one exploration well during the initial four year period of the 20 year development lease. The Company has issued a production guarantee in the amount of $1.0 million which will be released when the commitment well has been drilled.

In the normal course of its operations, the Company may be subject to litigation and claims. Although it is not possible to estimate the extent of potential costs, if any, management believes that the ultimate resolution of such contingencies would not have a material adverse impact on the results of operations, financial position or liquidity of the Company.

The Company is not aware of any material provisions or other contingent liabilities as at December 31, 2020.

20. SHARE CAPITAL

The Company is authorized to issue an unlimited number of common shares with no par value. Shares in issue as at December 31, 2020 and December 31, 2019 are outlined below:

	2020		2019	
(000s)	**Shares**	**Amount ($)**	Shares	Amount ($)
Balance, beginning of year	**72,543**	**152,805**	72,206	152,084
Stock options exercised	**-**	**-**	337	547
Contributed surplus re-class on exercise	**-**	**-**	-	174
Balance, end of year	**72,543**	**152,805**	72,543	152,805

21. SHARE-BASED PAYMENTS

Stock option plan

The Company operates a stock option plan (the "Plan") to provide equity-settled share-based remuneration to directors, officers and employees. The number of common shares that may be issued pursuant to the exercise of options awarded under the Plan and all other Security-Based Compensation Arrangements of the Company is 10% of the common shares outstanding from time to time. All incentive stock options granted under the Plan have a per-share exercise price equal to the weighted average trading price of the common shares for the five trading days prior to the date of grant. Each tranche of an award with different vesting dates is considered a separate grant for the calculation of fair value and the resulting fair value is amortized over the vesting period of the respective tranche.

The following tables summarize information about the stock options outstanding and exercisable at the dates indicated:

	2020		2019	
(000s)	**Number of Options**	**Weighted-Average Exercise Price ($C)**	Number of Options	Weighted-Average Exercise Price ($C)
Options outstanding, beginning of year	**4,481**	**2.86**	4,876	3.60
Granted	**819**	**0.79**	976	2.83
Exercised	**-**	**-**	(337)	2.18
Expired	**(711)**	**4.99**	(1,034)	6.55
Options outstanding, end of year	**4,589**	**2.16**	4,481	2.86
Options exercisable, end of year	**2,797**	**2.35**	2,585	3.01

	Options Outstanding			**Options Exercisable**		
Exercise Price (C$)	**Number Outstanding at December 31, 2020 (000s)**	**Weighted-Average Remaining Contractual Life (Years)**	**Weighted-Average Exercise price (C$)**	**Number Exercisable at December 31, 2020 (000s)**	**Weighted-Average Remaining Contractual Life (Years)**	**Weighted-Average Exercise price (C$)**
0.79 - 1.48	819	4.4	0.79	-	-	-
1.49 - 2.17	826	1.4	2.16	826	1.4	2.16
2.18 - 2.41	1,002	0.2	2.19	1,002	0.2	2.19
2.42 - 2.73	966	2.4	2.62	644	2.4	2.62
2.74 - 2.83	976	3.2	2.83	325	3.2	2.83
	4,589	**2.3**	**2.16**	**2,797**	**1.4**	**2.35**

Compensation expense of $0.4 million was recorded during the year ended December 31, 2020 (2019 - $0.7 million) in general and administrative expenses in the Consolidated Statements of (Loss) and Comprehensive (Loss) and Changes in Shareholders' Equity in respect of stock options. The fair value of all common stock options granted is estimated on the date of grant using the lattice-based trinomial option pricing model.

The weighted average fair value of options granted during the period and the assumptions used in their determination are noted below:

	2020	2019
Weighted average fair market value per option (C$)	**0.29**	0.88
Risk free interest rate	**0.37%**	1.54%
Expected volatility (based on actual historical volatility)	**58.36%**	54.74%
Dividend rate	**-**	3.30%
Suboptimal exercise factor	**1.25**	1.25

All options granted vest annually over a three-year period and expire five years after the grant date. During the year ended December 31, 2020, employees exercised nil stock options (2019 – 337,000). As at December 31, 2020 and December 31, 2019, the entire balance in contributed surplus was related to previously recognized share-based compensation expense on equity-settled stock options.

Restricted share unit, performance share unit and deferred share unit plans

In May 2014, the Company implemented a restricted share unit ("RSU") plan, a performance share unit ("PSU") plan and a deferred share unit ("DSU") plan.

RSUs may be issued to directors, officers and employees of the Company, and each RSU entitles the holder to a cash payment equal to the fair market value of a TransGlobe common share on the vesting date of the RSU. All RSUs granted vest annually over a three-year period, and all must be settled within 30 days of their respective vesting dates.

PSUs are similar to RSUs, except that the number of PSUs that ultimately vest is dependent on achieving certain performance targets and objectives as set by the Board of Directors. Depending on performance, PSUs can vest between 0% to 200% of the original PSU grant. All PSUs granted vest on the third anniversary of their grant date, and all must be settled within 60 days of their vesting dates.

