This announcement contains inside information as stipulated under the UK version of the Market Abuse Regulation No 596/2014 which is part of English Law by virtue of the European (Withdrawal) Act 2018, as amended. On publication of this announcement via a Regulatory Information Service, this information is considered to be in the public domain.

1 June 2023

Trinity Exploration & Production plc
("Trinity" or "the Group" or "the Company")

Full Year Results to 31 December 2022

Trinity Exploration & Production plc (AIM: TRIN), the independent E&P company focused on Trinidad and Tobago, announces its final results for the year ended 31 December 2022 ("the Period" or "FY 2022").

During 2022 Trinity put in place the foundations for an ambitious growth programme, developing a series of catalysts to drive shareholder value that we are now starting to execute in 2023. These include:

- drilling the Jacobin well targeting the deeper Miocene-age turbidite play in our onshore blocks;
- the application for the highly prospective Buenos Ayres block in the 2022 Onshore Bid Round, the outcome of which is expected shortly; and
- revised planning to further exploit the Galeota offshore block, focused on greater capital efficiency and shorter development and payback times.

Underlining the resilience of the base business, the Company is committing to a new Capital Allocation Policy which will include a modest but sustainable dividend commencing in Q3 2023 with an intent for that to form part of a broader distribution of operating cash flow to shareholders, depending on realised oil prices.

Highlights

- Group net sales for 2022 were 2,975 bopd (2021: 3,006 bopd)
- Revenues of USD 92.2 million (2021: USD 66.3 million)
- Profit before tax of USD 2.5 million (2021: USD 3.0 million)
- Average price per barrel received was USD 84.9/bbl (2021: USD 60.4/bbl)
- Adjusted EBITDA (before hedge costs) of USD 35.1 million (2021: USD 21.1 million)
- Adjusted EBITDA of USD 24.7 million (2021: USD 19.8 million)
- Operating Profit* of USD 19.0 million (2021: USD 9.3 million)
- Cash generated from continuing operations USD 12.0 million (2021: USD 12.6 million)
- Cash flow used in investing activities USD 15.6 million (2021: USD 13.9 million)
- Year-end cash USD 12.1 million (2020: USD 18.3 million)

* Before SPT, Impairments and Exceptional Items

New Capital Allocation Policy

- The Company aims to distribute 15% of operating cash flow to shareholders, for each calendar year when the realised oil price is greater than $50/bbl, and at least 20% of operating cash flow for periods when the realised price is above $80/bbl
- Payment of a modest but sustainable dividend and the scope for additional distributions in the form of share buybacks or special dividends

- Expected to include a total dividend (split 1/3 interim, 2/3 final) of 1.5p per share, provided the realised price is at least $50/bbl
- It is expected that the maiden interim dividend will be declared following publication of the 2023 interim results, in Q3 2023, followed by a final dividend declared following publication of the 2023 preliminary results in Q2 2024

<u>Positioned for Next Growth Phase and progressing catalysts</u>

- Dynamic strategy for growth is underpinned by a strong balance sheet and resilient and dependable cash flow
- Clearly defined, risk-mitigated strategy to drive returns for shareholders – focus on maximising value from existing assets and through acquisitions and partnerships
- Strengthened Management Team
  - Additions of Julian Kennedy, Mark Kingsley and Alistair Green further strengthening financial/commercial, operational and wider industry skill sets
- Creation of Technical Committee
  - Focused on risk-mitigation and assurance of opportunities which can increase scale and optimise returns

<u>Post Period Highlights</u>

- Continued momentum into Q1 2023
  - Q1 production levels resilient with sales volumes averaging 2,899 bopd (Q4 2022: 2,961 bopd). Average production in 2023 will be influenced by the timing and outcome of the drilling campaign and continued workover and recompletion programme.
  - Average realisation of USD 67.9/bbl for Q1 2023 (Q4 2022: USD 75.4/bbl, Q1 2022: USD 83.1/bbl)
  - Cash balance of USD 11.4 million (unaudited) as at 31 March 2023 versus USD 12.1 million as at 31 December 2022 and USD 17.5 million as at 31 March 2022.
  - The Group had drawn borrowings (overdraft) of USD 2.3 million as at 31 March 2023 (USD 2.7 million as at 31 December 2022 and USD 2.7 million as at 31 March 2022).
- On 9 January 2023, the Company submitted a bid for the Buenos Ayres block in the 2022 Onshore and Nearshore Competitive Bid Round. The results of the Bid Round are expected shortly.
- On 3 May 2023, the Government of Trinidad and Tobago Ministry of Energy and Energy Industries ("MEEI") provided confirmation of the renewal of the PGB Licence for an additional 25 years from the Effective Date of 18 December 2012. Consequently, the PGB Licence expires on 17 December 2037. There were no additional liabilities and commitments arising from the renewed Licence.
- The Company commenced drilling the Jacobin prospect on 15 May 2023, the first of the nine 'Hummingbird' deeper prospects our 3D seismic has identified across our Palo Seco acreage.

<u>Jeremy Bridglalsingh, Chief Executive Officer of Trinity, commented:</u>

"During 2022 Trinity initiated an ambitious growth programme, seeking to develop a series of catalysts to drive shareholder value that we are now starting to execute in 2023. We have actioned three key growth initiatives which we believe have the potential to deliver meaningful value for shareholders.

Our core business has continued to perform consistently, forming the basis upon which the capital allocation policy has been designed. The spudding of Jacobin is an important milestone for the Company and will help determine our further activities throughout 2023 as we look to harness the potential of the extensive Palo Seco play which extends into the Buenos Ayres block to the west, which Trinity applied for in the 2022 Onshore Bid

Round. On Galeota we initiated a revised development plan, including the existing Trintes producing field as well as appraisal and exploration opportunities, which we are aiming to finalise by Q4 this year.

2022 was a significant year for Trinity and 2023 has begun to bear the fruits of this work. I believe we have the right focus to deliver further progress and I look forward to updating our key stakeholders as we move through the year."

Investor Presentation

The Company will host a presentation through the digital platform Investor Meet Company on 14 June 2023 at 10:00 British Summer Time. Management will discuss the results and the Company's growth strategy.

The presentation is open to all existing and potential shareholders. Questions can be submitted pre-event via the Investor Meet Company dashboard up until 09.00 the day before the meeting or at any time during the live presentation.

Investors can sign up to Investor Meet Company for free and add to meet Trinity Exploration via the following link https://www.investormeetcompany.com/trinity-exploration-production-plc/register-investor. Investors who already follow Trinity on the Investor Meet Company platform will automatically be invited.

Enquiries:

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About Trinity (www.trinityexploration.com)

Trinity is an independent oil production company focused solely on Trinidad and Tobago. Trinity operates producing and development assets both onshore and offshore, in the shallow water West and East Coasts of Trinidad. Trinity's portfolio includes current production, significant near-term production growth opportunities from low-risk developments and multiple exploration prospects with the potential to deliver meaningful reserves/resources growth. The Company operates all of its ten licences and, across all of the Group's assets, management's estimate of the Group's 2P reserves as at the end of 2022 was 17.96 mmbbls. Group 2C contingent resources are estimated to be 48.88 mmbbls. The Group's overall 2P plus 2C volumes are therefore 66.84 mmbbls.

Trinity is quoted on AIM, a market operated and regulated by the London Stock Exchange Plc, under the ticker TRIN.

Competent Person's Statement

All reserves and resources related information contained in this announcement has been reviewed and approved by Dr. Ryan Ramsook, Trinity's Executive Manager, Exploration. Dr. Ryan Ramsook also lectures and is involved in collaborative Geoscience research with the University of the West Indies and Fellow of the Geological Society (FGS) of London. He is a Geologist by background with 19+ years' experience.

Disclaimer

This document contains certain forward-looking statements that are subject to the usual risk factors and uncertainties associated with the oil exploration and production business. Whilst the Group believes the expectation reflected herein to be reasonable in light of the information available to it at this time, the actual outcome may be materially different owing to macroeconomic factors either beyond the Group's control or otherwise within the Group's control.

CHAIRMAN & CEO STATEMENT

Strategic Performance
During 2022 Trinity put in place the foundations for an ambitious growth programme, developing a series of catalysts to drive shareholder value that we are now starting to execute in 2023. This important process has involved taking tough decisions based on identifying the most efficient allocation of capital across the portfolio. We chose not to pursue several initiatives which we had previously been exploring, such as the Jubilee field off the West Coast and NWD deeper play, and instead decided to focus on three key initiatives which we believe have the potential to deliver meaningful value for shareholders.

First, the Company has matured its understanding of the deeper prospectivity across its onshore portfolio using the 3D seismic which we had acquired to map nine 'Hummingbird' prospects across its Palo Seco assets. In May 2023 we commenced the first well, Jacobin, the start of an ambitious, risk-appropriate exploration programme that we hope will fast-track the monetisation of these substantial resources. In a success case, this will generate material growth for our shareholders, further de-risk this potentially extensive play across our existing acreage and allow us to quickly evaluate the significant potential in the Buenos Ayres block offered in the 2022 Onshore and Nearshore Competitive Bid Round.

Second, during 2022, the Company participated in the 2022 Onshore and Nearshore Competitive Bid Round, bidding for the Buenos Ayres block, which is located immediately to the west of Trinity's existing Palo Seco interests, comprising Blocks WD5-6, WD-2 and PS-4 and, at its closest, is only around 500 metres from the Company's existing sub-licences. If awarded, Trinity intends to take advantage of its unique understanding of the stratigraphy in this area onshore Trinidad, where there are strong analogues to the Company's existing acreage, to quickly progress from drilling to production. As an Exploration and Production licence, Buenos Ayres would benefit from better commercial and fiscal terms than the Lease Operatorship Agreements; principally, no overriding royalty payable, instead state-owned Heritage participating as a joint venture partner with a 15% working interest carried through the exploration phase.

Third, having paused the Galeota farm-out process, we initiated an in-depth review of the opportunities across the offshore Galeota block, including the existing Trintes producing field, to formulate a revised development plan that offers greater capital efficiency and shorter development and payback timelines, with the aim of avoiding significant dilution for existing shareholders. This work continues in 2023 and we aim to finalise the development option in order to progress by Q4 this year.

In addition to progressing each of these attractive opportunities, Trinity has continued to lobby the Trinidadian Government to take the steps necessary to stimulate activity in the energy sector. As well as the successfully completed 2022 Onshore and Nearshore Competitive Bid Round, we welcomed the fiscal changes that were introduced, particularly changes to Supplemental Petroleum Tax ("SPT"), announced in September 2022 which took effect from 1 January 2023. This positive approach from the Government will provide additional growth opportunities for Trinity and we continue to engage with Government in a constructive way, as we believe further reform is necessary to achieve the Government's aim to stimulate greater activity levels across our sector.

Operating Performance
Trinity delivered a robust operating performance in 2022 which continues to highlight the strength and resilience of our core business. We delivered production for the year within guidance, and we remain on track to progress our growth agenda in 2023.

Group net sales for 2022 were 2,975 bopd (2021: 3,006 bopd). Trinity managed to substantially mitigate natural production decline through a programme including 3 new wells, 17 RCPs, 120 Workovers, swabbing across its asset base, including the recently acquired PS-4, and improved production monitoring using automation and revised completion strategies.

The Company's investment in technology to automate and remotely optimise over 50% of its production is proving to be effective, helping to ensure steady production whilst minimising non-productive downtime. The

Company aims to extend this automation to an additional 37 onshore wells during 2023, which would result in the proportion of Group production covered by automation rising from 50% to approximately 80%.

Three new development wells were drilled and completed during H2 2022. Initial production levels for the three wells were on prognosis but subsequent performance was below plan and increased supply chain costs have impaired the economic potential of conventional drilling. The data acquired through this campaign is helpful, however, and is currently being used to revise our plans for future drilling campaigns.

Financial Performance

Our 2022 financial results demonstrate the Company's resilience despite encountering significant external headwinds. Adjusted EBITDA for the year was USD 24.7 million (2021: USD 19.8 million) and cash resources were USD 12.1 million (2021: USD 18.3 million) at year-end.

Global supply chain pressures and cost inflation saw our operating breakeven nudge above USD 30.0/bbl (to USD 32.1/ bbl) (2021: USD 29.2/bbl) for the first time in seven years. This still represents a relatively low operating cost, which provides a buffer in times of low oil prices. Nevertheless, we are continuing to experience inflationary pressures within the supply chain and are working with our contractors and partners proactively to manage our cost base and execute our development programme in a cost-effective manner.

In 2022, in line with previous years, we hedged around 50% of our production to counteract the impact of low oil prices and the impact of SPT which, prior to the recent reforms, was at its most punitive when realised oil prices were between USD 50.01 and USD 55.0 per barrel. The hedging programme, put in place during 2021 to shield the Company from the possibility of weaker oil prices, worked against us in 2022 when prices rose sharply in response to Russia's invasion of Ukraine. This resulted in a cash payment for hedging of USD 10.4 million for the year (compared to USD 1.3 million in 2021). The Company has elected to remain unhedged moving into 2023.

Returns to Shareholders

Following the share capital re-organisation undertaken in 2021, to restore distributable reserves at PLC level, the Board sanctioned two share buyback programmes in 2022, commencing in September/October 2022 to repurchase up to USD 2.0 million in shares. The second share buyback concluded at the end of April 2023. The first and second share buyback acquired 1,432,000 shares, representing 3.6% of our issued share capital for USD 2.0 million, terms which the Board believes are accretive to shareholder value. A third share buyback was announced on 28 April 2023 to return up to USD 1.0 million to shareholders of the Company.

The Board believes that consistent returns to shareholders should be an important driver for capital and operational discipline whilst not impeding the Company's growth potential and has accordingly affirmed a new Capital Allocation Policy which will comprise payment of a modest but sustainable dividend and the scope for additional distributions in the form of share buybacks or special dividends. Going forward, the Board intends to aim to distribute 15% of operating cash flow to shareholders, for each calendar year when the realised oil price is USD80/bbl and below, and at least 20% of operating cash flow for each calendar year when the realised price is above $80/bbl. This is expected to include a total dividend (split 1/3 interim, 2/3 final) of 1.5p per share, provided the realised price is at least USD50/bbl. It is expected that the maiden interim dividend will declared following publication of the 2023 interim results, in Q3 2023, followed by a final dividend being declared following publication of the 2023 preliminary results in Q2 2024.

HSSE and ESG performance

HSSE performance remains a high priority for Trinity, and at the beginning of 2022 an HSSE Improvement Plan was developed to enhance the existing HSSE Management System. Key elements of this plan included creating a Steering Committee, chaired by the CEO, developing a monthly HSSE Scorecard of key leading and lagging indicators that is disseminated throughout the organisation, the introduction of an ongoing Critical Safety Rule campaign and more focus on contractor management and inclusion. The HSSE Team was instrumental in achieving "STOW" (Safe to Work) recertification for a further two years with a score of 100%. Unfortunately, we recorded two Lost Time Incidents in 2022. Since then, we have bolstered our incident investigation procedure to ensure that actions and lessons learnt are being implemented throughout the organisation.

During 2022, we also commenced the quantification of our Scope 1 and 2 emissions across all assets; established the Bruce Dingwall Memorial Scholarship (in memory of our Founder and former Executive Chairman) for Caribbean nationals pursuing studies in Geoscience; and we continued to foster partnerships with our fence line communities through the sponsorship of awards for excellence in education to students undertaking the 11+ examinations.

Cyber Incident

In December 2022 Trinity was subject to a ransomware attack, something that is becoming increasingly commonplace across all businesses and geographies. We responded quickly and comprehensively to this external attack on our business. Our production facilities remained safe and continued to produce. We suffered a temporary disruption to our administrative systems, but Trinity's IT team and our external advisers have returned systems to full capacity incorporating changes and learnings from the incident and embedding more resilient IT infrastructure, cybersecurity systems and procedures.

Organisational changes

The Board and management team was restructured and strengthened in 2021 following the untimely passing of our founder and Executive Chairman Bruce Dingwall, CBE. During 2022 the management team was further reinforced by the recruitment of Julian Kennedy (Chief Financial Officer), Alistair Green (Development Manager) and, more recently, Mark Kingsley (Chief Operating Officer). We welcome them all and look forward to driving the business forward with their assistance. Angus Winther has completed two full terms as a Director and specifically in the role of the Audit Committee Chairman. Therefore, he has decided not to stand for reelection at this forthcoming Annual General Meeting which coincides with Angus taking on greater levels of responsibility in other roles outside of Trinity. We want to express our thanks and that of our fellow Directors for his conscientious stewardship of the Audit Committee since he joined the Board in 2017.

Thanks

Your Board is appreciative of the support we continue to receive from shareholders during what are very demanding and complex times. On behalf of the Board, we must also thank our employees and suppliers for their commitment which has allowed Trinity to deliver its core business in a safe manner while positioning the Company to hopefully move into a period of growth.

In summary, following significant challenges experienced by Trinity in 2021, 2022 proved to be a year of consolidation and focus, resulting in the identification of numerous near-term and medium-term catalysts to drive growth and value. We will continue to advance these during 2023, with a view to generating meaningful returns for shareholders.

Nicholas Clayton	Jeremy Bridglalsingh
Non-Executive Chairman	Chief Executive Officer

OPERATIONS REVIEW

The Group achieved net sales of 2,975 bopd in 2022 (2021: 3,006 bopd). Investments into production related activities, such as the three new infill wells, RCPs, workovers and swabbing, together with greater automation and monitoring of our key wells, enabled the Company to deliver annual production rate in-line with the prior year, thereby largely offsetting the expected natural field decline rate of between 7% and 10%.

ONSHORE ASSETS

Trinity's onshore assets comprise the lease operatorship blocks: WD-5/6, WD-2 and PS-4 (together "Palo Seco"), FZ-2, WD-13, WD-14 (together "Forest Reserve") and one farmout block, Tabaquite.

The average net sales for 2022 was 1,655 bopd (2021: 1,644 bopd) which accounts for 56% of our total annual sales. A breakdown of the sales by block is shown in the table below.

Table 1: 2022 vs 2021 Onshore Sales breakdown by block

Block	**2021 Avg Sales (bopd)**	**2022 Avg Sales (bopd)**
Palo Seco		
WD-5/6	1,050	1,004
WD-2	246	258
PS-4*	4	62
Forest Reserve		
FZ-2	122	117
WD-13	95	109
WD-14	110	100
Tabaquite		
TABAQUITE	17	4
Annual Avg.	**1,644**	**1,655**

Note PS-4* was acquired on 1 Dec 2021 at an average monthly rate of 52 bopd

Trinity drilled 3 new onshore development wells in 2022 (2021: nil), completed 17 RCPs (2021: 7), 1 sand control job (2021: 5), and 86 workovers (2021: 74), which, together with the inclusion of PS-4 for the full year, resulted in a modest uplift in our onshore production for the year as a whole.

Table 2: 2022 Onshore Work Programme Breakdown by Block

Block	**New Wells**	**Recompletions**	**Workovers**	**SCN**
Palo Seco				
WD-5/6	1	0	38	0
WD-2	1	2	3	0
PS-4	0	5	17	0
Forest Reserve				
FZ-2	0	7	12	0
WD-13	1	1	9	0
WD-14	0	2	7	1
Tabaquite				
TABAQUITE	0	0	0	0
TOTAL	**3**	**17**	**86**	**1**

In 2023, Trinity intends to manage its base production through additional automation of wells, further RCP activity, re-evaluation of the inactive well hopper, and swabbing. Trinity's use of automation to optimise production and costs continues to meet our objectives. The three new wells drilled in 2022 contributed 20 bopd to the annual average.

EAST COAST ASSETS

Current East Coast production is generated from the Alpha, Bravo and Delta platforms in the Trintes field located in the Galeota block.

Average net sales for 2022 from the East Coast were 1,051 bopd (2021: 1,107 bopd) which accounts for 35% of Group sales for the period. A total of 23 workovers in 2022 (2021: 16) were conducted across the assets focusing on optimising and stabilising production from all wells via a data-driven strategy utilising automation. Chemical injection initiatives were also deployed to counteract increased solids deposition in mature wells.

The Galeota licence has significant growth potential from undeveloped reserves and resources in the Trintes field and broader development of the Galeota block.

Having paused the Galeota farm-out process in May 2022, the Company initiated an in-depth review of the opportunities across the offshore Galeota block, including the existing Trintes producing field, to formulate a revised development plan that offers greater capital efficiency and shorter development and payback timelines.

WEST COAST ASSETS

West Coast production is generated from the Point Ligoure-Guapo Bay-Brighton Marine ("PGB") and Brighton Marine ("BM") licence areas.

West Coast net sales averaged 269 bopd in 2022 (2021: 255 bopd) which accounted for 9% of the Group's total annual average sales. This was a 5% year on year increase on the 2021 average. The increase was achieved through increased swabbing activity via 10 conversions to swab workovers in 2022 (2021: nil) conducted across the assets. Subsequent to the period end, in March 2023, ABM-151, was producing at a managed rate of 140 bopd, higher than the expected range of 60 to 110 bopd, thereby significantly improving the economics of our West Coast assets in 2023.

