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

Preliminary Results

A year of strong performance and wider development focused on delivering a step change in scale

Trinity, the independent E&P company focused on Trinidad and Tobago, today announces its unaudited preliminary results for the 12 months ended 31 December 2020 ("the Period" or "FY 2020").

This was a year of both strong performance and wider development as the Group positioned itself to deliver a step change in scale – establishing a broader opportunity set from which to grow. Furthermore, while the depressed oil price impacted revenues and profits, the Group proved its resilience, with cash flows remaining strong.

Importantly, in order to further enhance Trinity's standing in the region and drive the business forward the Group established partnerships with significant industry players, grew its portfolio and leveraged datasets and relationships - with a view to creating a roadmap for significantly increased production over the medium term by building on its strong existing base.

Key Performance Indicators

The Group was profitable at an operating level in 2020, despite the material reduction in the realised oil price, with a 46% increase in the year-end cash balance to USD 20.2 million (2019: USD 13.8 million) and a 25% increase in the net cash plus working capital surplus of USD 21.7 million (2019: USD 17.3 million).

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

		FY 2020	FY 2019	Change %
Average realised oil price	USD/bbl	37.7	58.1	35
Average net production	bopd	3,226	3,007	7
Annual production	mmbbls	1.2	1.1	8
Revenues	USD million	44.1	63.9	31
Cash balance	USD million	20.2	13.8	46
IFRS Results				
Operating Profit before SPT & PT	USD million	3.0	10.3	71
Operating Profit before Exceptional Items	USD million	2.6	2.4	9
Operating Profit/(Loss)	USD million	1.4	(12.8)	111
Total Comprehensive Loss For The Year	USD million	(2.8)	(9.6)	70
Lloss Per Share - Diluted	USD cents	(0.7)	(2.3)	70
APM Results				
Adjusted EBITDA	USD million	12.3	21.8	43
Adjusted EBITDA	USD/bbl	11.4	19.8	42
Adjusted EBITDA margin	%	28	34	18
Adjusted EBITDA Per Share - Diluted	US cents	3.0	5.3	43
Adjusted EBITDA after SPT & PT	USD million	12.0	13.9	14
Adjusted EBITDA after SPT & PT	USD/bbl	11.1	12.6	12
Adjusted EBITDA after SPT & PT Per Share - Diluted	US cents	2.9	3.3	14
Consolidated operating break-even	USD/bbl	20.1	26.4	24
Net cash plus working capital surplus	USD million	21.7	17.3	25

Financial Highlights

- Revenues of USD 44.1 million (2019: USD 63.9 million) – reflecting the significantly lower average realised oil price in 2020
- Cash operating costs down 7% to USD 13.9/bbl (2019: USD 15.0/bbl)
- Adjusted EBITDA of USD 12.3 million (2019: USD 21.8 million)
- Adjusted EBITDA margin of 28% (2019 34%) or USD 11.4/bbl (2019: USD 19.8/bbl)
- Adjusted EBITDA after SPT & PT of USD 12.0 million (2019: USD 13.9 million)
- Group operating break-even price reduced by 24% to USD 20.1/bbl (2019: USD 26.4/bbl)
- Cash balance of USD 20.2 million (2019: USD 13.8 million)
    - Net cash (cash minus USD 2.7 million drawn working capital facility) of USD 17.5 million (2019: USD 13.8 million)
- Cash plus working capital surplus of USD 21.7 million (2019: USD 17.3 million)

Operational Highlights

- Average production volumes grew in aggregate by 7.3% to 3,226 bopd in 2020 (2019: 3,007 bopd)
    - This increase was achieved despite no new drilling during the Period
- Created strategic framework to meaningfully scale the business
    - Acquisition of Onshore 3D & 2D Seismic Data package
    - MOU with NGC to Explore and Develop New Energy Projects
    - Established partnership with a large international operator
- Continued roll out of wellsite automation and the digitalisation of operations
    - Driving efficiencies and increasing recovery rates
    - Reducing carbon emissions

Post Period Highlights

- Changes to Supplemental Petroleum Tax (“SPT”)
    - Significant improvement for the Company
    - Will enhance returns from onshore operations
- Licence Renewals
    - Renewal of Onshore LOAs with Heritage is expected imminently
- Partnership established with the University of the West Indies (“UWI”)
    - MOU signed to explore and develop new projects to enable energy transition in Trinidad and, potentially, in the wider Caribbean and beyond
    - UWI rated among the top 3% of universities globally
- Acquisition of Onshore PS-4 Block
    - Further enhances Trinity's contiguous acreage
    - Part of the broader strategy to drive scale
    - Substantial synergies from a financial, operational and technical perspective
- Continued momentum into Q1 2021
    - Q1 production levels resilient with volumes averaging 3,107 bopd (Q4 2020: 3,202 bopd)
    - Cash balance of UDS 20.0 million as at 31 March 2021 (unaudited) (USD 20.2 million as at 31 December 2020) despite increased investment in growth initiatives occurring in Q1 2021
    - Average realisation of USD 52.3/bbl for Q1 (Q1 2020: USD 46.3/bbl)

Bruce Dingwall CBE, Executive Chairman of Trinity, commented:

“We are a forward-looking company focused on deploying new technologies and innovative approaches to generate increasing scale and returns from our existing assets, and on pursuing new development opportunities through acquisitions and partnerships. We believe that during the Period we have established a strong path for a step change in production, revenue, profitability and cash flow, and consequent re-rating opportunities, as the Company leverages relationships and development strategies to generate scale.

“While balance sheet strength and strong cash flow, along with prudent expense management and low-cost growth, remain the cornerstones of the business, given the number of growth initiatives now underway, 2021 will be a year of investment as we seek to advance current developments, identify new opportunities via the

strategic partnerships we have recently entered into and pursue further low-cost appraisal and exploration targets.

"The current opportunity set offers scalability with numerous potential game changers in regards to our future production, revenue, profitability and cash flow profile."

Analyst Briefing
A briefing for Analysts will be held at 12.00 today via web conference. Analysts wishing to join should contact trinityexploration@walbrookpr.com.

Investor Presentation
The Company will be hosting a presentation through the digital platform Investor Meet Company at 13:30 today.

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

Enquiries

For further information please visit www.trinityexploration.com or contact:

Trinity Exploration & Production plc	+44 (0)131 240 3860
Bruce Dingwall CBE, Executive Chairman	
Jeremy Bridglalsingh, Managing Director	
Tracy Mackenzie, Corporate Development Manager	
SPARK Advisory Partners Limited (Nominated Adviser and Financial Adviser)	+44 (0)20 3368 3550
Mark Brady	
James Keeshan	
Cenkos Securities PLC (Broker)	
Neil McDonald	+44 (0)20 7397 8900
Derrick Lee	+44 (0)131 220 6939
Walbrook PR Limited	+44 (0)20 7933 8780
Nick Rome/Nicholas Johnson	trinityexploration@walbrookpr.com

About Trinity (www.trinityexploration.com)

Trinity is an independent oil and gas exploration and 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 nine licences and, across all of the Group's assets, management's estimate of 2P reserves as at the end of 2020 was 19.55 mmbbls. Group 2C contingent resources are estimated to be 23.25 mmbbls. The Group's overall 2P plus 2C volumes are therefore 42.80 mmbbls.

Trinity is quoted on the AIM market of the London Stock Exchange under the ticker TRIN.

Chairman's Statement

This was a year of both strong performance and wider development as the Group positioned itself to achieve a step change in scale – establishing a broader opportunity set from which to grow.

Stronger than when we started
Being able to come out of 2020 as a stronger, more innovative and strategically focused company is a testament to the mutual trust and hard work of our team of women and men in the fields and offices alike. So as we review and report on our achievements during 2020 we have to begin by acknowledging and thanking the entire Trinity team and their families for adapting incredibly quickly to the challenging conditions in which we found ourselves, and their above and beyond efforts to not only deliver but thrive in such adverse circumstances.

Health, well-being & safety
The health, well-being and safety of our team will always be our paramount priority and we moved quickly to put measures in place to protect them, the wider community and those suppliers and contractors with whom we engage. I am proud to tell you that our response to the Pandemic was acknowledged by The American Chamber of Commerce of Trinidad and Tobago in their Business Continuity and Surviving the Pandemic 2020 awards, giving us an honourable mention among SMEs operating in the Energy and Manufacturing Sector. But we are not complacent. The ultimate reward for us will be the continued well-being of our team and the safe delivery of our operations, generating sustainable value for our shareholders and other stakeholders.

Against the grain production growth
Production for 2020 averaged 3,226 bopd (2019: 3,007 bopd) in line with market guidance. This represents a 7% increase over the prior year despite the challenges presented by COVID-19 and no new drilling activity taking place during the year. This is the third consecutive year of delivering production growth and meeting our stipulated production targets.

Whilst keeping focus on the bottom-line
As a business we pride ourselves on our cost efficient operations and we're delighted to have further driven down our FY2020 operating break-even to USD 20.1/bbl, meeting the challenging target set in response to the COVID-19 pandemic and being the fifth consecutive year of maintaining a sub USD 30.0/bbl operating break-even.

While the depressed oil price impacted revenues and profits, the Group proved its resilience, with cash flows remaining strong during the period and the Group's cash balances at the year-end 2020 increasing 46% to USD 20.2 million (USD 13.8 million as at 31 December 2019).

The Group remains conscious of wider market instability, and to that end we continue to implement our hedging strategy with a view to protecting future cash flows from the prevailing macro and fiscal regimes. Importantly, the recent changes to Supplemental Petroleum Tax ("SPT") are a significant improvement for the Group and will enhance returns from our onshore operations.

Becoming a technological leader
We continued to roll out our wellsite automation via Supervisory, Control and Data Acquisition ("SCADA") using Weatherford's ForeSite® Production Optimization Platform 4.0 which provides software and optimisation technology for real time pump monitoring and optimisation. Not only is this helping drive efficiencies and increase recovery rates, it also means that we are able to reduce carbon emissions through focused logistics and managing field operations remotely.

We see technology and data as key enablers in enhancing productivity and analysis techniques and believe that we are ahead of the curve locally, setting ourselves apart from our peers. Our focus moving forward will be to build on the proven benefits of this model.

Transforming the growth potential of our Onshore assets
Following the recent acquisition of a 2D & 3D seismic package from Heritage, the 3D data (37km2) integration has commenced, and the subsurface team has been bolstered to accelerate the data integration and mapping process. This is the first time 3D seismic has been utilised by a lease operator in this area and offers the potential

to high grade existing infill development candidates, assist in identifying high angle and horizontal well opportunities and explore the possibilities for enhanced oil recovery opportunities. The redefinition of basin fill and deformation (stratigraphy and structure) could enable the development of new plays on both a local and regional level providing the potential to build an onshore appraisal and exploration prospect inventory of scale in the near term. Given the need to complete the data integration and mapping process, we are not expecting to drill any new onshore wells during H1 2021. Decisions regarding the timing and scale of any H2 2021 drilling campaign will be taken in light of the prevailing oil price and results from analysis of the 3D data.

Creating scale by becoming the partner of choice in the region

Our desire to further enhance Trinity's standing in the region and drive the business forward is highlighted by the steps we took to establish partnerships with significant operators, grow our portfolio and to leverage data sets and relationships - to create a roadmap for significantly increased production over the medium term.

We believe that there are excellent opportunities for us to scale up production from our existing licences by utilising new technologies, and these organic opportunities alone underpin our ambitious growth plans. However, we also want to remain well-placed and funded to pursue acquisitions and joint ventures to further scale the business.

We have established and developed relationships with a number of top-tier companies during the latest period with a view to developing existing licences and establishing a broader production and development portfolio. The fact that we are now working alongside a FTSE 250 oil & gas operator, the NGC and Heritage, reflects both our ability to attract partners of choice and to further strengthen our standing in the region.

Partnerships will be a key part of our development strategy moving forward, providing a low cost, low risk mechanism for us to build on existing projects and pursue new opportunities.

ESG focus at the core of our forward planning

We are passionate about sustainability and reducing emissions and measure our performance not only in terms of our financial and production delivery, but also in terms of our environmental and social impact. We are committed to continuing to operate all of our assets in a safe and responsible manner, to ensure the safety of employees and to minimise the potential risk to the environment.

While we have been working hard across our existing operations (notably via increasing automation) we aim to go further via our partnership with the NGC to explore and develop new energy projects. Of particular focus as part of this MoU will be the pursuit of lower carbon micro LNG production and supply. We are also excited to have recently signed an MoU with the Regional University, rated amongst the top 3% of universities globally, to work together to advance renewable projects in T&T and the wider Caribbean region.

Outlook

We are a forward-looking company focused on deploying new technologies and innovative approaches to generate increasing scale and returns from our existing assets, whilst pursuing new development opportunities through acquisitions and partnerships. We believe that we have established a strong path for a step change in production, revenue, profitability and cash flow, and consequent re-rating opportunities, as the Company leverages relationships and development strategies to generate scale.

Managing Director's Statement

2020 was a successful year for Trinity, notwithstanding the challenging circumstances, as we continued to consistently deliver on our operational and financial targets. We not only met our production targets safely but also delivered an operating break-even below USD 30.0/bbl for the fifth consecutive year. To put this in context, over the past five years, Trinity has increased production by 27% whilst simultaneously reducing the operating break-even by 30%, resulting in a business with a robust production base and a strong and resilient margin. Our success in delivering these results, despite the unprecedented backdrop, reflects the quality of our assets, the strength of our team, and our unrelenting focus on operational efficiencies and innovation. This is complemented by maintaining a strong balance sheet, which is essential as we develop strategic options to meaningfully scale the business.

Looking at the growth initiatives in front of us, we see opportunity in two areas. Firstly, in advancing current developments both onshore and offshore, and secondly, via the strategic partnerships we have recently entered into. This strategy is aimed at pursuing further low-cost appraisal and exploration targets alongside the development of transitional energy projects such as micro LNG, wind and solar power.

We proved the strength of our model during the most difficult of circumstances in 2020 and have ambitious plans to build on this during the current year and beyond."

COVID-19 response protocols and impact

Our principal priority at all times is the safety and health of our people. So early in 2020 we put in place a full suite of measures to achieve this including regular and updated advisories, enhanced hygiene practices, a series of practise drills and full contingency plans should any team member be exposed to the virus. Following the first confirmed case in T&T in 12 March 2020, Trinity implemented Work From Home ("WFH") practices for all but essential field operators and these are continuing to work well. All international travel has been suspended and minimal local travel to maintain well operations in the fields is being undertaken under the strict proviso of appropriate physical distancing measures being adhered to.

The Group's activities have not, during 2020, been negatively impacted by COVID-19 and have, by law, been classified an essential business and therefore we have been able to continue operations. We will continue to monitor the evolving situation and put further appropriate measures in place as and when required. Refer to the Risk Management and Internal Controls Section below for further details.

In Q2 2020, oil prices fell significantly (with WTI turning briefly negative during April) due to fears of the spread of COVID-19 and its continuing potential impact on the global demand for oil. The WTI oil price subsequently stabilised around USD 40.0/bbl before breaking upwards in the latter part of Q4 2020 and, at the time of writing, is back above USD 65.0/bbl.

