Company Registration No. 10647966 (England and Wales)

NEPTUNE ENERGY GROUP HOLDINGS LIMITED

CONSOLIDATED FINANCIAL STATEMENTS

FOR THE YEAR ENDED 31 DECEMBER 2022

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General information

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Company number and type

Neptune Energy Group Holdings Limited is a private limited company, limited by shares and registered in England and Wales. (No. 10647966)

Strategic Report

The Directors present their strategic report for Neptune Energy Group Holdings Limited ('the Company') its consolidated subsidiaries and equity-accounted investments ('Neptune' or 'Neptune Energy', 'Group', 'we', 'us', and 'our') for the year ended 31 December 2022.

Principal activities

Through subsidiary companies acquired in February 2018 Neptune is an independent oil and gas exploration and production ("E&P") company with a regional focus on Europe, North Africa and Asia Pacific. The company's aim is to build an E&P company with material scale and operating capability. The Company provides management and technical services to the Neptune group. The parent company is Neptune Energy Group Midco Ltd and ultimate parent company is Neptune Energy Group Limited.

REVIEW OF THE BUSINESS

GROUP OVERVIEW

Russia's invasion of Ukraine, coupled with long-term structural underinvestment in energy infrastructure, combined to increase commodity price volatility in 2022, resulting in significantly higher energy prices across western energy markets. While oil prices fell towards the end of the year, gas prices, while also falling, remained above historical averages and look set to remain volatile in 2023, particularly in Europe.

Against this backdrop, Neptune delivered a strong operational and financial performance in 2022. Our performance reflects a focus on operational improvements and is the result of a significant investment programme totalling more than $4 billion since 2018. This capital programme has delivered five development projects, with two more expected to come onstream during 2023, increasing potential production to around 180 kboepd by the end of the year.

Neptune has been transformed since our acquisition of ENGIE E&P International S.A. in 2018, with material improvements in safety, operations and our balance sheet. Neptune now has a greater proportion of developed reserves, is better capitalised and has developed significant new growth opportunities that will deliver both energy security and support the energy transition.

In 2022, Neptune delivered a strong financial performance, with EBITDAX of $3.9 billion and post-tax operating cash flow of $2.4 billion, enabling dividends and capital distributions by our ultimate parent company totalling $1.1 billion in the period. Our balance sheet has further strengthened with lower net debt and leverage and our credit ratings from S&P (BB stable), Moody's (Ba2 stable) and Fitch (BB+ stable) also improved. We continue to work with our bank syndicate with a view to refinancing our RBL facility in the first half of 2023.

Our production in 2022 was higher than in 2021 as we benefitted from the resumption of operations at Snøhvit (Norway), a full year of production from Duva (Norway) and continued strong production efficiency. However, the extension to the outage at the joint venture-operated Touat gas plant (Algeria) restricted production growth and, as a result, Group production for the full year averaged 135.0 kboepd, at the lower end of guidance. Production including production-equivalent insurance income was 135.6 kboepd.

With a full-year contribution from Snøhvit, the scheduled restart of Touat and the ramp-up of production from our new projects at Njord (Norway), Fenja (Norway) and Seagull (UK), we expect production in 2023 to average 150-165 kboepd and to end the year at around 180 kboepd.

Despite a high level of operational activity in 2022, we maintained a strong environmental performance, with carbon intensity from our operated portfolio remaining modest, at 6.5 kg CO_2/boe, 60% lower than the International Association of Oil & Gas Producers industry average. Our methane intensity also remained low at 0.02%, against an industry average of 0.17%.

Strategic Report (continued)

We continued to make good progress with our ESG strategy, developing a new three-year roadmap to 2025. Our progress was recognised with industry leading ESG ratings from both Sustainalytics (23.4) and EcoVadis (gold medal).

Our roadmap includes actions to meet our 2030 climate targets, including our ambition to store more carbon than is emitted from our operations and the use of our sold products by 2030. We are making good progress on these plans and are working on a pipeline of around 15 opportunities across the portfolio, mainly in CCS.

In 2022, we finalised a cooperation agreement with our partners at our L10 CCS project and continued to mature the project towards concept selection. In the second half of the year, we announced a partnership with Horisont Energi to develop the Errai CCS project in Norway. We also submitted CO_2 storage licence applications in Norway and the UK.

We continue to pursue opportunities to lower the carbon intensity of our operations and in December 2022 submitted plans for the electrification of Snøhvit and Njord. The Gudrun electrification project is due to start operation in mid-2023. By 2028, 100% of our production in Norway is expected to be from hubs that have been fully or partially electrified.

At the end of 2022, we had 2P reserves of 552 mmboe and a reserves to production ratio of 11 years. The decrease in reserves reflects production in the year and the disposal of non-core assets in Norway. Our contingent resources increased to 468 mmboe, due mainly to recent discoveries and licence acquisitions in Norway and the Netherlands, providing us with additional growth opportunities.

Neptune is well positioned for further growth as we enter 2023, with a geographically diverse, long life, lower cost and lower carbon portfolio. Our growth plans are supported by strong operating cash flow and a strong balance sheet. We retain a disciplined approach to capital allocation and will invest selectively in new opportunities, including through M&A, where it makes strategic sense and delivers strong returns and near-term cash flow generation.

Strategic Report (continued)

Operational performance

Health and safety

We saw an improvement in the number of health and safety events in 2022. During the year we had no tier 1 process safety events and no serious injuries. Our process safety event rate (PSER) improved to 1.13 in 2022 from 1.28 in 2021, but remained higher than our target of 1.04. In 2022, we changed our PSER to be a weighted metric, with more severe incidents having a higher weighting. We have restated 2021 performance accordingly.

In 2022, our total recordable injury rate (TRIR) was 1.94, an improvement from 2.07 in 2021, but remained higher than our target of 1.67, largely as a result of minor incidents in the category of slips, trips and falls. Our lost time injury frequency (LTIF) rate was also higher than our target of 0.60 per million hours worked at 0.97, again driven by slips, trips and falls, but improved compared with 1.09 in 2021. These figures include co-operated joint venture activities and are calculated for the 12-month period ended 31 December 2022.

Improvements in 2022 were achieved by delivering safety training and conducting audits of our systems and activities. We increased our focus on psychological safety, to build on our speak up culture. We also held our first global HSE day in April 2022, bringing together some of our youngest team members, our HSE team and the Neptune Executive Team to take a fresh look at safety leadership and how to create a culture of psychological safety within the workplace, with projects initiated being tracked to completion.

In 2023, we will roll out a human factors training programme across the organisation, highlighting 12 key elements that contribute to the majority of safety events. We aim to achieve a reduction in safety events through training and developing new checklists of safeguards that must be in place before work commences. Investigating and understanding the decisions and actions that led to a near miss will also help us prevent more serious incidents from occurring.

Environment, social and governance (ESG)

During 2022, we made good progress delivering our ESG strategy, which is key to our ability to create value for all our stakeholders. Our strong ESG performance and disclosure was recognised by Sustainalytics, which named us an ESG Industry Top Rated company in 2022, out of more than 250 oil and gas producers. We were also awarded a Gold Medal by EcoVadis, which ranked us in the top 5% of 95,000 global organisations.

As we reached the final year of our initial three-year ESG roadmap in 2022, we updated our ESG strategy and roadmap, building on the solid progress made to date. The strategy and roadmap, which are aligned with the UN Sustainable Development Goals, set out our near-term plans to 2025, complementing our 2030 ambitions. It includes actions on emissions and environmental management, safety, diversity and inclusion, human rights, socio-economic impact, human rights and ethical conduct.

We are on track to meet our ambitious carbon and methane intensity targets of 6 kg CO_2/boe and net zero methane emissions by 2030. In 2022, our carbon intensity remained stable at 6.5 kg CO_2/boe. This is significantly below the industry average of 16 kg CO_2/boe. Progress against our carbon intensity target is a factor in determining bonuses for the Executive Team and employees.

Methane intensity from our managed production was flat at 0.02% (2021: 0.02%), again far lower than the industry average of 0.17%. We expect it to remain at similarly low levels in 2023. We were awarded Gold Standard status for our reporting to the Oil and Gas Methane Partnership 2.0 framework in 2022. This achievement recognised our robust plans to report and reduce methane emissions for our operated and non-operated assets.

We progressed our plans to reduce operational emissions in 2022. In Germany, we began sourcing electricity for our assets from renewable energy, saving around 11,000 tonnes of CO_2 emissions per year. In the UK, we assessed emission reduction opportunities at our Cygnus field and selected several opportunities for further evaluation. These include replacing diesel with biofuels for power generation, measures to reduce flaring and moving gas compression

Strategic Report (continued)

onshore. We will evaluate the technical and economic viability of these initiatives in 2023. If implemented, they could reduce emissions by an estimated 30,000 tonnes of CO_2 a year by 2028, equivalent to more than a third of our projected UK Scope 1 emissions for that year. We are sharing the learnings from this assessment across the organisation and will develop emission reduction plans for our remaining operated countries in 2023.

In November 2022 we launched an ambitious goal to achieve gender parity. We are targeting equal gender representation in all our external hires and internal promotions, and this applies across our bands, functions and locations. This target is part of our equality, diversity and inclusion (ED&I) charter, which outlines the actions we are taking to advance a diverse and inclusive culture.
During 2022, we also established our Women in Neptune and LGBTQ+ affinity groups, with both groups led by executive sponsors. We held our second global ED&I month in November 2022, running a range of activities to showcase and promote ED&I. A total of 587 people participated in the sessions (2021: 352).

We conduct an annual employee engagement survey to find out what our employees think about Neptune. A total of 78% of employees participated in 2022 (2021: 76%). Our overall engagement score increased to 80% (2021: 73%), our highest rate to date. The survey found that our people are motivated to contribute and that they feel valued. Scores on being treated fairly and with respect increased, as did our people's understanding of our strategy and direction. Safety scores remained strong. While scores on training increased to 67% (2021: 57%), there is still more work for us to do and we will continue to work with employees to address this in 2023.

We have been working to align with the UN Guiding Principles on Business and Human Rights and progressed our human rights roadmap in 2022, using the outcomes from the independent human rights assessment that we commissioned in 2021. Following the introduction of our new third-party screening platform, we have a more rigorous process in place for assessing potential third parties before engaging with them. To build greater awareness within our own business, we ran training sessions on human rights including modern slavery awareness.

We continue to make a significant economic contribution to the countries in which we operate. Our work helps create jobs, supports supply chains and contributes to national tax reserves. In 2022, we supported an estimated $4.8 billion gross value added contribution to the gross domestic product of our European countries (Germany, the Netherlands, Norway and the UK), and some 9,251 jobs, directly and through our supply chain. We also assessed our economic impact in Indonesia, where we supported an estimated $510 million gross value added contribution to the gross domestic product of Indonesia, and some 7,856 jobs, principally through the supply chain in the wholesale/retail trade, mining services and transportation sectors.

Metrics and targets

TCFD recommendation: Disclose the metrics and targets used to assess and manage relevant climate-related risks and opportunities where such information is material.

We set out our key metrics and targets to assess and manage climate-related risks and opportunities below. Progress against our carbon intensity target is a factor (6.7% weighting in 2022) in determining bonuses for the Executive Team and employees.

We recognise that the majority of emissions from oil and gas products come from their end use, which is why we report our Scope 3 emissions from the use of our sold products. As a purely upstream company we have less opportunity to reduce these emissions but have included this metric to provide additional transparency on our product footprint.

In addition to reporting our direct Scope 1 emissions on an operational control basis (see below), we have calculated our direct Scope 1 emissions on an equity share basis as 774,045 tonnes of CO_2e. These emissions are based on 2021 data, due to the availability of partner data within our reporting period.