Block	**2021 Avg Sales (bopd)**	**2022 Avg Sales (bopd)**
Brighton	155	158
PGB (70%)	100	111
TOTAL	255	269

Facilities Management and Infrastructure

In 2022, the Facilities team focused on asset integrity, welfare initiatives and projects supporting production.

On Trintes, the Company replaced gratings on offshore platform production decks and improved key electrical equipment on the Alpha, Bravo and Delta platforms, resulting in the repurposing of floor space allowing for better access and more efficient use of the work area. Accommodation units were replaced, fuel and water tanks were upgraded and repositioned for better use of the available space.

The construction of a new 10,000 bbl storage tank to accommodate production from the Trintes field was 86% complete at the end of 2022. The project experienced some delays but is now expected to be fully operational in Q2-2023.

Activities for the Onshore and West Coast operations focused on upgrading welfare facilities and construction of a new crow's nest to support the ABM-151 well reactivation.

In total, the team progressed 40 projects of which 32 were completed by the end of 2022 and 8 rolled over in 2023.

Facilities Management and Infrastructure spend in 2022 was USD 4.0 million (comprising East Coast – USD 2.9 million, West Coast – USD 0.7 million and Onshore - USD 0.4 million).

Onshore Drilling

Trinity's onshore development drilling campaign during 2022 comprised three wells drilled in the second half of the year (one well in each of WD-5/6, WD-2 and WD-13) targeting Lower Forest and Upper Cruse reservoirs. Supply chain challenges and inflationary pressures significantly increased the cost of drilling and impaired economics. While we encountered reservoir in all wells broadly on prognosis, we observed higher than expected depletion in all three which resulted in stabilised production rates being lower than predicted. Our intention is to manage the wells' up-hole potential to maximise the economic recovery. Data acquired from the 2022 drilling campaign and the performance of these wells will be incorporated into our regional model to de-risk and re-prioritise future infill development candidates.

Reserves and Resources

A comprehensive reserves and resources review of all assets has been completed by Management which estimates Trinity's current 2P reserves to be 17.96 mmstb at the end of 2022, compared to the year-end 2021 reserve estimate of 19.73 mmstb. This represents a 9% year-on-year decrease. The overall decrease in reserves of 1.77 mmstb comprise 1.09 mmstb produced in 2022 and revisions, including re-categorisation of reserves from 2P to 2C of 0.68 mmstb. Factoring in the 2022 produced volume of 1.09 mmstb, the 2P year-on-year decline is 3.4%.

(USD/bbl)	2023	2024	2025	2026	2027	2028	2029	2030	2031
Price Strip	82.13	77.09	73.50	70.83	68.78	67.85	68.31	67.50	68.72

Brent Forward Price Deck applied to Reserves Economic Limit Testing ("ELT") from Britannic Trading LLC as at 3 January 2023

Management considers the reserves presented in the table below to be its best estimate as at 31 December 2022 of the quantity of reserves that can be recovered from Trinity's current assets. It includes forecasted production, which is commercially recoverable, either to licence/relevant permitted extension end or earlier via the application of the economic limit test. The subsurface review has defined investment programmes and constituent drilling targets to commercialise these reserves as detailed by asset area shown in the table:

Unaudited 2022 2P Reserves

Net Oil Reserves	31-Dec-21 mmstb	Production mmstb	Revisions mmstb	**31-Dec-22 mmstb**
Asset				
Onshore	7.26	(0.60)	(0.13)	**6.53**
West Coast	2.70	(0.11)	(0.42)	**2.17**
East Coast	9.77	(0.38)	(0.13)	**9.26**
Total	19.73	(1.09)	(0.68)	**17.96**

Note:

- The 2022 produced volume of 1.09 mmstb accounts for 61.6% of the overall 2P decrease in 2022 compared to 2021.
- Revisions:
  - Onshore: FZ-2 +0.22 mmstb and WD-14 +0.26 mmstb due to Economic Limit Testing. Onshore sub-licences decrease (-0.61 mmstb) due to uneconomic infills.
  - West cost: Reactivation of ABM-151 in March 2023 and revised IP of 80 bopd; +0.15 mmstb. Reallocation of infill wells from 2P to 2C category (-0.20 mmstb). PGB base decreased -0.37 mmstb.
  - East coast: Reduced base performance due to decreased well performance from key producers in Trintes (-0.78 mmstb). Reduced RCP 2P from 2021 to 2022 mainly due to reduced RCP count (-0.07 mmstb). Reclassification of three conventional infill wells from the Echo FDP back to Trintes development 2P reserves. +0.72 mmstb.

Management's Estimate of 2C Resources as at 31 December 2022

Net Oil Resources	31-Dec-21 mmstb	Revisions mmstb	**31-Dec-22 mmstb**
Asset			
Onshore	3.82	4.80	**8.62**
West Coast	3.01	0.44	**3.45**
East Coast	40.39	(3.58)	**36.81**
Total	47.22	1.66	**48.88**

Note (*):

Onshore:

- Recently concluded 3D seismic mapping work across WD-5/6, WD-2, PS-4 assets has redefined the subsurface structure/model resulting in the addition of 2C resources +4.80 mmstb in Year End 2022.

West Coast:

- Reallocation of infill wells from 2P to 2C category across West Coast +0.44 mmstb

East Coast:

- Year End 2021 most likely case of 12-well development inclusive of three Trintes infills re-categorised at Year End 2022 as part of Trintes development 2P rather than as Echo 2C (-3.58 mmstb)

Management's Estimate of Reserves and Resources as at 31 December 2022

	2022 2P Reserves mmstb	**2022 2C Resources mmstb**	**2022 2P Reserves and 2C Resources mmstb**	2021 2P Reserves and 2C Resources mmstb
Asset				
Onshore	**6.53**	**8.62**	**15.15**	11.08
West Coast	**2.17**	**3.45**	**5.62**	5.71
East Coast	**9.26**	**36.81**	**46.07**	50.16
Total	**17.96**	**48.88**	**66.84**	66.95

Financial Review

KPIs

During 2022 the Group benefitted from higher oil prices and, combined with the Group's robust cost control structure, resulted in Adjusted EBITDA (before hedge costs) increasing by 66% to USD 35.1 million (2021: USD 21.1 million). The crude oil hedges in place muted our upside exposure, although the Group delivered a resilient operating performance as shown by Adjusted EBITDA (after hedge costs) increasing by 25% to USD 24.7 million and IFRS Operating Profit before SPT doubling compared to 2021.

A summary of the year-on-year operational and financial highlights are set out below:

		FY 2022	**FY 2021**	**Change %**
Average realised oil price[1]	USD/bbl	84.9	60.4	41
Average net production [2]	bopd	2,975	3,006	(1)
Revenues	USD million	92.2	66.3	39
Cash balance	USD million	12.1	18.3	(34)
IFRS Results				
Operating Profit before SPT	USD million	19.0	9.3	104
Total Comprehensive income for the year	USD million	0.1	7.7	(99)
Earnings Per Share - Diluted	USD cents	0.0	18.0	(100)
APM Results				
Adjusted EBITDA (before hedge costs)[3]	USD million	35.1	21.1	66
Adjusted EBITDA (after hedge costs)[4]	USD million	24.7	19.8	25
Adjusted EBITDA (after hedge costs)[5]	USD/bbl	22.7	18.0	26
Adjusted EBITDA margin (after hedge costs)[6]	%	26.8	29.9	(10)
Adjusted EBIDA after Current Taxes[7]	USD million	12.3	14.8	(17)
Adjusted EBIDA after Current Taxes Per Share – Diluted	US cents	30.6	35.0	(13)
Consolidated operating break-even[8]	USD/bbl	32.1	29.2	10
Net cash plus working capital surplus[9]	USD million	14.2	20.8	(32)

Notes:

1. Average realised price (USD/bbl): Actual price received for crude oil sales per barrel ("bbl").
2. Average net sales (bopd): Production sold in barrels per day in a given year.
3. Adjusted EBITDA (before hedge) (USD MM): Adjusted EBITDA for the period, before Derivative expense.
4. Adjusted EBITDA (USD MM): Operating Profit before Taxes for the period, adjusted for non-cash DD&A, SOE, ILFA, FX gain/(loss) and Fair Value Gains/Losses on Derivative Financial Instruments.
5. Adjusted EBITDA (USD/bbl): Adjusted EBITDA/Annual sales volume.
6. Adjusted EBITDA margin (%): Adjusted EBITDA/Revenues.
7. Adjusted EBIDA after Current Taxes: Adjusted EBIDA less Supplemental Petroleum Taxes ("SPT"), Petroleum Profits Tax ("PPT") and Unemployment Levy ("UL").
8. Consolidated operating break-even: The realised price/bbl where the Adjusted EBITDA/bbl for the Group is equal to zero.
9. Net cash plus working capital surplus: Current Assets less Current Liabilities (other than Derivative financial asset / liability and Provision for other liabilities).

Note (*): See Note 26 to Consolidated Financial Statements – Adjusted EBITDA for further details.

Adjusted EBITDA Calculation

Adjusted EBITDA is an Alternative Performance Measure guideline ("APM") used by the Group to measure business performance. The Group presents Adjusted EBITDA metrics as they are used by Management to assess the Group's underlying operational and financial performance.

	2022	2021	
	USD MM	USD MM	Change %
Operating Profit Before SPT, Impairment and Exceptional Items	**19.0**	9.3	104
Add back realised hedge costs	10.4	1.3	697
DD&A	**7.6**	7.4	3
Share Option Expense	**0.6**	0.6	0.0
Impairment Losses on Financial Assets	**0.0**	(0.7)	(100)
FX loss/(gain)	**0.4**	0.0	2,857
FV gain/(loss) on derivative financial instruments	**(2.9)**	3.2	(191)
Adjusted EBITDA (before hedge)	**35.1**	**21.1**	**66**
Deduct realised hedge costs	(10.4)	(1.3)	697
Adjusted EBITDA (APM Result)	**24.7**	**19.8**	**25**
Current Taxes:			
SPT	**(9.0)**	(5.1)	77
PPT and UL	**(3.4)**	(1.4)	143
Adjusted EBIDA after Current Taxes (APM Result)	**12.3**	**13.3**	**(17)**

Refer to Glossary for abbreviations.

2022 Trading Summary

A five-year historical summary of realised price, sales, operating break-even, Royalties, Production Costs ("Opex") and General & Administrative ("G&A") expenditure metrics is set out below.

		2018[1]	2019	2020	2021	**2022**
Realised Price	USD/bbl	59.8	58.1	37.7	60.4	**84. 9**
Sales						
Onshore	bopd	1,563	1,616	1,793	1,644	**1,655**
West Coast	bopd	198	185	245	255	**269**
East Coast	bopd	1,110	1,208	1,188	1,107	**1,051**
Consolidated	bopd	2,871	3,007	3,226	3,006	**2,975**
Metrics						
Royalties/bbl - Onshore	USD/bbl	24.2	22.3	11.5	22.6	**35.9**
Royalties/bbl - West Coast	USD/bbl	10.0	10.0	6.1	11.1	**15.8**
Royalties/bbl - East Coast	USD/bbl	14.5	14.1	8.3	13.0	**17.9**
Royalties/bbl – Consolidated	USD/bbl	19.1	10.7	9.9	18.1	**27.7**
Opex/bbl - Onshore	USD/bbl	11.7	12.1	12.2	14.4	**17.0**
Opex/bbl - West Coast	USD/bbl	22.1	26.9	20.3	26.2	**30.7**
Opex/bbl - East Coast	USD/bbl	20.1	17.1	16.5	18.3	**23.2**
Opex/bbl – Consolidated	USD/bbl	16.8	14.9	14.0	16.0	**17.7**
G&A/bbl – Consolidated[2]	USD/bbl	5.0	5.1	4.3	6.3	**6.6**
Operating Break-Even[3]						
Onshore	USD/bbl	16.1	16.4	16.5	19.0	**19.2**
West Coast	USD/bbl	26.8	32.4	24.6	32.2	**31.8**
East Coast	USD/bbl	25.9	21.9	21.0	23.2	**24.4**
Consolidated[4]	USD/bbl	29.0	26.4	20.1	29.2	**32.1**

Notes

1. Metrics for 2018 and prior are pre-IFRS 16 adoption effective 1 January 2019 which impacted the Operating Break-Even Levels and Opex/bbl & G&A/bbl Metrics for historical comparative purposes. Full details of the impact were set out in the 2019 annual report and accounts.
2. G&A/bbl – Consolidated: Excludes SOE, ILFA, Derivative FV gain/loss and FX gain/loss.
3. Operating break-even: The realised price where Adjusted EBITDA ([before hedge]) for the respective asset or the entire Group (Consolidated) is equal to zero.
4. Consolidated operating break-even: Includes G&A but excludes SOE, ILFA, Derivative FV gain/loss and FX gain/loss.

Review of Financial Statements

Trinity and its subsidiaries' ("the Group") consolidated financial information has been prepared on a going concern basis, in accordance with international accounting standards as adopted in the United Kingdom. This consolidated financial information has been prepared under the historical cost convention, modified for fair values under IFRS. The Group's accounting policies and details of accounting judgements and critical accounting estimates are disclosed within Notes 1 to 3 of the Financial Statements.

Throughout this report, reference is made to adjusted results and measures. The Board believe that the selected adjusted measures allow Management and other stakeholders to better compare the normalised performance of the Group between the current and prior year, without the effects of one-off or non-operational items, and better reflects the underlying cash earnings achieved in the year. In exercising this judgment, the Board has taken appropriate regard of International Accounting Standards ("IAS") 1 "Presentation of financial statements".

In particular, the APM measure of Adjusted EBITDA excludes the impact of Depreciation, Depletion & Amortisation ("DD&A"), as well as the non-cash impact of Share Option Expense ("SOE"), Impairment losses on financial assets ("ILFA"), FX gain/loss and Fair Value Gains/Losses on Derivative Financial Instruments. Each of these are summarised on the face of the Consolidated Income Statement as well as being described in Note 21 to the consolidated financial statements.

Summary of Results for the Year

Higher revenue driven by higher average realised oil price in 2022:

The positive impact of a 41% increase in average oil price realisations to USD 84.9/bbl (2021: USD 60.4/bbl), and a modest 1% decrease in average annual sales to 2,975 bopd (2021: 3,006 bopd), resulted in a 39% increase in revenues to USD 92.2 million (2021: USD 66.3 million).

Maintained robust operating profits despite inflationary pressures:

The Group continued to deliver strong operating margins despite the inflationary pressures on goods and services. Operating profit before taxes was USD 19.0 million (2021: USD 9.3 million). The Adjusted EBITDA margin (pre-hedge costs) increased to 38.1% (2021: 31.9%), with consolidated operating break-even moving up to USD 32.1 (2021: USD 29.2) demonstrating the Group's ability to be profitable across a broad range of oil prices. The 25% increase in Adjusted EBITDA (after hedge costs) to USD 24.7 million (2021: USD 19.8 million) is a direct result of the increased realised oil price and strong operational performance.

Increased capex investment programme to drive growth:

USD 15.5 million (2021: USD 13.6 million) invested to drive future production growth. This comprised:

- USD 8.4 million Production capex comprising three onshore wells drilled (USD 5.8 million), 17 RCP's (USD 1.5 million) and ABM-151 reactivation project (USD 1.1 million).
- USD 4.8 million Infrastructure Capex including facilities, operations and ICT.
- USD 1.7 million Subsurface and time-writing costs.
- USD 0.3 million in Exploration and Evaluation ("E&E") relating to Onshore and West Coast.
- USD 0.3 million Exploration and Evaluation ("E&E") assets relating to Galeota.

Refer to Notes to Financial Statements: Note 13 Property, Plant and Equipment – Additions (USD 15.1 million) and Note 15 – Intangible Assets – E&E Additions (USD 0.5 million) inclusive of accruals.

Continued financial strength:

The Group's cash balances at year end were USD 12.1 million (2021: USD 18.3 million), primarily reflecting positive cash generated from operations of USD 12.0 million (after derivative payments and taxes), Capex spend of USD (15.6) million and Financing activities of USD (2.2) million (which included effecting our first share buyback). In aggregate, despite these significant cash outflows, the Group's net cash plus working capital surplus stood at USD 14.2 million (2021: USD 20.8 million) and our current ratio was a healthy 2.1x (2021: 2.2x).

Statement of Comprehensive Income

2022 Financial Highlights

Average realisation of USD 84.9/bbl (2021: USD 60.4/bbl).

Operating Revenues

Operating revenues up 39% to USD 92.2 million (2021: USD 66.3 million).

Operating expenses

Operating expenses increased by 29% in 2022 to USD (73.3) million reflecting operating in a higher crude oil price environment (2021: USD (56.9) million) and comprised:

Operating Expenses (excluding non-cash items): USD (67.6) million (2021: (46.4) million):

- Royalties of USD (30.1) million (2021: USD (19.8) million), this increase being driven by the higher average realised oil price.
- Opex of USD (19.2) million (2021: USD (17.6) million), the increase mainly due to impact of inflationary pressures on goods and services as well as increased repairs and maintenance, workovers and fuel in the year.
- G&A expenses of USD (7.2) million (2021: USD (7.0) million), the increase mainly due to recruitment and replacement of key personnel to support the businesses growth strategy, increased levies, business travel, and administrative costs including professional fees.
- Derivative expense of USD (10.4) million (2021: Derivative expense of USD (1.3) million) being the cash impact of derivative instruments paid out for 2022.
- Covid 19 expense of USD (0.6) million (2021: USD (0.7) million) being the costs associated with accommodation, testing and sanitisation related to our prevention and response.
- Cash FX loss USD (0.1) million (2021: USD 0.0 million)

Non-Cash Operating Expenses: USD (5.7) million (2021: USD (10.5) million):

- DD&A of USD (7.6) million (2021: USD (7.4) million).
- Derivative credit of USD 2.9 million (2021: Derivative expense of USD (3.2) million) being the movement in the FV of derivative instruments held at the beginning and end of the financial year.
- SOE of USD (0.7) million (2021: USD (0.6) million).
- ILFA reversal USD 0.0 million (2021: USD 0.7 million).
- FX loss USD (0.3) million (2021: USD 0.0 million).

Operating Profit Before SPT, Impairment and Exceptional Items

The operating profit before SPT, impairment and exceptional items for the year amounted to USD 19.0 million (2021: USD 9.3 million) and was mainly due to higher operating revenues resulting from higher oil prices despite inflationary pressures on cost.

SPT and PT

SPT and PT of USD (9.0) million (2021: USD (3.6) million) and comprised:

- SPT of USD (9.0) million (2021: USD (5.1) million) mainly due to the higher realised oil prices in relation to the Group's operations in 2022. Both onshore and offshore assets were subject to SPT in 2022 as the realised oil price throughout the year was higher than USD 75/bbl.
- PT nil (2021: USD 1.5 million net reversal), as no Notice of Assessment has been received in relation to this tax.

Operating Profit before Impairment and Exceptional items

The Group's reported operating profit before impairment and exceptional items was USD 10.0 million (2021: USD 5.8 million). Adjusting for non-cash expenses, the Group's Adjusted EBIDA after Current Taxes was USD 12.3 million (2021: USD 14.8 million) (further details below).

Impairment charge

Impairment charges taken were USD (6.1) million (2021: USD (1.3) million) relating to the Impairment of property, plant, and equipment USD (5.8) million and Inventory (0.3) million.

See Note 3(d) to Consolidated Financial Statements - Impairment of Property, Plant and Equipment for further details.

Exceptional items

Exceptional items were USD (0.2) million relating to the cyber incident costs in December 2022 (2021 : USD (0.1) million relating to fees for corporate restructuring advice).

See Note 7 to Consolidated Financial Statements - Exceptional items for further details.

Finance Income

Finance income is solely related to bank interest income received on short term investments with financial institutions of USD 0.1 million (2021: 0.1 million).

Finance Costs

Finance costs amounted to USD (1.3) million (2021: USD (1.5) million) and comprised:

- Unwinding of the discount rate related to the decommissioning liability USD (1.1) million (2021: USD (1.2) million).
- Bank overdraft interest USD (0.1) million (2021: (0.2) million).
- Interest on Leases USD (0.1) million (2021: USD (0.1) million).

See Note 9 to Consolidated Financial Statements – Finance Costs for further details.

Income Taxation

Income Taxation charge for 2022 of USD (2.3) million (2021: USD 4.7 million credit), comprising the following:

- Current Taxes comprising
  - Petroleum Profit Tax ("PPT") USD (2.4) million (2021: (1.0) million).
  - Unemployment Levy ("UL") USD (1.0) million (2021: USD (0.4) million).
- Increase in Deferred Tax Assets ("DTA") recognised on available tax losses of USD 1.0 million (2021: Increase in DTA of USD 5.5 million).
- Decrease in Deferred Tax Liabilities ("DTL") USD 0.1 million due to accelerated accounting impairments/depreciation (2021: USD 0.6 million decrease).

See Note 10 to Consolidated Financial Statements – Income Taxation for further details.

Total Comprehensive Income

Total Comprehensive Income for the period was USD 0.09 million (2021: USD 7.7 million income).