The volatile macro-environment serves to highlight the importance of Trinity's operating break-even being consistently below USD 30.0/bbl in all periods since the current Management's measures took effect in 2016. The fact that the Group continued to accrete cash at lower oil prices during 2020 is testament to our financial discipline and our lean business model putting us in a highly resilient position. That said, a protracted period of 'low oil price' realisations would start to erode cash balances. We have therefore created financial plans for the business at various oil price scenarios such that any necessary changes to the operating cost structure (Opex and G&A) would be able to be implemented quickly to preserve the integrity of the balance sheet while maintaining safe operations. We took immediate actions to manage Opex and G&A costs during 2020. This, in conjunction with only incurring essential capex focused on asset integrity, RCPs and keeping our Galeota project moving towards FDP and FID, meant the Group ended the year stronger than it began and confident it can maintain sufficient liquidity and cash through 2021 and beyond.

Strong operational and financial performance despite unprecedented backdrop

2020 was a year in which Trinity clearly evidenced the strength of its operating model, proving its resilience and ability to adapt quickly due to the virus protocols, and that a strong foundation is firmly in place to support our growth aspirations. We built on our progress in 2019 when we adopted new operating practices, along with new technologies and techniques, with a view to better securing, and growing, our base production levels. The aim remains to protect against the downside, whilst yielding better and more repeatable and scalable returns on investment in the future.

Whilst increasing top-line production/ revenues is an engine for growth, it is only effective growth if we are able to sustain and leverage the cash returns. Despite a significantly lower average realised oil price during 2020, we maintained operating profitability and cash generation by adapting quickly to the severe environment and successfully bringing our operating break-even down to its lowest ever level of USD 20.1/bbl. This further secures our position as among the lowest cost operators in the sector.

Trinity has to adapt and respond to a number of key variables which are beyond Management's control, most notably the oil price, the regressive nature of the T&T fiscal regime (SPT specifically) and, most recently, the impact of the COVID-19 global pandemic. Trinity employs a number of operational and financial levers to mitigate against these, with a view to ensuring our operations remain sustainably and significantly free cash flow generative even in low oil price environments.

The operating levers we are able to deploy include:

- Reducing Production Costs, Opex/bbl and G&A/bbl by increasing production (preserving base production levels and higher EUR reserves from new wells) and reducing costs (economies of scale and well optimisations).
- Increasing new well economics by reducing capex per well and seeking higher EUR reserves from new wells.
- Increasing initial production ("IP") rates from new wells due to an increased focus on automating wells and drilling HAWs.
- Ensuring that the commercial terms, applying across the various assets, that we operate allow us to receive an appropriate return on investment and thereby protect and grow shareholder value, in divergent oil price scenarios.

The financial levers we are able to deploy include maintaining a strong balance sheet, an active programme of financial hedging and our substantial tax losses. Whilst SPT is not payable if oil price realisations remain below an average of USD 50.01/bbl in any calendar quarter, as was the case during 2020, we had layers of hedging in place to mitigate the impact of SPT when realisations are in its most impactful price range (USD 50.0/bbl to 56.0/bbl). Trinity took advantage of the oil price movements in January, June, July and November 2020, and again in February and March 2021, to put layers of hedging in place which were designed to protect a portion of Group cash flows between USD 50.0 to USD 56.0/bbl, thereby partially offsetting the impact of SPT, and also to provide a degree of protection against a period of lower oil prices. As a result, the Group currently has crude derivatives in place of 45,000 bbls/month for 2021 (equating to c. 45% of its 2020 exit production) and will start to receive derivatives income if Brent Crude Prices trades below USD 42.50/bbl during 2021 and USD 60.00/bbl in H1 2022.

Trinity also benefits from a large tax loss position of USD 237.2 million (YE 2020) which effectively means, from 2020 onwards, 75% of taxable profits would be sheltered from Petroleum Profits Taxes ("PPT") by brought forward losses, with any remaining tax losses continuing to be carried forward indefinitely.

The financial hedging supports our effective operational hedging strategy, centered on preserving base production and retaining flexibility with multiple options to sustain and grow production including low cost RCPs, WOs and drilling new infill wells Onshore.

We ended the period in a stronger position than what we started it with 2020 year end net cash (cash minus USD 2.7 million drawn working capital facility) of USD 17.5 million as at 31 December 2020, versus USD 13.8 million as at 31 December 2019. The 27% increase in net cash balances during the year was driven by strong operating cash flow generation and achieved despite a 35% reduction in average oil price realisations versus 2019. Refer to the Financial Review below for further details.

SPT reforms

A revised threshold for SPT for small onshore producers was announced on 5 October 2020 and implemented via The Finance Act, 2020 which became law on 4 January 2021.

As a result, the threshold at which SPT becomes due for individual producers producing less than 2,000 bopd onshore has now increased from USD 50.0/bbl to USD 75.0/bbl for the financial years 2021 and 2022. Therefore, Trinity expects to be exempt from SPT across all of its onshore licences below USD 75.0/bbl, which will have a significant positive impact on future cash flows.

- Based on current onshore production levels, Trinity estimates that SPT of c.USD 3.5 million per annum or more would previously have been payable if realisations were above USD 50.01/bbl (although this could be partially mitigated by the investment tax credits shelter).
- The confirmation of these reforms therefore represents a considerable boost to potential cash generation from Trinity's onshore licences should realisations average above USD50.01/bbl for any calendar quarter during 2021 and 2022.

We have long championed SPT reform and believe that this first step is good news for all smaller producers in Trinidad & Tobago, demonstrating clearly that the GORTT recognises that SPT is an outdated and regressive tax in need of reform. This initial change should begin to provide a greater stimulus to investment activity in the country, enabling the Group to generate increased returns and further leverage its low cost production model. The Group continues to lobby at the highest levels for further reform, with a view to obtaining a longer duration relief period and for this to apply to both onshore and mature offshore fields, thereby further enabling all smaller producers in Trinidad & Tobago to invest and grow production, for the long term benefit of all stakeholders.

Licence updates

Onshore, the Company extended the term of its Lease Operatorship Agreements ("LOAs") with Heritage Heritage for its WD-2, WD-5/6, WD-13 and WD-14 blocks to 31 May 2021 with renewal expected during Q2 2021. The LOAs were originally set to expire on 31 December 2020 and have been extended under existing terms and conditions while Heritage finalise the regulatory approvals necessary for the longer term extensions and renewals for its LOA properties.

Offshore the East Coast, a more robust legal and commercial framework is also being established for Galeota, to include a new 25-year Licence, Joint Operation Agreement (“JOA”), Commercial Terms and Sales Agreement (“COSA”), each of which are expected to be finalised during Q2 2021. These new agreements will better enable future developments to be brought into production by offering potential partners and funders the appropriate visibility and comfort on the legal and commercial framework.

Internal Growth Pathways

Trinity is ideally placed amongst the top five largest T&T crude oil producers and is focused on developing its reserves and resources with the medium term objective of increasing its onshore and offshore production from 2020 average production levels of 3,226 bopd to over 7,500 bopd.

Offshore East Coast

Production from the Group's east coast assets (Galeota) continued to meet expectations during 2020. As well as the current production from the Trintes field, the Galeota asset also includes a series of development opportunities (Echo, Foxtrot and Golf) which are being progressed.

The Phase 1 offshore development on the Galeota licence has the potential to add additional peak production of at least 4,000 bopd on the current development concept. Work is currently ongoing on pre-Front End Engineering Design (“FEED”) studies and environmental approvals as we move towards a Final Investment Decision (“FID”) at the earliest opportunity. The First Phase currently contemplates the installation of a low cost eight well conductor supported platform (“Echo”), a new pipeline from Echo to shore, with the existing Trintes platforms tied in, and “T” sections installed for the potential development of TGAL NE (Foxtrot) and Trintes SW (Golf) areas in the future. It is expected that Echo would be powered from shore (offshoot of offshore wind power cable technologies) with tiebacks to the Trintes platforms. Combined with there being no offshore power generation (i.e. no diesel and no generators) and being unmanned, the development would have a nominal carbon footprint when compared to standard offshore developments.

It is also worth noting that a large proportion of Trinity’s tax loss position of USD 237.2 million (YE 2020) can be applied to the Galeota field development, which further underpins the attractive economics of the development.

Offshore West Coast

Production from the Group's west coast assets performed ahead of expectations during 2020 facilitated by WOs and upgrades. The Group has also focused on maturing reactivation opportunities, with ABM 151 having the potential to add c.175 bopd, and development options for existing discoveries, notably ALM 22 with 2C resources of c.3.1 mmstb and is an extension of the Jubilee/Cluster 6 developments currently on production, operated by Heritage.

Onshore: Well automation roll-out & wider technology drive continues
Our innovative approach to operations is at the heart of our business and as we ramp up our efficiency drives, we expect to see the real benefits come to fruition. We have established an enhanced operational management system that builds repeatability and scalability as we grow while simultaneously driving further efficiencies in terms of well uptime resulting in reduced WOs and the better allocation of human resources.

We are on track to meet our target of having 31 wells automated at our largest onshore field, WD-5/6, during H2 2021. This is expected to facilitate an increase in revenues from the field by allowing production levels to be optimised and downtimes to be minimised. Automation is also expected to improve margins and free cash flow generation by reducing well intervention works (including workovers).

This is the first time this technology has been deployed in our Onshore fields and provides a low-cost means of protecting and enhancing base production levels with the full production benefits and operating cost savings expected to become more apparent as our top-tier onshore wells are automated. By becoming more data driven, we have a vision to digitalise the business so that we can develop analytics for our 1000+ wells (across various reservoirs which have been producing for decades) and by applying a methodical approach to better reservoir management that minimises production volatility, increases recovery factors and thereby maximises reserves extraction, further securing the business for the future.

Onshore: Acquisition & Integration of Seismic
The acquisition of the onshore 3D & 2D seismic package is potentially transformative for our onshore licences.

- The Onshore seismic is of good quality and initial first pass screening shows interesting prospective features not previously mapped.
- The development, appraisal and exploration pipeline is to be augmented following 3D onshore seismic interpretation (now underway).
- The ability to accurately locate HAWs, and ultimately fully horizontal wells, is greatly enhanced by the use of 3D seismic data.
- HAWs could be expected to yield IP rates and reserves of over 2x those from conventional vertical wells, whilst fully horizontal wells commonly deployed globally can yield rates 4x to 6x higher than vertical wells.

New Growth Pathways
Asset acquisitions and partnerships offer the potential to increase scale, share risk and drive returns to shareholders.

Pursuing New Projects alongside NGC and the Regional University
A Memorandum of understating ("MOU") was signed with the NGC, to explore and develop new projects to enable energy transition in T&T and, potentially, in the wider Caribbean and Latin America, including:

- A Micro Liquefied Natural Gas ("micro LNG") business;
- Renewable energy opportunities, inclusive of a wind power generation project;
- Pursuit of stranded gas assets and associated opportunities in existing Trinity assets; and
- Pursuit of other mutually beneficial business opportunities.

A MOU was also more recently signed with the Regional University, to collaborate across a range of business initiatives to explore and potentially develop new projects in areas of mutual interest and for the benefit of Trinidad,the wider Caribbean and beyond, including;

- Renewable energy opportunities, inclusive of a wind power generation project; and
- Pursuit of any other opportunities, renewables or otherwise, which may be mutually beneficial.

Pursuing New Projects alongside a larger international operator

A partnership has been formed with a FTSE 250 oil & Gas operator to evaluate two potential new projects:

1) a material offshore Gulf of Paria production and development asset (Jubilee).
2) a potentially high impact onshore exploration play (North West District).

Asset acquisitions and partnerships offer the potential to increase scale, share risk and drive returns to shareholders.

Jubilee Process

- The consortium have been granted access to the data room for the Jubilee Field evaluation which forms the next stage of the bid process.
- Trinity and its partner are one of only a limited number of groups to have been granted access to the data room in order to evaluate and potentially prepare and submit a development proposal.
- Trinity is hopeful that a successful bid on Jubilee would add significant value to the Company. Jubilee is a rare example of a sizeable producing field with significant undeveloped reserves.
- Current production from the area subject to the bid is c. 2,800 bopd from 26 wells but the field has approximately 1 billion bbls of estimated oil in place and 14 million barrels of proven heavy oil reserves.
- The bid area is part of the giant Trinmar group of fields that has produced over 750 million barrels of oil to date and is located adjacent to the Group's West Coast assets in the shallow water area between Trinidad and Eastern Venezuela.

NWD Expression of Interest (EOI)

Trinity and its partner have submitted a joint EOI for the potentially high impact onshore exploration play in the NWD of Trinidad. The NWD is located to the southwest of Trinidad within the western segment of the Southern Basin geologic province with stratigraphy ranges from the Cretaceous through to recent deposits. The NWD contains a number of low-risk Tertiary and Cretaceous targets and is situated on trend with the giant turbidite and basin-floor fan oil discoveries offshore Guyana and Suriname.

The consortium have been short-listed for the next stage of the bid process and are expecting to access the data room during Q2 2021.

Acquisitions

Our robust financial strength compared to many of our peers, where operating break-evens are higher and finances are potentially more constrained, means that Trinity is well placed to take advantage of commercial opportunities as and when they arise. The recent acquisition of the PS-4 Block Lease Operatorship Sub-Licence, onshore Trinidad, demonstrates our ability to bolt on assets when we foresee upside potential alongside significant technical, operational and financial synergies to leverage value.

Approach to ESG

Our approach to good Environmental, Social and Governance ("ESG") practices is more than just 'box ticking'. Very simply, we firmly believe that doing the right things for the right environmental 'and' commercial reasons leads to the best outcome for shareholders and the holistic ecosystem that contributes to this outcome. What does that mean from a practical standpoint?

- Pursuing more sustainable environmental/lower carbon alternative energy sources for power generation, i.e. renewable power, transition fuels, to generate more energy with a low carbon footprint;
- Proactive adoption of social solutions (i.e. WFH, protocols, healthcare provision, wellness programmes, community engagement);
- Whilst simultaneously aiming to reduce our costs and appeal to a wider shareholder and partner base; and
- To help reduce our cost of capital and provide a sustainable growth trajectory.

On behalf of the Board, we must thank all our staff and suppliers for their diligence, commitment and support which has allowed Trinity to focus on growth whilst maintaining a safe working environment. The Board would additionally like to take this opportunity to thank shareholders and other stakeholders, notably Heritage, the Ministry of Energy and Energy Industries ("MEEI") and the Board of Inland Revenue ("BIR"), for their support as we move forward strongly positioned to add value from future opportunities in the changing environment in T&T.

Operational Review

Production
In 2020 average net production was 3,226 bopd (2019: 3,007 bopd), an increase of 7%. The Group managed to grow production despite no new drilling taking place during the year, the challenges resulting from a suppressed oil price and the Covid-19 pandemic. In addition, production increased during Q4 2020, providing a strong start to 2021.

Onshore Assets
Current onshore production is from Lease Operatorship Blocks: FZ-2, WD-2, WD-5/6, WD-13, WD-14 and Farmout Block, Tabaquite.

Average 2020 net production from the onshore assets was 1,793 bopd (an 11% increase from 2019: 1,613 bopd), which accounted for 56% of the Group's total annual average production. This significant growth in the year on year production is a direct result of the performance of the 2020 RCP campaign, reduced downtimes facilitated by more-active well management, improved swabbing, reactivations and numerous other production initiatives undertaken in the year.