Strategic Report (continued)

GHG and energy use performance table[a]

	2022	2021	2020
Total Scope 1 emissions (direct) (t CO_2e)[b]	589,267	570,084	512,113
UK Scope 1 emissions (direct) (t CO_2e)[b]	80,263	38,237	32,396
Total Scope 2 emissions (indirect) – location based (t CO_2e)[c]	16,487	17,652	19,451
UK Scope 2 emissions (indirect) – location based (t CO_2e)[c]	291	286	169
Total Scope 2 emissions (indirect) – market based (t CO_2)[c]	130,250	132,519	–
Total Scope 1 and 2 emissions (t CO_2e)[cd]	605,754	587,736	531,564
UK Scope 1 and 2 emissions (t CO_2e)[cd]	80,554	38,523	32,565
Total carbon intensity (kg CO_2/boe)[e]	6.5	6.4	6.3
UK carbon intensity (kg CO_2/boe)[e]	4.1	1.7	1.3
Total carbon intensity (t CO_2e per kt hydrocarbon production)[f]	52.0	56.3	54.2
UK carbon intensity (t CO_2e per kt hydrocarbon production)[f]	35.3	19.9	10.9
Total methane intensity (%)[g]	0.02	0.02	0.01
Total energy consumption (MWh)[d]	2,689,680	2,481,141	2,538,760
UK energy consumption (MWh)[d]	279,845	103,199	104,331
Total reductions in energy use as a result of energy efficiency initiatives (MWh)	2,249	247	1,581
Total flaring (GJ million)	0.41	0.48	0.39
Energy use from well testing (GJ million)[h]	48.85	-	-
Total Scope 3 emissions (business travel) (t CO_2e)[i]	1,493	439	843
UK Scope 3 emissions (business travel) (t CO_2e)[i]	763	277	225
Total Scope 3 emissions (use of sold products) (Mte CO_2e)[j]	14.8	13.5	–

a We report our GHG emissions and energy consumption data on an operational control basis, reporting 100% of emissions from activities operated by Neptune Energy. This includes Germany, the Netherlands, Norway and the UK. This table includes disclosure to comply with the Streamlined Energy and Carbon Reporting requirements. Our UK figures include the UK offshore area. Our calculation methodology follows the IPIECA/API/IOGP Petroleum Industry Guidelines for Reporting GHG Emissions. In 2021, we changed our reporting boundary to include emissions from the flaring of our reservoir hydrocarbons during contractor drilling activities. Further information on our methodology is below and in our Basis of Reporting and Assurance of Non-Financial Data at *neptuneenergy.com/esg.*

b This includes CO_2, N_2O and methane emissions from combustion for energy, flare, direct hydrocarbon emissions, company cars, fleet vehicles and exclusive contract logistics from operations we own or control.

Strategic Report (continued)

c This includes emissions from the purchase of electricity. Less than 1% of our Scope 2 emissions is for the purchase of heat, steam and cooling for our own use.
Emissions are calculated using location based grid average emission factors supplied by UK Government GHG Conversion Factors for Greenhouse Gas Company Reporting (Department for Business, Energy & Industrial Strategy, 2021) and for the remaining countries are purchased from the IEA. Scope 2 market based calculations use supplier specific emission factors where supplier specific data in the form of contractual agreements is available. Where this is not available, factors from AIB, using the European Residual Mix, are used. We have restated this metric for 2021 and 2020 on the basis of revised emission factors (previously, we reported totals of 37,758 t CO_2e in 2021 and 43,701 t CO_2e in 2020. For the UK, we reported 861 t CO_2e in 2021 and 478 t CO_2e in 2020). We have restated our total Scope 1 and 2 emissions accordingly.

d Scope 2 emissions for this metric are calculated using the location based method. Our total UK Scope 1 and 2 emissions were 13% of the total emissions from assets under our operational control. Our total UK energy consumption was 10% of the total. All of our emissions in the UK were emitted by entities in our Group incorporated in the UK.

e This includes Scope 1 and 2 emissions related to production/operations. We calculate intensity using wellhead production, in line with the IPIECA/API/IOGP Petroleum Industry Guidelines for Reporting GHG Emissions.

f As per SECR requirements, we are reporting t CO_2e per 1,000 tonnes hydrocarbon production. This includes emissions from production only.

g This metric, which is calculated using Oil and Gas Climate Initiative (OGCI) methodology, refers to methane emissions from our production operations as a percentage of the volume of the total gas exported.

h From 2022, we are including energy use from well testing activities performed by third-party contractors in our total flaring metric. The majority of flaring in 2022 was from well testing activity (non-routine flaring) at the Seagull well in the UK. We optimise the duration of well testing to ensure quality data acquisition while minimising the energy and emissions associated with the flaring of reservoir hydrocarbons. This metric includes energy associated with the emissions from well testing that are reported as part of our Scope 1 emissions.

i This includes car and air travel from our operated countries. Emissions from business travel cars only was 152 t CO_2e.

j This includes emissions related to Neptune's share of sold products for both operated and non-operated assets and is calculated using IPIECA/API/IOGP's final content method.

EY has provided limited independent assurance over all 2022 metrics in the GHG and energy use performance table above. See *neptuneenergy.com/assurance* for EY's assurance statement.

Strategy

Despite volatile energy markets and unstable government fiscal policy, we made good progress delivering our strategy set out at the beginning of 2022 to produce lower carbon energy and develop integrated energy hubs. Since 2018, we have delivered five new projects, progressed two further projects close to completion and are pursuing around 15 lower carbon opportunities.

1. Lower carbon energy production: producing lower carbon gas and oil safely and efficiently

   We continue to target new production opportunities in our key producing regions, while maintaining our gas-weighted portfolio and lower carbon intensity. In December 2022, we brought online the Njord project and in 2023 we expect to bring onstream Fenja and Seagull. Together these projects are expected to contribute 47 kboepd of new production at plateau rates.

   Due to the already lower carbon intensity of our portfolio, we expect to deliver further reductions in carbon emissions through electrification of assets, while improving operating emissions where we see opportunities. With Gjøa (Norway) and Q13a-A (Netherlands) already electrified, and the Gudrun electrification project close to completion, we expect to have around 33 kboepd of our production electrified in 2023.

   Our electrification strategy targets our highest producing assets in areas where it is economic and where the regulatory regime is supportive. In 2022, we sanctioned electrification projects at Njord and Snøhvit and expect these to come online in 2027 and 2028, respectively. We continue to evaluate further electrification opportunities in the UK and the Netherlands as part of our integrated energy hub strategy.

   During 2022, scientists working for the Environmental Defense Fund completed evaluation of methane emissions data gathered from Cygnus in 2021. The report concluded that while the rotary drone methane measurements and emissions reported at the facility were closely aligned, the fixed wing drone measurements showed greater variance. We plan to conduct further studies in the UK and Norway in 2023 so that we can identify an accurate benchmark for measuring total methane emissions and to determine what action we can take to reduce them.

Strategic Report (continued)

Investment in lower carbon energy production will target opportunities close to our core hubs where there is strong alignment with our lower carbon objectives and we can mitigate carbon emissions. We are maturing a number of our pre-development projects towards sanction, mainly in Norway and Indonesia, which will help maintain high production levels in these regions. Our successful exploration programme added further new growth opportunities close to our Gjøa and Njord hubs in 2022.

While the UK, the Netherlands and Germany remain prospective, windfall profit taxes introduced in 2022 make further development opportunities economically challenging. Investment allowances mitigate the impact of higher taxes partially, but any new projects will require higher rates of return to be sanctioned.

2. Integrated energy hubs: utilising existing infrastructure to integrate energy systems

Through utilising and repurposing existing infrastructure, our integrated energy hub strategy provides an excellent opportunity to drive decarbonisation and facilitate CO_2 storage and hydrogen production, using domestic, lower carbon intensive gas or wind power. By extending field life, electrification will become more economic, supporting further decarbonisation.

In 2022, we made good progress expanding our CCS opportunities, particularly in Norway and the UK. In Norway, we announced a new partnership with Horisont Energi to develop the Errai CCS project and have already made good progress identifying an onshore location for intermediate CO_2 storage. At L10 CCS, our most advanced CCS project in the Netherlands, we expect to commence FEED in the first half of 2023. CO_2 storage licence applications are due to be submitted in Norway and the Netherlands during 2023.

In December 2022, we announced the signing of a Memorandum of Understanding with Ørsted and Goal7 to explore powering new integrated energy hubs in the UK North Sea with offshore wind-generated electricity. The companies will initially examine the potential to supply renewable energy from Ørsted's Hornsea offshore windfarm to carbon storage facilities, as well as to oil and gas assets to help decarbonise production.

In Germany, we are pursuing opportunities for lithium extraction from produced water in the Saxony-Anhalt region and geothermal energy production in the Rhine Valley, with discussions ongoing with partners to progress these projects.

Hydrogen could play a significant role in decarbonising energy use. However, we believe that there are technical and economic challenges to overcome before this technology is scalable. Therefore, our approach has been to undertake R&D at PosHYdon to transfer learnings into more commercial-scale projects.

Across the portfolio, we are pursuing around 15 New Energy opportunities. Most of these opportunities are at the pre-development stage and we will be disciplined to allocate capital only to those projects in countries with stable fiscal regimes and that align with our strategy and deliver robust returns.

Production

Group production for 2022 averaged 135 kboepd, higher than in 2021 due mainly to the restart of Snøhvit and a full-year's contribution from Duva, which started up in 2021. Production was at the lower end of our guidance range, as a result of the extended outage at Touat.

The Touat gas processing plant remained shut-in throughout much of 2022 to enable repairs and upgrades to the plant's mercury removal unit. Further issues identified during restart operations in September 2022 revealed a cold box failure, requiring a further period of downtime. Gas exports are due to recommence in April 2023.

In Norway, operations at Snøhvit resumed in June 2022, with production in the second half of the year averaging more than 16 kboepd. Production efficiency at our other fields in Norway was strong as we maintained high production to support energy security in Europe. This included a temporary agreement with the Norwegian authorities to double gas exports from Duva from April 2022.

Strategic Report (continued)

Output in the UK increased slightly in 2022, with higher production efficiency driven by improved blend gas availability and fewer third-party export restrictions. Gas compression commenced in May 2022, supporting production in the second half of the year.

In the Netherlands, production reflected natural decline during the period and our continued focus on operational efficiency, asset integrity and field extensions. Output in Germany was slightly lower as production growth from Adorf was offset by the cessation of gas sales from Altmark. A gas-to-power project commenced at Altmark in May, but at lower equivalent rates.

In Indonesia, production from the Jangkrik and Merakes fields continued to be optimised in 2022 to maintain high utilisation of the Jangkrik FPU. Production in Egypt was lower due to delays to the 2022 drilling programme and an unsuccessful gas well.

Production efficiency at our operated assets was 85% in 2022, improving from 82% in 2021. Taking into consideration planned shutdowns, including activities for our new projects, production efficiency was 90%. Production efficiency at our non-operated and joint venture assets continued to be impacted by the outage at Touat.

We continue to take steps to improve production efficiency across the portfolio and target opportunities where we can best influence performance to deliver value over volume. This includes enhanced production surveillance, predictive maintenance, shutdown optimisation and inventory management.

Group production is expected to increase materially in 2023 due to a full year's contribution from Njord, start-up of our Fenja and Seagull projects and the restart of gas exports from Touat. Output in the UK and Germany is expected to be supported by new wells coming onstream. A recent side-track campaign in Indonesia is expected to help maintain high capacity utilisation at the Jangkrik FPU. Shutdowns are planned at Fram, Gjøa and Gudrun in Norway, the G blocks, L10-A and L5-A in the Netherlands and at Cygnus in the UK.

Projects

We continued to make good progress with our development projects in 2022 and successfully brought onstream the Njord project in December at an initial rate of 8 kboepd net. The Hyme (March) and Bauge (April) tie-backs are due to start-up shortly, with net production from the Njord area expected to increase to plateau rates of around 20 kboepd at the end of the year. Production from Njord will be supported through a development drilling programme, which will continue through 2023 and 2024.