DSUs are similar to RSUs, except that they become fully vested on the date of grant and are only issued to directors of the Company. Distributions under the DSU plan do not occur until the retirement of the DSU holder from the Company's Board of Directors.

The number of RSUs, PSUs and DSUs outstanding as at December 31, 2020 are as follows:

(000s)	**RSUs**	**PSUs**	**DSUs**
Units outstanding, December 31, 2018	864	1,683	828
Granted	400	529	190
Exercised	(381)	(636)	(454)
Forfeited	(70)	(13)	-
Expired	(15)	-	-
Reinvested	41	77	25
Units outstanding, December 31, 2019	839	1,640	589
Granted	689	1,196	392
Exercised	(385)	(431)	(155)
Forfeited	(308)	(133)	-
Units outstanding, December 31, 2020	**835**	**2,272**	**826**

Compensation expense of $0.4 million was recorded in general and administrative expenses in the Consolidated Statement of (Loss) and Comprehensive (Loss) during the year ended December 31, 2020 in respect of share units granted under the three plans described above (2019 - $1.6 million).

22. PER SHARE AMOUNTS

The weighted-average number of common shares outstanding (basic and diluted) for the year ended December 31, 2020 was 72,542,071 (2019 - basic 72,513,657). These outstanding share amounts were used to calculate net earnings (loss) per share in the respective periods.

In determining diluted net earnings (loss) per share, the Company assumes that the proceeds received from the exercise of "in-the-money" stock options are used to repurchase common shares at the average market price. In calculating the weighted-average number of diluted common shares outstanding for the year ended December 31, 2020, the Company excluded 4,589,042 stock options (2019– 4,480,935) as their exercise price was greater than the average common share market price in the year.

23. DIVIDENDS

During the year ended December 31, 2020, the Company did not pay out dividends.

During the year ended December 31, 2019, the Company paid the following dividends on its common shares:

Ex-dividend date	**Record date**	**Payment date**	**Per share amount**
March 18, 2019	March 29, 2019	April 18, 2019	$ 0.035
August 29, 2019	August 30, 2019	September 13, 2019	$ 0.035

24. RELATED PARTY DISCLOSURES

Details of controlled and consolidated entities active as at December 31, 2020 are as follows*:

	Country of Incorporation	Ownership Interest 2020	Ownership Interest 2019
TG Energy UK Ltd	United Kingdom	100%	100%
TransGlobe Petroleum International Inc.	Turks & Caicos	100%	100%
TG Holdings Yemen Inc.	Turks & Caicos	100%	100%
TransGlobe West Bakr Inc.	Turks & Caicos	100%	100%
TransGlobe West Gharib Inc.	Turks & Caicos	100%	100%
TG Holdings Egypt Inc.	Turks & Caicos	100%	100%
TG Energy Marketing Inc.	Turks & Caicos	100%	100%
TG NW Gharib Inc.	Turks & Caicos	100%	100%
TG S Ghazalat Inc.	Turks & Caicos	100%	100%

*Includes only entities that were active as at December 31, 2020.

25. COMPENSATION OF KEY MANAGEMENT PERSONNEL

Key management personnel have been identified as the Board of Directors and the three executive officers of the Company (2019 – four executive officers).

Key management personnel remuneration consisted of the following:

($000s)	**2020**	2019
Salaries, incentives and short-term benefits	**1,762**	2,560
Share-based compensation	**826**	2,736
Total	**2,588**	5,296

26. SEGMENTED INFORMATION

The Company has two reportable segments for the years ended December 31, 2020 and December 31, 2019: the Arab Republic of Egypt and Canada. The Company, through its operating segments, is engaged primarily in oil exploration, development and production and the acquisition of oil and gas properties. In presenting information on the basis of operating segments, segment revenue is based on the geographical location of assets which is also consistent with the location of the segment customers. Segmented assets are also based on the geographical location of the assets. There are no inter-segment sales. The accounting policies of the operating segments are the same as the Company's accounting policies.