In 2020, production continued to benefit from the contribution of the 2018/19 infill drilling programme. Furthermore, Trinity has developed a tactical multi-disciplinary team to manage the delivery of these development wells, using best in class models, which in turn helps to ensure they deliver the best economic returns. As such, best in class models were developed to economically maximise well deliverability. This would have pointed to the execution of two RCPs, which yielded positive results, enhancing the team's confidence in the productivity of the Lower Forest sands.

Trinity executed 16 RCPs Onshore for the period (2019: 22) as well as 94 WOs (2019: 104). This intensive work campaign successfully maintained base production and provides a stable platform for future production growth. The continued reduction in WO frequency is a testament to the teams drive to reduce pump failure frequency and optimise operating efficiency.

Over the period the team particularly targeted the stabilisation and optimisation of its largest onshore field, the WD-5/6 Block. Focus teams were established to ensure quicker responses to offline wells and drive the redesign of operating thresholds to combat declines.

In 2021, the team intends to explore further cost-effective means of production maintenance through the expansion of the active well stock via RCPs, reactivations and swabbing. Furthermore, the automation roll-out is moving ahead at pace and we remain on target to have 31 new Tier-1 well systems in place by H2 2021.

Automation: a key aspect of our well management system
The positive results recorded to date provides confidence in being able to deliver our objectives for the WD-5/6 Block:

- to stabilise 85% of the Block's production via increased well uptimes.
- to reduce the number of WOs by employing 24/7 remote well surveillance.
- to build capacity through increased operational field efficiencies and productivity.
- to reduce the carbon footprint with less workovers and wellsite visits.
- to manage well performance with the use of real time data.

The use of Weatherford's Foresite Well Optimization platform will support our well management system to manage wells by exception, remotely optimise well performance, and to alert teams for earlier well responses and avert possible premature well failures.

Preparations for the execution of our next infill development campaign are underway. We expect to drill a combination of vertical and horizontal wells, with the timings and location selection dependent on the findings of the on-going 3D seismic data review across our onshore acreage.

New sub-surface models – building low risk exploration & development inventory with best in class partnerships

With the 3D seismic data (37km2) now acquired we have accelerated its integration and interpretation to:

- high grade current drilling locations (HAW/horizontal candidates/well trajectories =>higher IP's and reserves/well).
- to look at enhanced oil recovery projects.
- to generate new appraisal/ exploration prospects.

This is the first time high quality 3D seismic data has been utilised by a lease operator in this area. The analysis will enable Trinity to redefine basin fill & deformation (stratigraphy & structure) as well as assisting the development of new plays at a local and regional level. As well as targeting deeper (traditional) targets, two teams are working to accelerate the data interpretation of non-traditional plays and targets.

East Coast Assets

Current East Coast production is from the Alpha, Bravo and Delta platforms in the Trintes Field which resides within the Galeota Block.

Average 2020 net production from the East Coast was 1,188 bopd (2019: 1,205) which accounted for 37% of the Group's total, with production levels broadly maintained from the prior year.

To achieve this, the team conducted 16 restorative WOs (2019: 13) and 4 well reactivations to underpin production. With the focus being placed on operational intelligence during optimisation and troubleshooting activity, minimal wellbore interventions were required on our high-volume ESP wells.

Throughout 2020, the team retained focus on the management and maintenance of all critical assets in the field. The positive performance indicators experienced in power reliability and operational efficiency are reflected in the field's low production volatility. Trinity's ability to effectively and economically manage these mature assets is a testament to a series of innovative solutions which form the foundation to our approach on all our projects.

Facilities Management

In 2020, the Facilities team continued to execute a robust plan aimed at improving facility integrity and equipment reliability. The maintenance plan for the Trintes cranes was revised to capitalise on the competencies of the team and to deliver more frequent scheduled preventative maintenance activities. The benefit of this approach was that the cranes were able to be recertified without delays, with no downtime and at a reduced cost. Of the 33 projects progressed during 2020 25 were completed with 7 continuing into 2021. Most projects continued to focus on welfare, structural and operational reliability. Of note was the construction of a new 10,000 bbls tank in the Trintes asset which commenced in October 2020 and is well on its way to completion (targeted for Q4 2021). This tank will bring additional storage capacity and operational flexibility to the Trintes operations ensuring tank certification compliance without disruption to production.

West Coast Assets

West coast production is from the Point Ligoure-Guapo Bay-Brighton Marine ("PGB") and Brighton Marine ("BM") fields.

Average 2020 net production from the West coast was 245 bopd which accounted for 8% of the Group's total annual average production. This represents a 30% increase in production from 2019 average levels of 189 bopd. The step change in production was delivered through targeted production and infrastructural initiatives.

On the PGB asset production increases were realised through the modification of the surface equipment allowing for the optimisation of the wells operating parameters. No RCPs or WOs (2019: 4) were conducted in the PGB block asset for the period.

A multifaceted approach was utilised on the management of the BM asset ensuring that safety, logistical efficiency and infrastructural integrity remained paramount. These attributes coupled with an adequately resourced team, modified operational strategies and the inclusion of a second swab unit led to 21% production growth across the asset. The work programme entailed 2 RCPs (2019: nil) along with 1 WO (2019: 1) being conducted on the land-based wells in the Brighton field.

The team continues to explore multiple opportunities to achieve optimal production from all offshore platforms in this asset along with expansion of the land- based wells via RCPs, reactivations and swabbing activities.

Reserves and Resources

A comprehensive management review of all assets has been concluded and has estimated the current 2P reserves to be 19.55 mmstb at the end of 2020, compared to the year-end 2019 reserve estimate of 20.94 mmstb. This represents a 6.6% decrease year-on-year from 2019. The reduction in reserves of -1.39 mmstb predominantly reflects 2020 production of 1.18 mmstb together with the application of the oil price forward curve prevailing at 2 January 2021, as well as updated well numbers and decline curve analysis on planned infills and producing wells onshore and offshore the East Coast.

WTI Forward Price Deck applied to Reserves Economic Limit Testing (“ELT”) from Britannic Trading LLC as at 2 January 2021

(USD/bbl)	2021	2022	2023	2024	2025	2026	2027	2028
Price Strip	49.30	47.13	45.75	44.90	44.51	44.45	44.80	44.80

Management considers the reserves and resources presented herein to represent the best estimate as at 31 December 2020 of the quantity of reserves that will actually be recovered from the assets. It represents 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 in the following table:

Unaudited 2020 2P Reserves

Net Oil Production	31 December 2019 mmstb	Production mmstb	Revisions mmstb	31 December 2020 mmstb
Asset				
Onshore	7.43	(0.66)	(1.34)	5.44
East Coast	11.27	(0.44)	0.83	11.66
West Coast	2.24	(0.09)	0.30	2.45
Total	20.94	(1.18)	(0.21)	19.55

Note (*):

- Onshore 2P reserves decreased due to production of 0.66 mmstb during 2020 and by 1.34 mmstb largely as a result of the lower applied forward oil price strip and a downward revision in decline curve analysis of producing wells which has been re-classified as 2C resources.
- East Coast and West Coast 2P reserve changes primarily reflects increased well production performance and the positive revision of infill well decline profiles.
- Across the portfolio Trinity has further risked the production profiles to reflect reservoir performance from more recent drills, RCPs and WOs which resulted in a more cautious assessment of initial flow rates and production profile declines.

Management’s best estimate of 2C resources as at 31 December 2020 is 23.25 mmstb (2019: 20.13 mmstb). The positive movement of 3.12 mmstb in 2C resources primarily reflects the re-categorisation of some infill development drilling locations to 2C (previously carried as 2P in 2019) and the allocation of the ALM22 discovery (+2.17mmstb) also provided a significant uplift to 2C across the West Coast asset as a result of revised subsurface work across the PGB asset in 2020.

Management’s Estimate of 2C Resources as at 31 December 2020

Asset	31 December 2019 mmstb	Revisions mmstb	31 December 2020 mmstb
Onshore	1.85	2.16	4.01
East Coast	17.28	(1.34)	15.94
West Coast	1.00	2.30	3.30
Total	20.13	3.12	23.25

Management's Estimate of Reserves and Resources as at 31 December 2020

Asset	2020 2P Reserves mmstb	2020 2C Resources mmstb	2020 2P Reserves and 2C Resources mmstb	2019 2P Reserves and 2C Resources mmstb
Onshore	5.44	4.01	9.45	9.28
East Coast	11.66	15.94	27.60	28.55
West Coast	2.45	3.30	5.75	3.24
Total	19.55	23.25	42.80	41.07

Trintes (Trinity: 100% WI)

On the East Coast, Trinity has an established production hub on the Trintes field with four offshore platforms; (Alpha, Bravo, Charlie & Delta) that have an aggregate of 36 active wells. Current 2P reserves underpin only the producing Trintes field. However, across the East Coast Galeota anticline licence area, Management estimates total gross STOIIP of over 700 mmstb of which only 249 mmstb of STOIIP is mapped against the Trintes Field. Trintes has current booked East Coast 2P reserves of 11.66 mmstb which represents an incremental recovery factor of 4.7% with a further 1.43 mmstb booked within current contingent resources.

Galeota Asset Development (Trinity: 65% WI)

The TGAL discovery area (proposed Echo hub) lies in the Galeota Licence and sits within a separate Fault Block (mapped as Fault Block 6), an updip panel located to the north east of the Trintes Field, confirmed as being oil bearing in six major stacked reservoir horizons by the TGAL-1 exploration well with an internal best estimate STOIIP of 186 mmstb. The FDP (to be submitted in May 2021) describes the first phase of a potential wider development across the Galeota anticline to fully develop the reserves potential from the large volumes of oil in place. Some of the key aspects of the proposed Echo Development include:

- An unmanned platform with minimal top-side design (Platform Echo).
- 25-year design life.
- Drilling via the use of a jack-up rig.
- A new pipeline from the Echo Platform to shore.
- Subsea power cable from shore to the Echo Platform.
- First oil estimated to be produced during 2023, subject to prevailing market conditions with peak production estimated at over 4,000 bopd.
- 2C resources of c.22.32 mmstb gross (14.51 mmstb net).
- 2C resources are expected to be revised upwards following completion of the dynamic modelling exercise during 2021.
- At FID, Trinity anticipates the net 2C resources developed by the Echo Platform would be reclassified as 2P reserves.

The COVID-19 pandemic and subsequent oil price crash in April 2020 did impact the project by triggering a slowdown in activity between May and June 2020 while management attempted to evaluate the overall impact on the company's financial position. However, the project ramped up activity again in the second half of the year.

Works progressed (and are continuing) on various pre-FEED studies to improve the topside and other aspects of the hardware design. In addition, work continued on building a dynamic reservoir model for forecasting production performance and cumulative estimated ultimate recoverable (EUR) volumes. Of equal importance, the environmental impact assessment ("EIA") field work was completed in 2020; advancing the permitting process with the EMA into 2021. The EIA is a key item on the critical path to FID. The EIA was submitted in February 2021 and represented a significant milestone. The FDP isto be submitted in May 2021.

Financial Review

Trinity assesses the Group's performance using both International Financial Reporting Standards ("IFRS") and Alternative Performance Measures Guidelines ("APM") governed by the European Securities and Markets Authority ("ESMA"). Management believes that analysis of both these performance measures promote better guidance to Management for both operational and strategic decision making purposes.

KPI'S

The Group was profitable at an operating level in 2020, despite the material reduction in the realised oil price, with a 46% increase in the year-end cash balance to USD 20.2 million (2019: USD 13.8 million) and a 25% increase in the net cash plus working capital surplus of USD 21.7 million (2019: USD 17.3 million).

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

		FY 2020	FY 2019	Change %
Average realised oil price[1]	USD/bbl	37.7	58.1	35
Average net production	bopd	3,226	3,007	7
Annual production[2]	mmbbls	1.2	1.1	8
Revenues	USD million	44.1	63.9	31
Cash balance	USD million	20.2	13.8	46
IFRS Results				
Operating Profit before SPT & PT	USD million	3.0	10.3	71
Operating Profit before Exceptional Items	USD million	2.6	2.4	9
Operating Profit/(Loss)	USD million	1.4	(12.8)	111
Total Comprehensive Loss For The Year	USD million	(2.8)	(9.6)	70
Loss Per Share - Diluted	USD cents	(0.7)	(2.3)	70
APM Result				
Adjusted EBITDA[3]	USD million	12.3	21.8	43
Adjusted EBITDA[4]	USD/bbl	11.4	19.8	42
Adjusted EBITDA margin[5]	%	28	34	18
Adjusted EBITDA Per Share - Diluted[6]	US cents	3.0	5.3	43
Adjusted EBITDA after SPT & PT[7]	USD million	12.0	13.9	14
Adjusted EBITDA after SPT & PT[8]	USD/bbl	11.1	12.6	12
Adjusted EBITDA after SPT & PT Per Share - Diluted[9]	US cents	2.9	3.3	14
Consolidated operating break-even[10]	USD/bbl	20.1	26.4	24
Net cash plus working capital surplus[11]	USD million	21.7	17.3	25

Notes:

1. Realised price: Actual price received for crude oil sales per barrel ("bbl").
2. Annual production (mmbbls) – Production sold in a given year.
3. Adjusted EBITDA (USD MM): Operating Profit before Taxes for the period, adjusted for non-cash DD&A, SOE, ILFA and FX gain/(loss).
4. Adjusted EBITDA (USD/bbl): Adjusted EBITDA/Annual production.
5. Adjusted EBITDA margin (%): Adjusted EBITDA/Revenues.
6. Adjusted EBITDA per Share – Diluted: Adjusted EBITDA / Weighted average ordinary shares outstanding-diluted.
7. Adjusted EBITDA after SPT & PT (USD MM): Adjusted EBITDA after SPT & PT.
8. Adjusted EBITDA after SPT & PT (USD/bbl): Adjusted EBITDA after SPT & PT / Annual production.
9. Adjusted EBITDA after SPT & PT per Share — Diluted: Adjusted EBITDA after SPT & PT / Weighted average ordinary shares outstanding-diluted.
10. Consolidated operating break-even: The realised price where Adjusted EBITDA for the entire Group is equal to zero.
11. Net cash plus working capital surplus: Current Assets less Current Liabilities (other than Provisions for other liabilities).

Note (*): See Note 24 to Consolidated Financial Statements – Adjusted EBITDA for further details.

Adjusted EBITDA Calculation

Adjusted EBITDA is an 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.