The Neptune-operated Fenja project was also completed in 2022, with start-up deferred until the completion of the Njord host facility and scheduled start-ups of Hyme and Bauge. Fenja is due to commence production in April 2023 at an initial rate of 6 kboepd, before increasing to plateau rates of around 10 kboepd in the fourth quarter of the year.

At our Seagull project, the first development well has been completed successfully and is ready for production. Operations at the second well are ongoing. The remaining two development wells are expected to be drilled in 2023 and brought onstream in 2024. The topside programme made good progress in 2022, with all key modules installed and commissioning under way. The Seagull field is scheduled to start-up in May at an initial rate of 12 kboepd from the first two development wells, before increasing to 17 kboepd in 2024.

Strategic Report (continued)

Reserves

Reserves summary	Proved plus probable reserves (mmboe)
2P reserves at 31 December 2021	**604**
Production	(49)
Revisions, extensions and discoveries	4
Acquisitions and divestments	(7)
2P reserves at 31 December 2022	**552**
Total reserves replacement ratio in 2022	-6%
Total reserves to production ratio	11 years

1. The above are management estimates, the majority of which are independently audited by ERCe.

At the end of 2022, our proved plus probable reserves (2P) were 552 mmboe. Our reserves replacement ratio was negative, reflecting production in the period and the divestment of non-core assets in Norway. Within 2P reserves, higher reserves related to extensions and discoveries and price effects were offset partially by small negative engineering revisions. The proportion of developed 2P reserves has increased to 55% from 50% at the end of 2021. Over a five-year period, from the inception of Neptune, our reserves replacement ratio is 99%. Our 2P reserves to production ratio was 11 years.

Contingent resources

Contingent resources summary	2C resources (mmboe)
2C resources at 31 December 2021	**433**
Revisions, extension and discoveries	12
Acquisitions and divestments	23
2C resources at 31 December 2022	**468**

1. The above are management estimates, the majority of which are independently audited by ERCe in 2020.

At the end of 2022, our best estimate of contingent resources (2C) was 468 mmboe. The increase is due mainly to recent discoveries and licence acquisitions in Norway and the Netherlands. Since 2019, our exploration programme has added 102 mmboe net 2C resources from 11 commercial discoveries in Norway, the UK and the Netherlands.

Exploration and appraisal

Our exploration programme continued to deliver positive results in 2022, with new discoveries announced in Norway and the Netherlands. The discoveries, located close to existing infrastructure, provide fast-track development potential and add significant value to our hubs in these areas. At the end of 2022, we concluded appraisal drilling at the Isabella discovery in the UK and are evaluating the results.

In Norway, we made discoveries at the Hamlet and Ofelia prospects, with both located within tie-back distance to the Neptune-operated Gjøa platform. With further wells planned in the Gjøa area, development planning for the Hamlet discovery has been paused as we evaluate how to optimise development of resources within the greater Gjøa area. In December, we announced the Calypso discovery, which is located close to the Draugen field and Njord A platform.

In the Netherlands, we encountered hydrocarbons at the Clover, Pollux and N04-04 wells. The Clover gas discovery is located close to Neptune-operated infrastructure and has further follow-on potential, which we are maturing for future drilling.

Strategic Report (continued)

2022 drilling results

Country	Licence	Well	Working interest	Outcome
Norway	PL929	Ofelia	40%	Oil & gas discovery
Norway	PL153	Hamlet	30%	Oil & gas discovery
Norway	PL938	Calypso	30%	Oil & gas discovery
Netherlands	F5	F5-A	28.33%	Dry
Netherlands	F3c	Pollux	15%	Oil & gas discovery
Netherlands	L11d	Clover	20%	Gas discovery
Netherlands	N4-A	N04-04	3.2%	Gas discovery
UK	P1820	Isabella	50%	Oil & gas discovery
Egypt	AESW	Assil C106	100%	Dry

Notes: Includes exploration and appraisal drilling.

In 2023, we plan to drill nine new exploration and appraisal wells, including key wells in Norway, Indonesia and Egypt. We also expect to progress evaluation of the Isabella appraisal results, as we assess commerciality of the reservoir.

In Norway we are planning to drill four wells, including appraisal of the Ofelia discovery and an exploration well targeting the Cerisa prospect, which could add further resources within the Gjøa area. Non-operated wells are planned to target the Eirik and Mulder prospects.

Two further wells are planned in the Netherlands, including an appraisal well at the recently awarded Rhone gas field and an exploration well targeting the Maple prospect. The Rhone gas field is located close to our L10 hub, so could provide a near-term development opportunity.

In Egypt, we expect to drill the Yakoot prospect at the start of the third quarter. This is the first Neptune-operated well in the North West El Amal Concession and follows the acquisition of advanced 3D seismic in 2020. We have identified a number of prospects and leads within the licence area. In the Alam El Shawish West Concession, we plan to drill the Assil C104 prospect.

In Indonesia, the Geng North exploration well is scheduled to commence drilling in mid-2023, with the well targeting a large multi-Tcf gas prospect. A successful well result at Geng North could create a significant new growth opportunity for Neptune.

Our exploration strategy is focused on lower risk, value-creating opportunities close to existing infrastructure, preferably as operator. This approach has delivered positive results, with 14 discoveries since 2019 and a success rate of 56%. Adding additional reserves close to existing facilities can extend the life of our hubs, supporting our electrification and integrated energy hub strategy. Recent licence awards in Norway and the Netherlands strengthen our position in these areas.

Strategic Report (continued)

2023 drilling programme

Country	Licence	Well	Working interest	Type
Norway	PL929	Ofelia	40%	Appraisal
Norway	PL636	Cerisa	30%	Exploration
Norway	PL817	Eirik	30%	Exploration
Norway	PL090	Mulder	15%	Exploration
Netherlands	L7	Rhone	60%	Appraisal
Netherlands	E15c	Maple	30%	Exploration
Indonesia	North Ganal	Geng North	40.48%	Exploration
Egypt	AESW	Assil C104	25%	Exploration
Egypt	NWEA	Yakoot	100%	Exploration

Notes: Drilling schedule subject to change.

Financial performance

Neptune delivered a strong financial performance in 2022, with EBITDAX of $3.9 billion and post-tax operating cash flow of $2.4 billion materially higher than in 2021. Our financial performance was supported by stronger commodity prices, along with higher production and continued good cost control.

During 2022, our post-hedge gas realisation averaged $16.0 per mmbtu, 68% higher than in 2021, as a reduction in supplies of Russian gas into Europe increased competition for LNG and raised fears of potential energy shortages during the 2022 winter period. Post-hedge oil realisations increased by 47% to $96.2 per bbl and post-hedge LNG realisations increased by 129% to $17.3 per mmbtu. Our average post-hedge realisation increased by 70% to $94.0 per boe.

Towards the end of 2022, gas prices declined as supply concerns eased and storage levels remained above seasonal averages due to higher winter temperatures and softer demand. While oil and gas prices are now trading well below levels from a year earlier, we expect prices to remain volatile in the near term as markets adjust to structural changes and macroeconomic events.

To protect cash flows, we have continued to manage our hedging positions, while maintaining appropriate exposure to the upside. As of 31 December 2022, our post-tax hedge ratio was 45% for 2023. We remain unhedged for 2024. We have successfully increased the weighted floor price of our gas hedges to $8.4/mmbtu.

Operating costs in 2022 increased slightly to $12.3 per boe, reflecting higher transportation, fuel costs, royalties and CO_2 emissions taxes in Europe. G&A costs were stable at $78.6 million. Despite inflationary pressures in the supply chain, we remain focused on limiting cost increases in 2023, through inventory management and longer-term sourcing.

Our exploration expense in 2022 was $32.7 million, including $7.2 million for unsuccessful exploration and $25.5 million for geological and geophysical studies.

Equity-accounted entities contributed profits of $24.5 million, compared with $61.1 million in 2021, due to the outage at Touat (Algeria).

Our tax charge in 2022 more than doubled to $2.2 billion, representing an effective tax rate of 70%. The higher level of tax was due to the increase in pre-tax profit, along with the introduction of windfall taxes in the UK, the Netherlands and Germany. Cash taxes paid in 2022 were $1.2 billion, compared with a $57.6 million net cash refund in 2021.

During 2022 we continued to make significant investment in our assets, predominantly at Njord and Fenja, in Norway, and Seagull in the UK. Adjusted development capex, which includes our share of capex at Touat, was $537.2 million, down from

Strategic Report (continued)

$635.8 million in 2021, reflecting projects brought onstream in the previous period. In addition, we invested a further $135.7 million in exploration and pre-development activities, with the lower annual spend reflecting our focused exploration strategy targeting near field and lower risk growth opportunities. Decommissioning expenditure was $29.1 million in 2022.

With strong post-tax operating cash flows and slightly lower levels of investment, we increased free cash flow to $1.7 billion in 2022 from $862.7 million in 2021. This enabled dividends and capital distributions by Neptune Energy Group Limited totalling $1.1 billion and a $413.1 million reduction in net debt (RBL definition) to $1.7 billion at the end of 2022. The increase in 12-month rolling EBITDAX and lower net debt resulted in a decline in our leverage ratio to 0.44 times in 2022 from 1.00 times in 2021.

At 31 December 2022, headroom under the RBL of $995 million, together with cash of $234.1 million, provided available liquidity of $1.2 billion at year end. We have engaged with the bank syndicate and some preliminary work has been conducted, with the intention of completing a refinancing of our RBL facility in the first half of 2023.

During 2022, Moody's, S&P and Fitch upgraded their credit ratings on Neptune Energy Group Midco Ltd and Neptune Energy Bondco plc's existing $850 million senior notes due in 2025 as follows:

- In July, Moody's upgraded its corporate family rating for Neptune Energy Group Midco Ltd to Ba2 from Ba3. Moody's also upgraded Neptune Energy Bondco plc's existing $850 million senior notes due in 2025 to Ba3 from B1. The outlook is stable.

- In August, S&P announced it had upgraded Neptune Energy Group Midco Ltd corporate credit rating to BB from BB-. S&P also upgraded Neptune Energy Bondco plc's senior notes to BB from BB-. The outlook is stable.

- In October, Fitch announced it had upgraded Neptune Energy Group Midco Ltd corporate credit rating to BB+ from BB. Fitch also upgraded Neptune Energy Bondco plc's senior notes to BB+ from BB. The outlook is stable.

Outlook for 2023

With the conflict in Ukraine continuing, energy demand recovering from COVID-19 related restrictions in China and an uncertain economic outlook for OECD countries, energy markets are expected to remain volatile throughout 2023. Gas prices are likely to remain above long-term trends, supported by high competition for international supplies, with Europe increasing demand for non-Russian gas to rebuild inventories.

We continue to prioritise safety, with operational activity expected to remain high throughout the year as we bring online new projects and execute an active drilling programme.

With a full year of production from Snøhvit, new volumes from Njord, Fenja and Seagull, and a resumption of gas exports from Touat, we expect production to increase materially to 150-165 kboepd in 2023 and to potentially end the year at around 180 kboepd.

As a result of project completions, we expect adjusted development capex to decline to around $450 million in 2023, with investment mainly at Njord and Seagull. We are also investing selectively in our existing producing assets at Cygnus, Adorf and Merakes as we target incremental near-term production opportunities.

Exploration and pre-development spend in 2023 is likely to increase to around $200 million, due to a rise in net drilling costs, along with an expected ramp-up in pre-development activity in Norway and Indonesia. Following the deferral of activity from 2022, decommissioning spend is expected to increase to around $110 million in 2023 and will be focused largely on the UK, the Netherlands and Germany.

Investment in lower carbon projects is likely to increase as we mature opportunities. While remaining at a moderate level in 2023, spend will be focused on our L10 and Errai CCS projects. Our near-term carbon intensity is expected to rise moderately in 2023 due to compression at Cygnus (UK) and additional power generation requirements at the

Strategic Report (continued)

Altmark field (Germany) but remains significantly lower than our peers. As outlined in our three-year ESG roadmap, we remain on track to achieve our 2030 carbon and methane intensity targets.