Adjusted EBITDA

Adjusted EBITDA is a non-IFRS measure used by the Group to measure business performance. It is calculated as Operating Profit before SPT, Impairment and Exceptional Items for the year, adjusted for non-cash DD&A, SOE, ILFA, FX and FV of Derivative Instruments.

The Group presents Adjusted EBITDA after hedge expense at USD 24.7 million and Adjusted EBIDA after Current Taxes at USD 12.3 million as it is used by Management and judged to be a better measure of underlying performance.

Statement of Cash Flows

Cash inflow from operating activities

Operating Cash Flow was USD 12.0 million (2021: USD 12.6 million) comprising:

- Operating cash flow before working capital and income taxes of USD 15.5 million (2021: USD 16.1 million).
- Changes in working capital resulted in a net decrease of USD (0.1) million (2021: USD (1.8) million decrease).
- Income taxes, PPT and UL paid USD (3.4) million (2021: USD (1.7) million paid) resulting from the higher oil price.

Cash (outflow) from investing activities

Cash outflow from investing activities was USD (15.6) million (2021: USD (13.8) million):

- Property, plant and equipment for the year totaling USD (15.0) million (2021: USD (10.0) million).
- Expenditure on exploration and evaluation assets and other intangible assets USD (0.4) million (2021: USD (3.2) million) as the Group continued to invest in Galeota.
- Computer software USD (0.1) million (2021: USD (0.4) million).
- Performance bond related to the onshore lease operatorship assets USD (0.1) million (2021: USD (0.3) million)

Cash outflow from financing activities

Cash outflow from financing activities was USD (2.2) million (2021: USD (0.6) million):

- Share buyback of USD (1.5) million (2021: nil).
- Principal paid on lease liability USD (0.5) million (2021: (0.4) million).
- Interest paid on lease liability USD (0.1) million (2021: (0.1) million).
- Net Finance cost of USD (0.1) million (2021: (0.1) million).

Closing Cash Balance

Trinity's cash balance at 31 December 2022 was USD 12.1 million (31 December 2021: USD 18.3 million).

Net Cash Plus Working Capital Surplus

		FY 2022	FY 2021	FY 2020	FY 2019
	(All figures in USD million)	Audited	Audited	Audited	Audited
A:	Current Assets				
	Cash and cash equivalents	12.1	18.3	20.2	13.8

	Trade and other receivables	10.7	10.8	7.2	9.4
	Inventories	4.6	3.8	5.3	5.2
	Derivative Financial Instrument	--	--	0.3	0.1
	Total Current Assets	27.4	32.9	33.0	28.5
B:	Current Liabilities				
	Trade and other payables	9.9	8.8	7.8	10.4
	Bank overdraft	2.7	2.7	2.7	—
	Lease liability	0.6	0.6	0.6	0.6
	Taxation payable	--	--	0.2	0.1
C:	Derivative Financial Instrument	--	2.9	--	--
D:	Provision for other liabilities	0.2	0.1	--	--
	Total Current Liabilities	13.4	15.1	11.3	11.1
(A-B+C+D):	Cash plus working capital surplus	14.2	20.8	21.4	17.3

Note: Net cash plus working capital surplus: Current Assets less Current Liabilities (other than Derivative financial asset/liability and Provision for other liabilities).

Events since year end

1. Subsequent to 31 December 2022, the Group has received further VAT refunds of USD 2.6 million as at 31 May 2023. On 10 May 2023, the Government of Trinidad and Tobago announced that it intends to settle outstanding VAT refunds via interest bearing bonds in order to meet VAT arrears of those registrants who are owed in excess of USD 0.03 million in VAT refunds. At the end of May 2023, the Group had USD 2.0 million in VAT refunds recoverable in VAT bonds.

2. On 31 December 2022, the FZ-2 Lease Operating Agreement ("LOA") expired. Trinity obtained an interim renewal of the LOA to 31 March 2023 and obtained a further extension to 30 June 2023 to execute the LOA for the period 1 January 2023 to 30 September 2031.

3. On 29 March 2023, the Group provided six-months' notice to Heritage to terminate the sub-licence Farm-Out agreement for the Tabaquite block. The new sub-licencee requirements proposed to the Group makes this licence uneconomic to operate.

4. Cyber incident – The Group was the subject of a sophisticated cyber incident in December 2022 and immediately took precautionary measures to protect its IT infrastructure. The Group engaged with external specialists to investigate the nature and extent of the incident and implement its systems recovery plan. Trinity moved quickly to notify relevant regulators and law enforcement agencies. Trinity's production facilities continued to operate safely throughout. In 2023, the Group continues to execute its recovery plan. Trinity's IT team and its external advisers continue to support the business in returning its administrative systems to full capacity incorporating learnings from the incident and embedding more resilient IT infrastructure, cyber security systems and procedures.

5. Trintes Field Incident - On the evening of 10 April 2023, a fire occurred in one of the two generators on the Trintes Bravo platform. Production across the field was halted and the fire was contained. Production restarted from Alpha and Delta platforms on 11 April 2023. Four operators, all Trinity staff, were on Bravo at the time of the incident and, having suffered minor injuries, all have now recovered and resumed work. Following approval from the Ministry of Energy and Energy Industries, received on 17 April 2023, the Company successfully restored oil production from all previously producing wells on the Bravo platform on 18 April 2023. Production from the field is in-line with pre-incident levels at approximately 1,010 bopd.

6. Share buyback – As at 31 December 2022, the second tranche of the share buyback programme was still ongoing with 400,000 shares having been repurchased to 31 December 2022 utilising USD 0.5 million of the USD 1.0 million second tranche. On 26 April 2023, the second tranche of the share

buyback programme was completed and a third tranche was announced on 28 April 2023 for up to a further USD 1.0 million. This tranche will be funded from the Group's existing cash resources and will, unless terminated at an earlier date, expire at the conclusion of the 2023 AGM, or 30 June 2023, whichever is earlier.

7. Renewal of PGB Exploration and Production Licence – On 3 May 2023, the MEEI provided confirmation of the renewal of the PGB Licence for an additional 25 years from the Effective Date of 18 December 2012. Consequently, the PGB Licence expires on 17 December 2037. There were no additional liabilities and commitments arising from the renewed Licence.

Consolidated Statement of Comprehensive Income
For the year ended 31 December 2022
(Expressed in United States Dollars)

	Note	2022	2021
		$'000	**$'000**
Revenues			
Crude oil sales	4	92,232	66,257
Other income		7	1
		92,239	66,258
Operating Expenses			
Royalties		(30,091)	(19,828)
Production costs		(19,242)	(17,625)
General & Administrative ("G&A") expenses		(7,181)	(7,030)
Covid-19 expenses*		(579)	(669)
Depreciation, Depletion & Amortisation ("DD&A")	13-15	(7,617)	(7,428)
Share Option Expense ("SOE")		(647)	(626)
Foreign exchange ("FX") loss		(394)	(14)
Net reversal of Impairment losses on financial assets ("ILFA")		46	754
Derivative expenses	6	(10,446)	(1,293)
Fair value income/(expense) derivative instruments	6	2,883	(3,149)
		(73,268)	(56,908)
Operating Profit before Supplemental Petroleum Taxes ("SPT") & Property Taxes ("PT")		**18,971**	**9,350**
SPT		(9,012)	(5,074)
PT net reversal		-	1,516
		(9,012)	(3,558)
Operating Profit before Impairment and Exceptional items		**9,959**	**5,792**
Impairment	8	(6,050)	(1,316)
Exceptional items	7	(161)	(113)
Operating Profit		**3,748**	**4,363**
Finance income	9	48	94
Finance costs	9	(1,339)	(1,475)
Profit Before Income Taxation		**2,457**	**2,982**
Income taxation (charge)/ credit	10	(2,344)	4,744
Profit for the year		**113**	**7,726**
Other Comprehensive Income/(Expense)			
Items that may be subsequently reclassified to profit or loss			
Exchange differences on translation of foreign operations		(20)	-
Total Comprehensive Income for the year		**93**	**7,726**
Earnings per share (expressed in dollars per share)			
Basic	11	0.00	0.20
Diluted	11	0.00	0.18

** Covid-19 expenses have been reclassified as Operating Expenses*

Consolidated Statement of Financial Position
at 31 December 2022
(Expressed in United States Dollars)

	Note	2022	2021
ASSETS		**$'000**	**$'000**
Non-current Assets			
Property, plant and equipment	13	44,987	49,507
Right-of-Use ("ROU") assets	14	838	616
Intangible assets	15	33,537	30,759
Abandonment fund	16	4,511	4,021
Performance bond	17	602	473
Deferred Tax Assets ("DTA")	18	12,465	11,530
		96,940	96,906
Current Assets			
Inventories	19	4,615	3,820
Trade and other receivables	20	10,678	10,747
Cash and cash equivalents	22	12,131	18,312
		27,424	32,879
Total Assets		**124,364**	**129,785**
EQUITY AND LIABILITIES			
Capital and Reserves Attributable to Equity Holders			
Share capital	23	399	389
Share based payment reserve	25	2,990	3,784
Reverse acquisition reserve	26	(89,268)	(89,268)
Translation reserve		(1,667)	(1,650)
Treasury shares	24	(1,522)	--
Retained earnings		145,199	143,666
Total Equity		**56,131**	**56,921**
Non-current Liabilities			
Lease liability	14	341	97
Deferred Tax Liabilities ("DTL")	18	1,940	2,025
Provision for other liabilities	28	52,460	55,690
Employee benefits		23	--
		54,764	57,812
Current Liabilities			
Trade and other payables	29	9,932	8,814
Bank overdraft	30	2,700	2,700
Lease liability	14	584	609
Provision for other liabilities	28	249	46
Derivative financial liabilities	21	--	2,883
Taxation Payable		4	--
		13,469	15,052
Total Liabilities		**68,233**	**72,864**
Total Equity and Liabilities		**124,364**	**129,785**

Company Statement of Financial Position
at 31 December 2022
(Expressed in United States Dollars)

	Note	2022 $'000	2021 $'000
ASSETS			
Non-current Assets			
Investment in subsidiaries	12	60,864	60,347
Current Assets			
Trade and other receivables	20	233	200
Intercompany	20	2,830	3,372
Cash and cash equivalents	22	2,102	3,108
		5,165	6,680
Total Assets		**66,029**	**67,027**
EQUITY AND LIABILITIES			
Capital and Reserves Attributable to Equity Holders			
Share capital	23	399	389
Share based payment reserve		3,775	4,569
Merger reserves		6,552	6,552
Treasury shares	24	(1,522)	--
Retained earnings		43,529	51,526
Total Equity		**52,733**	**63,036**
Current Liabilities			
Trade and other payables	29	565	327
Intercompany	31	12,731	781
Derivative financial liabilities	21	--	2,883
		13,296	3,991
Total Liabilities		**13,296**	**3,991**
Total Equity and Liabilities		**66,029**	**67,027**

The Company has elected to take the exemption under section 408 of the Companies Act 2006, to not present the Statement of comprehensive income. The net loss for the parent company was $9.4 million (2021: $6.4 million).

Consolidated Statement of Changes in Equity
for the year ended 31 December 2022
(Expressed in United States Dollars)

	Share Capital	Share Premium	Share Based Payment Reserve	Reverse Acquisition Reserve	Merger Reserves	Treasury Shares	Translation Reserve	Retained Earnings	Total Equity
Year ended 31 December 2021	**$'000**	**$'000**	**$'000**	**$'000**	**$'000**	**$'000**	**$'000**	**$'000**	**$'000**
At 1 January 2021	97,692	139,879	14,764	(89,268)	75,467	--	(1,650)	(188,332)	48,552
Capital reorganisation	(97,303)	(139,879)	(11,485)	--	(75,467)	--	--	324,134	--
LTIPs exercised[1]	--	--	--	--	--	--	--	47	47
Share based payment expense (Note 25)	--	--	505	--	--	--	--	91	596
Profit for the year	--	--	--	--	--	--	--	7,726	7,726
Total comprehensive income for the year	--	--	--	--	--	--	--	7,726	7,726
At 31 December 2021	**389**	**--**	**3,784**	**(89,268)**	**--**	**--**	**(1,650)**	**143,666**	**56,921**
Year ended 31 December 2022									
At 1 January 2022	389	--	3,784	(89,268)	--	--	(1,650)	143,666	56,921
Issue of shares	10	--	--	--	--	--	--	--	10
LTIPs lapsed (Note 25)	--	--	(1,416)	--	--	--	--	1,416	--
Share based payment expense (Note 25)	--	--	622	--	--	--	--	--	622
Treasury shares (Note 24)	--	--	--	--	--	(1,522)	--	--	(1,522)
Translation adjustment	--	--	--	--	--	--	3	4	7
Profit for the year	--	--	--	--	--	--	--	113	113
Other comprehensive income/ (expense)									
Exchange differences on translation of foreign operations	--	--	--	--	--	--	(20)	--	(20)
Total comprehensive income for the year	--	--	--	--	--	--	(20)	113	93
At 31 December 2022	**399**	**--**	**2,990**	**(89,268)**	**--**	**(1,522)**	**(1,667)**	**145,199**	**56,131**

[1] – As described in the notes to the consolidated financial statements, in 2020 the Company issued 4,745,057 ordinary shares (pre share consolidation) to certain employees on exercise of LTIPs at less than the nominal value in contravention of S580 of the Companies Act 2006. In 2021, on becoming aware of the issue, the Company sought remedial advice and corrected this.

Company Statement of Changes in Equity
for the year 31 December 2022
(Expressed in United States Dollars)

	Share Capital $'000	Share Premium $'000	Share Based Payment Reserve $'000	Merger Reserves $'000	Treasury Shares $'000	Retained Earnings/ Accumulated Losses $'000	Total Equity $'000
Year ended 31 December 2021							
At 1 January 2021	97,692	139,879	4,064	56,652	--	(229,422)	68,865
Capital Reorganisation	(97,303)	(139,879)	--	(50,100)	--	287,282	--
Share based payment charge (Note 25)	--	--	505	--	--	--	505
LTIPs exercised[1]	--	--	--	--	--	47	47
Total comprehensive loss for the year	--	--	--	--	--	(6,381)	(6,381)
At 31 December 2021	**389**	**--**	**4,569**	**6,552**	**--**	**51,526**	**63,036**
Year ended 31 December 2022							
At 1 January 2022	389	--	4,569	6,552	--	51,526	63,036
Issue of shares	10	--	--	--	--	--	10
Share based payment charge (Note 25)	--	--	622	--	--	--	622
LTIPs lapsed (Note 25)	--	--	(1,416)	--	--	1,416	--
Treasury shares (Note 24)	--	--	--	--	(1,522)	--	(1,522)
Total comprehensive loss for the year	--	--	--	--	--	(9,413)	(9,413)
At 31 December 2022	**399**	**--**	**3,775**	**6,552**	**(1,522)**	**43,529**	**52,733**

[1] – As described in the notes to the consolidated financial statements, in 2020 the Company issued 4,745,057 ordinary shares (pre share consolidation) to certain employees on exercise of LTIPs at less than the nominal value in contravention of S580 of the Companies Act 2006. In 2021, on becoming aware of the issue the Company sought remedial advice and corrected this.

Consolidated Statement of Cash Flows
at 31 December 2022
(Expressed in United States Dollars)

	Note	2022 $'000	2021 $'000
Operating Activities			
Profit before taxation		2,457	2,982
Adjustments for:			
Foreign exchange ("FX") loss/(gain)		394	(39)
Finance cost – loans and interest	9	229	254
Finance income	9	(48)	(94)
Finance cost – decommissioning provision	28	1,110	1,222
Share-based payment expense		647	626
DD&A	13-15	7,617	7,428
Net reversal of impairment on financial assets		(46)	(754)
Inventory impairment		334	1,220
Impairment of property, plant and equipment	8	5,558	96
Fair value (gain)/ loss on derivative financial instruments		(2,883)	3,149
Other non-cash items		158	47
		15,527	16,137
Changes In Working Capital			
(Decrease)/increase in inventories	19	(1,129)	228
Decrease in trade and other receivables	16,20,21	(376)	(3,019)
Increase in trade and other payables	21,28,29	1,353	909
		(152)	(1,882)
Income taxation paid		(3,390)	(1,700)
Net Cash Inflow from Operating Activities		11,985	12,555
Investing Activities			
Purchase of Exploration and Evaluation ("E&E") assets	15	(388)	(3,262)
Purchase of computer software and investment in research & development	15	(102)	(401)
Purchase of property, plant and equipment	13	(15,016)	(9,957)
Performance Bond		(130)	(220)
Net Cash Outflow from Investing Activities		(15,636)	(13,840)
Financing Activities			
Finance income		48	94
Finance cost		(94)	(153)
Proceeds from the issue of shares		10	--
Principal paid on lease liability		(536)	(480)
Interest paid on lease liability		(135)	(101)
Acquisition of treasury shares		(1,522)	--
Net Cash Outflow from Financing Activities		(2,229)	(640)
Decrease in Cash and Cash Equivalents		(5,880)	(1,925)
Cash and Cash Equivalents			
At beginning of year		18,312	20,237
Effects of foreign exchange rates differences on cash		(301)	19
Decrease in Cash and Cash equivalents		(5,880)	(1,944)
At end of year	22	12,131	18,312

Company Statement of Cash Flows
for the year ended 31 December 2022
(Expressed in United States Dollars)

	Note	2022 $'000	2021 $'000
Operating Activities			
Loss before taxation		(9,413)	(6,381)
Adjustments for:			
Foreign exchange ("FX") loss		306	28
Finance income		(156)	(152)
Share based payment charge		107	178
Net reversal of impairment loss on financial assets		(14)	(28)
Fair value loss on derivative financial instruments			3,149
Other non-cash items		(2,883)	(13)
		(12,053)	(3,219)
Changes In Working Capital			
Increase in trade and other receivables		521	1,537
Increase in trade and other payables		12,188	354
		12,709	1,891
Taxation Paid		--	--
Net Cash Inflow/(Outflow) from Operating Activities		656	(1,328)
Financing Activities			
Finance income		156	147
Issue of shares		10	--
Treasury Shares		(1,522)	--
Net Cash (Outflow)/Inflow from Financing Activities		(1,356)	147
Decrease In Cash and Cash Equivalents		(700)	(1,181)
Cash and Cash Equivalents			
At beginning of year		3,108	4,317
Effects of foreign exchange rates differences on cash		(306)	(28)
Decrease Cash and Cash equivalents		(700)	(1,181)
At End of Year	22	2,102	3,108

1 Background and Summary of significant accounting policies

The principal accounting policies applied in the preparation of this consolidated financial information are set out below. These policies have been consistently applied to all the years presented, unless otherwise stated. The financial statements are for Trinity Exploration & Production plc ("Trinity" or "the Company" or "Parent") and its subsidiaries (together "the Group").

Background

Trinity is an independent energy company limited by shares and listed on the Alternative Investment Market ("AIM") market of the London Stock Exchange ("LSE"). The Company is incorporated and domiciled in England and the address of the registered office is c/o Pinsent Masons LLP 1 Park Row, Leeds LS1 5AB, United Kingdom ("UK"). The Group is involved in the exploration, development and production of oil reserves in Trinidad & Tobago ("T&T").

Basis of preparation

The Group's and Company's financial statements have been prepared and approved by the Board of Directors ("Board") in accordance with international accounting standards as adopted in the United Kingdom.

The preparation of the consolidated financial statements in compliance with IFRS requires the use of certain critical accounting estimates. It also requires the Board and Executive Management Team ("EMT") (together "Management") to exercise its judgement in the process of applying the Group's accounting policies. The areas involving a higher degree of judgement or complexity, or areas where assumptions and estimates are significant to the consolidated financial information, are disclosed in Note 3: Critical Accounting Estimates and Assumptions.

The Company has taken advantage of the exemption in Section 408 of the Companies Act 2006 not to present its own income statement or Statement of Comprehensive Income. The loss for the Company for the year was $9.4 million (2021: $6.4 million loss) driven mainly by the derivative expenses incurred in 2022.

Basis of measurement

The consolidated financial statements have been prepared under the historical cost convention, except certain financial assets and liabilities (including derivative financial instruments) – which are measured at fair value through the Consolidated Statement of Comprehensive Income. Accounting policies have been applied consistently, other than where a new accounting policy has been adopted.

Going Concern

The Board adopted the going concern basis in preparing the Financial Statements.

In making their going concern assessment, the Board have considered the Group's current financial position, budget and cash flow forecast. The going concern assessment has considered the current operating environment and the potential impact of the volatility of the oil price.

The Group started 2023 with a stable operating and financial position; 2022 average production of 2,975 barrels of oil per day ("bopd"), (2021 3,006 bopd), and cash and short-term investments of $12.1 million as at 31 December 2022 (2021: $18.3 million). The Group's base case going concern assessment is based upon management's best estimate of forward commodity price curves and uses production in line with approved asset plans. The base case forecast was prepared with consideration of the following:

- Future oil prices are assumed to be in line with the forward curve prevailing as at 3 May 2023. The forward price curve applied in the cash flow forecast starts at a realised price of $67.3/bbl in May 2023, fluctuating each month down to $64.8/bbl in December 2023 through to $62.0/bbl in December 2024.
- Average forecast production for the years to December 2023 and December 2024 are in line with the Group's asset development plans, with production being maintained by RCPs, WOs and swabbing activities;
- Whilst the estimated full cost of drilling the deeper Jacobin well is included, a prudent assumption is utilised in the forecast whereby production from Jacobin is assumed to be no greater than that of an

onshore conventional well.