	2020 USD MM	2019 USD MM	Change %
Operating Profit before SPT & PT (IFRS Result)	3.0	10.3	71
DD&A	8.2	9.8	16
SOE	1.0	1.0	7
ILFA	0.3	0.6	59
FX loss/(gain)	(0.0)	0.1	109
Adjusted EBITDA (APM Result)	12.3	21.8	43

2020 Trading Summary

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

Details		2016[4]	2017[4]	2018[4]	2019	2020
Realised Price	USD/bbl	39.4	48.6	59.8	58.1	37.7
Production						
Onshore	bopd	1,343	1,347	1,563	1,616	1,793
West Coast	bopd	190	212	198	185	245
East Coast	bopd	1,009	961	1,110	1,208	1,188
Consolidated	bopd	2,542	2,519	2,871	3,007	3,226
Operating Break-even[1]						
		2016[4]	2017[4]	2018[4]	2019	2020
Onshore	USD/bbl	17.4	16.6	16.1	16.4	16.5
West Coast	USD/bbl	37.7	26.6	26.8	32.4	24.6
East Coast	USD/bbl	26.3	24.9	25.9	21.9	21.0
Consolidated[2]	USD/bbl	29.2	28.4	29.0	26.4	20.1
Metrics						
Opex/bbl - Onshore	USD/bbl	11.8	11.1	11.7	12.1	12.2
Opex/bbl - West Coast	USD/bbl	31.6	22.1	22.1	26.9	20.3
Opex/bbl - East Coast	USD/bbl	20.1	18.9	20.1	17.1	16.5
G&A/bbl – Consolidated[3]	USD/bbl	4.4	4.4	5.0	5.1	4.3

Notes

1.. Operating break-even: The realised price where Adjusted EBITDA for the respective asset or the entire Group (Consolidated) is equal to zero.

2. 2020 consolidated break-even benefits from derivative income of USD 1.6 million (2019: expense of USD 0.1 million).
consolidated operating break-even: Includes G&A but excludes SOE and FX gain/loss.

3. G&A/bbl – Consolidated: Excludes SOE and FX gain/loss.

4. 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.

Production increased by 7% to 3,226 bopd, the second consecutive year that production averaged over 3,000 bopd and the third consecutive year of production increases. This strong performance was achieved despite COVID-19, depressed WTI oil prices and no new wells being drilled during 2020, and demonstrates the benefits of innovation and the continued performance of the new development wells drilled during 2018/19.

Of particular note from a financial standpoint is that operating break-evens were reduced by an aggregate 24% to USD 20.1/bbl (2019: USD 26.4/bbl). The consolidated operating breakeven includes the Group's cash G&A costs and therefore captures the corporate costs associated with supporting the asset base. At the corporate level, the ability to yield such a robust operating break-even level reflects higher production volumes and lower combined expenses as detailed below:

- Opex increased by 1% to USD 16.5 million (2019: 16.4 million) with a 7% decrease on an Opex/bbl basis to USD 13.9/bbl (2019: USD 15.0/bbl). This was largely a function of a reduced costs due to Strategic Business Partnering, reduced WO programme, production optimisation and better well uptimes, re-negotiated terms of the supply/ personnel vessels and port rental.
- G&A costs (which excludes non-cash SOE and FX gain/loss) decreased by 9% to USD 5.1 million (2019: USD 5.6 million) with a 13% decrease in G&A/bbl to USD 4.5/bbl (2019: USD 5.1/bbl). This resulted from decreased staff costs, reduced levies and lower corporate expenses.

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 Financial Reporting Standards ("IFRS") Interpretations Committee ("IFRS IC") interpretations in conformity with those parts of the Companies Act ("CA") 2006 applicable to companies reporting under IFRS. 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 Note 1 of the Financial Statements.. The Group has adopted additional accounting policies in the year ended 31 December 2020 as set out in Note 1 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 have 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") and FX gain/loss and these are summarised on the face of the Consolidated Income Statement as well as being described in Note 1 to the financial statements.

Summary of Results for the Year

Revenue declined due to the significantly lower average realised oil price in 2020:
The 35% decrease in average oil price realisations to USD 37.7/bbl (2019: USD 58.1/bbl), partially mitigated by a 7% increase in production to 3,226 bopd (2019: 3,007 bopd), resulted in a 31% decrease in revenues to USD 44.1 million (2019: USD 63.9 million).

Focus on controlling costs and preserving strong operating margins:
The Group maintained its focus on controlling costs and preserving strong operating margins in the lower oil price environment. The Adjusted EBITDA margin declined to 28% (2019: 34%), with the 24% lower consolidated operating break-even price of USD 20.1/bbl (2019: USD 26.4/bbl) demonstrating the Group's ability to adapt to adverse conditions by enacting cost reductions. The 43% reduction in Adjusted EBITDA to USD 12.3 million (2019: USD 21.8 million) is a direct result of the lower realised oil price, which was only partially mitigated by higher production levels, expense reductions and the Group's derivative income of USD 1.6 million.

Successful Capex work programme:
USD 5.3 million (2019: USD 12.7 million) incurred in predominantly infrastructure, production and exploration and evaluation expenditure. 2020 saw the Group spend on Infrastructure Capex across the assets to maintain asset integrity and to support the production initiatives, complete 18 Onshore RCP's and exploration and evaluation assets comprising of internal time writing and third-party costs for the Galeota asset development project. Capex included:

- USD 0.3 million New Wells (drilling planning, no New Wells drilled)
- USD 2.5 million Infrastructure Capex
- USD 0.8 million 18 RCP's
- USD 0.6 million Subsurface time-writing costs
- USD 1.1 million Exploration and Evaluation ("E&E") assets

Refer to Notes to Financial Statements: Note 11 Property Plant and Equipment – Additions (USD 4.1 million) and Note 13 – Intangible Assets – Additions (USD 1.2 million) inclusive of accruals.

Increased financial strength:
The Group's cash balances at year end increased by 46% to USD 20.2 million (2019: USD 13.8 million). The higher cash balance is as a result of a strong operating performance, no SPT being payable in 2020 and drawdown of USD 2.7 million under the Group's CIBC facility. In aggregate, the net cash plus working capital surplus stood at USD 21.7 million, a 25% increase (2019: USD 17.3 million).

Statement of Comprehensive Income

Revenues
Crude oil sales revenues of USD 44.1 million (2019: USD 63.9 million).

Operating expenses
Operating expenses decreased by 23% in 2020 to USD (41.2) million (2019: USD (53.6) million) and comprised:

Cash Expenses: USD (31.7) million (2019: (42.1) million):

- Royalties of USD (11.7) million (2019: USD (20.0) million) decreased due to a combination of lower overriding royalties (ORR rates fell 4.5% as a percentage of sales) and a decrease in production royalties (as income was affected by the lower average realised oil price).
- Opex of USD (16.5) million (2019: USD (16.4) million) was a function of labour costs for new hires in Q4 2019 impacting the full year, 2020 salary adjustments in 2020 together with increased WO costs (as 1 ESP and 2 MPHU type WOs were conducted incurring higher costs).
- G&A expenses of USD (5.1) million (2019: USD (5.6) million) have decreased due to lower travel, business development, professional, ICT and other expenses.
- Derivative Income of USD 1.6 million (2019: USD (0.1) million) includes the net impact of derivative instruments income of USD 2.4 million, partially offset by derivative purchase costs of USD (1.0) million and USD 0.02 fair value derivative financial adjustments primarily to protect future periods.

Non-Cash Expenses: USD (9.4) million (2019: USD (11.5) million):

- DD&A of USD (8.2) million (2019: USD (9.8) million).
- SOE of USD (1.0) million (2019: USD (1.0) million).
- ILFA: USD (0.3) million (2019: USD (0.6) million).
- FX gain of USD 0.0 million (2019: USD (0.1) million loss).

SPT & PT
SPT & PT were USD (0.4) million (2019: USD (7.9) million) and comprised:

- SPT of USD 0.2 million (2019: USD (7.4) million) comprising a credit related to an ITC claim filed in 2020. There were no SPT liabilities incurred for 2020 as the average oil price realised was below USD 50.01 per bbl (SPT threshold) for each of the four quarters.
- PT charge of USD (0.5) million (2019: USD (0.5) million). There is still no official and formal indication on the PT valuation method as it relates to oil and gas entities.

The Group's reported operating profit before impairment and exceptional items was USD 2.6 million (2019: USD 2.4 million). Adjusting for non-cash expenses, the Group's Adjusted EBITDA after SPT & PT was USD 12.0 million (2019: USD 13.9 million) (further details below).

Impairments
Impairments were USD (1.2) million (2019: USD (15.2) million) related to the Impairment of property, plant, and equipment.

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

Exceptional items
Exceptional items were USD 0.04 million (2019: nil) related to the reversal of the Impairment of property, plant and equipment and fees relating to corporate restructuring advice.

See Note 6 to Consolidated Financial Statements - Exceptional items for further details.

Finance Income
Finance income is solely related to bank interest income received on investments with financial institutions (short term investments) of USD 0.1 million (2019: 0.1 million).

Finance Costs
Finance costs amounted to USD (1.4) million (2019: USD (1.4) million) and comprised the:

- Unwinding of the decommissioning liability USD (1.2) million (2019: USD (1.2) million).
- Interest on Leases USD (0.2) million (2019: (0.1) million).
- Bank overdraft USD (0.1) million (2019: nil).
-

See Note 7 to Consolidated Financial Statements – Finance Costs for further details.

Income Taxation
Income Taxation Expense for 2020 of USD (2.9) million (2019: USD 4.4 million Income Taxation credit), comprise the following below.

- Reduction in Deferred Tax Assets ("DTA") due to the de-recognition of tax losses of USD (3.4) million charge (2019: Increase in DTA of USD 3.4 million).
- Decrease in Deferred Tax Liabilities ("DTL") USD 1.6 million due to accelerated accounting impairments/depreciation (2019: USD 1.4 million decrease).
- Unemployment Levy ("UL") USD (0.3) million (2019: USD (0.4) million).
- Petroleum Profit Tax ("PPT") charge USD (0.8) million (2019: Nil).

See Note 8 to Consolidated Financial Statements – Income Taxation for further details.

The Group's comprehensive post-tax loss for the period was therefore USD (2.8) million (2019: USD (9.6) million loss).

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 for the period, adjusted for non-cash DD&A, SOE, ILFA and FX.

The Group presents Adjusted EBITDA at USD 12.3 million and Adjusted EBITDA after SPT & PT at USD 12.0 million as it is used by Management to assess the Group's underlying operational and financial efficiencies and judged to be a better measure of underlying performance.

Statement of Cashflows

Cash inflow/ (outflow) from operating activities
Operating Cash Flow ("OCF") was USD 10.3 million (2019: USD 15.6 million): Note: year-on-year comparative based on Restatement to Cash Flow Statement as per inthe Financial Review.

- Operating cash flow (pre-working capital movements and income tax) of USD 12.1 million (2019: USD 13.1 million) reflected a reported Operating Profit before income tax of USD 0.1 million (2019: USD (14.1) million.
- Changes in working capital of USD 0.8 million outflow (2019: USD 2.8 million inflow), primarily as a result of the decrease in trade receivables compared to the 2019 year end.
- Current income taxation paid USD (1.0) million outflow (2019: USD (0.3) million outflow).

Cash (outflow) from investing activities
Cash outflow from investing activities was USD (6.0) million (2019: USD (11.5) million):

- Expenditure on property, plant and equipment for the year was USD (5.0) million (2019: USD (11.0) million) which mainly included 18 RCPs and infrastructure upgrades.

- Expenditure on exploration and evaluation assets USD (1.1) million (2019: USD (0.4) million) as the Group continued to invest in Galeota and other growth initiatives.

Cash (outflow)/inflow from financing activities

Cash inflow from financing activities was USD 2.2 million (2019: USD (0.6) million outflow):

- Drawdown of CIBC working capital Facility of USD 2.7 million (2019: nil*).
- Finance cost of USD (0.01) million (2019: nil*).
- Principal paid on lease liability USD (0.4) million (2019: (0.4) million)
- Interest paid on lease liability USD (0.1) million (2019: (0.2) million)
- Finance Cost of USD (0.01) million (2019: nil).

Note (*): Amount restated as per note 33 in Financials.

Net Cash Plus Working Capital Surplus

	All figures in USD million	FY 2020 USD MM Audited	FY 2019 USD MM Audited	FY 2018 USD MM Audited
A:	Current Assets			
	Cash and cash equivalents	20.2	13.8	10.2
	Trade and other receivables	7.2	9.3	13.3
	Inventories	5.3	5.2	3.7
	Derivative Financial Instrument	0.3	0.1	-
	Total Current Assets	33.0	28.4	27.2
B:	Liabilities			
	Trade and other payables	7.8	10.4	9.1
	Bank overdraft	2.7	—	—
	Lease liability	0.6	0.6	—
	Taxation payable	0.2	0.1	—
	Derivative Financial Instrument	—	—	—
	Total Current Liabilities	11.3	11.1	9.1
(A-B):	Cash plus working capital surplus	21.7	17.3	18.1

Note: Current Liabilities excludes Provision for other liabilities

Events since Year End

1. ***Hedging***

The Company implemented additional crude derivatives over the Group's monthly production in 2021 and H1 2022. The derivative protection currently in effect for 2021-2022 is as follows:

Type of Derivatives	Index	Sell Put	Buy Put	Sell Call	Production	Effective Date	Expiry Date	Execution Date	Premium USD MM
		USD/bbl	USD/bbl	USD/bbl	Monthly Barrels				
Put Spread	WTI	20.0	30.0	-	15,000	01-Jan-21	31-Dec-21	21-Jul-20	0.36
Put Spread	WTI	20.0	30.0	-	15,000	01-Jan-21	31-Dec-21	17-Nov-20	0.25
Put Spread	Dated Brent	32.5	42.5	-	15,000	01-Jan-21	30-Jun-21	25-Nov-20	0.19
2-Way Cost Collar	ICE Brent		42.5	64.4	15,000	01-Jul-21	31-Dec-21	5-Feb-21	-
3-Way Cost Collar	ICE Brent	50.0	60.0	66.9	10,000	01-Jan-22	30-Jun-22	4-Mar-21	-

2. **CIBC Full Overdraft Credit Facility Drawdown**

Trinity fully drew down its USD 2.7 million overdraft credit facility with CIBC effective 2 April 2020 as part of its strategy of maximising available cash during the COVID-19 pandemic. This facility was increased on 5 January 2021 by USD 2.3 million to a total of USD 5.0 million. This additional portion remains fully undrawn to date. The facility is a revolving overdraft credit available to Trinity which is repayable upon demand to CIBC. Interest is payable monthly at an interest rate equivalent to the US Prime Rate (currently 9%) minus 4.05% per annum (current effective rate 4.95%) with a floor rate of 3.95%.

3. **Fiscal Reforms**

The revised threshold for SPT for small onshore producers was implemented via The Finance Act No. 30 of 2020 which came into effect on 1 January 2021. As a result, the threshold at which SPT becomes due for individual onshore producers producing less than 2,000 bopd has now increased from average realisations of USD 50.0/bbl to USD 75.0/bbl (in any given quarter) for the financial years 2021 and 2022.

4. **Acquisition of onshore block PS-4**

On 4 May 2021, Trinity announced that it had entered into a sale and purchase agreement with Moonsie Oil Company Limited to acquire an operated 100% interest in the PS-4 onshore block for a headline cash consideration of USD 3.5 million, to be funded from the Group’s existing cash resources. The Group anticipates that the transaction will complete towards the end of Q2 2021.