Given volatile commodity prices and supply chain inflation, we will continue to focus on cost containment. While our opex remains low, it is expected to average $12-13/boe for the full year, falling towards the end of the year as new projects come online.

Despite an expected increase in production, softer oil and gas prices, along with materially higher cash taxes, are expected to result in post-tax operating cash flow (before working capital movements) of around $2.0 billion in 2023. Leverage is expected to remain well below targeted levels of 1.5 times throughout 2023.

Cash taxes in 2023 are expected to increase to around $2.0 billion, due to windfall taxes and the timing of our tax payments in respect of earnings in 2022 and including windfall taxes. Windfall profit taxes are expected to total around $65 million in 2023 (relating to the UK), with a further $40 million paid in royalties (in Germany and the Netherlands). Windfall taxes in the Netherlands and Germany are due to be paid in 2024. The introduction of windfall taxes/levies is expected to have a negative impact on investment intentions, with higher returns now required for projects to be sanctioned in the Netherlands, the UK and Germany.

Strategic Report (continued)

Summary of production by area - wholly owned affiliates

	Fourth quarter 2022	Third quarter 2022	Second quarter 2022	First quarter 2022	Full year 2022	Full year 2021
Gas production (kboepd)						
Norway	27.3	25.8	25.3	22.9	25.4	20.2
UK	15.1	12.3	16.6	16.6	15.1	14.8
Netherlands	16.6	16.1	16.7	20.4	17.4	19.9
Germany	10.8	10.2	12.1	14.9	12.0	12.9
North Africa	2.3	2.1	2.1	2.7	2.3	3.0
Asia Pacific	5.4	5.7	5.6	5.5	5.5	5.4
Total Gas production (kboepd)	**77.5**	**72.2**	**78.4**	**83.0**	**77.7**	**76.2**
Gas production for sale as LNG (kboepd)						
Norway	14.1	13.3	4.4	-	8.0	-
Asia Pacific	14.6	13.3	14.2	16.1	14.6	14.7
Total Gas production for sale as LNG (kboepd)	**28.7**	**26.6**	**18.6**	**16.1**	**22.6**	**14.7**
Oil production (kbpd)						
Norway	19.2	18.3	17.5	19.5	18.6	17.9
UK	-	-	-	-	-	-
Netherlands	0.7	0.6	1.0	1.1	0.9	1.1
Germany	5.1	5.4	5.7	5.8	5.5	5.9
North Africa	0.5	0.4	0.4	0.5	0.4	0.5
Asia Pacific	-	-	-	-	-	-
Total Oil production (kbpd)	**25.5**	**24.7**	**24.6**	**26.9**	**25.4**	**25.4**
Other Liquid production (kbpd)						
Norway	6.2	7.7	6.6	4.7	6.3	7.6
UK	0.3	0.2	0.2	0.3	0.3	0.3
Netherlands	0.2	0.1	0.1	0.2	0.1	0.2
Germany	-	-	-	-	-	-
North Africa	-	-	-	-	-	-
Asia Pacific	0.3	0.3	0.3	0.3	0.3	0.4
Total Other Liquid production (kbpd)	**7.0**	**8.3**	**7.2**	**5.5**	**7.0**	**8.5**
Total production (kboepd)						
Norway	66.8	65.0	53.8	47.1	58.3	45.7
UK	15.4	12.5	16.8	16.9	15.4	15.1
Netherlands	17.5	16.8	17.8	21.7	18.4	21.2
Germany	15.9	15.6	17.8	20.7	17.5	18.8
North Africa	2.8	2.5	2.5	3.2	2.7	3.5
Asia Pacific	20.3	19.3	20.1	21.9	20.4	20.5
Total production (kboepd)	**138.7**	**131.7**	**128.8**	**131.5**	**132.7**	**124.8**

Strategic Report (continued)

Summary of production by area – equity-accounted affiliates

	Fourth quarter 2022	Third quarter 2022	Second quarter 2022	First quarter 2022	Full year 2022	Full year 2021
Gas production (kboepd)						
North Africa	2.8	2.0	2.2	2.2	2.3	5.1
Total Gas production (kboepd)	**2.8**	**2.0**	**2.2**	**2.2**	**2.3**	**5.1**
Oil production (kbpd)						
North Africa	-	-	-	-	-	0.1
Total Oil production (kbpd)	**-**	**-**	**-**	**-**	**-**	**0.1**
Total production (kboepd)						
North Africa	2.8	2.0	2.2	2.2	2.3	5.2
Total production (kboepd)	**2.8**	**2.0**	**2.2**	**2.2**	**2.3**	**5.2**

Summary of production by area – wholly owned and equity-accounted affiliates

	Fourth quarter 2022	Third quarter 2022	Second quarter 2022	First quarter 2022	Full year 2022	Full year 2021
Total production (kboepd)						
Norway	66.8	65.0	53.8	47.1	58.3	45.7
UK	15.4	12.5	16.8	16.9	15.4	15.1
Netherlands	17.5	16.8	17.8	21.7	18.4	21.2
Germany	15.9	15.6	17.8	20.7	17.5	18.8
North Africa	5.6	4.5	4.7	5.4	5.0	8.7
Asia Pacific	20.3	19.3	20.1	21.9	20.4	20.5
Total production (kboepd)	**141.5**	**133.7**	**131.0**	**133.7**	**135.0**	**130.0**

Strategic Report (continued)

FINANCIAL REVIEW

This report includes the Group results for the year ended 31 December 2022.

Results of operations

In millions of US$	Year ended 31 December 2022	Year ended 31 December 2021
Revenue	4,640.1	2,490.1
Operating profit (note a)	3,180.6	1,514.7
Underlying operating profit (note b)	3,151.2	1,368.3
Profit before tax	3,094.4	1,391.1
Taxation charge	(2,171.5)	(1,005.2)
Net profit after tax	922.9	385.9
EBITDAX (RBL basis) (note c)	3,854.0	2,109.3
Net cash flows from operating activities	2,374.6	1,698.2
Adjusted development cash capital expenditure (note d)	537.2	635.8
Net debt (book value) (RBL basis) (note e)	1,690.8	2,103.9
Net debt/EBITDAX (RBL basis) (note e)	0.44x	1.00x

a) Operating profit comprises current operating income after share in net income of entities accounted for using the equity method and is stated before tax and finance costs, but after mark-to-market on commodity contracts and non-recurring items.

b) Underlying operating profit is calculated as operating profit before the impact of impairment reversals/losses, restructuring costs, pension curtailment credits and certain one off costs. A full calculation is shown on page 21.

c) EBITDAX, on a 12-month rolling basis, comprises net income for the period before income tax expense, financial expenses, financial income, impairment reversals/losses, other operating gains and losses, exploration expense and depreciation and amortisation.

d) Includes capital expenditure of $15.0 million for the year (2021: $20.1 million) in respect of the Touat project, held by a joint venture company which Neptune accounts for under the equity method.

e) Net debt excludes the Subordinated Neptune Energy Group Limited Loan as defined by the RBL. Net debt is calculated by taking total borrowings of $2,024.9 million (see note 20), deducting the Subordinated Neptune Energy Group Limited Loan of $100.0 million and less the cash balance at 31 December 2022 of $234.1 million.

Revenue for the year was $4,640.1 million (2021: $2,490.1 million), reflecting total production from wholly owned subsidiaries of 48.4 mmboe (2021: 45.5 mmboe). Realised prices, before and after hedging, are shown in the following table. Production for the year was higher than in 2021, reflecting the contribution from Snøhvit (Norway) after the plant restarted in June 2022, a full year of production from Duva (Norway) and continued strong production efficiency. This was also aided by higher commodity prices in 2022 compared with 2021.

The Brent crude price averaged $101.3 (2021: $70.9) per barrel for the year and our average realised oil price (pre hedging) was $98.7 per barrel (2021: $72.2) for the year. Including hedging our average realised oil price was $96.2 per barrel (2021: $65.5) for the year.

The average realised gas price was $26.0 (2021: $13.2) per mmbtu (pre hedging) and $16.0 (2021: $9.5) per mmbtu (post hedging) for the year.

During the year, Russia's invasion of Ukraine, security of supply concerns in European markets along with greater competition for LNG supplies combined to generate volatile and higher average commodity prices than in previous years.

LNG sales prices are linked to a combination of movements in oil and gas market prices, depending on the terms and conditions of the commercial contract.

Strategic Report (continued)

Realised prices for wholly owned affiliates:

	Fourth quarter 2022	Fourth quarter 2021	Year ended 31 December 2022	Year ended 31 December 2021
Excluding impact of hedging:				
Average realised gas price ($/mmbtu)	21.5	24.6	26.0	13.2
Average realised LNG price ($/mmbtu)	21.7	9.7	17.6	8.2
Average realised oil price ($/bbl)	79.3	77.6	98.7	72.2
Average realised price, other liquids ($/bbl) (note a)	66.3	52.5	73.4	48.6
Average realised price of all production ($/boe)	113.5	114.5	128.2	70.5
Including impact of hedging:				
Average realised gas price ($/mmbtu)	15.6	15.0	16.0	9.5
Average realised LNG price ($/mmbtu)	21.4	9.7	17.3	7.5
Average realised oil price ($/bbl)	79.4	71.6	96.2	65.5
Average realised price, other liquids ($/bbl) (note a)	66.3	52.5	73.4	48.6
Average realised price of all production ($/boe)	95.4	78.7	94.0	55.4

a. Other liquids include condensate and other natural gas liquids.

In 2022, $7.2 million (2021: $128.6 million) of other operating income was recognised in relation to business interruption insurance proceeds for loss of revenue in relation to an incident at Hammerfest LNG plant in Norway where Neptune is a non-operated joint venture partner.

Operating costs were $595.0 million (2021: $512.5 million) for the year to 31 December 2022 and our average operating cost per boe produced was $12.3/boe compared with $11.3/boe for 2021. Operating costs for the purpose of per boe expense are decreased by $144.2 million for the year ended 31 December 2022 (2021: $20.3 million increase) to exclude changes in the value of over/under-lifted entitlement to production, to net-off income from tariffs and services which serve to recover costs, to exclude pre-development costs and to exclude abandonment costs incurred on non-producing fields. The higher operating cost per barrel is principally due to the effect of increased operating costs from increases in royalties driven by higher prices, higher prices for carbon emissions allowances in Europe and higher production costs. The effect of higher operating costs is slightly netted off by increased production from Norway and the UK, offset by lower production from the Netherlands, Germany and Egypt.

The depreciation and amortisation expense was $539.7 million (2021: $575.1 million). The charge represents $11.2/boe produced compared with $12.6/boe produced for the year ended 31 December 2021. The lower overall depreciation charge is primarily due to higher reserves and lower production in the Netherlands in 2022 and a lower depreciation expense in the UK, the Netherlands and Germany due to the strengthening of USD in the year.

Exploration expense for the year was $32.7 million (2021: $67.7 million), which includes costs incurred on geological and geophysical studies (G&G) to review strategic growth opportunities as well as seismic costs. The 2022 exploration expense was mainly incurred in Norway, the Netherlands, Egypt and Indonesia, which included $7.2 million of an unsuccessful well evaluation cost principally in the Netherlands. Higher expense in 2021 included $32.2 million of unsuccessful well evaluations costs principally in relation to Norway.

General and administration (G&A) expense of $78.6 million (2021: $78.4 million) for the year to 31 December 2022 remained in line with 2021. It consists primarily of costs that are not directly incurred for production or capital projects (including exploration), such as staff recharge costs related to corporate functions and selling expenses, office costs and fees for services provided to us. The G&A expense in 2022 also included $2.0 million of donations in relation to humanitarian efforts to help the people of Ukraine and $0.6 million to The Childhood Trust.