- No SPT is assumed to be incurred on the onshore assets in 2023 or 2024, as the forecast realised price is below $75.0/bbl;
- Trinity continuing to progress various growth and business development opportunities; and
- No derivative instruments being put in place for 2023.

Management considers this is a reasonable base scenario, reflecting a prudent outlook for the future oil price, production profile and costs. The cash flow forecast showed that the Group will remain in a strong financial position for at least the next twelve months, and as such being able to meet its liabilities as they fall due.

Management has considered a separate stressed scenario including:

- the effect of reductions in Brent oil prices at $60.0/bbl being sustained across the forecast period, noting that the base case pricing is in line with market prices; and
- the compounded impact of a reduction in production by 10%.

The stressed case cash flow forecast allows for the impact of mitigating actions that are within the Group's control which include:

- Reducing non-core and discretionary opex and administrative costs across the forecast period.
- Reducing discretionary Capital Expenditure and Capital Returns over the forecast period.

All reasonably plausible forecasts demonstrate that the Group's cash balances are maintained under such scenarios and as such are sufficient to meet the Group's obligations as they fall due.

As a result, at the date of approval of the financial statements, the Board have a reasonable expectation that the Group has sufficient and adequate resources to continue in existence for at least twelve months post approval of these financial statements and is poised for continued growth. For this reason, the Board have concluded it is appropriate to continue to adopt the going concern basis of accounting in the preparation of the consolidated and company financial statements.

Changes in accounting policies

(a) <u>New standards, interpretations and amendments adopted from 1 January 2022:</u>

The following amendments are effective for the period beginning 1 January 2022:

- Onerous Contracts – Cost of Fulfilling a Contract (Amendments to IAS 37).
- Property, Plant and Equipment: Proceeds before Intended Use (Amendments to IAS 16).
- Annual Improvements to IFRS Standards 2018-2020 (Amendments to IFRS 1, IFRS 9, IFRS 16 and IAS 41).

The application of these standards has had no impact on the disclosures, or the amounts recognised in the Group's consolidated financial statements.

(b) <u>New standards, interpretations and amendments not yet effective</u>

There are a number of standards, amendments to standards, and interpretations which have been issued by the IASB that are effective in future accounting periods that the Group has decided not to adopt early.

The following amendments will become effective for the period beginning 1 January 2023:

- IFRS 17 Insurance Contracts (effective 1 January 2023)
- IAS 1 Presentation of Financial Statements and IFRS Practice Statement 2 (Amendment – Disclosure of Accounting Policies)
- IAS 8 Accounting policies, Changes in Accounting Estimates and Errors (Amendment - Definition of Accounting Estimates)
- IAS 12 Income Taxes (Amendment – Deferred Tax related to Assets and Liabilities arising from a Single Transaction)

While no formal assessment has been performed, the Group does not expect any other standards issued by the IASB, but not yet effective, to have a material impact on the Group.

Basis of consolidation

The Consolidated Financial Statements comprise the financial statements of the subsidiaries listed in Note 12. The financial information incorporates the financial information of the Group made up to 31 December each year. Control is achieved where the Company has the power to govern the financial and operating policies of an entity so as to obtain benefits from its activities. The results of subsidiaries acquired or disposed of during the year are included in the Consolidated Statement of Comprehensive Income from the effective date of acquisition and up to the effective date of disposal, as appropriate.

The acquisition method of accounting is used to account for the acquisition of subsidiaries by the Group. The cost of an acquisition is measured as the fair value of the assets given, equity instruments issued and liabilities incurred or assumed at the date of exchange. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured initially at their fair values at the acquisition date, irrespective of the extent of any non-controlling interest. If the cost of acquisition is less than the fair value of the net assets of the subsidiary acquired, the difference is recognised directly in the Statement of Comprehensive Income. Costs related to an acquisition are expensed as incurred.

Uniform accounting policies have been adopted across the Group. All intra-group transactions, balances, income and expenses are eliminated on consolidation.

Share-based payments

The Group operates a number of equity-settled, share-based compensation plans comprised of Share Options and Long-Term Incentive Plans ("LTIPs") as consideration for services rendered by the Group's employees. The fair value of the services received in exchange for the grant of share-based payments is recognised as an expense. The total amount to be expensed is determined by reference to the fair value of the options or LTIP awards granted:

- including any market performance conditions (for example, an entity's share price);
- excluding the impact of any service and non-market performance vesting conditions; and
- including the impact of any non-vesting conditions.

Non-market performance and service conditions are included in assumptions about the number of share-based payments that are expected to vest. The total expense is recognised over the vesting period, which is the period over which all of the specified vesting conditions are to be satisfied.

At the end of each reporting period, the Group revises its estimates of the number of options or LTIP awards that are expected to vest based on the non-market vesting conditions. It recognises the impact of the revision to original estimates, if any, in the Consolidated Statement of Comprehensive Income, with a corresponding adjustment to equity. When the options are exercised, the Group issues new shares. The proceeds received net of any directly attributable transaction costs are credited to share capital (nominal value) and share premium.

The grant by the Company of options and LTIPs over its equity instruments to the employees of subsidiary undertakings in the Group is treated as a capital contribution. The fair value of employee services received, measured by reference to the grant date fair value, is recognised over the vesting period as an increase to investment in subsidiary undertakings, with a corresponding credit to equity.

Employee Benefit Trust
On 15 November 2021, the Group established the Trinity Exploration and Production plc Employee Benefit Trust, which is consolidated in accordance with the principles in Note 1 – Basis of consolidation. When the options are exercised, the trust transfers the appropriate amount of shares to the employee. The proceeds received, net of any directly attributable transaction costs, are credited directly to equity.

Cash-settled share-based payments

The Group operates a cash-settled share-based plan comprised of reference shares as consideration for services rendered by the Group's employees.

Cash-settled share-based payments result in the recognition of a liability, which is an obligation to make a payment in cash or other assets, based on the price of the underlying equity instrument. At each reporting date, and ultimately at the settlement date, the fair value of the recognised liability is remeasured. Remeasurement applies to the recognised portion of the liability through to vesting date. The full amount is remeasured from vesting date to settlement date. The cumulative net cost and amounts recognised in profit or loss that will ultimately be recognised in respect of the transaction will be equal to the amount paid to settle the liability.

Foreign currency translation

(a) Functional and presentation currency

Company: The functional and presentation currency of the Company is United States Dollars ("USD" or "$").

Group: The functional currencies of the Group operating entities are Trinidad & Tobago Dollars ("TTD") and United States dollars as these are the currencies of the primary economic environment in which the entities operate. The presentation currency is USD which better reflects the Group's business activities and improves the ability of users of the consolidated financial statements to compare financial results with others in the international Oil and Gas industry. The Consolidated Statement of Financial Position is translated at the closing rate and Consolidated Statement of Comprehensive Income is translated at the average rate from both USD and Great British Pound ("GBP" or "£") currencies. The following exchange rates have been used in the preparation of these financial statements:

	2022		**2021**	
	$	£	$	£
Average rate TTD= $/£	6.754	8.357	6.765	9.006
Closing rate TTD= $/£	6.742	8.146	6.763	9.151

(b) Transactions and balances

Foreign currency transactions are translated into the functional currency using the exchange rates at the dates of the transactions. FX gains/losses resulting from the settlement of such transactions and from the translation of monetary assets and liabilities denominated in foreign currencies at year end exchange rates are generally recognised in the consolidated Statement of Comprehensive Income. They are deferred in equity if they relate to qualifying cash flow hedges and qualifying net investment hedges or are attributable to part of the net investment in a foreign operation.

Non-monetary items that are measured at fair value in a foreign currency are translated using the exchange rates at the date when the fair value was determined. Translation differences on assets and liabilities carried at fair value are reported as part of the fair value gain or loss. For example, translation differences on non-monetary assets and liabilities such as equities held at fair value through profit or loss are recognised in the consolidated Statement of Comprehensive Income as part of the fair value gain or loss and translation differences on non-monetary assets.

(c) Group companies

The results and financial position of foreign operations (none of which has the currency of a hyperinflationary economy) that have a functional currency different from the presentation currency are translated into the presentation currency as follows:

- assets and liabilities for each Statement of Financial Position presented are translated at the closing rate at the date of that Consolidated Statement of Financial Position
- income and expenses for each Statement of Comprehensive Income are translated at average exchange rates (unless this is not a reasonable approximation of the cumulative effect of the rates prevailing on the transaction dates, in which case income and expenses are translated at the dates of the transactions), and
- all resulting exchange differences are recognised in other comprehensive income.

On consolidation, exchange differences arising from the translation of any net investment in foreign entities, and of borrowings and other financial instruments designated as hedges of such investments, are recognised in other comprehensive income. When a foreign operation is sold or any borrowings forming part of the net investment are repaid, the associated exchange differences are reclassified to profit or loss, as part of the gain or loss on sale.

(d) Translation differences

Differences arising from retranslation of the financial statements at the year-end are recognised in the Translation reserve through "Other comprehensive income".

Intangible assets

(a) Exploration and Evaluation (“E&E”) assets

i) Capitalisation

E&E assets are initially classified as intangible assets. Such costs include those directly associated with an exploration area. Upon discovery of commercial reserves capitalisation is recognised within Property, Plant and Equipment.

Oil and natural gas E&E expenditures are accounted for using the successful efforts method of accounting. Under this method, costs are accumulated on a prospect-by-prospect basis and capitalised upon discovery of commercially viable mineral reserves. If the commercial viability is not achieved or achievable, such costs are charged to expense.

Costs incurred in the E&E of assets includes*:*

- *Licence and property acquisition costs*

Exploration and property leasehold acquisition costs are capitalised within E&E assets.

- *E&E expenditure*

Costs directly associated with an exploration well are capitalised until the determination of reserves is evaluated. Such costs include topographical, geological, geochemical, and geophysical studies, exploratory drilling costs, trenching, sampling and activities in relation to evaluating the technical feasibility and commercial viability of extracting mineral resources. Capitalisation is made within property, plant and equipment or intangible assets according to its nature, although a majority of such expenditure is capitalised as an intangible asset. If commercial reserves are found, the costs continue to be carried as an asset. If commercial reserves are not found, E&E expenditures are written off as a dry hole when that determination is made.

Once commercial reserves are found, E&E assets are tested for impairment and transferred to development tangible and intangible assets as applicable. No depreciation and/or amortisation are charged during the E&E phase.

Where development costs have been capitalised and Management has determined a strategic change to focus on E&E activities in an asset, these costs are transferred from development costs to E&E assets in the period the strategic change was made. An Impairment assessment is performed prior to the transfer in accordance with IFRS 6 impairment guidance noted below.

ii) Impairment

E&E assets are tested for impairment (in accordance with the criteria set out in IFRS 6: Exploration for and Evaluation of Mineral Resources) whenever facts and circumstances indicate impairment. An impairment loss is recognised for the amount by which the E&E assets’ carrying amount exceed their recoverable amount. The recoverable amount is the higher of the E&Es assets’ Fair Value Less Costs of Disposal (“FVLCD”) and their Value In Use (“VIU”). For the purposes of assessing impairment, the E&E assets subject to testing are grouped with existing Cash Generating Units (“CGU”) of related production fields located in the same geographical region. The geographical region is the same as that used for reserves reporting purposes.

The following indicators are evaluated to determine whether these assets should be tested for impairment:

- The period for which the Group has the right to explore in the specific area has lapsed.
- Whether substantive expenditure on further E&E in the specific area is budgeted or planned.
- Whether E&E in the specific area have not led to the discovery of commercially viable quantities and the Company has decided to discontinue such activities in the specific area; and/or
- Whether sufficient data exists to indicate that, although a development in the specific area is likely to proceed, the carrying amount of the E&E asset is unlikely to be recovered in full from successful development or by sale.

(b) Computer software

Computer software is initially recognised at cost, once it is purchased. Internally generated software is capitalised once it is proven technological feasibility, probable future benefits, intent and ability to use the software, resources to complete the software, and ability to measure cost. It is amortised over its four-year useful life, based on pattern of benefits (straight-line is the default) and charge recognised under DD&A.

Property, plant and equipment

(a) Oil & Gas Assets

i) Development and Producing Assets – Capitalisation

Development expenditures are costs incurred to obtain access to proven reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. These costs include transfers from E&Es subsequent to finding commercially viable reserves, development drilling and new reserve type, infrastructure costs and development Geological and Geophysical ("G&G") costs. Acquisitions of oil and gas properties are accounted for under the acquisition method where the transaction meets the definition of a business combination.

Transactions involving the purchases of an individual field interest, or a group of field interests, that do not meet the definition of a business (and therefore do not apply business combination accounting) are treated as asset purchases, irrespective of whether the specific transactions involve the transfer of the field interests directly, or the transfer of an incorporated entity. Accordingly, the consideration is allocated to the assets and liabilities purchased on a relative fair value basis.

Proceeds on disposal are applied to the carrying amount of the specific asset or development and production assets disposed of. Any excess is recorded as a gain on disposal in the Consolidated Statement of Comprehensive Income and any shortfall between the proceeds and the carrying amount is recorded as a loss on disposal in the Consolidated Statement of Comprehensive Income.

Development expenditure on the construction, installation or completion of infrastructure facilities such as platforms, pipelines and the drilling of development commercially proven wells is capitalised according to its nature. When development is completed on a specific field it is transferred to Production Assets. No depreciation and/or amortisation are charged during the development phase.

Expenditure on G&G surveys used to locate and identify properties with the potential to produce commercial quantities of oil and gas as well as to determine the optimal location for development wells are capitalised.

ii) Development and Producing Assets – Impairment

An impairment test is performed whenever events and circumstances arising during the development or production phase indicate that the carrying value of a development or production asset may exceed its recoverable amount. Impairment triggers include but are not limited to, declining long term market prices for oil and gas, significant downward reserve revisions, increased regulations or fiscal changes, market capitalisation being below net assets, deteriorating local conditions such that it become unsafe to continue operations) and obsolescence.

The carrying value is compared against the expected recoverable amount. The recoverable amount is the higher of an asset's FVLCD and the VIU. For the purposes of assessing impairment, assets are grouped at the lowest levels (its CGU) for which there are separately identifiable cash flows. The CGU applied for impairment test purposes is generally the field. These fields are the same as that used for reserves reporting purposes.

iii) Producing Assets – DD&A

The provision for DD&A of developed and producing Oil & Gas Assets are calculated using the unit-of-production method. Oil & Gas Assets are depreciated generally on a field-by-field basis using the unit-of-production method which is the ratio of oil and gas production in the period to the estimated quantities of commercial reserves at the end of the period plus the production in the period. Costs used in the unit of production calculation comprise the net book value of capitalised costs plus the estimated future development costs. Changes in the estimates of commercial reserves or future development costs are dealt with prospectively.

iv) Decommissioning asset

Provision for decommissioning is recognised in accordance with the contractual obligations at the commencement of oil and gas production. The amount recognised is the net present value of the estimated cost of decommissioning at the end of the economic producing lives of the wells and the end of the useful lives of refinery and storage units. Such costs include removal of equipment and restoration of land or seabed. The unwinding of the discount on the provision is included in the Consolidated Statement of Comprehensive Income within finance costs.

A corresponding asset is also created at an amount equal to the provision. This is subsequently depleted as part of the capital costs of the production assets. Any change in the present value of the estimated expenditure or discount rates are reflected as an adjustment to the provision and the asset and dealt with prospectively.

(b) Non-Oil & Gas Assets

All property, plant and equipment are recorded at historical cost less accumulated depreciation and any impairment losses. Historical cost includes the original purchase price of the asset and expenditure that is directly attributable to bringing the asset to its working condition for its intended use. Subsequent costs are included in the asset's carrying amount or recognised as a separate asset, as appropriate, only when it is probable that future economic benefits associated with the item will flow to the Group and the cost of the item can be measured reliably.

The provision for depreciation with respect to operations other than oil and gas producing activities is computed using the straight-line method based on estimated useful lives as follows:

Leasehold and buildings	20 years
Plant and equipment	4 years
Other	4 years

The assets' residual values and useful lives are reviewed and adjusted if appropriate at each Statement of Financial Position date. An asset's carrying amount is written down immediately to its recoverable amount if the asset's carrying amount is greater than its estimated recoverable amount. Gains and losses on disposals are determined by comparing proceeds with carrying amounts and are included in the Consolidated Statement of Comprehensive Income.

Repairs and maintenance are charged to the Consolidated Statement of Comprehensive Income during the financial period in which they are incurred. The cost of major renovations is included in the carrying amount of the asset when it is probable that future economic benefits in excess of the originally assessed standard of performance of the existing assets will flow to the Group. Major renovations such as leasehold improvements are depreciated over the remaining useful life of the related asset.

Impairment of non-financial assets

At each reporting date, assets that are subject to amortisation are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. An impairment loss is recognised for the amount by which the asset's carrying amount exceeds its recoverable amount. The recoverable amount is the higher of an asset's FVLCD and VIU. For the purposes of assessing impairment, assets are grouped at the lowest levels for which there are separately identifiable cash flows (CGUs). Non-financial assets that suffered impairment are reviewed for possible reversal of the impairment at each reporting date.

Inventories

Crude oil is stated at the lower of cost and net realisable value. Cost is determined by the average cost method. Net realisable value is the estimated selling price in the ordinary course of business, less applicable variable selling expenses. Materials and supplies used mainly in drilling wells, RCPs and WOs are stated at lower of cost and net realisable value. Cost is determined using the weighted average cost method.

Cash and Cash equivalents

For the purpose of presentation in the Consolidated Statement of Cash Flows, Cash and Cash equivalents includes cash on hand, deposits held at call with financial institutions, other short-term, highly liquid investments with original maturities of three months or less that are readily convertible to known amounts of cash and which are subject to an insignificant risk of changes in value.

Trade receivables

Trade receivables are amounts due from customers for crude oil sold in the ordinary course of business. They are generally due for settlement within thirty days and therefore are all classified as current. Trade receivables are recognised initially at the amount of consideration that is unconditional unless they contain significant financing components, when they are recognised at fair value.

The Group applies the simplified approach to determine impairment of trade receivables. The simplified approach requires expected lifetime losses to be recognised from initial recognition of the receivables. This involves determining the expected loss rates using a provision matrix that is based on the historical default rates observed over the expected life of the receivable and adjusted forward-looking estimates. This is then applied to the gross carrying amount of the receivable to arrive at the loss allowance for the period.

Trade payables

Trade payables are recognised initially at fair value and subsequently measured at amortised cost using the effective interest method.

Impairment of Financial Assets

The financial assets within the Group are subject to the Expected Credit Losses ("ECL") model. The Group applies the ECL model to trade receivables for sales of inventory and from the provision of consulting services as well as Intercompany receivables. While Cash and Cash equivalents are also subject to the impairment requirements of IFRS 9, the identified impairment loss was immaterial.

(i) Trade receivables

The Group applies the IFRS 9 simplified approach to measuring ECL which uses a lifetime expected loss allowance for all trade receivables.

Financial assets recognition of impairment provisions under IFRS 9 is based on the ECL model. The ECL model is applicable to financial assets classified at amortised cost and contract assets under IFRS 15: Revenue from Contracts with Customers. The measurement of ECL reflects an unbiased and probability weighted amount that is available without undue cost or effort at the reporting date, about past events, current conditions and forecasts of future economic conditions. The Group applied the simplified approach to determine impairment of its trade and other receivables. The simplified approach requires expected lifetime losses to be recognised from initial recognition of the receivables. This involves determining the expected loss rates using a provision matrix that is based on the Group's historical default rates observed over the expected life of the receivables and adjusted forward looking estimates. This is then applied to the gross carrying amount of the receivables to arrive at the loss allowance for the period.

(ii) Intercompany receivables

The Company applies IFRS 9 through the recognition of ECL for intercompany positions. Intercompany positions eliminate in the consolidated financial statements. In measurement of the ECL, IFRS 9 notes that the maximum period over which expected impairment losses is measured is the longest contractual period where the Company is exposed to credit risk. The three-stage general impairment model was used, Probability of Default ("PD") x Loss Given Default ("LGD") x Exposure at Default ("EAD"). Measurement of the ECL at a probability-weighted amount that reflects the possibility of a credit loss occurs, and the possibility that no credit loss occurs and even if the possibility of a credit loss occurring is low.

Income tax

The income tax expense or credit for the period is the tax payable on the current period's taxable income based on the applicable income tax rate for each jurisdiction adjusted by changes in DTA and DTL attributable to temporary differences and to unused tax losses.

The current income tax charge is calculated on the basis of the tax laws enacted or substantively enacted at the end of the reporting period in the countries where the Company's subsidiaries and associates operate and generate taxable income. Management periodically evaluates positions taken in tax returns with respect to situations in which applicable tax regulation is subject to interpretation. It establishes provisions where appropriate on the basis of amounts expected to be paid to the tax authorities.