Consolidated Statement of Comprehensive Income for the year ended 31 December 2020

	Note	2020	2019
		$'000	**$'000**
Revenues			
Crude oil sales			
		44,074	63,878
Other income		4	14
		44,078	63,892
Operating Expenses			
Royalties		(11,746)	(20,034)
Production costs		(16,458)	(16,426)
Depreciation, Depletion & Amortisation	11-13		
("DD&A")		(8,174)	(9,772)
General & Administrative ("G&A") expenses		(5,095)	(5,589)
Impairment losses on financial assets ("ILFA")		(252)	(608)
Share Option Expense ("SOE")		(963)	(1,038)
Foreign exchange ("FX") gain/(loss)		7	(76)
Derivative income/(expenses)	19	1,568	(78)
		(41,113)	(53,621)
Operating Profit before Supplemental Petroleum Taxes ("SPT") & Property Taxes ("PT"), Impairment and Exceptional Items		**2,965**	**10,271**
SPT		153	(7,413)
PT		(532)	(492)
Operating Profit before Impairment and Exceptional Items		**2,586**	**2,366**
Impairment	3d	(1,218)	(15,187)
Exceptional items	6	43	--
Operating Profit/(Loss)		**1,411**	**(12,821)**
Finance income	7	108	138
Finance costs	7	(1,416)	(1,372)
Profit/(Loss) Before Income Taxation		**103**	**(14,055)**
Income taxation (expense)/credit	8	(2,938)	4,408
Loss for the year		**(2,835)**	**(9,647)**
Other Comprehensive Income			
Items that may be subsequently reclassified to profit or loss			
Currency translation		(1)	85
Total Comprehensive Loss For The Year		**(2,836)**	**(9,562)**
Earnings per share (expressed in dollars per share)			
Basic	9	(0.01)	(0.03)
Diluted	9	(0.01)	(0.03)

Trinity Exploration & Production Plc-
Consolidated and Company Financial Statements
(Expressed In United States Dollars)
Consolidated Statement of Financial Position at 31 December 2020

	Note	2020	2019
ASSETS		**$'000**	**$'000**
Non-current Assets			
Property, plant and equipment	11	37,756	42,380
Right-of-Use ("ROU") assets	12	1,014	1,402
Intangible assets	13	27,349	26,255
Abandonment fund	14	3,490	3,378
Performance bond	15	253	253
Deferred Tax Assets ("DTA")	16	5,997	9,362
		75,859	83,030
Current Assets			
Inventories	17	5,267	5,143
Trade and other receivables	18	7,239	9,337
Derivative financial instruments	19	266	85
Cash and Cash equivalents	20	20,237	13,810
		33,009	28,375
Total Assets		**108,868**	**111,405**
EQUITY AND LIABILITIES			
Capital and Reserves Attributable to Equity Holders			
Share capital	21	97,692	97,692
Share premium	21	139,879	139,879
Share based payment reserve	22	14,764	14,328
Merger reserves	23	75,467	75,467
Reverse acquisition reserve	23	(89,268)	(89,268)
Translation reserve		(1,650)	(1,649)
Accumulated losses		(188,332)	(186,024)
Total Equity		**48,552**	**50,425**
Non-current Liabilities			
Lease liability	12	465	841
Deferred Tax Liabilities ("DTL")	16	2,611	4,188
Provision for other liabilities	25	45,405	44,330
		48,481	49,359
Current Liabilities			
Trade and other payables	26	7,803	10,386
Bank overdraft	27	2,700	--
Lease liability	12	614	637
Provision for other liabilities	25	516	518
Taxation payable	29	202	80
		11,835	11,621
Total Liabilities		**60,316**	**60,980**
Total Equity and Liabilities		**108,868**	**111,405**

Company Statement of Financial Position at 31 December 2020

	Note	2020	2019
ASSETS		**$'000**	**$'000**
Non-current Assets			
Investment in subsidiaries	10	60,021	59,306
Current Assets			
Trade and other receivables	18	424	218
Intercompany	18	4,318	3,631
Derivative financial instruments		266	85
Cash and Cash equivalents.	20	4,317	5,286
		9,325	9,220
Total Assets		**69,346**	**68,526**
EQUITY AND LIABILITIES			
Capital and Reserves Attributable to Equity Holders			
Share capital	21	97,692	97,692
Share premium	21	139,879	139,879
Share based payment reserve		4,064	3,628
Merger reserves		56,652	56,652
Accumulated losses		(229,422)	(229,833)
Total Equity		**68,865**	**68,018**
Current Liabilities			
Trade and other payables	26	481	508
		481	508
Total Liabilities		**481**	**508**
Total Equity and Liabilities		**69,346**	**68,526**

Trinity Exploration & Production Plc-
Consolidated and Company Financial Statements
(Expressed In United States Dollars)

Consolidated Statement of Changes in Equity for the year ended 31 December 2020

	Share Capital	Share Premium	Share Based Payment Reserve	Reverse Acquisition Reserve	Merger Reserves	Translation Reserve	Accumulated Losses	Total Equity
Year ended 31 December 2019	**$'000**	**$'000**	**$'000**	**$'000**	**$'000**	**$'000**	**$'000**	**$'000**
At 1 January 2019	97,692	139,879	13,290	(89,268)	75,467	(1,638)	(176,473)	58,949
Share based payment expense (Note 22)	--	--	1,038	--	--	--	--	1,038
Translation difference	--	--	--	--	--	(11)	96	85
Loss for the year	--	--	--	--	--	--	(9,647)	(9,647)
Total comprehensive loss for the year	--	--	--	--	--	(11)	(9,551)	(9,562)
At 31 December 2019	**97,692**	**139,879**	**14,328**	**(89,268)**	**75,467**	**(1,649)**	**(186,024)**	**50,425**
Year ended 31 December 2020								
At 1 January 2020	97,692	139,879	14,328	(89,268)	75,467	(1,649)	(186,024)	50,425
LTIPs exercised (Note 21)	--	--	(527)	--	--	--	527	--
Share based payment expense (Note 22)	--	--	963	--	--	--	--	963
Translation difference	--	--	--	--	--	(1)	--	(1)
Loss for the year	--	--	--	--	--	--	(2,835)	(2,835)
Total comprehensive loss for the year	--	--	--	--	--	(1)	(2,835)	(2,836)
At 31 December 2020	**97,739**	**139,879**	**14,764**	**(89,268)**	**75,467**	**(1,650)**	**(188,332)**	**(48,552)**

Company Statement of Changes in Equity for the year ended 31 December 2020

	Share Capital	Share Premium	Share Based Payment Reserve	Merger Reserves	Accumulated Losses	Total Equity
	$'000	**$'000**	**$'000**	**$'000**	**$'000**	**$'000**
Year ended 31 December 2019						
At 1 January 2019	97,692	139,879	2,590	56,652	(228,126)	68,687
Share based payment charge (Note 22)	--	--	1,038	--	--	1,038
Total comprehensive expense for the year	--	--	--	--	(1,707)	(1,707)
At 31 December 2019	**97,692**	**139,879**	**3,628**	**56,652**	**(229,833)**	**68,018**
Year ended 31 December 2020						
At 1 January 2020	97,692	139,879	3,628	56,652	(229,833)	68,018
LTIPs exercised (Note 21)	--	--	(527)	--	527	--
Share based payment charge (Note 22)	--	--	963	--	--	963
Total comprehensive expense for the year	--	--	--	--	(116)	(116)
At 31 December 2020	**97,692**	**139,879**	**4,064**	**56,652**	**(229,422)**	**68,865**

Trinity Exploration & Production Plc-
Consolidated and Company Financial Statements
(Expressed In United States Dollars)
Consolidated Statement of Cash Flows for the year ended 31 December 2020

	Note	2020 $'000	2019 $'000 As Restated*
Operating Activities			
Profit/(Loss) before taxation		103	(14,055)
Adjustments for:			
Translation difference		83	(63)
Finance cost – loans and interest	7	195	174
Finance income	7	(108)	(138)
Finance cost – decommissioning provision	25	1,221	1,198
Share based payment charge	22	963	1,038
DD&A	11-13	8,174	9,772
Loss on disposal of assets	11	2	--
Impairment losses on financial assets		515	--
Reversal of impairment		(126)	--
Impairment of property, plant and equipment	11	1,121	15,187
		12,143	13,113
Changes In Working Capital			
Inventories	17	(124)	(1,454)
Trade and other receivables	14,18,19	1,290	3,638
Trade and other payables	25,26	(1,985)	605
		(819)	2,789
Income taxation paid		(1,028)	(316)
Net Cash Inflow From Operating Activities		10,296	15,586
Investing Activities			
Purchase of Exploration and Evaluation ("E&E") assets	13	(1,062)	(420)
Purchase of computer software	13	--	(99)
Purchase of property, plant and equipment	11	(4,979)	(11,020)
Net Cash Outflow From Investing Activities		(6,041)	(11,539)
Financing Activities			
Finance income		108	138
Finance cost		(55)	--
Principal paid on lease liability**		(441)	(403)
Interest paid on lease liability**		(140)	(173)
Bank overdraft		2,700	--
Net Cash Inflow/(Outflow) From Financing Activities		2,172	(438)
Increase in Cash and Cash Equivalents		6,427	3,609
Cash and Cash Equivalents			
At beginning of year		13,810	10,201
Effects of foreign exchange rates differences on cash		(14)	(27)
Increase in Cash and Cash equivalents		6,441	3,636
At end of year	20	20,237	13,810

Notes
* *Comparative amounts for the year have been restated. Refer to Note 33 for further details.*
** *The prior year was split to show principal and interest.*

Trinity Exploration & Production Plc-
Consolidated and Company Financial Statements
(Expressed In United States Dollars)

Company Statement of Cash Flows for the year ended 31 December 2020

	Note	2020 $'000	2019 $'000
Operating Activities			
Loss before taxation		(116)	(1,707)
Adjustments for:			
Translation differences		--	1
Finance income		(126)	(233)
Share based payment charge		248	221
		6	(1,718)
Changes In Working Capital			
Trade and other receivables		(1,074)	(4,015)
Trade and other payables		(27)	6,730
		(1,101)	2,715
Taxation Paid		--	--
Net Cash (Outflow)/Inflow from Operating Activities		(1,095)	997
Financing Activities			
Finance income		126	233
Net Cash Inflow from Financing Activities		126	233
(Decrease)/Increase In Cash and Cash Equivalents		(969)	1,230
Cash and Cash Equivalents			
At beginning of year		5,286	4,056
(Decrease)/Increase Cash and Cash equivalents		(969)	1,230
At End of Year	20	4,317	5,286

Notes to the Consolidated Financial Statements 31 December 2020

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 the 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 T&T.

Basis of preparation

The financial information of the Group set out above does not constitute "statutory accounts" for the purposes of Section 435 of the Companies Act 2006. The financial information for the year ended 31 December 2020 has been extracted from the Group's audited financial statements which were approved by the Board of directors on 17 May 2021 and will be delivered to the Registrar of Companies for England and Wales in due course. The financial information for the year ended 31 December 2020 has been extracted from the Group's audited financial statements for that period which have been delivered to the Registrar of Companies for England and Wales.

The reports of the auditors on both these financial statements were unqualified, did not include any references to any matters to which the auditors drew attention by way of emphasis without qualifying their report and did not contain a statement under Section 498(2) or Section 498(3) of the Companies Act 2006. Whilst the financial information included in this preliminary announcement has been prepared in accordance with the recognition and measurement criteria of International Financial Reporting Standards ('IFRSs'), this announcement does not itself contain sufficient information to comply with those IFRSs. This financial information has been prepared in accordance with the accounting policies set out in the December 2020 report and financial statements.

The Group's financial statements have been prepared and approved by the Board of Directors ("Board") in accordance with International Financial Reporting Standards, International Accounting Standards and Interpretations (collectively "IFRS") applied in accordance with the provisions of the Companies Act 2006. This consolidated financial information has been prepared under the historical cost convention, except certain financial assets and liabilities (including derivative financial instruments) and certain classes of property, plant and equipment – 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.

The preparation of the consolidated financial information in conformity 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 $0.04 million (2019: $1.7 million loss).

<u>*Prior year comparatives*</u>

During the year ended 31 December 2020 a classification error was identified in the prior year Consolidated Statement of Cash Flows, whereby cash flows from investing activities included non-cash accruals which were not adjusted from changes in working capital. As a result the net cash inflow from operating activities and net cash outflow from investing activities were both overstated by $1.2 million. To correct the error, amounts in the prior year consolidated financial statements have been reclassified, resulting in a $1.2 million decrease in net cash inflows from operations and a $1.2

million decrease in net cash outflows from investing activities. There is no profit or net asset impact as a result of the prior year restatement. See note 33 for further details.

Going Concern

The Board have 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 past twelve months has seen the Group's measured response to the COVID-19 pandemic where there were no forced shut-ins or interruptions affecting the Group's operations. The Board have considered the continued potential impact of the COVID-19 pandemic on the Group's operational capabilities, liquidity and financial position over the next twelve month period and beyond. The going concern assessment has considered the current measures put in place by the Group to preserve cash and the ability to reduce discretionary expenditure during a period when the Group has to adapt to a volatile oil price environment.

The Group started 2021 with a strong operating and financial position; 2020 average production of 3,226 barrels of oil per day ("bopd") (2019: 3,007 bopd), cash in hand and at bank of $20.2 million as at 31 December 2020 (2019: $13.8 million), and Derivative financial instruments in place protecting a significant proportion of near-term production. In making their going concern assessment, the Board have considered a cash flow forecast based on expected future oil prices, production volumes and discretionary expenditure reductions which could be implemented in response to oil price volatility. The base case forecast was prepared with consideration of the following:

- Future oil prices assumed to be in line with the forward curve prevailing as at May 2021, with an average realised oil price of $58.6/bbl in the period to December 2021. The forward price curve applied in the cash flow forecast starts at $59.5/bbl in May 2021, fluctuating each month down to $57.3/bbl in December 2021 through to $55.3/bbl in June 2022
- Average forecast production for the year to December 2021 of 3,067 bopd and for the six months to June 2022 of 3,057 bopd with production being maintained by Recompletions ("RCPs"), Workovers ("WOs") and swabbing activities and no new drilling;
- No SPT incurred on the onshore assets, as the SPT threshold for small onshore has been increased to $75.0/bbl;
- The purchase of Onshore PS 4 block being completed;
- Trinity continuing with various growth and business development opportunities; and
- Although derivative instruments are in place to protect a portion of cashflows against declining oil prices, no derivative income is assumed to be received over the forecast period.

Management considers this is a reasonable base scenario, reflecting the outlook of the future oil price, current 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 separate stressed scenarios including:

- the effect of reductions in oil prices as low as $10.0/bbl being sustained across the forecast period, noting that the base case pricing is in line with market prices; and

- the impact of temporary disruption from localised COVID-19 cases reducing forecast production by 15%, albeit operations have continued uninterrupted to date and the nature of the operations reduces the risk of such an eventuality.

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

Based on the cash flow forecast, when combined with mitigating actions that are within the Group's control, and having considered the potential impact of COVID-19 pandemic, together with the Government of Trinidad and Tobago's ("GORTT's") response to date, the Board currently believe the Group can maintain sufficient liquidity and a healthy positive cash balance, and remain in operational existence, for at least the next twelve months.

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 as it expects market conditions to improve. 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 2020:</u>

New standards impacting the Group that have been adopted in the annual financial statements for the year ended 31 December 2020 are:

- Definition of a Business (Amendments to IFRS 3); and
- COVID-19-Related Rent Concessions (Amendments to IFRS 16).