Share in net income of entities accounted for under the equity method was $24.5 million (2021: $61.1 million) for the year ended 31 December 2022. This represents the share of net income from the Touat joint venture of $21.1 million (2021: $62.4 million) and share of net income of one of our Dutch pipeline interests of $3.4 million (2021: $1.3 million loss). The lower income from the Touat joint venture in 2022 reflects the impact of the Touat processing facility remaining shut-in throughout 2022, the income predominantly reflects other income from the settlement of a

Strategic Report (continued)

performance guarantee of $29.3 million. The 2021 income from the Touat joint venture reflects the impact of higher revenue as a result of increased gas prices, $32.2 million of impairment reversal recognised due to improved macroeconomic conditions, and recognition of business interruption insurance proceeds for loss of revenue from the production outage.

Group net impairment reversals (pre-tax and excluding our share of the Touat impairment reversal mentioned above) for the year was $nil (2021: $113.6 million impairment reversals). The impairment reversals in 2021 include a $43.4 million impairment reversal for a single cash-generating unit (CGU) in Indonesia and a reversal of a property, plant and equipment (PP&E) impairment of $96.5 million for a single CGU in the Netherlands due to an upward reserves revision. This was partially offset by a PP&E impairment of $18.7 million for a second CGU in the Netherlands due to a deterioration of underlying reservoir performance, a $6.7 million impairment in the UK as the planned Pegasus West development did not proceed, and an impairment to intangibles in Denmark of $0.9 million due to the sale of a legacy asset.

Other operating losses were $101.0 million (2021: $65.4 million loss) for the year to 31 December 2022. The 2022 loss is predominantly due to mark-to-market losses on currency derivatives and the ineffective portion of commodity derivative instruments of $100.2 million. The other operating losses in 2022 include a $13.0 million loss from irrecoverable indirect taxation which Neptune intends to challenge through appeal proceedings, a $2.8 million gain from disposal of Norwegian assets, a $2.1 gain from net movement in inventory provision, a $1.8 million release of contingent consideration, a $0.1 million net restructuring release and $5.4 million of other gains.

The 2021 loss of $65.4 million included a loss on mark-to-market on commodity contracts other than trading instruments of $73.8 million, release of contingent consideration of $2.5 million, pension schemes curtailment credit of $4.1 million, net restructuring release of $0.5 million, a net movement in inventory provision of $1.0 million loss and other gains of $2.3 million. Other gains included gains recognised on the completion of the sales for the disposal of two properties in Germany; this was offset by a legacy licence cost and a loss in relation to the sale of an asset which included the Solsort exploration licence.

The Group's operating profit for the year to 31 December 2022 was $3,180.6 million (2021: $1,514.7 million) before net finance costs. Underlying operating profit is calculated before the impact of impairment reversals/losses, restructuring costs, pension curtailment credits and certain one off costs. For 2022, underlying operating profit was $3,151.2 million (2021: $1,368.3 million). The increase in the operating profit and underlying operating profit was mainly due to the significant increase in commodity prices.

In millions of US$	Year ended 31 December 2022	Year ended 31 December 2021
Operating profit before financial items and tax	3,180.6	1,514.7
Adjusted for:		
Other income – equity method investments (see note 15)	(29.3)	-
Net restructuring (release)/cost	(0.1)	(0.5)
Impairment (reversal)/loss in share of net income/(loss) from investments using equity method	-	(32.2)
Net impairment reversals	-	(113.6)
Legacy licence cost	-	4.0
Pension scheme curtailment credit	-	(4.1)
Underlying operating profit before financial items and tax	**3,151.2**	**1,368.3**

Net financing expenses were $86.2 million (2021: $123.6 million) for the year and main components include $118.9 million (2021: $120.7 million) of interest expense, unwinding of discount on provisions of $35.4 million (2021: $35.4 million), $17.2 million (2021: $14.9 million) of commitment fees, $3.8 million (2021: $5.7 million) interest expense in relation to right-of-use lease liabilities, reduced by a foreign exchange gain of $82.2 million (2021: $46.8 million gain). The decrease in net financing expense in 2022 is driven by the increase in foreign exchange gain. The net foreign exchange gain arises principally on the revaluation of loans and working capital balances for internal funding purposes

Strategic Report (continued)

across the Group and is principally impacted by the exchange rates for Euros, Norwegian Kroner and Sterling with the US Dollar.

The Group's profit before tax for the year to 31 December 2022 was $3,094.4 million (2021: $1,391.1 million). EBITDAX, on a 12-month rolling basis (as defined by the RBL), for the year was $3,854.0 million, compared with $2,109.3 million for the year ended 31 December 2021. The increase in EBITDAX principally reflects higher realised commodity prices in the year.

In millions of US$	Year ended 31 December 2022	Year ended 31 December 2021
Profit before tax, after financial items	3,094.4	1,391.1
Add back:		
Net financing expenses	86.2	123.6
Other operating losses	101.0	65.4
Net impairment reversals	-	(113.6)
Exploration expense	32.7	67.7
DD&A	539.7	575.1
EBITDAX (RBL basis)	**3,854.0**	**2,109.3**

Our income tax expense, deferred tax assets and liabilities, and liabilities for unrecognised tax benefits reflect management's best estimate of current and future taxes to be paid. We are subject to income taxes in the UK and numerous foreign jurisdictions.

The Group's total tax charge for 2022 is $2,171.5 million (2021: $1,005.2 million), comprising a current tax charge of $2,054.3 million (2021: $427.8 million) and a deferred tax charge of $117.2 million (2021: $577.4 million). The total tax charge for 2022 represents an effective tax rate of 70.2% (2021: 72.2%).

Please see the taxation note 11 for an explanation of the main drivers for the difference between the expected tax charge of $2,267.9 million and the actual tax charge of $2,171.5 million.

Net profit after tax for the year ended 31 December 2022 was $922.9 million (2021: $385.9 million) on a reported basis.

The petroleum tax regime in Norway was amended, now allowing immediate tax deduction on new investments in the special tax base from 2022, with the current depreciation and uplift deductions discontinued. The new tax regime was approved by the Norwegian parliament in June 2022 and is effective retroactively from 1 January 2022 with the tax impact already included in the tax values.

On 20 December 2021, the OECD published the Global Anti-Base Erosion (GloBE) Model Rules. These model rules, which are also known as Pillar 2, are part of the BEPS 2.0 project and offer governments a template for implementing the Pillar 2 agreement that was reached in October 2021 by 137 jurisdictions in the OECD/G20 BEPS Inclusive Framework. The GloBE rules aim to impose a global minimum tax rate of 15% on multinational enterprises with revenues of €750 million and above. We do not expect to be significantly impacted by Pillar 2, as the tax rate in the countries we work in is significantly higher than the 15% minimum tax rate.

Windfall taxes

The Energy (Oil and Gas) Profits Levy Act 2022 (EPL) legislation for the UK Energy Profits Levy was enacted on 14 July 2022. The EPL is an additional 25% tax on profits, resulting in a tax rate in the UK of 65%. No deductions are allowed for finance costs, decommissioning costs and existing tax losses in calculating the EPL. The Finance Act 2023 increased the EPL tax rate to 35% from 25% thus resulting in an effective tax rate of 75%, as of 1 January 2023. The sunset clause is also extended to 31 March 2028 from the previous 31 December 2025 and the rate of investment allowance reduced to 29% from 80%. Since the Finance Act 2023 was substantively enacted prior to 31 December 2022, deferred tax balances as at 31 December 2022, where relevant, have been calculated at the 75% tax rate.

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On 30 September 2022, the Council of the European Union agreed to impose an EU-wide windfall profits tax on fossil fuel companies. The tax (or 'Solidarity Contribution') is calculated on taxable profits starting in 2022 and/or 2023, depending on national tax rules, that are above a 20% increase of the average yearly taxable profits over the period 2018 - 2021. Both Germany and the Netherlands introduced the 33% Solidarity Contribution to apply retroactively as of 1 January 2022 and the impact of the Solidarity Contribution is included in the tax values. Germany will also apply the 33% Solidarity Contribution in 2023. The Netherlands will apply a levy in the form of a temporary increase in the duty rate in the Mining Act for 2023 and 2024 instead of the Solidarity Contribution. A temporary duty rate of 65% has been proposed for that part of the turnover realised from the sale of natural gas at a price higher than €0.50 per m^3 of natural gas in the years 2023 or 2024, for natural gas extracted both on land and offshore. The mining levy (called 'Cijns' in the Netherlands) will not impact the effective tax rate as it is not considered an income tax under IFRS (IAS 12 Income Taxes) and is also tax deductible for calculating the corporate income tax.

Hedging

Group policy is to seek to reduce risk related to commodity price fluctuations by using hedging instruments to set a floor for the sales realisations for a proportion of forecast revenues on a rolling basis, with reducing levels of hedging for each of the next three years. The Group actively manages this hedging programme using, among others, swaps, collars, puts and options.

As at 31 December 2022, the approximate share of post-tax production (which adjusts for different tax rates on physical sales and hedge gains and losses, meaning that effective post-tax hedges can be achieved through hedging contracts for volumes which may be significantly less than anticipated sales) hedged for future periods is shown in the table below. For oil, weighted average downside protection is $47.8/barrel for 2023, with upside capped at around $117.4/barrel.

Under the Reserves Based Lending (RBL) facility, the aggregate post-tax hedge ratio shall equal 50% for the first rolling 12-month period, 30% for the next rolling 12-month period and 15% for the last 12-month period. The Group currently benefits from a waiver until the period ended 31 March 2023, which allows the Group not to hedge for the last 12-month period. The RBL hedge compliance test takes place annually in May.

For gas, hedging provides weighted average floor prices of $8.4/mmbtu for 2023, with upside caps at $25.3/mmbtu.

The average hedge prices are reflective of open hedge positions, in the event positions have been closed out, these are not included in the average hedge prices. The average hedge prices do not include the effect of bought calls and certain of our existing capped hedges will reparticipate in higher market environments.

Aggregate pre-tax hedge ratio:

	2023	2024	2025
Oil	26%	-	-
Gas	28%	-	-
Total weighted average	**27%**	**-**	**-**

Aggregate post-tax hedge ratio:

	2023	2024	2025
Oil	45%	-	-
Gas	44%	-	-
Total weighted average	**45%**	**-**	**-**

1. Oil price hedges include hedges of realisations for gas production sold as LNG and priced in relation to oil prices.
2. Post-tax hedge ratios adjust for different tax rates on physical sales and hedge gains and losses, which means that effective post-tax hedges can be achieved through hedging contracts for volumes which may be significantly less than anticipated sales.
3. Hedge percentages are based on total Group forecast production volumes including Algeria.

Strategic Report (continued)

The estimated net fair value (comprising current and non-current assets and liabilities) on a mark-to-market basis of all our commodity derivative instruments at 31 December 2022, was a net liability of $396.9 million (2021: $1,123.2 million) which will expire in 2023.

Cash flow

Operating cash flow, after cash taxes, for the year to 31 December 2022 was $2,374.6 million (2021: $1,698.2 million). Cash taxes paid were $1,153.0 million (2021: $57.6 million received). The significant increase in cash tax payments in 2022 was predominantly driven by the increase in profits in Norway. The net cash tax receipts in 2021 resulted predominately from our Norwegian investment programme and the temporary Norwegian fiscal changes.

Capital expenditure

Cash capital expenditure for the year to 31 December 2022, was $633.4 million (2021: $747.1 million), including $110.1 million (2021: $118.7 million) of capitalised exploration expenditure and pre-development capital expenditure. This excludes expenditure at Touat in Algeria, where the joint venture is accounted for under the equity method of accounting as a joint venture. Our statement of cash flows includes net investment at Touat in terms of the cash injections and capital reductions made with the joint venture company, which were $3.6 million cash inflow in 2022 (2021: $2.8 million outflow).

In millions of US$	Year ended 31 December 2022	Year ended 31 December 2021
Investing cash flows:		
Development capex (note a)	522.2	615.7
Acquisitions - development assets	1.1	3.7
Exploration and pre-development capex	110.1	118.7
Acquisitions - exploration assets	-	9.0
Total cash capital expenditure	**633.4**	**747.1**

a) Capex figures are for wholly-owned affiliates only.