Deferred income tax is provided in full, using the liability method, on temporary differences arising between the tax bases of assets and liabilities and their carrying amounts in the consolidated financial statements. However, DTLs are not recognised if they arise from the initial recognition of goodwill. Deferred income tax is also not accounted for if it arises from initial recognition of an asset or liability in a transaction other than a business combination that at the time of the transaction affects neither accounting nor taxable profit/loss. Deferred income tax is determined using tax rates (and laws) that have been enacted or substantially enacted by the end of the reporting period and are expected to apply when the related deferred income tax asset is realised or the deferred income tax liability is settled.

DTA are recognised only if it is probable that future taxable amounts will be available to utilise those temporary differences and losses.

DTL and DTA are not recognised for temporary differences between the carrying amount and tax bases of investments in foreign operations where the Company is able to control the timing of the reversal of the temporary differences and it is probable that the differences will not reverse in the foreseeable future.

DTA and DTL are offset when there is a legally enforceable right to offset current tax assets and liabilities and when the deferred tax balances relate to the same taxation authority. Current tax assets and tax liabilities are offset where the entity has a legally enforceable right to offset and intends either to settle on a net basis, or to realise the asset and settle the liability simultaneously.

Current and deferred tax is recognised in profit or loss, except to the extent that it relates to items recognised in other comprehensive income or directly in equity. In this case, the tax is also recognised in other comprehensive income or directly in equity, respectively.

Property Tax ("PT")

From 2018 until 2020, PT had been recognised initially at fair value and subsequently measured at amortised cost using the effective interest method. Assessments were based on the Annual Rental Value ("ARV") of property. The Annual Taxable Value ("ATV") is the ARV subject to deductions and allowances in respect of voids and loss of rent multiplied by the respective PT rate. The PT rates applicable to the Group were industrial with building rates at 6% and industrial without building rates at 3%.

PT accrued for past years is now considered unlikely to be charged and paid, and so no liability is now being recognised. Refer to note 3 (f).

Revenue recognition

IFRS 15 Revenue from Contracts with Customers requires that revenue is recognised by performance obligation, as or when each performance obligation is satisfied, and that variable elements of pricing are recognised and to the extent that it is not highly probable they will be reversed.

The Group has evaluated its customer contract with the Heritage Petroleum Company Limited ("Heritage"), to identify the performance obligations, the timing of the revenue recognition and the treatment of variable elements of pricing. Sales revenue represents the sales value of the Group's oil sold in the year.

Revenue associated with the sale of crude oil is measured based on the consideration specified in contracts with customers.

Revenue is recognised when control is transferred from the Group to its customer and the Group has the present right to payment. The transfer of control of crude oil coincides with title passing to the customer and the customer taking physical possession. Typically, payment for the sale of the oil is received by the end of the month following the month in which the sale is recognised.

Prices are based on prices determined by Heritage, with agreed contractual adjustments for quality. Revenue is measured at the fair value of the consideration received or receivable, and represents amounts receivable for oil and gas products in the normal course of business.

Provisions

Provisions are recognised when the Group has a present legal or constructive obligation as a result of past events, where it is probable that an outflow of resources will be required to settle the obligation, and a reliable estimate of the amount of the obligation can be made. Provisions are not recognised for future operating losses. Where there are a number of similar obligations, the likelihood that an outflow will be required in settlement is determined by considering the class of obligations as a whole. A provision is recognised even if the likelihood of an outflow with respect to any one item included in the same class of obligations may be small.

Provisions are measured at the present value of the expenditures expected to be required to settle the obligation using a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the obligation. The increase in the provision due to passage of time is recognised as a finance cost.

Leases

All leases are accounted for by recognising a right-of-use asset and a lease liability except for:

- Leases of low value assets; and
- Leases with a duration of 12 months or less.

Lease liabilities were measured at the present value of the contractual payments due to the lessor over the lease term, with the discount rate determined by reference to the group's incremental borrowing rate. The lease payments are discounted using the Group's incremental borrowing rate, being the rate that the Group would have to pay to borrow the funds necessary to obtain an asset of similar value to the ROU asset in a similar economic environment with similar terms, security and conditions. To determine the incremental borrowing rate, Trinity received an indicative third-party lending rate from Central Bank of Trinidad and Tobago.

Right of use assets were initially measured at the amount of the lease liability. Subsequent to initial measurement lease liabilities increase as a result of interest charged at a constant rate on the balance outstanding and are reduced for lease payments made. Right-of-use assets are amortised on a straight-line basis over the remaining term of the lease.

The lease term can be described as the non-cancellable period of the lease plus periods covered by an option to extend or an option to terminate if the lessee is reasonably certain to exercise the extension option or not exercise the termination option.

In 2022 the Group revised its estimates due to additional vehicles and copier assets included in lease agreements and the extension of staff house leases in December 2022. As a result, there was a revision to the carrying amount of the lease liability to reflect the payments to being made over the revised term, which was discounted using the same incremental rate. Equivalent adjustment is made to the carrying value of the right-of-use asset, with the revised carrying amount being amortised over the remaining (revised) lease term.

Share capital

Ordinary shares are classified as equity. The nominal value of any shares issued is recognised in share capital with the excess above the nominal amount paid being shown within share premium.

Incremental costs directly attributable to the issue of new ordinary shares are shown in equity. Where, on issuing shares, share premium has been recognised, the expenses of issuing those shares and any commission paid on the issue of those shares have been written off against the share premium account.

Treasury Shares

Where any Group company purchases the Company's equity instruments, for example as the result of a share buy-back or a share-based payment plan, the consideration paid is deducted from equity attributable to the owners of the Company as treasury shares until the shares are cancelled or reissued. Where such ordinary shares are subsequently reissued, any consideration received is included in equity attributable to the owners of the Company. Shares held by the Company are disclosed as treasury shares and deducted from equity.

Derivative financial Instruments and hedging activities

Derivatives are initially recognised at fair value on the date a derivative contract is entered into and are subsequently re-measured to their fair value at the end of each reporting period. The accounting for subsequent changes in fair value depends on whether the derivative is designated as a hedging instrument, and if so, the nature of the item being hedged. The Group has not applied hedge accounting and all oil price derivative financial instruments (categorised as Derivative Income/(Expenses)) are measured at fair value through profit and loss.

Financial assets at fair value through profit or loss are classified in this category if acquired principally for the purpose of selling in the short term. Derivatives are also categorised as held for trading unless they are designated as hedges. Assets in this category are classified as current assets if expected to be settled within twelve months, otherwise they are classified as non-current. Financial assets are derecognised when the rights to the cash flows expire, risks and rewards are transferred or control of the asset is transferred.

A financial liability is removed from the Statement of Financial Position only when it is extinguished; that is, when the obligation specified in the contract is discharged, cancelled or expired.

Investments

Investments are shown at cost less provision for any impairment in value. The Company performs impairment reviews in respect of investments whenever events or changes in circumstances indicate that the carrying amount of the investment may not be recoverable. An impairment loss is recognised when the higher of the investment's net realisable value and fair value less cost of disposal is less than the carrying amount.

Exceptional Items

Exceptional items are disclosed separately in the consolidated financial statements where it is necessary to do so to provide further understanding of the financial performance of the Group. They are distinct from routine operations which are material items of income or expense that have been shown separately due to the non-recurring nature and in the significance of their nature or amount.

2 Financial Risk Management

Financial risk factors

The Group's activities expose it to a variety of financial risks. The Group's overall Risk Management program seeks to minimise potential adverse effects on the Group's financial performance.

Management is responsible for Group Risk Management and for identifying and evaluating financial risks.

(a) Market risk

(i) Foreign currency ("FX") risk

The Group is exposed to FX risk primarily with respect to the United States dollar. FX risk arises from future commercial transactions and recognised assets and liabilities which are denominated in a currency that is not the entity's functional currency.

Foreign currency sensitivity

The Group is mainly exposed to the currency fluctuations of the US dollar. The sensitivity analysis principally arises on FX gain/loss on translation of the USD denominated receivables. The following table details the Group's sensitivity to a 10% (2021: 10%) increase and decrease in the functional currency (TT Dollar) of the main operating subsidiary against the US Dollar with all other variables held constant. 10% (2021: 10%) is the sensitivity rate that best represents Management's assessment of the possible change in the foreign exchange rates affecting the Group. A positive number below indicates an increase in profit and equity when the US dollar weakens against the functional currency. For a strengthening of the US Dollar against the functional currency, there would be an equal and opposite impact on the profit and equity, and the balances below would be negative.

	2022 **$'000**	**2021** **$'000**
Profit/(loss) for the year and Equity		
10% strengthening of the US Dollar/ (2021: 10%)	(269)	(247)
10% weakening of the US Dollar/ (2021: 10%)	269	247

(ii) Price risk

The Group is exposed to commodity price risk regarding its sales of crude oil which is an internationally traded commodity.

Price risk sensitivity

The Group is a price taker and is mainly exposed to the risk relating to price fluctuations. The following table details the Group's sensitivity to a 20% (2021: 20%) increase and decrease in realised oil prices. 20% (2021: 20%) is the sensitivity rate that best represents Management's assessment of the possible change in the oil prices that may affect the Group. A positive number below indicates an increase in revenue, while there would be an equal and opposite impact on revenue if there is a decrease in prices by 20%.

	2022 **$'000**	**2021** **$'000**

Revenue		
20% increase in price/ (2021: 20%)	18,931	13,168
20% decrease in price/ (2021: 20%)	(18,931)	(13,168)

The Group implemented hedge options during the financial year, the purpose of which is to offer protection in the event of oil prices declining significantly.

(iii) Cash flow and fair value interest rate risk

The Group's main interest rate risk arises from borrowings which expose the Group to cash flow interest rate risk. The Group manages risk by limiting the exposure to floating interest rates and maintaining a balance between floating and fixed contract rates.

At 31 December 2022, there were no loan commitments to attract interest rates on foreign currency-denominated borrowings, (2021: nil). During 2022 there was a bank overdraft facility which incurred $0.1 million interest (2021: $0.1 million).

(b) **Credit risk**

Credit risk arises from Cash and Cash equivalents, deposits with banks and financial institutions, as well as credit exposures to customers, including outstanding receivables. For banks and financial institutions, Management determines the placement of funds based on its judgement and experience to minimise risk.

All sales are made to a state-owned entity, Heritage.

The Group applies an IFRS 9 simplified model for measuring the ECL which uses a lifetime expected loss allowance and are measured on the days past due criterion. Having reviewed past payments combined with the credit profile of its existing trade debtors in order to assess the potential for impairment, Management made the decision in keeping with the standard to calculate a provision for long outstanding receivables associated with the Petrotrin outstanding ORR incentive receipts. The ECL for those sales were assessed at the end of the year and was immaterial. A provision matrix was applied to determine the historical and forward-looking loss rates which was used to ultimately calculate an ECL allowance, which resulted in a provision being made of $0.01 million.

For Heritage sales, the ECL was immaterial as all sales payments were made during the stipulated time frame. However, ECL was also calculated on Joint interest billings outstanding, which resulted in a provision of $0.1 million (2021: $0.1 million). Similar to sales, a provision matrix was applied to determine the historical and forward-looking loss rates which was used to ultimately calculate an ECL allowance.

The Company also assessed impairment through the three-stage approach to derive at the ECL. Through assessing impairment via this method, a provision amount of $0.1 million (2021: $0.1 million) was calculated.

(c) **Liquidity risk**

Prudent liquidity risk management implies maintaining sufficient cash and short-term funds and the availability of funding through an adequate amount of committed credit facilities. Management monitors rolling forecasts of the Group's liquidity and Cash and Cash equivalents on the basis of expected cash flow. At the end of the year the Group held cash at bank of $12.1 million (2021: $18.3 million).

Management monitors rolling forecasts of the Group's Cash and Cash equivalents on the basis of expected cash flows. This is carried out at the Group level in accordance with practice and limits set by the Group, refer to the disclosures in Note 1: Background and accounting policies – Going Concern for more information regarding the factors considered by the Company in managing liquidity risk.

The table below analyses the Group's and Company's financial liabilities into relevant maturity groupings based on their contractual maturities for:

(a) All non-derivative financial liabilities, and
(b) Net and gross settled derivative financial instruments for which the contractual maturities are essential for an understanding of the timing of the cash flows.

The following table sets out the contractual maturities (representing undiscounted contractual cash-flows) of financial liabilities.

Group	Less than 1 year	1 to 2 years	2 to 5 years	Total
At 31 December 2022				
	$'000	$'000	$'000	$'000
Non-derivatives				
Trade and other payables	9,932	--	--	9,932
Bank overdraft	2,700	--	--	2,700
Lease liabilities	584	204	137	925
	13,216	204	137	13,557
At 31 December 2021	$'000	$'000	$'000	$'000
Non-derivatives				
Trade and other payables	8,814	--	--	8,814
Bank overdraft	2,700	--	--	2,700
Lease liabilities	609	50	47	706
	12,123	50	47	12,220

Company	Less than 1 year	Total
At 31 December 2022		
	$'000	$'000
Non-derivatives		
Trade and other payables	565	565
Intercompany	12,731	12,731
	13,296	13,296
At 31 December 2021	$'000	$'000
Non-derivatives		
Trade and other payables	327	327
Intercompany	781	781
	1,108	1,108

(d) **Capital risk**

The Group's objectives when managing capital are to safeguard the Group's ability to continue as a going concern in order to provide returns for shareholders and benefits for other stakeholders and to maintain an optimal capital structure to reduce the cost of capital. In order to maintain or adjust the capital structure, the Group may adjust the amount of dividends paid to shareholders, issue new shares or sell assets to reduce debt.

Consistent with others in the industry, the Group monitors capital on the basis of the gearing ratio. This ratio is calculated as Net Cash/(Debt) divided by Total Capital. Net Cash/(Debt) is calculated as total borrowings less Cash and Cash equivalents. Borrowing relates to the overdraft facility where all covenants (current ratio not less than 1.25:1) were met. Total capital is calculated as 'equity' as shown in the Consolidated Statement Of Financial position plus Net Cash/(Debt).

	2022 **$'000**	**2021** **$'000**
Net cash	9,431	15,612
Total equity	(56,131)	(56,921)
Total capital	(46,700)	(41,309)
Gearing ratio	(20.2)%	(37.8)%

(e) **Fair value estimation**

The Group and Company have classified financial instruments into the three levels prescribed under the accounting standards.

- Level 1: The fair value of financial instruments traded in active markets (such as publicly traded derivatives, and equity securities) is based on quoted market prices at the end of the reporting period. The quoted market price used for financial assets held by the Group is the current bid price. These instruments are included in level 1.
- Level 2: The fair value of financial instruments that are not traded in an active market (for example, over-the-counter derivatives) is determined using valuation techniques which maximise the use of observable market data and rely as little as possible on entity-specific estimates. If all significant inputs required to fair value an instrument are observable, the instrument is included in level 2.
- Level 3: If one or more of the significant inputs is not based on observable market data, the instrument is included in level 3. This is the case for unlisted equity securities. See Note 21 for details.

3. Critical Accounting Estimates and Judgements

The preparation of the consolidated financial statements requires the use of accounting estimates which, by definition, seldom equal the actual results. Management also exercise judgement in applying the Group's and the Company's accounting policies. The estimates and assumptions that have a significant risk of causing a material adjustment to the carrying amounts of assets and liabilities within the next financial year are discussed below:

(a) **Recoverability of DTA**

DTA mainly arise from tax losses and are recognised only to the extent it is considered probable that those assets will be recoverable. This involves an assessment of when those DTA are likely to reverse, and a judgement as to whether or not there will be sufficient taxable profits available to offset the tax assets when they do reverse. This requires assumptions regarding future profitability on key estimates of future cost, production volumes, price and is therefore inherently uncertain. To the extent assumptions regarding future profitability change, there can be an increase or decrease in the level of DTA recognised which can result in a charge or credit during the period in which the change occurs. The Group has concluded that the DTA recognised will be recoverable using approved business plans and budgets for the specific subsidiaries in which the DTA arose. See note 18.

(b) **Provision for decommissioning costs**

This provision is significantly affected by changes in technology, laws and regulations which may affect the actual cost and timing of decommissioning to be incurred at a future date. The estimate is also impacted by the discount rates used in the provisioning calculations. The discount rates used are the Group's risk-free rate and the core inflation rate applicable. The provision has been estimated using a rate based on maturity and a core inflation rate. See Note 28: Provision for other liabilities

	Bands (years)	**2022**	**2021**
Risk free rates	7-12	3.96%	1.80%
	13-18	4.04%	1.96%
	19-21	4.14%	2.20%
	22-23	4.09%	2.20%
Inflation rate		3.20%	2.40%

The following table details the Group's sensitivity to a 1% (2021: 1%) increase and decrease in discount and inflation rates. 1% (2021: 1%) is the sensitivity rate that best represents Management's assessment of the possible change in the rates that may affect the Group. A positive number below indicates an increase in provisions and finance costs, while a negative number indicates a decrease in provisions and finance costs. The impact in 2022 of a 1% change in these variables is as follows:

	Consolidated Statement of Financial Position: Obligation 2022 $'000	**Consolidated Statement of Comprehensive: Income/Expense 2022 $'000**
Discount rate		
1% increase in assumed rate	(7,642)	259
1% decrease in assumed rate	9,246	(415)

Inflation rate		
1% increase in assumed rate	9,234	222
1% decrease in assumed rate	(7,769)	(189)

(c) **Estimation of reserves**

All reserve estimates involve some degree of uncertainty, which depends chiefly on the amount of reliable geological and engineering data available at the time of the estimate. Generally, reserve estimates are revised as additional data becomes available. The Group's reserve estimates are also evaluated when required by independent external reserve evaluators. The last independent external reserve valuation was done in 2012. Since 2012 up to and including 2021 the Group estimated its own commercial reserves, guided by international Petroleum Resource Management System (PRMS) application guidelines, based on technical information compiled by appropriately qualified persons relating to the geological and technical data on the size, depth, shape and grade of the hydrocarbon body and suitable production techniques and recovery rates.

The key assumptions used in the estimation of reserves are as follows:

- Technical production profiles for the various assets onshore and offshore held by the Group.
- Economic assumptions such as forecast period, discount rate, crude price, operating cost, capital expenditure and fiscal structure.

As the economic assumptions used may change, and as additional geological information is obtained during the operation of a field, estimates of recoverable reserves may also change. Such changes may impact the Group's reported financial position and results, which include:

- The carrying value of E&E assets, oil and gas properties, property and plant and equipment, may be affected due to changes in estimated future cash flows. See notes 13 and 15.
- Depreciation and amortisation charges in the Statement of Comprehensive Income are depreciated on a unit of production basis at a rate calculated by reference to proved and probable ("2P") reserve estimates and incorporating the estimated future cost of developing and extracting those reserves. There may be changes where such charges are determined using the unit of production method, or where the useful life of the related assets change. See notes 13 and 15.
- Provisions for decommissioning may change - where changes to the reserve estimates affect expectations about when such activities will occur and the associated cost of these activities. See note 28.
- The recognition and carrying value of DTA may change due to changes in the judgements regarding the existence of such assets and in estimates of the likely recovery of such assets. See note 18.

As at 31 December 2022 all subsidiaries onshore and offshore 2P reserve estimates were re-evaluated by the EMT and approved by the Board.

(d) **Impairment of Property, Plant and Equipment**

Management performs impairment assessments on the Group's property, plant and equipment once there are indicators of impairment. Triggers for impairment relate to changes in the key factors that impact on impairment which are production, oil price, capital expenditures and operating expenditures. In order to test for impairment, the higher of FVLCD and VIU calculations are prepared and an estimate of the timing and amount of cash flows expected respectively to arise from the CGU. A CGU represents an individual field or asset held by the Group. During 2022 an impairment charge of $5.6 million was recognised on the Group's property, plant and equipment (2021: $0.1 million) see Note 13. The impairment charge resulted in the carrying amount of the respective CGUs being written down to their recoverable amount.

Oil & Gas Assets $5.6 million (2021: $0.1 million) impairment

Management has carried out an impairment test on the Oil & Gas Assets classified as property, plant and equipment. This test compares the carrying value of the assets at the reporting date with the recoverable amount for each CGU. The recoverable amount is the higher of the FVLCD and VIU. The FVLCD is the amount that a market participant would pay for the CGU less the cost of disposal. The FVLCD approach utilised a discounted cash flow based on the 2P reserve estimates of the CGUs of the Group. VIU is the present value of the future cash flows expected to be derived from an asset or CGU in its current condition. The period over which Management has projected its cash flow forecast, ranges between 7-24 year economic lives based on the field economic life profile. The field economic life profile was derived by using licence extension data which is permitted in accordance with the Society of Petroleum Engineers ("SPE") reserves reporting guidelines outlined in the 2019 Petroleum Resource Management System ("PRMS"). While there is the risk that licences may not be renewed upon expiry, Management considers this to be very low based on historic precedent. For the discounted cash flows to be calculated, Management has used a production profile based on its best estimate of proven and probable reserves of each CGU and a range of assumptions, including an external oil and gas price profile and a discount rate which, taking into account other assumptions used in the calculation, Management considers to be reflective of the risks. The impairment calculation considers the decommissioning asset and liability used to derive the impairment charge.