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

<u>Other standards</u>

New standards that have been adopted in the annual financial statements for the year ended 31 December 2020, but have not had a significant effect on the Group are:

- IAS 1 Presentation of Financial Statements and IAS 8 Accounting Policies, Changes in Accounting Estimates and Errors (Amendment – Disclosure Initiative - Definition of Material); and
- Revisions to the Conceptual Framework for Financial Reporting.

(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 2022:

- Interest Rate Benchmark Reform – IBOR 'phase 2' (Amendments to IFRS 9, IAS 39 and IFRS 7);
- Onerous Contracts – Cost of Fulfilling a Contract (Amendments to IAS 37);
- Property, Plant and Equipment: Proceeds before Intended Use (Amendments to IAS 16); and
- Annual Improvements to IFRS Standards 2018-2020 (Amendments to IFRS 1, IFRS 9, IFRS 16 and IAS 41).

In January 2020, the IASB issued amendments to IAS 1, which clarify the criteria used to determine whether liabilities are classified as current or non-current. These amendments clarify that current or non-current classification is based on whether an entity has a right at the end of the reporting period to defer settlement of the liability for at least twelve months after the reporting period. The amendments also clarify that 'settlement' includes the transfer of cash, goods, services, or equity instruments unless the obligation to transfer equity instruments arises from a conversion feature classified as an equity instrument separately from the liability component of a compound financial instrument.

The amendments were originally effective for annual reporting periods beginning on or after 1 January 2022. However, in May 2020, the effective date was deferred to annual reporting periods beginning on or after 1 January 2023. The Group is currently assessing the impact of these new accounting standards and amendments.

Basis of consolidation

The Consolidated Financial Statements comprise the financial statements of the subsidiaries listed in Note 10. 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.

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 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:

	2020		**2019**	
	$	£	$	£
Average rate TTD= $/£	6.758	8.646	6.759	8.617
Closing rate TTD= $/£	6.761	9.213	6.762	8.965

(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 profit or loss. 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 profit or loss 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 profit or loss and 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 however 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.

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 lost 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. However, 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. 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, DTL 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")

PT is recognised initially at fair value and subsequently measured at amortised cost using the effective interest method. Assessments are 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 are industrial with building rates at 6% and industrial without building rates at 3%.

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"), formerly the Petroleum Company of Trinidad and Tobago Limited ("Petrotrin"), 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.

In 2020 the Group revised its estimates due to the lease term of the copiers being renewed in August 2020 for an additional 36 months. As a result, there was an adjustment in the carrying amount of the lease liability to reflect the payments to be made over the revised term, which was discounted using a revised discount 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.

Extension and termination options are included in a few leases entered into by the Group. These are used to maximise operational flexibility in terms of managing the assets used in the Group's operations. The majority of extension options held are exercisable only by the Group and not by the respective lessor.

In determining the lease term, Management considers all facts and circumstances that create an economic incentive to exercise an extension option, or not exercise a termination option. Extension options (or periods after termination options) are only included in the lease term if the lease is reasonably certain to be extended (or not terminated).

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.

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 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% (2019: 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% (2019: 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.

	2020	**2019**
	$'000	**$'000**
Profit/(loss) for the year and Equity		
10% strengthening of the US Dollar/ (2019: 10%)	(168)	(303)
10% weakening of the US Dollar/ (2019: 10%)	168	303

(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% (2019: 20%) increase and decrease in realised oil prices. 20% (2019 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%.

	2020	**2019**
	$'000	**$'000**
Profit/(loss) for the year		
20% increase in price/ (2019: 20%)	11,702	12,701
20% decrease in price/ (2019: 20%)	(11,702)	(12,701)

The Group implemented crude derivatives 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 2020, there were no loan commitments to attract interest rates on foreign currency-denominated borrowings, (2019: nil). During 2020 there was a bank overdraft facility which incurred $0.1 million interest (2019:nil).

(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 the Heritage sales, the ECL was immaterial as all sales payments were made during the stipulated time frame. However, ECL was also calculated on other receivable balances and a provision of $0.9 million was derived. 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 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 $20.2 million (2019: $13.8 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 2020				
	$'000	$'000	$'000	$'000
Non-derivatives				
Trade and other payables	7,803	--	--	7,803
Lease liabilities	614	442	23	1,079
	8,417	442	23	8,882
At 31 December 2019	$'000	$'000	$'000	$'000
Non-derivatives				
Trade and other payables	10,386	--	--	10,386
Lease liabilities	637	447	393	1,477
	11,023	447	393	11,863

Company	**Less than 1 year**	**Total**
At 31 December 2020		
	$'000	$'000

Non-derivatives		
Trade and other payables	481	481
	481	481
At 31 December 2019	$'000	$'000
Non-derivatives		
Trade and other payables	508	508
	508	508

(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 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)

	2020	**2019**
	$'000	**$'000**
Net cash	(17,537)	(13,810)
Total equity	48,552	50,425
Total capital	31,015	36,615
Gearing ratio	(56.5)%	(37.7)%

(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 19 for details.

3. Critical Accounting Estimates and Judgements

The preparation of the 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 16.

(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 25: Provision for other liabilities

	Bands (years)	**2020**	**2019**
Risk free rates	9-12	3.14%	2.13%
	13-18	3.17%	3.07%
	19-24	2.42%	2.91%
Inflation rate		2%	2%

The following table details the Group's sensitivity to a 1% (2019: 1%) increase and decrease in discount and inflation rates. 1% (2019 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 2020 of a 1% change in these variables is as follows:

	Consolidated Statement of Financial Position: Obligation 2020 $'000	**Consolidated Statement of Comprehensive: Income/Expense 2020 $'000**
Discount rate		
1% increase in assumed rate	(7,790)	181
1% decrease in assumed rate	9,679	(289)
Inflation rate		
1% increase in assumed rate	9,638	231
1% decrease in assumed rate	(7,903)	(194)

(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 2020 the Group estimated its own commercial reserves based on 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 note 11 and 13.
- Depreciation and amortisation charges in profit or loss 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 note 11 and 13.
- 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 25.
- 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 16.

As at 31 December 2020 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 relates 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 2020 an impairment charge of $1.1 million was recognised on the Group's property, plant and equipment (2019: $15.2 million) see Note 11. The impairment charge resulted in the carrying amount of the respective CGUs being written down to their recoverable amount.

Oil & Gas Assets $1.1 million (2019: $15.2 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 9-24 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.

	2021	2022	2023	2024	2025	2026
Realised price	46.3	44.3	43.0	42.2	41.8	41.8

If the price deck used in the impairment calculation had been 10% lower than Management's estimates at 31 December 2020, the Group would have a $1.0 million increase on impairment of Oil & Gas Assets (2019: $3.5 million increase). If the price deck used in the impairment calculation had been 10% higher than Management's estimates at 31 December 2020, the Group would have a $0.6 million decrease on impairment of the Oil & Gas Assets (2019: $6.0 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 2020, Management's estimate of the Group's cost of capital was 12% (2019:13%). 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 $0.2 million decrease on impairment position for 2020 (2019: $0.7

million decrease) 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 $0.2 million increase on impairment for 2020 (2019: $0.7 million).

(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 2020 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 accrual**

Property Tax is assessed on property owned by the Group in Trinidad and Tobago governed by the Property Tax Act 2009 and later Property Tax (Amendment) Act 2018 of Trinidad and Tobago. The calculation of the Property Tax is described in note 1 Background and Summary of significant accounting policies.

At the end of 2020 the Property Tax accrued for the period 2018 to 2020 within Trade and other payables was $1.5 million (2019: $1.0 million). Property Tax has been accrued using Management's best estimate, as the administration arrangements of the Property Tax under the Valuation of Land Act is not in place and the actual method for calculating the Property Tax is therefore unavailable. There is sentiment, based on government communication, that until the administration arrangements are put in place by the Government of Trinidad and Tobago the Property Tax will not be collected over those respective years (2018-2020) and a waiver might be forthcoming. As at 31 December 2020 and the date of this report that waiver has not been enacted and Management's judgement is to continue to assess that a liability is required based on the current tax law enacted.

(g) **Share based payments**

The Company has in place a share-based compensation plan (the LTIP), for Executive Directors 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 22 for details.

4 Segment Information

The Steering Committee provides support, guidance and oversight on the progression of the Company through various project that may be undertaken. The committee is led by the Group's chief operating decision-maker. 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 comprises the Executive Chairman, Managing Director, 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 non-current assets of the Group are located in T&T.

5 Operating Profit Before Impairment and Exceptional Items

	2020 $'000	2019 $'000
Operating profit before exceptional items is stated after taking the following items into account:		
DD&A (Note 11)	7,566	9,218
Depreciation on ROU (Note 12)	502	477
Amortisation of computer software (Note 13)	106	77
Employee costs (Note 32)	7,662	7,773
Inventory recognised as expense, charged to operating expenses	330	104

Auditors' remuneration

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

	2020 $'000	2019 $'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) *	93	153
BDO Limited (T&T based)*	127	124
- Fees payable to the Company's auditors' for other services:		
The audit of Company's subsidiaries	13	20
Audit related assurance services – interim review	29	38
Total assurance and auditors' remuneration	**262**	**335**

** - Please note that prior year relates to previous auditors*

All fees in 2020 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.

6 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 financial statements are highlighted below.

Exceptional items:	**2020 $'000**	**2019 $'000**
Reversal of Impairment on equipment	(126)	--
Fees relating to corporate restructuring advice	83	--
Exceptional Income	**(43)**	**--**

Exceptional items 2020[1]:

- Reversal of Impairment on equipment: ($0.1) million credit in relation to reversal of impairment for Pumping Unit
- Fees relating to corporate restructuring advice: $0.1 million charge in relation to professional advice on a potential corporate restructuring

1 Impairment losses on property, plant and equipment have been reclassified from exceptional items in 2020 and 2019 comparative

7 Finance income and costs

Recognised in the consolidated statement of comprehensive income

Finance income

	2020 $'000	2019 $'000
Interest Income	108	138

Finance costs	**2020**	**2019**
	$'000	**$'000**
Decommissioning – Unwinding of discount (Note 25)	(1,221)	(1,198)
Interest on Leases	(140)	(174)
Interest on overdraft	(55)	--
	(1,416)	**(1,372)**

8 Income Taxation

	2020	**2019**
	$'000	**$'000**
Current tax		
Petroleum profits tax	817	--
Unemployment levy	333	390
Deferred Tax		
- Current year		
Movement in asset due to tax losses recognised (Note 16)	3,365	(3,389)
Movement in liability due to accelerated tax depreciation (Note 16)	(1,577)	(1,409)
Income tax expense/(credit)	**2,938**	**(4,408)**

The Group's effective tax rate varies from the statutory rate for UK companies of 19% (2019:19%) as a result of the differences shown below:

	2020	**2019**
	$'000	**$'000**
Profit/(loss) before taxation	**103**	**(14,055)**
Tax calculated at domestic tax rates applicable to profits in the respective countries	741	(6,236)
Expenses not deductible for tax purposes	2,163	9,833
Impact on tax losses	(2,187)	(2,962)
Deferred tax on capital allowances in the current period recognised	(1,389)	(2,044)
Tax losses previously generated now recognised in the current period	3,365	(3,389)
Other reconciling differences	245	390
Tax charge	**2,938**	**(4,408)**

Corporate income tax is calculated at 19% (2019: 19%) of the assessable profit for the year for the UK parent company, 55% for the operating subsidiaries in Trinidad and Tobago (2019: 55%) and 30% (2019: 30%) for the corporate subsidiaries in Trinidad and Tobago.

Taxation losses at 31 December 2020 available for set off against future taxable profits amounts to approximately $237.2 million (2019: $240.2 million), with tax losses recognised of $12.0 million in 2020. These losses do not have an expiry date and have not yet been confirmed by the Board of Inland Revenue ("BIR") and the Her Majesty's Revenue and Customs ("HMRC"). The 2019 reconciliation was revised using the same method as 2020.

9 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.

	Loss $'000	Weighted Average Number Of Shares '000'	Earnings Per Share $
Year ended 31 December 2020			
Basic	(2,835)	386,233	(0.01)
Diluted	(2,835)	386,233	(0.01)
Year ended 31 December 2019			
Basic	(9,647)	384,049	(0.03)
Diluted	(9,647)	384,049	(0.03)

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 in note 22 below) are considered potential ordinary shares. Share Options of 1,975,084 are considered potential ordinary shares and have not been included as the exercise hurdle would not have been met.

There was no impact on the weighted average number of shares outstanding during 2020 as all Share Options and LTIP's were excluded from the weighted average dilutive share calculation because their effect would be anti-dilutive and therefore both basic and diluted earnings per share are the same in 2020.

10 Investment In Subsidiaries

	Company	
	2020 $'000	2019 $'000
Opening balance	59,306	58,489
Share based payment	715	817
Closing balance	**60,021**	**59,306**

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.

Listing of Subsidiaries

The Group's subsidiaries at 31 December 2020 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	99.99%
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 %
Tabaquite Exploration & Production Company Limited	Trinidad address	Oil and Gas	100 %
Trinity Exploration and Production (GOP) Limited	Trinidad address	Oil and Gas	100 %
Trinity Exploration and Production (GOP-1B) Limited	Trinidad address	Oil and Gas	100 %

11 Property, Plant and Equipment

Year ended 31 December 2020	**Plant & Equipment $'000**	**Leasehold & Buildings $'000**	**Oil & Gas Assets $'000**	**Other $'000**	**Total $'000**
Opening net book amount at 1 January 2020	1,141	1,652	39,587	--	42,380
Disposals	--	(2)	--	--	(2)
Additions	1,124	(16)	2,983	--	4,091
Adjustment to decommissioning estimate (Note 24)	--	--	(152)	--	(152)
Impairment reversal equipment	126	--	--	--	126
Impairment charge$_1$	(116)	--	(1,005)	--	(1,121)
DD&A charge for year	(247)	(153)	(7,166)	--	(7,566)
Closing net book amount at 31 December 2020	**2,028**	**1,481**	**34,247**	**--**	**37,756**
At 31 December 2020					
Cost	14,894	3,338	300,857	336	319,425
Accumulated DD&A and impairment	(12,866)	(1,857)	(266,610)	(336)	(281,669)
Closing net book amount	**2,028**	**1,481**	**34,247**	**--**	**37,756**

Year ended 31 December 2019	**Plant & Equipment $'000**	**Leasehold & Buildings $'000**	**Oil & Gas Assets $'000**	**Other $'000**	**Total $'000**
Opening net book amount at 1 January 2019	962	1,705	50,932	--	53,599
Additions	369	111	11,676	--	12,156
Adjustment to decommissioning estimate (Note 25)	--	--	1,031	--	1,031
Impairment$_1$	--	--	(15,187)	--	(15,187)
DD&A charge for year	(190)	(164)	(8,864)	--	(9,218)
Translation difference	--	--	(1)	--	(1)
Closing net book amount at 31 December 2019	**1,141**	**1,652**	**39,587**	**--**	**42,380**
At 31 December 2019					
Cost	13,760	3,356	298,879	336	316,331
Accumulated DD&A and impairment	(12,619)	(1,704)	(259,291)	(336)	(273,950)

Translation difference	--	--	(1)	--	(1)
Closing net book amount	**1,141**	**1,652**	**39,587**	**--**	**42,380**

1 An impairment loss of $1.1 million (2019: $15.2 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.

12 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 2020	**31 December 2019**
	$'000	$'000
Right-of-use assets		
Non-current assets	1,014	1,402
Lease Liabilities		
Current	614	637
Non-current	465	841
	1,079	**1,478**

The ROU assets relate to Motor vehicles, Office building, Staff housing 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:

	2020	**2019**
	$'000	$'000
Depreciation charge of ROU assets		
Depreciation	(502)	(477)
Interest expense (including finance cost)	(140)	(173)

The total cash outflow for leases in 2020 was $0.6 million (2019: $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.