Total exploration expenditure of $135.6 million (2021: $154.1 million) comprised the $110.1 million (2021: $118.7 million) cash exploration and pre-development capex and $25.5 million (2021: $35.4 million) expensed in respect of G&G and seismic costs. Capex expenditure in 2022 has primarily been in Norway, the UK and the Netherlands.

Development cash capex was $522.2 million (2021: $615.7 million). The 2022 figure includes expenditure in Norway on the Njord, Fenja, Snøhvit and Gudrun projects, the Seagull and Cygnus projects in the UK, Adorf in Germany, K2b in the Netherlands, as well as expenditure in Indonesia on the Merakes and Jangkrik development projects.

We incurred $29.1 million (2021: $38.5 million) on decommissioning cash expenditure in the year to 31 December 2022, which was principally in the UK, Germany and Netherlands.

Disposals

On 31 March 2022, the Group completed the disposal of a portfolio of non-core Norwegian assets, which included the producing Draugen, Brage and Ivar Aasen fields, amounting to around 7 mmboe of proven reserves, as well as the Edvard Grieg Oil Pipeline and the Utsira High Gas Pipeline (note 19). This also reduced our annual net production by around 2 kboepd on a pro forma basis.

Financing and liquidity

Management's financing strategy is to manage Neptune's capital structure with the aim that, across the business cycle, net debt (excluding vendor loans) to 12-month rolling EBITDAX, as defined by the RBL, remains below 1.5 times. This ratio, as at 31 December 2022, was 0.44 times. The RBL covenants require this ratio to remain below 3.5 times.

Strategic Report (continued)

We funded our business mainly with cash generated from operations and debt facilities. At 31 December 2022, we had the following debt outstanding:

- $1,100 million drawn under the RBL facility, which matures in 2024;
- $550 million 6.875% Subordinated Neptune Energy Group Midco Limited loan, maturing in 2025;
- $300 million 6.625% Subordinated Neptune Energy Group Midco Limited loan, maturing in 2025, and
- $100 million 7.75% Subordinated Neptune Energy Group Midco Limited loan, maturing in 2024.

At 31 December 2022, our cash balance totalled $234.1 million (2021: $125.5 million) and our available and undrawn headroom under the RBL facility was $995 million. In March 2022, we completed the annual redetermination of our RBL facility and reconfirmed a borrowing base of $2.3 billion. We also had $11 million of letters of credit drawn under an ancillary facility to the RBL, $10 million of letters of credit issued outside the RBL, and $159 million in surety bonds outstanding. As at 31 December 2022, our weighted average cost of borrowing for the Group equalled 6.9%.

As of 31 December 2022, our credit ratings are shown in the table below:

Rating agency	Corporate credit ratings	Outlook
Fitch	BB+	Stable
S&P	BB	Stable
Moody's	Ba2	Stable

We will continue to seek to maintain or strengthen these ratings over time.

All debt, except for the debt drawn under the RBL facility, is carrying a fixed interest rate. As at 31 December 2022, 46% of the debt portfolio was fixed.

Financial condition

Operating cash flows were $2,374.6 million (2021: $1,698.2 million) with the increase primarily reflecting higher commodity prices and higher production, offset by $1,153.0 million of income tax paid (2021: $57.6 million tax receipt). Investing cash used was $596.6 million (2021: $724.4 million) for the year, being covered by operating cash flows. Net cash flows used in financing activities was $1,675.0 million (2021: $940.5 million) primarily consists of:

- The settlement of $1,146.8 million of dividends to parent company (2021: $544.7 million);
- Net repayment of borrowings of $528.2 million (2021: $59.5 million proceeds) during the year.

This resulted in a net cash inflow of $103.0 million for the year to 31 December 2022 (2021: $33.3 million). As at 31 December 2022, gross interest-bearing debt was $2,024.9 million (book value) and net debt on an RBL basis, (excluding Subordinated Neptune Energy Group Limited loan) was $1,690.8 million. Net debt on an RBL basis has decreased due to the RBL facility decreasing to $1,082.8 million in 2022 from $1,330.7 million in 2021, no short-term bilateral borrowing facilities as at 31 December 2022 (31 December 2021: $60.0 million), and an increase in the cash balance to $234.1 million at 31 December 2022 (31 December 2021: $125.5 million). This represents a net debt to 12-month rolling EBITDAX ratio of 0.44 times for the 12 months ended 31 December 2022 (2021: 1.00 times).

2023 outlook

We expect production to average 150-165 kboepd in 2023, reflecting new volumes from our Njord, Fenja and Seagull projects, a full year contribution from Snøhvit and the restart of gas exports from Touat. With these fields onstream, Group production has potential to increase to around 180 kboepd by the end of the year.

The increase in production, together with continued robust commodity prices and a focus on cost control, is expected to support our financial performance in 2023. However, the timing of tax payments for 2022 from our Norwegian operations and windfall taxes in the UK, the Netherlands and Germany are expected to negatively impact post-tax operating cash flow, which for 2023 is expected to be around $2.0 billion. Cash taxes, which include windfall taxes in the UK, are expected to total $2.0 billion. Leverage is expected to remain below targeted levels of 1.5 times throughout 2023.

Strategic Report (continued)

We retain a disciplined approach to capital allocation and will invest selectively in new opportunities, including through M&A, where it makes strategic sense and delivers strong returns and near-term cash flow generation. Operating costs are expected to increase modestly in 2023, reflecting industry cost inflation. As a result, while opex remains low, it is expected to average $12-13/boe for the full year.

Risks and uncertainties

Investment in Neptune involves risks and uncertainties, which are summarised in detail in the Neptune Energy Group Midco Limited Annual Report and Accounts.

As an oil and gas, exploration and production company, exploration results, reserve and resource estimates, and estimates for capital and operating expenditures involve inherent uncertainties. A field's production performance may be uncertain over time. The Group is exposed to various forms of financial risk, including, but not limited to, the impact of climate change, fluctuations in oil and gas prices, currency exchange rates, interest rates and capital requirements. The Group is also exposed to uncertainties relating to cyber threats, political risks, the international capital markets and access to capital and this may influence the speed with which growth can be accomplished.

Going concern

Given the total available liquidity as at 31 December 2022 of $1.2 billion, comprising our cash balance ($234.1 million) and available and undrawn headroom under the RBL facility ($995.0 million), and capital resources arrangements in place (see note 20), the consolidated accounts have been prepared on a going concern basis. As disclosed in the Group Overview section, the RBL is due to mature in the final quarter of the going concern period to 30 June 2024. The Group continues to work with the bank syndicate with a view to refinancing the RBL facility in the first half of 2023, however it is acknowledged that this is currently not committed. As such the going concern analysis reflects the RBL maturing in the final quarter of the going concern period, and no assumption has been made with respect to a refinancing of the facility.

The going concern basis is supported by future cash flow forecasts which project the Group's available liquidity and compliance with covenants through to 30 June 2024. The going concern cash flow forecasts reflect forecast production consistent with our Board-approved plans and externally published guidance, and commodity prices which reflect current market conditions.

In reaching the conclusion that the going concern basis is appropriate, stress testing of going concern cash flow forecasts and covenant compliance for the Group has been performed to evaluate the impact of plausible downside scenarios. These include scenarios that assume current commodity price levels as of early March 2023 are sustained through to 30 June 2024, which are significantly below the range of current market expectations for the going concern period. In addition, these scenarios consider the impact of unforeseen production outages. A reverse stress test has also been performed, which demonstrated that the Group is resilient to sustained low commodity prices more than 20% lower than those applied in the going concern cash flow forecast.

Under all plausible scenarios, it was concluded that the Group retains sufficient liquidity and headroom over its covenant ratios, and that the going concern basis remains appropriate. The likelihood of the circumstances identified in the reverse stress test materialising is considered remote on the basis of market consensus for short-term commodity prices.

Dividend

On 8 December 2022, the Board of Directors of Neptune Energy Group Holdings Limited declared and paid an interim dividend of $1,146.8 million to its immediate parent, Neptune Energy Group Midco Limited.

The total dividend declared in 2021 was $344.7 million and the total dividend paid in 2021 was $544.7 million.

Strategic Report (continued)

General dividend considerations

- Neptune's investment proposition is aimed at providing both yield and growth for bondholders and shareholders throughout the cycle, with capital investment allocated to exploration, development and production assets. Dividends form part of such expected shareholder returns, although the Group does not have a formal dividend policy.
- When determining a potential dividend and the level of such dividend, the Board takes into account the following metrics: production/capex profile, leverage (net debt/12-month rolling EBITDAX), total net debt, acquisitions or divestments, projected liquidity under different commodity price scenarios, as well as any potential impact on credit rating of the Group and bonds issued.
- Any dividend shall be sustainable in the context of allowing the Company to continue to pursue its organic growth strategy and to develop its contingent resources while maintaining a conservative gearing ratio and retaining an appropriate liquidity position within its available credit lines.

The Company and/or its affiliates may purchase Neptune Bond Notes in the open market on an opportunistic basis.

Strategic Report (continued)

Section 172(1) Statement

Section 172 of the Companies Act 2006 requires a director of a company to act in the way he or she considers, in good faith, would most likely promote the success of the company for the benefit of its members as a whole. In doing this section 172 requires a director to have regard, amongst other matters, to the:

a) Likely consequences of any decisions in the long-term;
b) Interests of the company's employees;
c) Need to foster the company's business relationships with suppliers, customers and others;
d) Impact of the company's operations on the community and environment;
e) Desirability of the company maintaining a reputation for high standards of business conduct; and
f) Need to act fairly as between members of the company.

In discharging our section 172 duties, we have regard to the factors set out above as well as other factors which we consider relevant to the decision being made. We acknowledge that every decision we make will not necessarily result in a positive outcome for all of our stakeholders. By considering the Company's purpose, vision and values together with its strategic priorities and having a clear process in place for decision-making, we do, however, aim to make sure that our decisions are consistent and predictable.

As is normal for large groups, we engage management in setting, approving and overseeing execution of the business strategy and related policies. We regularly review health, safety and environmental matters, financial and operational performance, as well as other areas over the course of the financial year including the Group's business strategy, key risks, employee-related matters, diversity and inclusivity, corporate responsibility, governance, compliance and legal matters.

As a result of this we have had an overview of engagement with stakeholders and other relevant factors which allows us to understand the nature of the stakeholders' concerns and to comply with our section 172 duty to promote success of the Company.

We set out below some examples of how we have had regard to the matters set out in section 172(1)(a)-(f) when discharging our section 172 duty and the effect of that on decisions taken by the Board:

- The Board recognises the environmental issues associated with the production and use of gas and oil and continue to focus on minimising the environmental impact of our existing operations while investing in lower carbon opportunities. Our Executive Team (which includes members of the Board) continued to track our carbon and methane intensity performance against our 2030 targets and engaged with stakeholders to drive our innovative hydrogen and CCS projects in the UK, Norway and the Netherlands. The Board also supported the Group joining partnerships with environmental NGOs to support biodiversity and initiatives (for example, the CEO-led Aiming for Zero Methane Emissions Initiative). During 2022, with approval of the Board, the Group submitted three CCS licence applications in the UK as well as electrification plans for Njord A and Snøhvit (together with our partners). The Group also signed an agreement with Horisont Energi in Norway to progress a large-scale CCS project demonstrating our continued commitment to progress the pipeline of CCS opportunities required to meet our 2030 ambition to store more carbon than is emitted from our operations and the use of our sold products by 2030. Please see the strategic report section of the 2022 Neptune Energy Group Midco Limited Annual Report for further information.