The discounted cash flow approach assessment involves judgement as to the likely commerciality of the asset. For the discounted cash flows to be calculated, Management has used a production profile based on its 2P reserve estimate of the assets and a range of assumptions *(see note 3(c)).* Its 2P reserves which are estimated using standard recognised evaluation techniques on a fully funded basis; future revenues and estimated development costs and decommissioning liabilities pertaining to the CGU's; and a discount rate utilised for the purposes of deriving a recoverable value.

	2023	2024	2025	2026	2027	2028
Realised price	69.8	65.5	62.5	60.2	58.5	57.7

If the price deck used in the impairment calculation had been 10% lower than Management's estimates at 31 December 2021, the Group would have a $16.1 million increase on impairment of Oil & Gas Assets (2021: $0.6 million increase). If the price deck used in the impairment calculation had been 10% higher than Management's estimates at 31 December 2021, the Group would have a $0.6 million decrease on impairment of the Oil & Gas Assets (2021: $0.1 million decrease). The valuation is considered to be a level 3 in the fair value hierarchy due to unobservable inputs used in the valuation.

For the year ended 31 December 2022, Management's estimate of the Group's cost of capital was 15.0% (2021:13.0%). If the estimated cost of capital used in determining the post-tax discount rate for the CGU's had been 1% lower than Management's estimates the Group would have a $0.0 million decrease (2021: $0.0 million) change to the impairment position for 2022 against Oil & Gas Assets within property, plant and equipment. If the estimated cost of capital had been 1% higher than Management's estimates the Group would have a $0.0 million increase to the impairment position for 2022 (2021: $0.0 million increase).

(e) Impairment of intangible E&E assets

In estimating the recoverability of exploration assets, Management considers contingent resources associated with certain evaluation assets as estimated by the Group's internal experts. Furthermore, Management factors in future development plans and licence expiries into the assessment. Exploration assets remain capitalised as long as sufficient progress is being made in assessing whether petroleum production is technically feasible and commercially viable. This assessment requires significant Management judgement, as exploration assets are subject to regular internal review to confirm the continued intent to establish the technical feasibility and commercial viability of a project. At the end of 2022 a review for impairment triggers was carried out and there were no impairment losses realised against the carrying values of the Group's E&E assets.

The Group reviews the carrying values of intangible E&E assets when there are impairment indicators which would tell whether an E&E asset has suffered any impairment. The amounts of intangible E&E assets represent the costs of active projects the commerciality of which is unevaluated until reserves can be appraised.

(f) Property tax

PT is assessed on property owned by the Group in T&T governed by the Property Tax Act 2009 and later Property Tax 2018 amendment of T&T. The calculation of the PT is described in *note 1 Background and Summary of significant accounting policies.*

The Property Tax Act and subsequent Amendment to the Act requires the Board of Inland Revenue to issue a Notice of Assessment on or before 31 March in each year. To date, none has been issued for any of the years 2018 to 2021. Based on public pronouncements the intention was to complete the assessment for residential properties by 2021, after which other categories can be assessed. Given the passage of time, it is remote that retroactive application will be implemented despite waivers being issued by the Government for periods 2010- 2017 but not for periods 2018-2021. Whilst there remains some ambiguity within the interpretation of the law, industry practice within T&T indicates that it is appropriate to not recognise a PT liability.

The Group has considered whether a contingent liability exists. However, given the judgement is that the law does not allow for retroactive application, there is no liability arising from a past event. A liability will arise when the valuation roll has been completed and the Notice of Assessment given. The Group will continue to monitor developments in the Property tax law and reassess this at each reporting period. As such, the Group has not recognised any PT liabilities to 31 December 2022.

(g) **Share based payments**

The Company has in place a share-based compensation plan (the LTIP) for the Executive Director and the EMT which is designed to provide long-term incentives to align interests with shareholders. The Company measures the cost of these equity-settled transactions by reference to the fair value of the equity instruments at the date at which they are granted. The fair value of share-based payments is measured using a Monte Carlo or Black-Scholes option pricing model. The measurement inputs to this model, including expected volatility, weighted average expected life of the instruments, expected dividends and risk-free interest rate, rely on Management judgements. See note 25 for details.

(h) **Transfer of PS-4 development costs to E&E assets**

The Group acquired the PS-4 asset on 1 December 2021 for $3.8 million and accounted for the full cost as development capital expenditure based on the available data when purchased. Subsequent to acquiring the asset reviewing the seismic acquired, the subsurface work matured allowing the technical team to demonstrate that multiple contingent and prospective resource areas exist in PS-4 and the seismic interpretations in 2022 have identified at least three exploration/appraisal prospects, one of which is planned to be drilled in 2023; the 2P and infill wells in this asset have not been drill due to supply chain costs and inflationary pressures.

These key developments in 2022 resulted in a strategic change by Management to focus on E&E activities as the findings confirm that the PS-4 asset has significant exploration potential.

Management applied judgement based on the specific facts and circumstances and considered the underlying nature of the asset and determined it was appropriate to transfer $2.5 million of development costs to E&E capital expenditure effective 31 December 2022. Judgment was required in determining the date at which such cost capitalisation commenced considering the timing of the strategic review being sufficiently concluded. In concluding that the costs met the cost capitalisation criteria under the Group's accounting policy for E&E assets, Management considered the nature of the activities, its objective and contribution to the E&E activities.

Prior to the strategic change, an impairment assessment was performed on PS-4 development costs and an impairment was recognised (refer to 3(d)). No impairment indicators were identified on the costs transferred to E&E asset.

4 Segment Information

Management has determined the operating segments which are Onshore, West Coast and East Coast reported in a manner consistent with the internal reporting provided to the chief operating decision maker. The chief operating decision maker is responsible for making strategic decisions inclusive of; allocating resources and assessing performance of the operating segments. The chief operating decision maker has been identified as the EMT (which includes the Chief Executive Officer, Chief Financial Officer, Chief Operations Officer and Chief of Staff & General Counsel), which makes strategic decisions in accordance with Board policy.

Management have considered the requirements of IFRS 8 Operating Segments, in regard to the determination of operating segments, and concluded that the Group has only one significant operating segment being the exploration and development, production and extraction of hydrocarbons.

All revenue is generated from crude oil sales in T&T to one customer, Heritage. All revenue is generated at a point in time. All non-current assets of the Group are located in T&T.

5 Operating Profit Before Impairment and Exceptional Items

	2022 $'000	2021 $'000
Operating profit before impairment and exceptional items is stated after taking the following items into account:		
DD&A (Note 13)	6,890	6,756
Depreciation on ROU (Note 14)	534	505
Amortisation of computer software (Note 15)	193	166
Employee costs (Note 35)	8,317	9,670
Inventory recognised as expense, charged to operating expenses	174	322

Auditors' remuneration

During the year the Group (including its overseas subsidiaries) obtained the following services from the Company's Auditors as detailed below:

	2022 $'000	2021 $'000
- Fees payable to the Company's auditors' and their affiliated firms for the audit of the parent Company and consolidated financial statements:		
BDO LLP (UK based) *	220	161
BDO Limited (T&T and Barbados based)*	107	84
- Fees payable to the Company's auditors' for other services:		
The audit of Company's subsidiaries	16	16
Audit related assurance services – interim review	29	32
Total assurance and auditors' remuneration	**372**	**293**

	2022 $'000	2021 $'000
Professional Services:		
Tax services	**--**	**1**

All fees in 2022 are in respect of services provided by BDO LLP and their affiliated firms. The independence and objectivity of the external auditors are considered on a regular basis by the Audit Committee, with particular regard to the level of non-audit fees incurred. The professional fees relates to tax services rendered for advice on tax losses.

6 Derivative expenses

The net (loss)/ gain in fair value is recognised in the Consolidated Statement of Comprehensive Income during the year:

	31 December 2022 $'000	31 December 2021 $'000
Derivative expenses (realised)	(10,446)	(1,293)
Movement in FV of derivative financial instruments (unreaslised)	2,883	(3,149)
	(7,563)	**(4,442)**

7 Exceptional Items:

Items that are material either because of their size, their nature, or that are non-recurring are considered as exceptional items and are presented within the line items to which they best relate. During the current period, exceptional items as detailed below have been included in the Consolidated Statement of Comprehensive Income. An analysis of the amounts presented as exceptional items in these consolidated financial statements are highlighted below.

	31 December 2022 $'000	31 December 2021 $'000
ICT incident costs	161	--
Fees relating to Capital Reorganisation	--	113
Exceptional items	**161**	**113**

Exceptional items:

- Charges relating to ICT incident: $0.2 million charge in relation to costs incurred in relation to the cyber incident (*refer to Note 36 (4)).*

8 Impairment

	31 December 2022 $'000	31 December 2021 $'000
Impairment of Inventory	334	1,220
Impairment of property, plant and equipment	5,558	96
Other impairment of property, plant and equipment	158	--
Total expense	**6,050**	**1,316**

- Impairment of inventory – $0.3 million charge in relation to inventory impairment. In 2021 $1.2 million on slow moving inventory items.
- Impairment of property, plant and equipment - $5.6 million charge in relation to property, plant and equipment and cash generating units. In 2021 the impairment of property, plant and equipment related to charges for impairment losses on cash generating units (refer to Note 3(d)).
- Other impairment of property, plant and equipment – $0.1 million charge in other property, plant and equipment relates to expense incurred on unsuccessful recompletion cost on wells.

9 Finance income and costs

Recognised in the consolidated statement of comprehensive income

Finance income

	2022 $'000	2021 $'000
Interest Income	48	94

Finance costs

	2022 $'000	2021 $'000
Decommissioning – Unwinding of discount (Note 28)	(1,110)	(1,222)
Interest on Leases (Note 14)	(135)	(101)
Interest and other expenses on overdraft	(94)	(152)
	(1,339)	**(1,475)**

10 Income Taxation

	2022 $'000	2021 $'000
Current Taxes		
Petroleum profits tax	2,404	982
Unemployment levy	960	393
Deferred Taxes		
Current year		
Movement in asset due to tax losses recognised (Note 18)	(935)	(5,533)
Movement in liability due to accelerated tax depreciation (Note 18)	(85)	(586)
Income tax expense/ (credit)	**2,344**	**(4,744)**

The Group's effective tax rate varies from the statutory rate for UK companies of 19% (2021:19%) as a result of the differences shown below:

	2022 $'000	2021 $'000
Profit before taxation	**2,457**	**2,982**

Tax calculated at domestic tax rates applicable to profits in the respective countries	4,836	3,441
Expenses not deductible for tax purposes	13,448	9,037
Impact on tax losses	(5,671)	(2,595)
Deferred tax on capital allowances in the current period recognised	(9,334)	(9,087)
Tax losses previously generated now recognised in the current period	(935)	(5,533)
Other reconciling differences	--	(7)
Tax charge/ (credit)	**2,344**	**(4,744)**

Corporate income tax is calculated at 19% (2021: 19%) of the assessable profit for the year for the UK parent company, 55% for the operating subsidiaries in Trinidad and Tobago (2021: 55%) and 30% (2021: 30%) for the corporate subsidiaries in Trinidad and Tobago.

Taxation losses at 31 December 2022 available for set off against future taxable profits amounts to approximately $227.5 million (2021: $234.6 million), with tax losses recognised of $24.9 million at the end of 2022. These losses do not have an expiry date and have not yet been confirmed by the Board of Inland Revenue ("BIR") or His Majesty's Revenue and Customs ("HMRC"). Tax losses carried forward by companies engaged in petroleum production business in Trinidad and Tobago are restricted to set off against 75% of the otherwise chargeable profits in a year.

11 Earnings Per Share

Basic earnings per share is calculated by dividing the earnings attributable to ordinary shareholders by the weighted average number of ordinary shares outstanding during the year. Diluted earnings per share is calculated using the weighted average number of ordinary shares adjusted to assume the conversion of all potentially dilutive ordinary shares.

	Profit for the year $'000	**Weighted Average Number of Shares '000'**	**Earnings Per Share $**
Year ended 31 December 2022			
Basic	113	38,813	0.00
Diluted	113	40,243	0.00
Year ended 31 December 2021			
Basic	7,726	38,879	0.20
Diluted	7,726	42,260	0.18

Impact of dilutive ordinary shares:

Diluted earnings per share is calculated by adjusting the weighted average number of ordinary shares outstanding to assume conversion of all dilutive potential ordinary shares. The awards issued under the Company's LTIP (see movements in number of LTIPs note 25) are considered potential ordinary shares. Share Options of 28,954 are considered potential ordinary shares and have not been included as the exercise hurdle would not have been met.

The basic shares balance was amended through the net effect of the issuance of new shares (following exercise of Options) and the repurchase of shares through the share buyback programme in 2022 (See notes 23 and 24).

12 Investment In Subsidiaries

	Company	
	2022	**2021**
	$'000	**$'000**
Opening balance	60,347	60,021
Share based payment reserve revision	--	(121)
Share based payment	517	447
Closing balance	**60,864**	**60,347**

The investment in subsidiaries is recognised initially at the fair value of the consideration paid. The Group subsequently measures the investment in subsidiaries at cost less impairments. Increases in the investment in subsidiaries relate to capital contributed by the Company to its subsidiary undertakings. In addition, in 2021 there was a revision to the Share based payment reserves as it relates to employees that no longer work for the Group.

Listing of Subsidiaries

The Group's subsidiaries at 31 December 2022 are listed below:

Name	**Registered Address/Country of Incorporation**	**Nature of Business**	**% Shares held by the Group**
Bayfield Energy Limited	c/o Pinsent Masons LLP, 1 Park Row, Leeds, LS1 5AB, UK	Holding Company	99.99998 %
Trinity Exploration & Production (UK) Limited	13 Queen's Road, Aberdeen, AB15 4YL, UK	Holding Company	100 %
Trinity Exploration and Production Services (UK) Limited	c/o Pinsent Masons LLP, 1 Park Row, Leeds, LS1 5AB, UK	Service Company	100 %
Bayfield Energy do Brasil Ltda	Av. Presidente Vargas 509, Rio de Janeiro, 20071-003, Brazil	Dormant	100 %
Trinity Exploration & Production (Barbados) Limited	Ground Floor, One Welches, Welches, St. Thomas BB22025, Barbados	Holding Company	100 %
Trinity Exploration and Production (Trinidad and Tobago) Limited	3rd Floor Southern Supplies Limited Building, 40 -44 Sutton Street, San Fernando, Trinidad & Tobago ("Trinidad address")	Holding Company	100 %
Trinity Exploration and Production (Galeota) Limited	Trinidad address	Oil and Gas	100 %
Oilbelt Services Limited	Trinidad address	Oil and Gas	100 %
Trinity Exploration and Production Services Limited	Trinidad address	Service Company	100 %
Trinity Midstream Limited	Trinidad address	Oil and Gas	100 %
Trinity Exploration and Production (Erin 1) Limited	Trinidad address	Oil and Gas	100 %
Trinity Exploration and Production (Erin 2) Limited	Trinidad address	Oil and Gas	100 %
Trinity Exploration and Production (Forest 1) Limited	Trinidad address	Oil and Gas	100 %
Trinity Exploration and Production (Forest 2) Limited	Trinidad address	Oil and Gas	100 %
Trinity Exploration and Production (Forest 3) Limited	Trinidad address	Oil and Gas	100 %
Trinity Renewable Resources Limited	Trinidad address	Oil and Gas	100 %
Trinity Exploration and Production plc Employee Benefit Trust	c/o Pinsent Masons LLP 1 Park Row, Leeds, LS1 5AB, UK	Employee Benefit Trust	100 %

13 Property, Plant and Equipment

Year ended 31 December 2022	Plant & Equipment $'000	Leasehold & Buildings $'000	Oil & Gas Assets $'000	Other $'000	Total $'000
Opening net book amount at 1 January 2022	2,919	1,388	45,200	--	49,507
Additions	1,999	71	13,062	--	15,132
Transfers (Note 3(h))	--	--	(2,451)	--	(2,451)
Adjustment to decommissioning estimate (Note 28)	--	--	(4,595)	--	(4,595)
Impairment charge[1]	(62)	--	(5,654)	--	(5,716)
DD&A charge for year	(601)	(188)	(6,101)	--	(6,890)
Closing net book amount at 31 December 2022	**4,255**	**1,271**	**39,461**	**--**	**44,987**
At 31 December 2022					
Cost	18,193	3,483	323,161	336	345,173
Accumulated DD&A and impairment	(13,938)	(2,212)	(283,700)	(336)	(300,186)
Closing net book amount	**4,255**	**1,271**	**39,461**	**--**	**44,987**

Year ended 31 December 2021	Plant & Equipment $'000	Leasehold & Buildings $'000	Oil & Gas Assets $'000	Other $'000	Total $'000
Opening net book amount at 1 January 2021	2,028	1,481	34,247	--	37,756
Additions	1,328	74	8,794	--	10,196
Adjustment to decommissioning estimate (Note 28)	--	--	8,407	--	8,407
Impairment charge[1]	--	--	(96)	--	(96)
DD&A charge for year	(437)	(167)	(6,153)	--	(6,757)
Translation differences	--	--	1	--	1
Closing net book amount at 31 December 2021	**2,919**	**1,388**	**45,200**	**--**	**49,507**
At 31 December 2021					
Cost	16,222	3,412	318,058	336	338,028
Accumulated DD&A and impairment	(13,303)	(2,024)	(272,858)	(336)	(288,521)
Closing net book amount	**2,919**	**1,388**	**45,200**	**--**	**49,507**

1 *An impairment loss of $5.7 million (2021: $0.1 million) was recognised on Oil & Gas Assets (see Note 3 (d)) as a result of the carrying value being higher than the recoverable amount. The recoverable amount was determined by assessing its fair value less costs of disposal.*

14 Leases

The Group has recognised ROU assets and lease liabilities.

(i) Amounts recognised in the Consolidated Statement of Financial Position

The Consolidated Statement of Financial Position shows the following amounts relating to leases:

	31 December 2022 $'000	**31 December 2021** $'000
Right-of-use assets		
Non-current assets	838	616
Lease Liabilities		
Current	584	609
Non-current	341	97

	925	**706**

The ROU assets relate to motor vehicles, office building, rental house and office equipment leases that met the recognition criteria of a Lease under IFRS 16.

(ii) Amounts recognised in the Consolidated Statement of Comprehensive Income

The Consolidated Statement of Comprehensive Income shows the following amounts relating to leases:

	2022 $'000	**2021** $'000
Depreciation charge of ROU assets		
Depreciation	(534)	(505)
Interest expense (including finance cost)	(135)	(101)

The total cash outflow for leases in 2022 was $0.7 million (2021: $0.6 million)

(iii) The Group's leasing activities and how these are accounted for

The Group leases various offices, equipment, staff housing and vehicles. Rental contracts are typically made for fixed periods of 6 months to 4 years.

Contracts may contain both lease and non-lease components. There were no non-lease components identified and as such the Group allocates the consideration in the contract to a single lease component based on their relative stand-alone prices.

Lease terms are negotiated on an individual basis and contain a wide range of different terms and conditions. The lease agreements do not impose any covenants other than the security interests in the leased assets that are held by the lessor. Leased assets may not be used as security for borrowing purposes.

15 Intangible Assets

The carrying amounts and changes in the year are as follows:

Year ended 31 December 2022	**Exploration and Evaluation assets $'000**	**Computer software $'000**	**Research and Development $'000**	**Total $'000**
Opening net book amount at 1 January 2022	30,217	496	46	30,759
Additions	235	102	183	520
Transfers (Note 3(h))	2,451	--	--	2,451
Amortisation charge for year	--	(193)	--	(193)
Closing net book amount at 31 December 2022	**32,903**	**405**	**229**	**33,537**
At 31 December 2022				
Cost	32,903	979	229	34,111
Accumulated amortisation	--	(574)	--	(574)
Closing net book amount	**32,903**	**405**	**229**	**33,537**

Year ended 31 December 2021	**Exploration and Evaluation assets $'000**	**Computer software $'000**	**Research and Development $'000**	**Total $'000**

Opening net book amount at 1 January 2021	27,042	307	--	27,349
Additions	3,175	355	46	3,576
Amortisation charge for year	--	(166)	--	(166)
Closing net book amount at 31 December 2021	**30,217**	**496**	**46**	**30,759**

- E&E assets: Represents the cost for the TGAL 1 exploration well and transfer of PS-4 Development cost to E&E costs of USD 2.5 million (refer to Note 3(h)). The Group tests whether E&E assets have suffered any impairment triggers on an annual basis and there were no impairment triggers identified (2021: nil).

- Computer Software: In 2022, costs incurred in connection with the acquisition of software.

- Research and Development: In 2022, there were costs associated for various initiatives in connection with reducing carbon emissions.

16 Abandonment fund

	2022	2021
	$'000	**$'000**
At 1 January	4,021	3,490
Additions	490	531
At 31 December	**4,511**	**4,021**

Abandonment funds are restricted cash put aside in escrow for abandonment and environmental purposes in accordance with contractual obligations to be used in accordance with the contract.