13 Intangible Assets

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

	Exploration and Evaluation assets	**Computer software**	**Total**

Year ended 31 December 2020	$'000	$'000	$'000
Opening net book amount at 1 January 2020	25,987	268	26,255
Additions	1,055	145	1,200
Amortisation charge for year	--	(106)	(106)
Closing net book amount at 31 December 2020	**27,042**	**307**	**27,349**
At 31 December 2020			
Cost	27,042	520	27,562
Accumulated amortisation	--	(213)	(213)
Closing net book amount	**27,042**	**307**	**27,349**

Year ended 31 December 2019	Exploration and Evaluation assets $'000	Computer software $'000	Total $'000
Opening net book amount at 1 January 2019	25,511	246	25,757
Additions	476	99	575
Amortisation charge for year	--	(77)	(77)
Closing net book amount at 31 December 2019	**25,987**	**268**	**26,255**
At 31 December 2019			
Cost	25,987	375	26,362
Accumulated amortisation	--	(107)	(107)
Closing net book amount	**25,987**	**268**	**26,255**

Computer Software: In 2020, capital cost incurred for software acquisition.

E&E assets: Represents the cost for the TGAL 1 exploration well and further field E&E cost. The Group tests whether E&E assets has suffered any impairment triggers on an annual basis and there were no impairment triggers (2019: nil)

14 Abandonment fund

	2020	2019
	$'000	$'000
At 1 January	3,378	2,979
Additions	112	399
At 31 December	**3,490**	**3,378**

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.

15 Performance bond

	2020	2019
	$'000	$'000
At 1 January and 31 December	253	253

A Performance Bond in favour of Heritage was put in place on 3 July 2017 of $0.3 million at 1.75% rate per annum, executed with First Citizens Bank Trinidad and Tobago Limited and effective until 31 December 2020. These funds have been restricted to a Fixed Deposit for 36 months at the agreed interest rate of 1.25%. The Performance Bond is a requirement under the Lease Operatorship Agreement ("LOAs") as Trinity is the Operator of the FZ2, WD2, WD5/6, WD13 and WD14 fields.

16 Deferred Income Taxation

Group

The analysis of DTA is as follows:

	2020 $'000	2019 $'000
DTA:		
-DTA to be recovered in more than 12 months	(4,447)	(5,127)
-DTA to be recovered in less than 12 months	(1,550)	(4,235)
DTL:		
-DTL to be settled in more than 12 months	2,611	4,188
Net DTA	**(3,386)**	**(5,174)**

The movement on the deferred income tax is as follows:

	2020 $'000	2019 $'000
At beginning of year	(5,174)	(375)
Movement for the year	1,879	(4,725)
Unwinding of deferred tax on fair value uplift	(91)	(74)
Net DTA	**(3,386)**	**(5,174)**

The deferred tax balances are analysed below:

	2018 $'000	Movement $'000	2019 $'000	Movement $'000	2020 $'000
DTA					
Acquisition	(33,436)	--	(33,436)	--	(33,436)
Tax losses recognised	(36,087)	(3,389)	(39,476)	--	(39,476)
Tax losses derecognised	63,550	--	63,550	3,365	66,915
	(5,973)	**(3,389)**	**(9,362)**	**3,365**	**(5,997)**

DTL	2018 $'000	Movement $'000	2019 $'000	Movement $'000	2020 $'000
Accelerated tax depreciation and non-current asset impairment	(16,043)	(1,337)	(17,380)	(1,487)	(18,867)
Acquisitions	19,580	--	19,580	--	19,580
Fair value uplift	2,061	(73)	1,988	(90)	1,898
	5,598	**(1,410)**	**4,188**	**(1,577)**	**2,611**

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 $3.4 million have been derecognised (2019: $3.4 million was recognised) based on future taxable profits. The Group has unrecognised deferred tax asset amounting to $102.2 million which have no expiry date.

DTL have decreased by $1.6 million as the temporary difference between the accounting values of property, plant and equipment and intangible assets and tax values decreased compared to 2019-year end

- 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).

- Tax losses – At the end of 2020 the Group had gross tax losses carried forward of $237.2 million (2019: $240.2 million) represented by corporate tax losses in the UK of $16.6 million (2019: $16.3 million) and PPT and Corporate tax losses in Trinidad and Tobago of $220.6 million (2019: $223.9 million). In Trinidad and Tobago PPT losses and corporate tax losses may be carried forward indefinitely to reduce the taxes in future years. As of 1 January 2020, PPT losses can only be utilised to shelter a maximum of 75 percent of PPT per annum.

17 Inventories

	Crude oil	Materials and supplies	Total
	$'000	$'000	$'000
At 1 January 2020	89	5,054	5,143
Net inventory movement	(22)	146	124
At 31 December 2020	**67**	**5,200**	**5,267**
At 1 January 2019	89	3,649	3,738
Impairment	--	(49)	(49)
Net inventory movement	--	1,454	1,454
At 31 December 2019	**89**	**5,054**	**5,143**

(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. There were no obsolete inventories written off during the year.

18 Trade and Other Receivables

	Group		Company	
	2020 $'000	2019 $'000	2020 $'000	2019 $'000
Due within 1 year				
Amounts due from related parties (Note 28 (d))	--	--	4,418	3,722
Trade receivables	3,357	5,307	--	--
Less: provision for impairment of trade and intercompany receivables	(6)	(225)	(100)	(91)
Trade receivables/amounts due from related parties – net	3,351	5,082	4,318	3,631
Prepayments	862	859	149	147
VAT recoverable	2,467	2,932	125	71
Other receivables	1,413	847	150	--
Less: provision for Impairment of other receivables	(854)	(383)	--	--
	7,239	**9,337**	**4,742**	**3,849**

All trade receivables are with the Group's only customer, Heritage. Ageing analysis of these trade receivables as at 31 December 2020 is as follows:

	2020 $'000	2019 $'000
Up to 30 days	3,217	4,491
>60 days	--	104
>180 days	140	712
	3,357	**5,307**

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

	Group		Company	
	2020 $'000	2019 $'000	2020 $'000	2019 $'000
USD	4,567	4,200	4,589	3,690

GBP	191	159	252	159
TTD	2,481	4,978	--	--
	7,239	**9,337**	**4,841**	**3,849**

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**	
	2020 $'000	**2019 $'000**	**2020 $'000**	**2019 $'000**
Trade receivables				
Counterparties without external credit rating:				
Existing customers with no defaults in the past	**7,239**	**9,337**	--	--

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 2020, trade receivables of $3.4 million (2019: $4.8 million) were therefore considered to be fully performing.

Although all Heritage revenue payments have been received on a timely basis, the Joint Interest billings has not. For other receivables, which relate to Joint Interest Billing receivable amounts from Heritage, an ECL of $0.9 million (2019: $0.4 million) was therefore calculated.

At the end of 2020 a total of $0.1 million was outstanding from Petrotrin (2019: $0.5 million), with $0.4 million of the outstanding amounts having been received during 2020. An ECL of $0.0 million was applied to the outstanding $0.1 million receivables amount due from Petrotrin.

19 Derivative financial assets

The following table compares the carrying amounts and fair values of the Group's financial assets and financial liabilities as at 31 December 2020.

-

	As at 31 December 2020 $'000	**As at 31 December 2019 $'000**
Derivative asset	266	85
Total	266	85

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 December 2020 $'000
Opening balance	85
Derivative instrument purchased	946
Derivative asset expensed	(765)
Closing balance	266

On 31 December 2020 the crude derivative contracts were valued using a mark to market report. The report provides forward looking value on the existing crude derivatives held at 31 December 2020.

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

	31 December 2020 $'000	**31 December 2019 $'000**
Derivative expense	(765)	(126)
Derivative income	2,333	48
Total income/(expense)	1,568	(78)
Net derivative income/(expense)	1,302	(78)
FV of derivative financial instruments	266	--
	1,568	**(78)**

20 Cash and Cash Equivalents

	Group 2020 $'000	**Group 2019 $'000**	**Company 2020 $'000**	**Company 2019 $'000**
Short term investment	4,055	5,081	4,055	5,081
Cash and cash equivalents	16,182	8,729	261	205
	20,237	**13,810**	**4,317**	**5,286**

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.

21 Share Capital and Share Premium

Group

	Number of shares	Share capital $'000	Share premium $'000	Total $'000
As at 1 January and 31 December 2019	**478,489,232**	**97,692**	**139,879**	**237,571**
As at 1 January 2020	478,849,232	97,692	139,879	237,571
LTIPs exercised*	4,745,056	--	--	--
As at 31 December 2020	**483,594,288**	**97,692**	**139,879**	**237,571**

- The Company does not have a limited amount of authorised share capital.
- Within the number of shares shown above there are 94,799,986 deferred shares of USD 0.99 each totalling $93.9 million of share capital. The deferred shares have no voting or dividend rights and on a return of capital on a winding up have no valuable economic rights.
- The remaining 388,794,302 Ordinary shares in issue as at 31 December 2020 have a par value of USD 0.01 per share.

Year ended 31 December 2020	Number of shares	Ordinary shares $'000	Deferred shares $'000	Share premium $'000	Total $'000
At 1 January 2020	478,849,232	3,840	93,852	139,879	237,571
LTIPs exercised*	4,745,056	--	--	--	--
At 31 December 2020	**483,594,288**	**3,840**	**93,852**	**139,879**	**237,571**

Note: $:GBP rate 1.312:1

**<u>LTIPs exercised</u>* - 4,745,056 LTIPs were exercised during the year ended 31 December 2020. These shares were issued for nil consideration and therefore for less than the nominal value of the shares which was in contravention of s580 of the UK Companies Act. Following the 31 December 2020 year end the Directors have sought legal advice with regards to this breach of UK company law and are in the process of implementing a remedy. Given remedial action can be taken, the Directors do not consider this to be a material breach of UK company law. The shares have been issued and therefore the number of shares in issue has been appropriately reflected in the table above. There is no corresponding increase to the value of share capital as they were issued below nominal value.

22 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 2020 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:

	2020 $'000	2019 $'000
At 1 January	14,328	13,290
Share based payment expense:		
LTIP exercised	(527)	--
LTIP expense	963	1,038
At 31 December	**14,764**	**14,328**

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:

Grant-Vest	Expiry Date	Exercise price per Share Options	2020 Number of Options	Exercise price per Share Options	2019 Number of Share Options
2012-2015	2022	GBP0.86	1,685,540	GBP0.86	1,685,540
2013-2016	2023	GBP1.20	289,544	GBP1.20	289,544
			1,975,084		1,975,084

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 1.19	GBP 1.20
Average Exercise price	GBP 1.20	GBP 0.89
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 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 LTIPs

One off LTIP awards were granted in August 2017 over 25,415,998 ordinary shares and in June 2020 over a further 1,422,961 ordinary shares (the "2017 LTIP Awards"). The 2017 LTIP awards, which ordinarily vest on 30 June 2022, partially vested on 30 June 2020 and may vest in full or in part on 30 June 2021, 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 4.98 pence per share. If the three month volume-weighted price ("VWAP") at the testing date is 35 pence or more per share, this part of the award will vest in full. If the VWAP at the testing date is 4.98 pence per share or less, this part of the award will not vest at all. If the VWAP at the testing date is between 4.98 pence and 35 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 LTIP Award is $2.6 million and will be expensed over the vesting period with the full charge pro-rated over the period up to 30 June 2022. However, the LTIP Award may vest in full or in part on 30 June 2020 or 2021 with the appropriate charge being taken over the vesting period. The fair value at grant date is 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 LTIP Awards granted in 2017:

Grant Date	25 August 2017	25 June 2020
Share price at grant date	GBP 10.75	GBP 7.90
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

2019 LTIPs

In January 2019 Options over 2,824,000 ordinary shares and in May 2019 Options over 3,832,824 ordinary shares were granted under the LTIP in accordance with the policy announced to the market on 25 August 2017. The LTIP awards are designed to provide long-term incentives for the EMT to deliver long-term shareholder returns. Under the plan, participants were 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.

The January 2019 LTIP awards vested on 1 January 2021, while the May 2019 awards will vest on 2 January 2022 subject to meeting the performance criteria set out in the table below and continued employment with the Company. The Options are exercisable at nil cost by the participants.

Performance targets	January 2019 LTIPs	May 2019 LTIPs
Below the Median	None of the award will vest	None of the award will vest
Median (50th percentile)	30% of the maximum award will vest	30% of the maximum award will vest
Between Median and Upper Quartile	Straight-Line basis between these points	Straight-Line basis between these points
Upper Quartile (75%) and above	100% of the maximum award will vest	100% of the maximum award will vest

The total fair value at grant date of the 2019 LTIP awards was $0.9 million and this will be expensed over the vesting period with the full charge pro-rated over the vesting period. The 2019 LTIP Awards are 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 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 2019 LTIP awards granted during the period ended 31 December 2019 included:

	January 2019 LTIPs	May 2019 LTIPs
Grant Dates	2 January 2019	9 May 2019
Share price at grant dates	GBp16.77	GBp14.66
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

2020 LTIPs

On 25 June 2020 and 30 October 2020 Options over a total of 3,815,856 ordinary shares and 1,000,000 ordinary shares respectively were granted under the LTIP in accordance with the policy announced to the market on 25 August 2017 to members of the EMT in respect of the performance of the Company in the financial year ended 31 December 2019. The LTIP awards are designed to provide long-term incentives for the EMT to deliver long-term shareholder returns. Under the plan, participants were 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.

These LTIP awards will vest on 2 January 2023, subject to meeting the performance criteria set and continued employment in the Company. The Options are exercisable at nil cost by the participants.

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

TSR is the increase in share price plus the value of any dividends paid over a period of time and captures the full return shareholders see on an investment. Relative TSR is the comparison of these returns against peer companies over a set period of time. For Trinity, the performance will be assessed over a three year period.

The Relative TSR ranking will be determined by calculating the three month average TSR to the end of the performance period and dividing this by the three month average TSR to the beginning of the performance period for all companies in the agreed comparator group. Companies will be ranked on this basis with the highest performing company ranked first. The share price used to calculate the start of the TSR calculation in respect of these awards is based on the three-month average TSR leading into 31 December 2019, being 9.683p.

The amount of the award which will vest at the end of the three year period is based on performance against a comparator group. Threshold vesting occurs when Trinity is ranked at median against the comparator group and maximum vesting occurs when Trinity is ranked at upper quartile (or above). The table below shows the level of vesting at threshold and maximum:

Vesting occurs on a straight line basis between threshold and maximum.