- Members of the Board engaged with the Group's employees through the Executive Team, who during 2022 held regular meetings with representatives of our works councils and employee forums during the year. The works councils in Germany, the Netherlands and Norway provide a formal setting through which our employees can provide feedback and raise concerns with senior management. Similarly, our UK and European employee forums give employees the opportunity to provide input on the Group's strategy and our approach to employee engagement. The Neptune European Employee Engagement Forum held multiple face-to-face meetings during 2022. These involved guest attendees from Board and the Executive Team, including our CEO, VP Business

Strategic Report (continued)

Development and Commercial and Director of Corporate Affairs as well as the Group's Director of New Energy, Director of Supply Chain and Logistics and Director of Employee Experience. There was also a joint training day for senior leaders and employee representatives to promote effective dialogue. The feedback received during the meetings and training session influenced our approach towards topics such as career development (including the introduction of an in-role promotion process), safety (including the introduction of 'stop the job' cards and visible contractor commitment) and transparency (including 25 webinars delivered on our pay and reward structure).

Please see the strategic report section of the 2022 Neptune Energy Group Midco Limited Annual Report for further examples of how we engaged with our stakeholders in 2022.

Approved by the Board on 8 March 2023 and signed on its behalf by:

By order of the board for and on behalf of Neptune Energy Group Holdings Limited
Director – Armand Lumens
London

Directors' Report

The Directors present their report and the financial statements for the year ended 31 December 2022.

Executive management

The Group is managed by an executive team (the "**Executive Team**") (see biographies in the 2022 Neptune Energy Group Midco Limited Annual Report) consisting of senior management, together with the heads of other functions and the Managing Directors of the countries in which we operate.

The Executive Team meets weekly in person or by video conference. HSE is always the first agenda item but other operational matters are also discussed, such as production, exploration and projects, and overall Group performance. During the weekly meeting, the team also discusses industry developments and key emerging risks, such as hybrid workforce disparities and the deterioration of the geopolitical and security environment. The Investment Committee, ESG Committee, Operational Integrity Committee, Incident Management Committee, Equality, Diversity and Inclusion Committee, Disclosure Committee and Hedging Committee, all comprising members of the Executive Team (and ultimate shareholder representatives in the case of the Hedging Committee), together with other members of the extended leadership team, help inform the Executive Team's decision-making processes.

Committees

The Group has constituted a Group Audit and Risk Committee, Remuneration Committee, Investment Committee and Environmental, Social and Governance ("**ESG**") Committee (each of which include members of the Board). These Committees support the Executive Team, the Board, as well as the boards of directors of other companies in the Group (including our ultimate parent company, Neptune Energy Group Limited). Details of the activities of the Committees can be found in the directors' report section of the 2022 Neptune Energy Group Midco Limited Annual Report.

Directors of the Company

The Company's Directors in office during the financial period and until the date of this report are as follows. Directors were in office for the entire period unless otherwise stated.

William Samuel Hugh Laidlaw
Armand Jean Margrete Lumens
Peter David Anderson Jones (appointed 1 January 2022)

Statement of corporate governance arrangements

For the year ended 31 December 2022, the Company continued to apply the Wates Corporate Governance Principles for Large Companies, published by the Financial Reporting Council in 2019. The following section describes how the Company has applied the Wates Principles in 2022.

Principle 1 – Purpose and leadership

The Group's vision is to be the leading independent exploration and production company by meeting society's changing energy needs and creating value for all stakeholders. We set out our new ambition in March 2022 to store more carbon than is emitted from our operations and the use of our sold products by 2030.

During the early part of 2022, the priority of the Board and the Executive Team was to ensure the longer-term success of the Group as we moved away from the international restrictions caused by COVID-19 while facing increased political and economic volatility as a result of Russia's invasion of Ukraine.

The Group held in-person meetings for the extended leadership team, comprising some 100 people, to ensure a consistent understanding of the Group's purpose, strategy and developments. The Executive Team met on a weekly basis to discuss safety and operational matters and continued to engage with employees via a weekly CEO blog. There were also all-company events and site visits by Directors. These and other initiatives ensured close communications throughout the year.

Recognising the increasing importance of environmental, social and governance (ESG) matters to our stakeholders (including shareholders, bondholders, host governments and employees), we made further progress in delivering our three-year ESG roadmap, which led to industry leading ESG ratings from Sustainanlytics and EcoVadis in 2022. The ratings

Directors' Report (continued)

reflect our enhanced performance and disclosure on greenhouse gas emissions, environmental management, labour and human rights and ethics. Our ESG Committee also approved new gender targets in September 2022 and we were awarded the Gold Standard status by the Oil and Gas Methane Partnership 2.0 (a voluntary initiative launched by the United Nation's Environmental Programme) in September 2022. This recognised our ambitious plans to reduce methane emissions to net zero by the end of this decade.

We continue to be guided by our principle to carry out all of our activities in a manner that is 'safer, faster and better' than our peer group and our own past performance. In 2022 we:

- Improved our process safety event rate to 1.13 per million hours worked (2021: 1.68). There were no tier 1 process safety events during 2022. Our total recordable injury rate (TRIR) also improved to 1.94 per million hours worked in the year but was above our target of 1.67, largely as a result of relatively minor incidents in the category of slips, trips and falls.
- Continued to stress the importance of life saving rules, with a focus on spatial awareness, hazard/risk identification and eye safety across our operations to enhance personal safety performance. We have also introduced human factors training, which we will roll out across our assets in 2023 to highlight the 12 common factors that can lead to incidents and accidents.
- Held a global HSE day where the Executive Team joined 80 colleagues and guest speaker Mark Leruste to take a fresh look at safety leadership and how to create a culture of psychological safety within the workplace.
- Raised the awareness and emergency preparedness level for our operations in Europe following damage to the Nord Stream pipelines (in Denmark and Sweden). We continue to work with key stakeholders to ensure continued safe and reliable exports into European markets. We progressed our development projects, with both Njord and Fenja (Norway) production ready and the first development well of our Seagull project (UK) having been cleaned up and tested successfully. With Seagull and Fenja onstream, we expect Group production to increase to around 180 kboepd by the end of 2023, reflecting the culmination of our investment programme, which has exceeded $4 billion since 2018.
- Continued to mature new growth projects, including fast-track development of the recent Hamlet discovery in Norway. Continued to make good progress with our lower carbon initiatives, as we aim to store more carbon than is emitted from our operations and the use of our sold product by 2030. At our L10 CCS project (Netherlands) we continued to progress towards concept selection and FEED-readiness, enabling an application to be made for a storage licence. In September 2022, we announced the award of contracts as part of our feasibility programme for the H_2opZee project (Netherlands) covering concept designs and engineering for platform, pipeline and wind turbine generator systems. In the UK, we submitted three applications for carbon capture and storage licences as part of a recent Carbon Dioxide Appraisal and Storage Licensing Round.

For further information, the Group's purpose, strategy and business model are set out in the Strategic Report on pages 4 to 29.

Principle 2 – Board composition

Details of the membership of the Board can be found on page 30. The Executive Chairman leads the Board and ensures that the views of all Directors are considered in the decision making process.

As is common for privately-owned companies, the Directors are nominated by the ultimate shareholders. Although there are no independent directors on the Board, the Directors are highly experienced business leaders and frequently consider the interests of a broad range of stakeholders (including employees, joint venture partners, bondholders, customers, suppliers, and others with whom we do business) in their decision-making processes. Given their diverse backgrounds as well as their extensive industry and financial experience, the Directors bring a variety of different points of view to Board discussions and decisions.

As at 31 December 2022, the Board consisted of three male directors.

Principle 3 – Director responsibilities

Decisions within the Group are carried out in accordance with strict principles set out in the shareholders' agreement in respect of Neptune Energy Group Limited and articles of association of that company. In reaching their decisions, the Directors also have regard to the Group's obligations to its bondholders, shareholders and other stakeholders, including employees, joint venture partners, customers, suppliers, and others with whom we do business.

Directors' Report (continued)

The Directors receive detailed information relating to the operations and performance of the Group, both through the cycle of Board meetings and through regular updates by telephone or in writing. The Committees also support the Board in its decision-making processes (see the directors' report section of the 2022 Neptune Energy Group Midco Limited Annual Report for further information).

Among other things, during 2022 the Directors:

- considered the financial and liquidity position of the Company and Group, including the repayment of certain debt facilities and its RBL refinancing;
- received regular updates – and provided input to – the Group's health, safety and environmental performance, with a particular focus on how performance could be improved;
- reviewed and discussed the Group's 2023 budget and business plan, including the Group's capital expenditure programme and operating expenditure;
- approved the 2021 annual report and accounts;
- reviewed and analysed regular monthly and quarterly performance data including production and financial metrics; and
- considered various business development opportunities, in particular in respect of lower carbon opportunities, including CCS and hydrogen projects, the Group is pursuing to help achieve its target to store more carbon than is emitted by its operations and the use of its sold products by 2030.

Under the Company's articles of association, any Director having a conflict of interest on any matter being discussed by the Board is be required to disclose this interest to the Board.

Principle 4 – Opportunity and risk

The Board looks for opportunities to enhance the Group's business in a sustainable and responsible manner while also mitigating risk to the greatest extent possible.

The Group continues to recognise both the risks and the opportunities associated with the energy transition while acknowledging the continued importance of gas and oil in the energy mix in the medium term. International commodity markets continued to experience a great deal of volatility in 2022 and gas prices further increased.

The Group continues to believe that, together, its lower carbon intensity exploration and production business, its gas-weighted portfolio and its growing lower carbon developments, mean the Group will be well positioned as the energy transition accelerates.

In 2022, the Group continued to make good progress with its lower carbon initiatives as part of its aim to store more carbon than is emitted from its operations and the use of its sold product by 2030. For example, in the UK, we submitted three applications for CCS licences as part of a recent Carbon Dioxide Appraisal and Storage Licensing Round. The Group's approach to strategic opportunities is set out in further detail in the strategic review section of the 2022 Neptune Energy Group Midco Limited Annual Report.

The Group's enterprise risk register and finance risk register are standing items at each meeting of the Group's Audit and Risk Committee (**ARC**). Although the Group does not have any direct exposure to Russia or Ukraine, the financial and political impact of Russia's invasion of Ukraine remained a key driver for risk in 2022 and the committee continued to carefully monitor the Group's response to rapid developments throughout the year. An industry-wide competence and capability gap and increased concentration of drilling activities were two further key risks identified as having a potential impact on the Group's safety performance. As part of the ARC's monitoring of the Group's enterprise risks, it reviewed climate change related risks as well as a number of emerging risks identified by management during the year, including increased scrutiny over climate change disclosures and deterioration of the geopolitical and security environment, as well as emerging risks associated with hybrid workforce disparities and changes in decommissioning security arrangements.

Please see the directors' report section of the 2022 Neptune Energy Group Midco Limited Annual Report) for further information on the Group's approach to risk and risk management and for information relating to the ARC and the Group's Ethics and Compliance programme.

Directors' Report (continued)

Principle 5 – Remuneration

The Group Remuneration Committee (**Remco**) is constituted primarily for the purpose of developing, maintaining and implementing remuneration policies. The overriding objective of such policies is to attract and retain high-calibre individuals with a competitive reward package based on the achievement of corporate performance targets. These are linked to individual performance and accountability, and are designed to support the Group's commitment to exemplary safety standards and ethical values while rewarding long-term sustainable value creation.

The Remco ensures that levels of compensation across the Group are sufficiently competitive to retain talent within the Group, as well as benchmarking the remuneration packages of the Executive Team. Additionally, the Remco reviews the Group's performance with regard to diversity and inclusion criteria, including benchmarking the Group against other industry players. Please see the directors' report section of the 2022 Neptune Energy Group Midco Limited Annual Report for further information on the activities of the Remco.

Principle 6 – Stakeholders

We set out examples of how the Group has engaged with some of its key stakeholders, including our workforce, shareholders, bondholders, suppliers, local communities, customers and others with whom we do business in the strategic review section of the 2022 Neptune Energy Group Midco Limited Annual Report. As well as informing business level decisions, an overview of the output of this engagement and related developments is reported to the Board, Committees and/or Executive Team, to ensure due consideration is given to stakeholders and the output of this engagement when decisions are taken at those levels.

Results and dividends

The results of the Company are set out on page 41. The net profit for the financial period ended 31 December 2022 was \$922.9 million (2021: \$385.9 million). Dividends of \$1,146.8 million (2021: \$344.7) were declared and paid in the year ended 31 December 2022. Refer to note 10.