	Years Ended December 31							
	2020	2019	**2020**	2019	**2020**	2019	**2020**	2019
($000s)	**Egypt**		**Canada**		**Corporate**		**Total**	
Revenue								
Oil sales	**173,086**	256,193	**8,679**	15,159	**-**	-	**181,765**	271,352
Natural gas sales	**-**	-	**2,815**	2,705	**-**	-	**2,815**	2,705
Natural gas liquids sales	**-**	-	**4,191**	4,872	**-**	-	**4,191**	4,872
Less: royalties	**(71,741)**	(136,616)	**(2,355)**	(2,217)	**-**	-	**(74,096)**	(138,833)
Petroleum and natural gas sales, net of royalties	**101,345**	119,577	**13,330**	20,519	**-**	-	**114,675**	140,096
Finance revenue	**16**	45	**-**	-	**90**	426	**106**	471
Other revenue	**-**	-	**-**	-	**641**	-	**641**	-
Total segmented revenue	**101,361**	119,622	**13,330**	20,519	**731**	426	**115,422**	140,567
Segmented expenses								
Production and operating	**58,305**	43,252	**6,157**	7,374	**-**	-	**64,462**	50,626
Selling costs	**2,111**	1,287	**-**	-	**-**	-	**2,111**	1,287
General and administrative	**4,781**	6,491	**920**	901	**6,289**	9,219	**11,990**	16,611
Foreign exchange gain	**-**	-	**-**	-	**24**	(147)	**24**	(147)
Finance costs	**2,159**	3,767	**343**	456	**18**	33	**2,520**	4,256
Depletion, depreciation and amortization	**22,927**	26,345	**7,320**	7,790	**802**	813	**31,049**	34,948
Asset retirement obligation accretion	**-**	-	**259**	215	**-**	-	**259**	215
(Gain) loss on financial instruments	**(6,621)**	2,845	**-**	-	**-**	-	**(6,621)**	2,845
Impairment loss	**69,434**	7,937	**4,061**	-	**-**	-	**73,495**	7,937
Gain on disposition of assets	**-**	-	**-**	(114)	**-**	-	**-**	(114)
Income tax expense	**13,530**	26,098	**-**	-	**-**	-	**13,530**	26,098
Segmented net (loss) earnings	**(65,265)**	1,600	**(5,730)**	3,897	**(6,402)**	(9,492)	**(77,397)**	(3,995)
Capital expenditures								
Exploration and development	**5,256**	27,239	**2,067**	9,525	**-**	-	**7,323**	36,764
Corporate	**-**	-	**-**	-	**175**	168	**175**	168
Total capital expenditures	**5,256**	27,239	**2,067**	9,525	**175**	168	**7,498**	36,932

The carrying amounts of reportable segment assets and liabilities are as follows:

	As at December 31, 2020			As at December 31, 2019		
($000s)	**Egypt**	**Canada**	**Total**	Egypt	Canada	Total
Assets						
Accounts receivable	**6,594**	**2,821**	**9,415**	6,266	3,874	10,140
Intangible exploration and evaluation assets	**-**	**584**	**584**	33,176	530	33,706
Property and equipment						
Petroleum and natural gas assets	**70,331**	**69,728**	**140,059**	117,591	78,559	196,150
Other assets	**1,985**	**11**	**1,996**	2,847	15	2,862
Other	**33,571**	**2,162**	**35,733**	48,652	2,269	50,921
Deferred taxes	**3,723**	**-**	**3,723**	8,387	-	8,387
Segmented assets	**116,204**	**75,306**	**191,510**	216,919	85,247	302,166
Non-segmented assets			**9,637**			6,159
Total assets			**201,147**			308,325
Liabilities						
Accounts payable and accrued liabilities	**14,342**	**2,040**	**16,382**	19,459	6,798	26,257
Derivative commodity contracts	**398**	**-**	**398**	217	-	217
Long-term debt	**14,897**	**6,567**	**21,464**	29,502	7,539	37,041
Asset retirement obligation	**-**	**13,042**	**13,042**	-	13,612	13,612
Lease obligation	**1,466**	**302**	**1,768**	718	276	994
Deferred taxes	**3,723**	**-**	**3,723**	8,387	-	8,387
Segmented liabilities	**34,826**	**21,951**	**56,777**	58,283	28,225	86,508
Non-segmented liabilities			**6,075**			7,327
Total liabilities			**62,852**			93,835

27. SUPPLEMENTAL CASH FLOW INFORMATION

Changes in non-cash working capital consisted of the following:

	Years ended December 31	
($000s)	**2020**	2019
Operating activities		
increase in current assets		
Accounts receivable	**685**	1,333
Prepaids and other	**886**	637
Product inventory[1]	**7,288**	(6,698)
(Decrease) increase in current liabilities		
Accounts payable and accrued liabilities	**(7,523)**	2,886
Other long-term liabilities	**(70)**	(193)
Total changes in non-cash working capital	**1,266**	(2,035)
Investing activities		
Increase in current assets		
Prepaids and other	**-**	4
Decrease in current liabilities		
Accounts payable and accrued liabilities	**(3,544)**	(295)
Total changes in non-cash working capital	**(3,544)**	(291)
Financing activities		
Increase (decrease) in current liabilities		
Other liabilities	**161**	(200)
Total changes in non-cash working capital	**161**	(200)

[1] The change in non-cash working capital associated with product inventory represents the change in operating costs capitalized as product inventory in the respective periods.

CORPORATE & SHAREHOLDER INFORMATION

DIRECTORS

David B. Cook - *Chairman*
Randy C. Neely (4) - *President & Chief Executive Officer*
Ross G. Clarkson (3)
Edward LaFehr (1)(3)
Carol Bell (1)(2)
Steven W. Sinclair (1)(2)
Timothy Marchant (2)(3)

OFFICERS

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Geoffrey Probert (4) - *Vice President & Chief Operating Officer*
Edward D. Ok (4) - *Vice President, Finance & Chief Financial Officer and Corporate Secretary*

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(2) Compensation Human Resources & Governance Committee
(3) Reserves Health Safety & Social Responsibility Committee
(4) Disclosure and AIM Compliance Committee

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