Performance	**Vesting**
Below the Median	None of the award will vest
Median (50^{th} 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

The total fair value at grant date of the 2020 LTIP awards 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 2020 LTIP awards granted during the period included:

	June 2020 LTIPs	**October 2020 LTIPs**
Grant Dates	25 June 2020	30 October 2020
Share price at grant dates	GBP7.90	GBP7.70
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

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

	2020 Average exercise price per Share Option	**Number of Options**	**2019 Average exercise price per Share Option**	**Number of Options**
At 1 January	GBP 0.00	31,789,818	GBP 0.00	25,415,998
Forfeited	GBP 0.00	(1,720,592)	GBP 0.00	(283,004)
Granted1	GBP 0.00	6,238,817	GBP 0.00	6,656,824
Exercised2	GBP 0.00	(4,745,056)	GBP 0.00	--
At 31 December	GBP 0.00	31,562,987	GBP 0.00	31,789,818

1 Weighted average fair value of LTIPs granted GBP 0.07

2 Weighted average share price at the date of exercise GBP 0.08

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

Grant-Vest	**Expiry date**	**Exercise price**	**2020**	**2019**
24/8/2017 – 30/6/2022	24/8/2027	GBP 0.00	21,030,319	25,415,998
2/1/2019 – 1/1/2021	1/1/2023	GBP 0.00	2,525,101	2,824,000
9/5/2019 – 2/1/2022	2/1/2024	GBP 0.00	3,191,712	3,549,820

25/6/2020 – 2/1/2023	2/1/2025	GBP 0.00	4,815,856	--

23 Merger and Reverse Acquisition Reserves

	Reverse Acquisition Reserve $'000	Merger Reserve $'000	Total $'000
At 1 January 2020	(89,268)	75,467	(13,801)
Movement	--	--	--
Translation differences	--	--	--
At 31 December 2020	**(89,268)**	**75,467**	**(13,801)**
At 1 January 2019	(89,268)	75,467	(13,801)
Movement	--	--	--
Translation differences	--	--	--
At 31 December 2019	**(89,268)**	**75,467**	**(13,801)**

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.

24 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, and FX Gain/(Loss).

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:

	2020 $'000	2019 $'000
Operating Profit Before SPT, PT, Impairment and Exceptional Items	2,965	10,271
DD&A (note 11 – 13)	8,174	9,772
ILFA (note 18)	252	608
SOE (note 22)	963	1,038
FX (loss)/gain	(7)	76
Adjusted EBITDA	12,347	21,765
	'000	**'000**
Weighted average ordinary shares outstanding - basic	386,233	384,049
Weighted average ordinary shares outstanding - diluted	417,796	415,840
	$	**$**
Adjusted EBITDA per share – basic (note 9)	0.032	0.057
Adjusted EBITDA per share - diluted (note 9)	0.030	0.052

Adjusted EBITDA after the impact of SPT & PT is calculated as follows:

	2020 $'000	2019 $'000
Adjusted EBITDA	12,347	21,765
SPT	153	(7,413)
PT	(532)	(492)

Adjusted EBITDA After SPT & PT	11,968	13,860
	'000	**'000**
Weighted average ordinary shares outstanding - basic	386,233	384,049
Weighted average ordinary shares outstanding - diluted	417,796	415,840
	$	**$**
Adjusted EBITDA After SPT & PT per share - basic	0.031	0.036
Adjusted EBITDA After SPT & PT per share - diluted	0.029	0.033

25 Provision for Other Liabilities

(a) Non-current:

	Decommissioning provision $'000
Year ended 31 December 2020	
Opening amount as at 1 January 2020	44,330
Unwinding of discount (Note 7)	1,221
Revision to estimates	(152)
Translation differences	6
Closing balance at 31 December 2020	**45,405**
Year ended 31 December 2019	
Opening amount as at 1 January 2019	41,802
Unwinding of discount (Note 7)	1,198
Increase in provision for new wells	755
Revision to estimates	380
Decommissioning contribution	195
Closing balance at 31 December 2019	**44,330**

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 – 2.00% (2019: 2.00%)
b. Risk free rate – 2.42% - 3.17% (2019: 2.13% - 3.07%)
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.

(b) Current:

	Litigation claims $'000	Closure of Pits $'000	Total $'000
Year ended 31 December 2020			
Opening amount as at 1 January 2020	46	472	518
Decrease in provision	--	(2)	(2)
Closing balance at 31 December 2020	**46**	**470**	**516**
Year ended 31 December 2019			
Opening amount as at 1 January 2019	115	232	347
Decrease in provision	(69)	--	(69)
Increase in provision	--	240	240
Closing balance at 31 December 2019	**46**	**472**	**518**

Litigation claims

In 2020 there were no litigation settlements.

Closure of Pits

In 2020 there was a decrease in the provision of $0.0 million relating to the revision to remedy and closure of pits associated with drilling new onshore wells. It is an environmental regulatory requirement set by the EMA that all open drill pits for onshore drilling must be closed after sufficient testing has deemed it safe to close the pit. Testing period can last up to or over a year depending on the testing criteria.

26 Trade and Other Payables

	Group		Company	
Current	**2020 $'000**	**2019 $'000**	**2020 $'000**	**2019 $'000**
Trade payables	2,024	2,123	130	87
Accruals	3,793	5,039	351	421
Other payables	471	619	--	--
SPT & PT	1,515	2,605	--	--
	7,803	**10,386**	**481**	**508**

27 Bank overdraft

	31 December 2020 $'000	31 December 2019 $'000
Bank Overdraft	2,700	--
	2,700	**--**

During the year, an on demand operating (overdraft) line of $2.7 million was entered 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 6.30 % per annum, effective rate 4.95%
- Repayment: Upon demand at CIBC's discretion
- Debenture: Floating charge debenture over inventory and Trade Receivables only
- Covenant: Current Ratio not less than 1.25:1

On 2 April 2020 the Company drew down the $2.7 million in full.

28 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	
	2020	**2019**
	$'000	**$'000**
Company subsidiaries:		
Trinity Exploration and Production Services	--	14
Trinity Exploration & Production (UK) Limited	10	4
Trinity Exploration and Production (Galeota) Limited	26	120
Bayfield Energy Limited	61	29
Oilbelt Services Limited	170	--
Trinity Exploration and Production (Trinidad and Tobago) Limited	--	4
Galeota Oilfield Services Limited	3	3
Trinity Exploration and Production Services Limited (UK) Limited	899	--
	1,169	**174**

(b) Transfer of funds to related parties

	Company	
	2020	**2019**
	$'000	**$'000**
Company subsidiaries:		
Trinity Exploration and Production Services	(473)	--
Oilbelt Services Limited	--	(338)
Trinity Exploration and Production Services Limited (UK) Limited	--	(2,744)
	(473)	**(3,082)**

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	
	2020	**2019**
	$'000	**$'000**
Salaries and short-term employee benefits	1,219	1,305
Post-employment benefits	26	41
Share-based payment expense[1] (Note 22)	469	697
	1,714	**2,043**

1 During 2020 LTIPs with a market value of $0.4 million were exercised by Key Management, refer to Directors remuneration report.

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

	Company	
	2020	2019
	$'000	$'000
Receivables from related parties:		
Trinity Exploration and Production Services Limited	408	881
Trinity Exploration & Production (UK) Limited	28	18
Trinity Exploration and Production (Galeota) Limited	159	133
Bayfield Energy Limited	104	43
Oilbelt Services Limited	1,029	859
Galeota Oilfield Services Limited	4	4
Trinity Exploration and Production (Trinidad and Tobago) Limited	414	411
Trinity Exploration and Production Services (UK) Limited	2,272	1,373
Total intercompany receivables (Note 18)	**4,418**	**3,722**
Less: provision for impairment of intercompany receivables	(100)	(91)
Closing intercompany receivables (Note 18)	**4,318**	**3,631**

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 (2019: 0.1 million).

29 Taxation Payable

	Group	
	2020	2019
	$'000	$'000
Taxation payable		
PPT	144	--
UL	58	80
	202	80

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.

30 Financial Instruments by Category

At 31 December 2020 and 2019, the Group held the following financial assets at amortised cost:

	Group		Company	
	2020	2019	2020	2019
	$'000	$'000	$'000	$'000
Trade and other receivables – current*	3,910	5,546	150	-
Abandonment fund – non current	3,490	3,378	--	--
Intercompany	--	--	4,318	3,631
Cash and Cash equivalents	20,237	13,810	4,317	5,286
	27,637	**22,734**	**8,785**	**8.917**

Note (*): Excludes prepayments and VAT recoverable

At 31 December 2020 and 2019, the Group held the following financial liabilities at amortised cost:

	Group		Company	
	2020	2019	2020	2019
	$'000	$'000	$'000	$'000
Accounts payable and accruals	7,803	10,386	481	508
Bank overdraft	2,700	--	--	--
	10,503	**10,386**	**481**	**508**

At 31 December 2020 and 2019, the Group held the following financial asset at fair value through profit or loss:

Group	Company

	2020 $'000	2019 $'000	2020 $'000	2019 $'000
Derivative financial instrument	266	85	266	85
	266	**85**	**266**	**85**

31 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 25: Provision for other liabilities.

b) Contingent Liabilities

i) The East Coast Galeota, West Coast Point Ligoure, Guapo Bay & Brighton Marine Outer ("PGB") licences and the Farm-Out Agreement for the Tabaquite Block (held by Coastline International Inc.) has expired. There may be additional liabilities and commitments arising when a new agreement is finalised, but these cannot be presently quantified until a new agreement is available.

ii) Parent Company Guarantee. A Letter of Guarantee was 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. The guarantee shall be reduced at the end of the twelve month period contingent upon specific clause within the Letter of Guarantee. The clause implied that 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. The PGB licence has expired (see note 31(b)(i)).

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 financial statements.

iv) The Group's Lease Operatorship Assets ("LOA") for WD 5/6, WD 2, WD 13 and WD 14 blocks expired on 31 December 2020, and are in final stages of being renewed with Heritage as of the date of this report and following their renewal a new performance bond will be put in place.

32 Employee Costs

	Group		Company	
Employee costs for the Group during the year	**2020 $'000**	**2019 $'000**	**2020 $'000**	**2019 $'000**
Wages and salaries	6,266	6,393	910	910
Other pension costs	358	342	--	--
Share based payment expense (Note 22)	963	1,038	248	221
	7,662	**7,773**	**1,158**	**1,131**

Average monthly number of people (including Executive and Non-Executive Directors') employed by the Group	**2020 number**	**2019 number**	**2020 number**	**2019 number**
Executive and Non-Executive Directors	6	6	6	6
Administrative staff	85	78	--	--
Operational staff	131	130	--	--
	222	**214**	**6**	**6**

33 Restatement

During 2020, a presentation error was identified in the prior year Cashflow Statement whereby the Cashflow from investing activities included non-cash accruals and these were not adjusted from the working capital movement (Trade and other payables). As a result, the cash inflow from operations and cashflow outflow from investing activities were overstated in the prior year financial statements by equivalent amounts. To correct the error, a reclassification was done as at 31 December 2019, resulting in a $1.2 million decrease in net cash inflows from operations and a $1.2 million decrease in net cash outflows from investing activities.

There is no profit or net asset impact as a result of the prior year restatement.

The adjustment is reflected in the statement below:

	2019 $'000 As previously reported	Impact of Prior period Adjustment $'000	2019 $'000 Restated
Operating Activities	13,113		13,113
Changes In Working Capital			
Inventories	(1,454)		(1,454)
Trade and other receivables	3,638		3,638
Trade and other payables	1,797	(1,192)	605
	17,094	(1,192)	15,902
Tax Paid	(316)		(316)
Investing Activities			
Purchase of Exploration and Evaluation ("E&E") assets	(476)	56	(420)
Purchase of computer software	(99)		(99)
Purchase of property, plant and equipment	(12,156)	1,136	(11,020)
Net Cash Outflow From Investing Activities	(12,731)	1,192	(11,539)
Net Cash (Outflow)/Inflow From Financing Activities	(438)		(438)
Increase/(Decrease) in Cash and Cash Equivalents	3,609		3,609
At end of year	13,810		13,810

34 Events after the Reporting Year

1. Derivative Financial Instruments

In addition to the crude oil derivatives put in place during 2020, the Company has put in place a number of crude oil derivative financial instruments post the year end to protect a portion of its revenue against fluctuation in oil prices. The crude oil derivative financial instruments currently in place are as follows:

Type of Derivatives	Index	Sell Put USD/bbl	Buy Put USD/bbl	Sell Call USD/bbl	Production Monthly Barrels	Effective Date	Expiry Date	Execution Date	Premium USD MM
Put Spread	WTI	20.0	30.0	-	15,000	01-Jan-21	31-Dec-21	21-Jul-20	0.36
Put Spread	WTI	20.0	30.0	-	15,000	01-Jan-21	31-Dec-21	17-Nov-20	0.25
Put Spread	Dated Brent	32.5	42.5	-	15,000	01-Jan-21	30-Jun-21	25-Nov-20	0.19
2-Way Cost Collar	ICE Brent		42.5	64.4	15,000	01-Jul-21	31-Dec-21	5-Feb-21	-
3-Way Cost Collar	ICE Brent	50.0	60.0	66.9	10,000	01-Jan-22	30-Jun-22	4-Mar-21	-

2. CIBC overdraft facility

Trinity fully drew down its $2.7 million overdraft credit facility with CIBC effective 2 April 2020 as part of its strategy of maximising available cash during the Covid-19 pandemic, and this remains outstanding. The facility was increased on 5 January 2021 by $2.3 million to a total of $5.0 million. This additional portion remains fully undrawn to date.

The facility is a revolving overdraft credit available to Trinity which is repayable upon demand to CIBC. Interest is payable monthly at an interest rate equivalent to US Prime (currently 9%) minus 4.05% per annum, with present effective rate of 4.95% and subject to a floor rate of 3.95%.

3. Fiscal Reforms

The revised threshold for Supplemental Petroleum Tax ("SPT") for small onshore producers has now been implemented via The Finance Act No. 30 of 2020 which came into effect on 1 January 2021. As a result, the threshold at which SPT would be due for individual producers producing less than 2,000 barrels of crude oil per day has now increased from $50.0 /bbl to $75.0/bbl for the financial years 2021 and 2022.

Trinity expects to be exempt from SPT across all of its onshore licences below $75.0/bbl, which will have a significant positive impact on future cash flows. Based on current onshore production levels, Trinity estimates that SPT of c. $3.5 million per annum or more would previously have been payable if realisations were above $50.01/bbl (although this could be partially mitigated by the Investment Tax Credit ("ITC") shelter). The confirmation of these reforms therefore represents a considerable boost to potential cash generation from Trinity's onshore licences should realisations average above $50.01/bbl for any calendar quarter during 2021 and 2022.

4. Acquisition of onshore block PS-4

On 4 May 2021, Trinity announced that it had entered into a sale and purchase agreement with Moonsie Oil Company Limited to acquire an operated 100% interest in the PS-4 onshore block for a headline cash consideration of $3.5 million, to be funded from the Group's existing cash resources. The Group anticipates that the transaction will complete towards the end of Q2 2021.