17 Performance bond

	2022	2021
	$'000	**$'000**
At 1 January and 31 December	602	473

The Group's Lease Operatorship Assets ("LOA") licences were renewed in June 2021. New Performance Bonds for each of the LOA were put in place totaling $0.47 million at a bond fee of 1.75% executed with First Citizens Bank Trinidad and Tobago Limited and effective until 31 December 2030. A performance bond of $0.13 million for PS-4 block was also executed with First Citizens Bank Trinidad and Tobago Limited in 2022 effective 31 December 2030 at a bond fee of 1.75%. These funds have been restricted to fixed deposits for the period of the respective LOA licences at varying rates of interest.

18 Deferred Income Taxation

Group

The analysis of DTA is as follows:

	2022 $'000	2021 $'000
DTA:		
DTA to be recovered in more than 12 months	(7,774)	(5,130)
DTA to be recovered in less than 12 months	(4,691)	(6,400)
DTL:		
DTL to be settled in more than 12 months	1,940	2,025
Net DTA	**(10,525)**	**(9,505)**

The movement on the deferred income tax is as follows:

	2022 $'000	2021 $'000
At beginning of year	(9,505)	(3,386)
Movement for the year	(935)	(6,041)

Unwinding of deferred tax on fair value uplift	(85)	(78)
Net DTA	**(10,525)**	**(9,505)**

The deferred tax balances are analysed below:

	2020 $'000	Movement $'000	2021 $'000	Movement $'000	2022 $'000
Acquisition	(33,436)	--	(33,436)	--	(33,436)
Tax losses recognised	(39,476)	(5,533)	(45,009)	(935)	(45,944)
Tax losses derecognised	66,915		66,915		66,915
	(5,997)	**(5,533)**	**(11,530)**	(935)	(12,465)

	2020	Movement	2021	Movement	2022
DTL	**$'000**	**$'000**	**$'000**	**$'000**	**$'000**
Accelerated tax depreciation and non-current asset impairment	(18,867)	(508)	(19,375)	--	(19,375)
Acquisitions	19,580	--	19,580	--	19,580
Fair value uplift	1,898	(78)	1,820	(85)	1,735
	2,611	**(586)**	**2,025**	**(85)**	**1,940**

DTA are recognised for tax loss carry-forwards to the extent that the realisation of the related tax benefit through future taxable profits are probable. Deferred tax assets of $0.9 million have been recognised (2021: $5.5 million was recognised) based on estimated future taxable profits. The Group has unrecognised deferred tax assets amounting to $87.2 million which have no expiry date.

DTL have decreased by $0.1 million related to unwinding of assets.

- DTA and DTL can only be offset in the Consolidated Statement of Financial Position if an entity has a legal right to settle current tax amounts on a net basis and Deferred Tax amounts are levied by the same tax authority (as per IAS 12). The Group has no legal right to offset any DTA and DTL.
- Tax losses – At the end of 2022 the Group had gross tax losses carried forward of $227.5 million (2021: $234.6 million) represented by corporate tax losses in the UK of $33.2 million (2021: $23.7 million) and PPT and Corporate tax losses in Trinidad and Tobago of $194.3 million (2021: $210.9 million). In the UK corporation tax losses may be carried forward indefinitely. Similarly, in Trinidad and Tobago PPT and corporate tax losses may be carried forward indefinitely to reduce the taxes in future years. As of 1 January 2020, however, PPT losses can only be utilised to shelter a maximum of 75 percent of PPT per annum.

19 Inventories

	Crude oil	Materials and supplies	Total
	$'000	**$'000**	**$'000**
At 1 January 2022	96	3,724	3.820
Impairment (see note 8)	--	(334)	(334)
Net inventory movement	29	1,100	1,129
At 31 December 2022	**125**	**4,490**	**4,615**
At 1 January 2021	67	5,200	5,267
Impairment (see note 8)	--	(1,220)	(1,220)
Net inventory movement	29	(256)	(227)
At 31 December 2021	**96**	**3,724**	**3,820**

(i) Assigning costs to inventories

The costs of individual items of inventory within the category material and supplies are determined using weighted average costs. The cost assigned for crude oil is based on the lower of cost and net realisable value. In the current year there was a total of $0.3 million of impairment of inventory items (2021: $1.2 million).

20 Trade and Other Receivables

	Group		Company	
	2022 $'000	2021 $'000	2022 $'000	2021 $'000
Due within 1 year				
Amounts due from related parties (Note 31 (d))	--	--	2,830	3,372
Trade receivables	4,643	4,641	--	--
Less: provision for impairment of trade and intercompany receivables	(4)	(6)	--	--
Trade receivables: net	4,639	4,635	2,830	3,372
Prepayments	969	895	198	175
VAT recoverable	4,544	4,550	29	25
Other receivables	582	767	6	--
Less: provision for Impairment of other receivables	(56)	(100)	--	--
	10,678	**10,747**	**3,063**	**3,572**

The fair value of trade and other receivables approximate their carrying amounts.

The Group applies the IFRS 9 simplified model for measuring ECL which uses a lifetime expected loss allowance and are measured on the days past due criterion.

Trade receivables – Heritage net sales receipts have been collected on a timely basis. Since the Joint Interest Billing ("Jibs") balances are outstanding, an ECL was calculated at 31 December 2022 of $0.1 million (31 December 2021: $0.1 million) against Other receivables.

VAT recoverable – At 31 December 2022 the VAT recoverable was $4.5 million. During 2022, the Group generated VAT refunds of $3.1 million and received VAT refunds of $3.2 million.

All trade receivables are with the Group's only customer, Heritage. Ageing analysis of these trade receivables as at 31 December 2022 is as follows:

	2022 $'000	2021 $'000
Up to 30 days	4,544	4,495
>60 days	--	--
>180 days	95	140
	4,639	**4,635**

The carrying amount of the Group's trade and other receivables are denominated in the following currencies:

	Group		Company	
	2022 $'000	2021 $'000	2022 $'000	2021 $'000
USD	3,381	3,292	2,873	3,416
GBP	260	169	190	156
TTD	7,037	7,286	--	--
	10,678	**10,747**	**3,063**	**3,572**

The maximum exposure to credit risk at the reporting date is the value of each class of receivable as shown above. The Group does not hold any collateral as security.

The credit quality of the financial assets that are neither past due nor impaired can be assessed by reference to historical information about the counterparty default rates:

	Group		Company	
	2022 $'000	2021 $'000	2022 $'000	2021 $'000
Trade receivables				
Counterparties without external credit rating:				

Existing customers with no defaults in the past	**10,678**	**10,747**	**--**	**--**

The fair value of trade and other receivables approximate their carrying amounts.

The Group applies the IFRS 9 simplified model for measuring expected credit losses ("ECL") using a lifetime expected loss provision for trade and other receivables. The expected loss rates are based on the Group's historical credit losses experienced over a period prior to the period end. The historical loss rates are then adjusted for current and forward-looking information on key macroeconomic factors affecting the Group's customer including GDP, foreign exchange rates, WTI crude oil price and inflation rates. In calculating an ECL, two default loss rates are established; default loss rate 1 which is calculated through the ageing profiles of sales, and default loss rate 2 which is default loss rate 1 adjusted based on forward looking information.

Having reviewed past payment performance combined with the credit rating of Heritage (and its predecessor, Petrotrin), a Provision matrix was completed to calculate a potential impairment on the receivable balances. Trade receivables that are less than six months past due are not considered impaired and at 31 December 2022, trade receivables of $4.6 million (2021: $4.6 million) were therefore considered to be fully performing.

At the end of 2022 a total of $0.1 million was outstanding from Petrotrin (2021: $0.1 million). An ECL of $0.0 million was applied to the outstanding $0.1 million receivables amount due from Petrotrin.

For other Joint Interest Billing receivable amounts from Heritage, an ECL of $0.1 million (2021: $0.1 million) was calculated.

21 Derivative financial instruments

The following table compares the carrying amounts and fair values of the Group's financial liabilities as at 31 December 2022.

	As at 31 December 2022	**As at 31 December 2021**
	$'000	**$'000**
Derivative liability	--	2,883
Total	--	2,883

By 31 December 2022 all crude derivative contracts expired.

The Group considers that the carrying amount of the following financial assets and financial liabilities are a reasonable approximation of their fair value:

- Trade receivables
- Trade payables
- Cash and cash equivalents

Fair Value Hierarchy

The level in the fair value hierarchy within which the derivative financial asset is categorised is determined on the basis of the lowest level input that is significant to the fair value measurement.

The derivative financial assets are classified in their entirety into only one of the three levels.

The fair value hierarchy has the following level:

- Level 1 - quoted prices (unadjusted) in active markets for identical assets or liabilities
- Level 2 - inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly (i.e. as prices) or indirectly (i.e. derived from prices)
- Level 3 - inputs for the asset or liability that are not based on observable market data (unobservable inputs).

Level 2 recurring fair value measurements:

	As at 31	**As at 31**

	December 2022 $'000	December 2021 $'000
Opening balance	(2,883)	266
Opening derivative instrument realised	2,883	(266)
Derivative expense (loss in fair value)	--	(2,883)
Closing balance	--	(2,883)

22 **Cash and Cash Equivalents**

	Group		Company	
	2022 $'000	2021 $'000	2022 $'000	2021 $'000
Short term investment	1,033	2,449	1,033	2,449
Cash and cash equivalents	11,098	15,863	1,069	659
	12,131	**18,312**	**2,102**	**3,108**

Cash and Cash equivalents disclosed above and in the Consolidated Statement of Cash Flows exclude restricted cash and are available for general use by the Group.

23 **Share Capital and Share Premium**

Group

	Number of shares	Ordinary shares $'000	Share premium $'000	Total $'000
As at 1 January 2022	38,879,431	389	--	389
Shares Issued at Nominal value	1,005,206	10	--	10
As at 31 December 2022	**39,884,637**	**399**	**--**	**399**

24 **Treasury Shares**

Treasury shares are shares in the Company that are held by the Company. In September 2022, the Group announced a share buyback programme to return up to $1 million to shareholders, which was completed with 672,000 ordinary shares having been repurchased. The Group subsequently announced a second tranche of its share buyback programme to return up to an additional $1 million to shareholders, and as at 31 December 2022, this programme was still ongoing with 400,000 shares having been repurchased for approximately $0.5m during 2022.

Group and Company

	Number of shares	Cost $'000	Total $'000
Share buyback – 1st tranche	672,000	994	994
Share buyback – 2nd tranche	400,000	528	528
As at 31 December 2022	**1,072,000**	**1,522**	**1,522**

25 **Share Based Payment Reserve**

The share-based payments reserve is used to recognise:

- The grant date fair value of options issued to employees but not exercised
- The grant date fair value of share awards issued to employees
- The grant date fair value of deferred share awards granted to employees but not yet vested; and
- The issue of shares held by the Employee Share Trust to employees.

During 2022 the Group had in place share-based payment arrangements for its employees and Executive Directors, the LTIP. The Share Option Plan referenced below is fully vested and expensed. The current year charge for share-based payments are solely in relation to the LTIP arrangements shown below, with further details of each scheme following:

	2022 $'000	2021 $'000
At 1 January	3,784	14,764
Capital Reduction	--	(11,485)
Share based payment expense:		
Lapsed options released to retained earnings	(1,416)	--
LTIP expense	622	505
At 31 December	**2,990**	**3,784**

Share Option Plan

Share Options were granted to Executive Directors and to selected employees. The exercise price of the granted option was equal to Management's best estimate of the fair value of the shares at the time of the award of the options. The Group has no legal or constructive obligation to repurchase or settle the options in cash. These Share Options were fully vested in 2015 and 2016 with nil exercised and expiry dates in 2022 and 2023. The table below gives details:

			2022		2021
Grant-Vest	**Expiry Date**	**Exercise price per Share Options**	**Number of Options**	**Exercise price per Share Options**	**Number of Share Options**
2012-2015	2022		--	GBP8.60	168,554
2013-2016	2023		28,954	GBP12.00	28,954
			28,954		197,508

The inputs into the Black-Scholes model for options granted in prior periods were as follows:

Grant date	29 May 2013	14 February 2013
Share price	GBP 11.90	GBP 12.00
Average Exercise price	GBP 12.00	GBP 8.90
Expected volatility	55%	78%
Risk-free rates	4.5%	4.5%
Expected dividend yields	0%	0%
Vesting period	3 years	3 years

LTIP

LTIP awards are designed to provide long-term incentives for the Executive Directors and other members of the EMT to deliver long-term shareholder returns. Under the plan, participants are granted options which only vest if certain performance standards are met. Participation in the plan is at the Board's discretion and no individual has a contractual right to participate in the plan or to receive any guaranteed benefits.

2017 One Off Award

One Off LTIP awards were granted in August 2017 over 2,541,600 ordinary shares and in June 2020 over a further 142,296 ordinary shares (the "2017 One Off Award"). The 2017 One Off Award vested in full on 30 June 2022, subject to meeting performance targets relating to the following:

- In respect of 70% of the award, the Company's share price growth from the 2017 placing price of 49.8 pence per share. If the three-month volume-weighted price ("VWAP") at the testing date is 350 pence or more per share, this part of the award will vest in full. If the VWAP at the testing date is 49.8 pence per share or less, this part of the award will not vest at all. If the VWAP at the testing date is between 49.8 pence and 350 pence per share, this part of the award will vest on a pro-rated straight-line basis;

- In respect of 20% of the award, repayment of the amount due to the BIR in accordance with the terms of the Creditors Proposal approved in 2017. The final payment occurred in 2018; and

- In respect of 10% of the award, redemption of all the Convertible Loan Notes ("CLN") issued in January 2017 before the second anniversary of their issue. All of the CLNs were redeemed in 2018.

The total fair value of the 2017 One Off Award was $2.6 million and was expensed over the vesting period with the full charge pro-rated over the period up to 30 June 2022. However, the 2017 One Off Award could vest in full or in part on 30 June 2020 or 2021 with the appropriate charge being taken over that vesting period. The fair value at grant date was independently determined using an adjusted form of the Black Scholes Model which includes a Monte Carlo simulation model that takes into account the exercise price, the term of the option, the share price at grant date and expected price volatility of the underlying share, the expected dividend yield, the risk-free interest rate for the term of the option and the correlations and volatilities of the peer group companies.

The model inputs for the 2017 One Off Award were as follows:

Grant Date	24 August 2017	30 June 2020
Share price at grant date	GBP 107.50p	GBP 79.00p
Exercise price	GBP 0.00	GBP 0.00
Expected volatility	73.3%	84.9%
Risk-free interest rates	0.44%	(0.07%)
Expected dividend yields	0%	0%
Vesting period 1	30 June 2020	--
Vesting period 2	30 June 2021	--
Vesting period 3	30 June 2022	30 June 2022

The final vesting of the 2017 One Off Award was due to occur on 30 June 2022. However, as the three-month average VWAP to 30 June 2022 of 130.0p was below that prevailing at 30 June 2021, the remaining 1,214,744 unvested options lapsed.

2017 and 2018 LTIP Awards

In January 2019 Options over 282,400 ordinary shares and in May 2019 Options over 383,282 ordinary shares were granted under the LTIP awards in accordance with the policy announced to the market on 25 August 2017 in respect of the performance of the Company in the financial years ended 31 December 2017 and 2018 respectively. These awards vested on 1 January 2021 and 2 January 2022 respectively, subject to meeting the performance criteria set out in the table below and continued employment with the Company.

Performance	**Vesting**
Below the Median	None of the award will vest
Median (50th percentile)	30% of the maximum award will vest
Between Median and Upper Quartile	Straight Line basis between these points
Upper Quartile (75%)	100% of the maximum award will vest.
Above the Upper Quartile	100% of the maximum award will vest

These awards were subject to the achievement of relative Total Shareholder Return ("TSR") performance targets measured over a 3-year performance period ending on 1 January 2021 and 31 December 2021 respectively. The amounts stated above represent the maximum possible opportunity.

The total fair value at grant date of the LTIP awards granted during the period ended 31 December 2019 was $0.9 million and this was expensed over the vesting period with the full charge pro-rated over the vesting period. The fair value at grant date was determined using a Monte Carlo simulation model that takes into account the exercise price, the term of the option, the share price at grant date and expected price volatility of the underlying share, the expected dividend yield, the risk-free interest rate for the term of the option and the correlations and volatilities of the peer group companies. The model inputs for the LTIP awards granted during the period ended 31 December 2019 included:

	2017 LTIP Award	**2018 LTIP Award**
Grant Dates	2 January 2019	9 May 2019
Share price at grant dates	GBP167.7p	GBP146.6p
Exercise price	GBP0.00	GBP0.00
Expected volatility	113.9%	113.9%
Risk-free interest rates	0.73%	0.73%
Expected dividend yields	0%	0%
Vesting period	1 January 2021	2 January 2022

2019 LTIP Award

On 25 June 2020 and 30 October 2020 Options over a total of 481,586 ordinary shares were granted under the LTIP in accordance with the policy announced to the market on 25 August 2017 in respect of the performance of the Company in the financial year ended 31 December 2019. These LTIP awards vested on 2 January 2023, subject to meeting the performance criteria set out in the table below and continued employment with the Company.

Performance	Vesting
Below the Median	None of the award will vest
Median (50th percentile)	30% of the maximum award will vest
Between Median and Upper Quartile	Straight Line basis between these points
Upper Quartile (75%)	100% of the maximum award will vest.
Above the Upper Quartile	100% of the maximum award will vest

These Awards are subject to the achievement of relative TSR performance targets measured over a three-year performance period ending on 31 December 2022. The amounts stated above represent the maximum possible opportunity.

The total fair value at grant date of the LTIP awards granted during the period ended 31 December 2020 was $0.4 million and this will be pro-rated and expensed over the vesting period. The fair value at grant date was determined using a Monte Carlo simulation model that takes into account the exercise price, the term of the option, the share price at grant date and expected price volatility of the underlying share, the expected dividend yield, the risk-free interest rate for the term of the option and the correlations and volatilities of the peer group companies. The model inputs for the LTIP awards granted during the period ended 31 December 2020 included:

	2019 LTIP Award	**2019 LTIP Award**
Grant Dates	25 June 2020	30 October 2020
Share price at grant dates	GBP79.0	GBP77.0
Exercise price	GBP0.00	GBP0.00
Expected volatility	84.9%	84.9%
Risk-free interest rates	(0.07%)	(0.07%)
Expected dividend yields	0%	0%
Vesting dates	2 January 2023	2 January 2023

2020 LTIP Award

On 13 August 2021, Options over a total of 325,000 ordinary shares were granted under the LTIP in accordance with a revised LTIP scheme (the Revised LTIP") in respect of the performance of the Company in the financial year ended 31 December 2020. These LTIP awards will vest on 1 January 2024, subject to meeting the performance criteria set and continued employment in the Company.

The performance targets set for awards made under the Revised LTIP during the period ended 31 December 2021 will be measured considering both the Company's absolute TSR performance and the Company's relative TSR performance over a three-year period, commencing with the current financial year of the Company (i.e. a measurement period of 1 January 2021 to 31 December 2023). TSR calculations will be determined by reference to the volume weighted three-month average price prior to the start and end of the measurement period (with the starting average price adjusted for the Share Consolidation). The three-month volume weighted average price at the start of the performance period was 88p (adjusted for the Share Consolidation).

The performance targets provide that:

- No portion of a distinct one-half of the LTIP Award (the "Absolute TSR Part") may vest unless the Company's compound annual growth rate of TSR over the performance period is at least 10% p.a., for which 30% of the Absolute TSR Part may vest, rising on a straight-line basis for full vesting of the Absolute TSR Part if the Company's compound annual growth rate of TSR over the performance period equals or exceeds 25% p.a.

- No portion of the other distinct one-half of the LTIP Award (the "Relative TSR Part") may vest unless the Company's TSR over the performance period ranks at least median relative to the TSR performance within a comparator group of companies, for which 30% of the Relative TSR Part may vest, rising on a straight line basis for full vesting of the Relative TSR Part if the Company's TSR over the performance period ranks upper quartile or better relative to the TSR performance within a comparator group. However, an underpin term applies to the Relative TSR Part which provides that, regardless of relative TSR performance, no vesting may ordinarily accrue in respect of the Relative TSR Part unless the Company's compound annual growth rate of TSR over the performance period is at least 10% per annum.

The total fair value at grant date of the LTIP awards granted during the period ended 31 December 2021 was $0.7 million and this will be pro-rated and expensed over the vesting period. The fair value at grant date was determined using a Monte Carlo simulation model that takes into account the exercise price, the term of the option, the share price at grant date and expected price volatility of the underlying share, the expected dividend yield, the risk-free interest rate for the term of the option and the correlations and volatilities of the peer group companies. The model inputs for the LTIP awards granted during the period ended 31 December 2021 included:

	2020 LTIP Award
Grant Date	13 August 2021
Share price at grant dates	GBP146.00p
Exercise price	GBP0.00
Expected volatility	6.3%
Risk-free interest rates	(0.20%)
Expected dividend yields	0%
Vesting dates	1 January 2024

2021 LTIP Award

On 6 June 2022, 24 October 2022 and 9 December 2022 Options over a total of 415,000 ordinary shares were granted in accordance with the Revised LTIP in respect of the performance of the Company in the financial year ended 31 December 2021. The earliest vesting date for the Award will be 1 January 2025, subject to meeting the performance criteria set and continued employment in the Company.

The performance targets set for awards made under the Revised LTIP during the period ended 31 December 2022 will be measured considering both the Company's absolute TSR performance and the Company's relative TSR performance over a three-year period, commencing with the current financial year of the Company (i.e. a measurement period of 1 January 2022 to 31 December 2024). TSR calculations will be determined by reference to the volume weighted three month average price prior to the start and end of the measurement period (with the starting average price adjusted for the Share Consolidation). The three-month volume weighted average price at the start of the performance period was £1.38 (adjusted for the Share Consolidation).

The performance targets provide that:

- No portion of a distinct one-half of the LTIP Award (the "Absolute TSR Part") may vest unless the Company's compound annual growth rate of TSR over the performance period is at least 10% p.a., for which 30% of the Absolute TSR Part may vest, rising on a straight line basis for full vesting of the Absolute TSR Part if the Company's compound annual growth rate of TSR over the performance period equals or exceeds 20% p.a.

- No portion of the other distinct one-half of the LTIP Award (the "Relative TSR Part") may vest unless the Company's TSR over the performance period ranks at least median relative to the TSR performance within a comparator group of companies, for which 30% of the Relative TSR Part may vest, rising on a straight line basis for full vesting of the Relative TSR Part if the Company's TSR over the performance period ranks upper quartile or better relative to the TSR performance within a comparator group. However, an underpin term applies to the Relative TSR Part which provides that, regardless of relative TSR performance, no vesting may ordinarily accrue in respect of the Relative TSR Part unless the Company's compound annual growth rate of TSR over the performance period is at least 10% per annum.

The total fair value at grant date of the LTIP awards granted in the period ended 31 December 2022 was $0.6 million and this will be pro-rated and expensed over the vesting period. The fair value at grant date was determined using a Monte Carlo simulation model that takes into account the exercise price, the term of the option, the share price at grant date and expected price volatility of the underlying share, the expected dividend yield, the risk-free interest rate for the term of the option and the correlations and volatilities of the peer group companies. The model inputs for the LTIP awards granted during the period ended 31 December 2022 included:

	2021 LTIP Award
Grant Date	Jun/Oct/Dec 2022
Share price at grant dates	GBP135p/120p/108p
Exercise price	GBP0.00
Expected volatility	79%
Risk-free interest rates	1.83%/3.59%/3.28%

Expected dividend yields	0%
Vesting dates	1 January 2025

Movements in the number of LTIPs outstanding and their related weighted average exercise prices are as follows:

	2022 Average exercise price per Share Option	Number of Options	2021 Average exercise price per Share Option	Number of Options
At 1 January	GBP 0.00	3,381,299	GBP 0.00	3,156,299
Forfeited/Lapsed	GBP 0.00	(1,360,733)	GBP 0.00	(100,000)
Granted[1]	GBP 0.00	415,000	GBP 0.00	325,000
Exercised[2]	GBP 0.00	(1,005,206)	GBP 0.00	--
At 31 December	GBP 0.00	1,430,360	GBP 0.00	3,381,299

1 Weighted average fair value of LTIPs granted GBP 1.38

2 Weighted average share price at the date of exercise GBP 1.00

LTIPs outstanding at the end of the year have the following expiry date and exercise prices:

Grant-Vest	Expiry date	Exercise price	2022	2021
24/8/2017 – 30/6/2022	24/08/2027	GBP 0.00	167,037	2,103,032
2/1/2019 – 1/1/2021	1/1/2024	GBP 0.00	50,858	252,510
9/5/2019 – 2/1/2021	2/1/2025	GBP 0.00	90,879	319,171
25/6/2020 – 2/1/2023	2/1/2026	GBP 0.00	381,586	381,586
13/8/2021 – 31/12/2023	2/1/2027	GBP 0.00	325,000	325,000
6/6/2022 – 1/1/2025	1/1/2027	GBP 0.00	415,000	-

26 Merger and Reverse Acquisition Reserves

	Reverse Acquisition Reserve $'000	Merger Reserve $'000	Total $'000
At 1 January 2022	(89,268)	--	(89,268)
Capital re-organisation/reduction	--	--	--
Translation differences	--	--	--
At 31 December 2022	(89,268)	--	(89,268)
At 1 January 2021	(89,268)	75,467	(13,801)
Capital re-organisation/reduction	--	(75,467)	(75,467)
Translation differences	--	--	--
At 31 December 2021	**(89,268)**	**--**	**(89,268)**

The issue of shares by the Company as part of the reverse acquisition (February 2013) met the criteria for merger relief such that no share premium was recorded. As allowed under the UK Companies Act 2006 and required by IAS 27 ('Consolidated and separate financial statements'), a merger reserve equal to the difference between the fair value of the shares acquired by the Company and the aggregation of the nominal value of the shares issued by the Company has been recorded.

27 Adjusted EBITDA

Adjusted EBITDA is a non-IFRS measure used by the Group to measure business performance. It is calculated as Operating Profit before SPT, PT, Impairment and Exceptional Items for the period, adjusted for DD&A, ILFA, SOE, FX Gain/(Loss) and the movement in the FV of Derivative Financial Instruments.

The Group presents Adjusted EBITDA as it is used in assessing the Group's growth and operational efficiencies as it illustrates the underlying performance of the Group's business by excluding items not considered by Management to reflect the underlying operations of the Group.

Adjusted EBITDA is calculated as follows:

	2022 $'000	2021 $'000
Operating Profit Before SPT, Impairment and Exceptional Items	18,971	9,350
DD&A (note 13 - 15)	7,617	7,428
ILFA (note 20)	(46)	(754)
SOE (note 24)	647	626
FX (loss)/gain	394	14
Movement in FV of Derivative Financial Instruments (note 6)	(2,883)	3,149
Adjusted EBITDA	24,700	19,813

	$'000	$'000
Weighted average ordinary shares outstanding - basic	38,813	38,879
Weighted average ordinary shares outstanding - diluted	40,243	41,969

	$	$
Adjusted EBITDA per share – basic (note 11)	0.64	0.51
Adjusted EBITDA per share - diluted (note 11)	0.61	0.47

Adjusted EBITDA after Current Taxes (*the impact of SPT and PPT/UL*) is calculated as follows:

	2022 $'000	2021 $'000
Adjusted EBITDA	24,700	19,813
PT	--	1,516
SPT	(9,012)	(5,074)
PPT/UL	(3,365)	(1,375)
Adjusted EBIDA After Current Taxes	12,323	14,880

	'000	'000
Weighted average ordinary shares outstanding - basic	38,813	38,879
Weighted average ordinary shares outstanding - diluted	40,243	41,969

	$	$
Adjusted EBIDA After Current Taxes per share - basic	0.32	0.38
Adjusted EBIDA After Current Taxes per share - diluted	0.31	0.35

28 Provision for Other Liabilities

(a) Non-current:

	Decommissioning provision $'000	Closure of pits $'000	Total $'000
Year ended 31 December 2022			
Opening amount as at 1 January 2022	55,220	470	55,690
Unwinding of discount (Note 9)	1,110	--	1,110
Revision to estimates (Note 13)	(4,595)	--	(4,595)
Additions	--	138	138
Translation differences	122	(5)	117
Closing balance at 31 December 2022	**51,857**	**603**	**52,460**

Year ended 31 December 2021			
Opening amount as at 1 January 2021	45,405	470	45,875
Unwinding of discount (Note 9)	1,222	--	1,222
Revision to estimates (Note 13)	8,407	--	8,407
Decommissioning contribution	195	--	195
Translation differences	(9)	--	(9)
Closing balance at 31 December 2021	**55,220**	**470**	**55,690**

Decommissioning cost

The Group operates oil fields and this cost represents an estimate of the amounts required for abandonment of the Group's wells, platforms, gathering station and pipeline infrastructures. The amounts are calculated based on the provisions of existing contractual agreements with Heritage and MEEI. Furthermore, liabilities for decommissioning costs are recognised when the Group has an obligation to dismantle and remove a facility or an item of plant and to restore the site on which it is located, and when a reasonable estimate of that liability can be made. An obligation for decommissioning may also crystallise during the period of operation of a facility through a change in legislation or through a decision to terminate operations.

The amount recognised is the present value of the estimated future expenditure determined in accordance with local conditions and requirements. A corresponding item of property, plant and equipment of an amount equivalent to the provision is also created. This is subsequently depreciated as part of the capital costs of the facility or item of plant. Any change in the present value of the estimated expenditure is reflected as an adjustment to the provision and the corresponding property, plant and equipment. Some of the key assumptions made in the present value decommissioning calculation include the following:

a. Core inflation rate – 3.20% (2021: 2.40%)
b. Risk free rate – 3.96% - 4.14% (2021: 1.80% - 2.20%)
c. Estimated market value/decommissioning cost
d. Estimated life of each asset

See Note 3(b): Critical Accounting Estimates and Assumptions for the rates used and sensitivity analysis.

Closure of Pits

Closure of pits relate to the remedy and closure of pits associated with drilling new onshore wells. It is an environmental regulatory requirement set by the Environmental Management Authority ("EMA") that all open drill pits for onshore drilling must be closed after sufficient testing has deemed it safe to close the pit.

(b) Current :	**Litigation claims $'000**	**Other provisions $'000**	**Total $'000**
Year ended 31 December 2022			
Opening amount as at 1 January 2021	46	--	46
Additions	91	112	203
Closing balance at 31 December 2022	**137**	**112**	**249**
Year ended 31 December 2021			
Opening amount as at 1 January 2021	46	--	46
Closing balance at 31 December 2021	**46**	**--**	**46**

Litigation claims

There was an increase in the provisions for $0.1 million to reflect the best estimate of litigation claims as at 31 December 2022.

Other provisions

There was a provision of $0.1 million arising from the ICT downtime due to the cyber incident arising in

December 2022 (Note 36 (4)).

29 Trade and Other Payables

Current	**Group**		**Company**	
	2022 $'000	**2021 $'000**	**2022 $'000**	**2021 $'000**
Trade payables	2,605	2,274	136	88
Accruals	4,661	4,486	429	239
Other payables	500	492	--	--
SPT	2,166	1,562	--	--
	9,932	**8,814**	**565**	**327**

30 Bank overdraft

	31 December 2022 $'000	**31 December 2021 $'000**
Bank Overdraft	2,700	2,700
	2,700	**2,700**

An on-demand operating (overdraft) line of $5.0 million exists with FirstCaribbean International Bank (Trinidad & Tobago) Limited ("CIBC"). Details of the overdraft facility:

- Description: Demand revolving credit
- Interest Rate: United States dollar prime rate minus 6.50% per annum, effective rate 6.75%. Interest is payable monthly.
- Repayment: Upon demand at CIBC's discretion.
- Debenture: Floating charge debenture giving the lender a first ranking floating charge over inventory and trade receivables only.
- Covenant: Current Ratio not less than 1.25:1

The credit limit on the facility is $5.0 million of which $2.7 million was drawn as at 31 December 2022.

31 Related Party Transactions

Group

The following transactions were carried out with the Group's subsidiaries and related parties. These transactions comprise sales and purchases of goods and services and funding provided in the ordinary course of business during the year. The following are the major transactions and balances with related parties:

(a) Transfers of funds from related parties

	Company	
	2022 $'000	**2021 $'000**
Company subsidiaries:		
Trinity Exploration and Production Services Limited	10,510	856
Trinity Exploration & Production (UK) Limited	--	8
Trinity Exploration and Production (Galeota) Limited	--	659
Bayfield Energy Limited	80	19
Oilbelt Services Limited	--	1,659
Trinity Exploration and Production (Trinidad and Tobago) Limited	1,800	393
Trinity Exploration and Production Services Limited (UK) Limited	1,100	30
Transfer of funds	--	73
	13,490	**3,697**

(b) Transfer of funds to related parties

Company

	2022 $'000	2021 $'000
Company subsidiaries:		
Trinity Exploration and Production Services Limited	--	(70)
Bayfield Energy Limited	--	(100)
Trinity Exploration and Production Services Limited (UK) Limited	(1,265)	(2,063)
	(1,265)	**(2,233)**

Related party transactions comprise of the transfer of funds to and from related parties which are payable on demand. Positive balances indicate increase in funds transferred to the entities, while negative balances indicate repayment to entities.

(c) Key Management and Directors' compensation: Key Management includes Board (Executive & Non-Executive). The compensation paid or payable to Key Management for employee services is shown below:

	Group	
	2022 $'000	2021 $'000
Salaries and short-term employee benefits	876	1,337
Post-employment benefits	30	27
Share-based payment expense	279	305
	1,185	**1,669**

(d) Year-end balances arising from transfer to and from related parties

	Company	
	2022 $'000	2021 $'000
Receivables from related parties:		
Trinity Exploration & Production (UK) Limited	40	28
Trinity Exploration and Production (Galeota) Limited	2	--
Bayfield Energy Limited	122	192
Trinity Exploration and Production (Trinidad and Tobago) Limited	--	22
Trinity Exploration and Production Services (UK) Limited	2,652	3,129
Employee Benefit Trust (See note 1)	--	73
Total intercompany receivables	**2,816**	**3,443**
Reversal of provision for impairment/ (provision for impairment)	14	(71)
Closing intercompany receivables (Note 20)	**2,830**	**3,372**

Company

- The receivables from related parties arise mainly from inter-group recharges. The receivables are unsecured and bear no interest. An ECL provision was calculated $0.1 million (2021: 0.1 million).

	Company	
	2022 $'000	2021 $'000
Payables to related parties:		
Trinity Exploration and Production Services Limited	10,683	167
Trinity Exploration and Production Services (UK) Limited	--	7
Trinity Exploration and Production (Galeota) Limited	--	112
Trinity Exploration and Production (Trinidad & Tobago) Ltd	1,779	--
Oilbelt Services Limited	269	495
Total intercompany payables	**12,731**	**781**

32 **Taxation Payable**

	2022 $'000	2021 $'000

Taxation payable		
PPT	4	--
UL	--	--
	4	--

Trinidad and Tobago statutory petroleum profit tax ("PPT") and unemployment levy ('UL") are a combined rate of 55% of taxable income. PPT has a tax charge of 50%, while UL has a tax charge of 5% on taxable profits.

33 Financial Instruments by Category

At 31 December 2022 and 2021, the Group held the following financial assets at amortised cost:

	Group		Company	
	2022	**2021**	**2022**	**2021**
	$'000	**$'000**	**$'000**	**$'000**
Trade and other receivables – current*	5,165	5,302	6	200
Abandonment fund – non current	4,511	4,021	--	--
Intercompany	--	--	2,830	3,372
Cash and cash equivalents	12,131	18,312	2,102	3,108
	21,807	**27,635**	**4,938**	**6,680**

Note (*): Excludes prepayments and VAT recoverable

At 31 December 2022 and 2021, the Group held the following financial liabilities at amortised cost:

	Group		Company	
	2022	**2021**	**2022**	**2021**
	$'000	**$'000**	**$'000**	**$'000**
Accounts payable and accruals	9,932	8,814	565	327
Intercompany	--	--	12,731	781
Bank overdraft	2,700	2,700	--	--
	12,632	**11,514**	**13,296**	**1,108**

At 31 December 2022 and 2021, the Group held the following financial liabilities at fair value through profit or loss:

	Group		Company	
	2022	**2021**	**2022**	**2021**
	$'000	**$'000**	**$'000**	**$'000**
Derivative financial liability	--	2,883	--	2,883
	--	**2,883**	**--**	**2,883**

34 Commitments and Contingencies

a) Commitments

There are commitments for decommissioning costs of the wells and facilities under the Group's agreements with Heritage, which have been provided for as described in Note 28: Provision for other liabilities.

b) Contingent Liabilities

i) The West Coast Point Ligoure, Guapo Bay and Brighton Marine Outer ("PGB") licences and the Farm-Out Agreement for the Tabaquite Block (held by Coastline International Inc.) was expired as at 31 December 2022. Subsequent to the year-end the PGB licence was renewed to 17 December 2037 (Note 36 (7)). There were no additional liabilities and commitments arising from the renewed agreement.

ii) Parent Company Guarantee:

a) PGB - A Letter of Guarantee has been established in substance over the PGB Block where a subsidiary of Trinity is obliged to carry out a Minimum Work Programme to the value of $8.4 million. A clause within the Letter of Guarantee implies that the Guarantor may reduce the Guarantee Sum available for payment to the MEEI under the Letter of Guarantee on an obligation by obligation basis provided PGB delivers to the Guarantor a certificate duly issued and signed by the MEEI.

b) Galeota - A Letter of Guarantee has been established in substance over the Galeota Block where a subsidiary of Trinity is obliged to carry out a Minimum Work Programme to the value of $0.9 million. A clause within the Letter of Guarantee implies that the Guarantor may reduce the Guarantee Sum available for payment to the MEEI under the Letter of Guarantee on an obligation by obligation basis provided the subsidiary of Trinity delivers to the Guarantor a certificate duly issued and signed by the Minister of the MEEI. The Letter of Guarantee was effective from 14 July 2021 until the earlier of performance of Minimum Work Programme or the Guarantor has paid the Guarantee amount.

iii) The Group is party to various claims and actions. Management has considered the matters and where appropriate has obtained external legal advice. No material additional liabilities are expected to arise in connection with these matters, other than those already provided for in these consolidated financial statements.

35 Employee Costs

Employee costs for the Group during the year	Group 2022 $'000	Group 2021 $'000	Company 2022 $'000	Company 2021 $'000
Wages and salaries	7,245	8,625	483	1,170
Other pension costs	425	372	--	--
Share based payment expense	647	673	107	94
	8,317	**9,670**	**590**	**1,264**

Average monthly number of people (including Executive and Non-Executive Directors') employed by the Group	2022 number	2021 number	2022 number	2021 number
Executive and Non-Executive Directors	6	6	6	6
Administrative staff	102	95	--	--
Operational staff	168	144	--	--
	276	**245**	**6**	**6**

36 Events after the Reporting Period

1. Subsequent to 31 December 2022, the Group has received further VAT refunds of $2.6 million as at 31 May 2023. On 10 May 2023, the Government of Trinidad and Tobago announced that it intends to settle outstanding VAT refunds via interest bearing bonds in order to meet VAT arrears of those registrants who are owed in excess of $0.03 million in VAT refunds. At the end of May 2023, the Group had $ 2.0 million in VAT refunds recoverable in VAT bonds.

2. On 31 December 2022, the FZ-2 Lease Operating Agreement (LOA) expired. Trinity obtained an interim renewal of the LOA to 31 March 2023 and obtained a further extension to 30 June 2023 to execute the LOA for the period 1 January 2023 to 30 September 2031.

3. On 29 March 2023, the Group provided six-months' notice to Heritage to terminate the sub-licence Farm-Out agreement for the Tabaquite block. The new sub-licencee requirements proposed to the Group makes this licence uneconomic to operate.

4. Cyber incident – The Group was the subject of a sophisticated cyber incident in December 2022 and immediately took precautionary measures to protect its IT infrastructure. The Group engaged with external specialists to investigate the nature and extent of the incident and implement its systems recovery plan. Trinity moved quickly to notify relevant regulators and law enforcement agencies. Trinity's production facilities continued to operate safely throughout. In 2023, the Group continues to execute its recovery plan. Trinity's IT team and its external advisers continue to support the business in returning its administrative systems to full capacity incorporating learnings from the incident and embedding more resilient IT infrastructure, cyber security systems and procedures.

5. Trintes Field Incident - On the evening of 10 April 2023, a fire occurred in one of the two generators on the Trintes Bravo platform. Production across the field was halted and the fire was contained. Production restarted from Alpha and Delta platforms on 11 April 2023. Four operators, all Trinity staff, were on Bravo at the time of the incident and, having suffered minor injuries, all are now recovered and resume work. Following approval from the Ministry of Energy and Energy Industries, received on 17 April 2023, the Company successfully restored oil production from all previously producing wells on the Bravo platform

on 18 April 2023. Production from the field is in-line with pre-incident levels at approximately 1,010 bopd.

6. Share buyback – As at 31 December 2022, the second tranche of the share buyback programme was still ongoing with 400,000 shares repurchased to 31 December 2022 utilising $0.5 million of the $1 million tranche. On 26 April 2023, the second tranche of the share buyback programme was completed and a third tranche was announced on 28 April 2023 for up to a further $1 million. This tranche will be funded from the Group’s existing cash resources and will, unless terminated at an earlier date, expire at the conclusion of the 2023 AGM, or 30 June 2023, whichever is earlier.

7. Renewal of PGB Exploration and Production Licence – On 3 May 2023, the MEEI provided confirmation of the renewal of the PGB Licence for an additional 25 years from the Effective Date of 18 December 2012. Consequently, the PGB Licence expires on 17 December 2037. There were no additional liabilities and commitments arising from the renewed Licence.