Future developments

Future developments are discussed in the Strategic Report on page 4-29.

Going concern

Given the total available liquidity as at 31 December 2022 of \$1.2 billion, comprising our cash balance (\$234.1 million) and available and undrawn headroom under the RBL facility (\$995.0 million), and capital resources arrangements in place (see note 20), the consolidated accounts have been prepared on a going concern basis. As disclosed in the Group Overview section, the RBL is due to mature in the final quarter of the going concern period to 30 June 2024. The Group continues to work with the bank syndicate with a view to refinancing the RBL facility in the first half of 2023, however it is acknowledged that this is currently not committed. As such the going concern analysis reflects the RBL maturing in the final quarter of the going concern period, and no assumption has been made with respect to a refinancing of the facility.

The going concern basis is supported by future cash flow forecasts which project the Group's available liquidity and compliance with covenants through to 30 June 2024. The going concern cash flow forecasts reflect forecast production consistent with our Board-approved plans and externally published guidance, and commodity prices which reflect current market conditions.

In reaching the conclusion that the going concern basis is appropriate, stress testing of going concern cash flow forecasts and covenant compliance for the Group has been performed to evaluate the impact of plausible downside scenarios. These include scenarios that assume current commodity price levels as of early March 2023 are sustained through to 30 June 2024, which are significantly below the range of current market expectations for the going concern period. In addition, these scenarios consider the impact of unforeseen production outages. A reverse stress test has also been performed, which demonstrated that the Group is resilient to sustained low commodity prices more than 20% lower than those applied in the going concern cash flow forecast.

Directors' Report (continued)

Under all plausible scenarios, it was concluded that the Group retains sufficient liquidity and headroom over its covenant ratios, and that the going concern basis remains appropriate. The likelihood of the circumstances identified in the reverse stress test materialising is considered remote on the basis of market consensus for short-term commodity prices.

Share Capital

To facilitate the future distribution of cash earned by the Group to its shareholders, on 1 September 2022 the Board undertook a US$1 billion capital reduction, resulting in the issued share capital of the Company being reduced from US$1,977,175,201 (comprising 1,977,175,201 ordinary shares of US$1.00 each), to US$977,175,201 (comprising of 977,175,201 ordinary shares of US$1.00 each).

On 17 November 2022 the Board undertook a further US$300 million capital reduction, resulting in the issued share capital of the Company being reduced from US$977,175,201 (comprising 977,175,201 ordinary shares of US$1.00 each), to US$677,175,201 (comprising of 677;175,201 ordinary share of US$1.00 each).

No shares were issued in 2022.

Directors' interests in share capital

As at 31 December 2022 the Directors had no interests in the share capital of the Company. The Directors each have an indirect economic interest in the share capital of the Company through their investments in Neptune Energy Group Limited.

Post-balance sheet events

Post-balance sheet events are detailed in note 31 of the financial statements.

Directors' and officers' liability

Qualifying third party indemnity provisions (as defined by section 234 of the Companies Act 2006) were in force during the course of the financial year ended 31 December 2022 for the benefit of the then Directors and, at the date of this report, are in force for the benefit of the Directors in relation to certain losses and liabilities which they may incur (or have incurred) in connection with their duties, powers or office. In addition, the Company maintains Directors' & Officers' Liability Insurance which gives appropriate cover for legal action brought against its Directors. The insurance does not provide cover in the event that the Director is proved to have acted fraudulently.

Political donations

The Group did not make any political donations (2021: $nil) or incur any political expenditure (2021: $nil) during the year.

Employee engagement

The Group conducted an employee engagement survey in 2022 and continued to operate an employee engagement forum, chaired by the group human resources director. There was also regular communication between leadership teams and staff through town halls, webinars, weekly CEO blogs and vlogs, Yammer, extended leadership meetings and many employee forums.

The Company believes diversity and equal opportunities empower its business and people. By championing both, the Company creates a high-performing workplace and a more resilient and innovative business. The Company wants its workforce to represent the societies in which we work and to create an environment where our people feel able to be themselves. Through deliberate actions, such as establishing our ED&I Committee and ED&I charter, good progress has been made in building a diverse and inclusive workplace. However, the Board understands that additional action is needed to make progress at the scale and pace needed to ensure greater diversity and inclusion, for example in relation to gender diversity. To that end, in November 2022, the Company launched an ambitious goal to achieve gender parity in all external hires and internal promotions, which applies across all bands, functions and locations. The Directors recognise diverse representation is not just about gender. Age, neurodiversity, sexual orientation, religion, political views, socio-economic status and ethnicity are just as important. While these attributes are more challenging to measure, the

Directors' Report (continued)

Company will continue to look for ways to encourage broader diversity and inclusion in all aspects of the organisation and promote diversity of thought.

From recruitment to career development to promotion, the Company aims to ensure equal opportunities for all employees, regardless of age, gender, sexual orientation, ethnicity, marital status, religion or belief, disability or political view. The Company's policy is that people with disabilities should be given fair consideration for all vacancies against the requirements for the role. Where possible, the Company makes reasonable adjustments in job design and provides appropriate training for existing employees who are or become disabled. Neptune are committed to treating everyone with dignity and respect, and to providing a workplace that is free from discrimination, harassment and bullying.

Financial instruments

Neptune holds a variety of financial instruments which contribute towards its financial objectives and policies, see note 24.

Research and development

The Group carries out various research and development activities, details of which can be found on pages 24-25 of the 2022 Neptune Energy Group Midco Limited Annual Report.

Appointment of auditors

Ernst & Young LLP has served as Neptune's independent external auditor for the six-year period ended 31 December 2022. In accordance with section 487 of the Companies Act 2006, the auditors will be deemed to be reappointed and Ernst & Young LLP will therefore continue in office.

Disclosure of information to auditors

Each of the Directors who held office at the date of approval of this Directors' Report confirm that so far as they are aware, there is no relevant audit information of which the Company's auditors are unaware, and that they have taken all steps that they ought to have taken as Directors to make themselves aware any relevant audit information and to establish that the Company's auditors are aware of that information.

The Company has chosen to include certain matters in its Strategic Report that would otherwise be required to be disclosed in a Directors' Report. For information relating to:

- Likely future developments in the business of the Company, see pages 15 and 16 (Outlook for 2023).
- Greenhouse gas emissions, energy consumption and energy efficiency action, see pages 7-9.

Approved by the Board on 8 March 2023 and signed on its behalf by:

By order of the board for and on behalf of Neptune Energy Group Holdings Limited
Director – Armand Lumens
London

Directors' report (continued)

Statement of Directors' Responsibilities

The Directors are responsible for preparing the Strategic Report, Directors' Report and the financial statements in accordance with applicable UK law and regulations.

Company law requires the Directors to prepare financial statements for each financial year. Under that law the Directors have elected to prepare the financial statements in accordance with UK adopted international accounting standards ('IFRSs'). Under company law the Directors must not approve the financial statements unless they are satisfied that they give a true and fair view of the state of affairs of the Company and of the profit or loss of the Company for that period. In preparing these financial statements, the Directors are required to:

- select suitable accounting policies and apply them consistently;
- make judgements and accounting estimates that are reasonable and prudent;
- State whether UK adopted international accounting standards ('IFRSs') has been followed, subject to any material departures disclosed in and explained in the financial statements;
- prepare the financial statements on the going concern basis unless it is inappropriate to presume that the Company will continue in business.

The Directors are responsible for keeping adequate accounting records that are sufficient to show and explain the Company's transactions and disclose with reasonable accuracy at any time the financial position of the Company and enable them to ensure that the financial statements comply with the Companies Act 2006. They are also responsible for safeguarding the assets of the Company and hence for taking reasonable steps for the prevention and detection of fraud and other irregularities.

INDEPENDENT AUDITOR'S REPORT TO THE MEMBERS OF NEPTUNE ENERGY GROUP HOLDINGS LIMITED

Opinion

We have audited the financial statements of Neptune Energy Group Holdings Limited ('the parent company') and its subsidiaries (the 'Group') for the year ended 31 December 2022 which comprise the Consolidated income statement, Consolidated statement of other comprehensive income, Consolidated and Company statement of financial position, Consolidated and Company statement of changes in equity, Consolidated and Company cash flow statement and the related notes 1 to 31, including a summary of material accounting policies. The financial reporting framework that has been applied in their preparation is applicable law and UK adopted International Accounting Standards and as regards the parent company financial statements, as applied in accordance with section 408 of the Companies Act 2006.

In our opinion:

- the financial statements give a true and fair view of the Group's and of the parent company's affairs as at 31 December 2022 and of the Group's profit for the year then ended;
- the Group financial statements have been properly prepared in accordance with UK adopted International Accounting Standards;
- the parent company financial statements have been properly prepared in accordance with UK adopted International Accounting Standards as applied in accordance with section 408 of the Companies Act 2006; and
- the financial statements have been prepared in accordance with the requirements of the Companies Act 2006.

Basis for opinion

We conducted our audit in accordance with International Standards on Auditing (UK) (ISAs (UK)) and applicable law. Our responsibilities under those standards are further described in the Auditor's responsibilities for the audit of the financial statements section of our report. We are independent of the Group in accordance with the ethical requirements that are relevant to our audit of the financial statements in the UK, including the FRC's Ethical Standard , and we have fulfilled our other ethical responsibilities in accordance with these requirements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Conclusions relating to going concern

In auditing the financial statements, we have concluded that the directors' use of the going concern basis of accounting in the preparation of the financial statements is appropriate.

Based on the work we have performed, we have not identified any material uncertainties relating to events or conditions that, individually or collectively, may cast significant doubt on the Group and parent company's ability to continue as a going concern for the period to 30 June 2024.

Our responsibilities and the responsibilities of the directors with respect to going concern are described in the relevant sections of this report. However, because not all future events or conditions can be predicted, this statement is not a guarantee as to the Group's ability to continue as a going concern.

Other information

The other information comprises the information included in the annual report, other than the financial statements and our auditor's report thereon. The directors are responsible for the other information contained within the annual report.

Our opinion on the financial statements does not cover the other information and, except to the extent otherwise explicitly stated in this report, we do not express any form of assurance conclusion thereon.

Our responsibility is to read the other information and, in doing so, consider whether the other information is materially inconsistent with the financial statements or our knowledge obtained in the course of the audit or otherwise appears to be materially misstated. If we identify such material inconsistencies or apparent material misstatements, we are required to determine whether this gives rise to a material misstatement in the financial statements themselves. If, based on the work we have performed, we conclude that there is a material misstatement of the other information, we are required to report that fact.

We have nothing to report in this regard.

Opinions on other matters prescribed by the Companies Act 2006

In our opinion, based on the work undertaken in the course of the audit:

- the information given in the strategic report and the directors' report for the financial year for which the financial statements are prepared is consistent with the financial statements; and

- the strategic report and directors' report have been prepared in accordance with applicable legal requirements.

Matters on which we are required to report by exception

In the light of the knowledge and understanding of the Group and the parent company and its environment obtained in the course of the audit, we have not identified material misstatements in the strategic report or directors' report.

We have nothing to report in respect of the following matters in relation to which the Companies Act 2006 requires us to report to you if, in our opinion:

- adequate accounting records have not been kept by the parent company, or returns adequate for our audit have not been received from branches not visited by us; or

- the parent company financial statements are not in agreement with the accounting records and returns; or

- certain disclosures of directors' remuneration specified by law are not made; or

- we have not received all the information and explanations we require for our audit.

Responsibilities of directors

As explained more fully in the directors' responsibilities statement set out on page 36, the directors are responsible for the preparation of the financial statements and for being satisfied that they give a true and fair view, and for such internal control as the directors determine is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, the directors are responsible for assessing the Group's and the parent company's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless the directors either intend to liquidate the Group or the parent company or to cease operations, or have no realistic alternative but to do so.

Auditor's responsibilities for the audit of the financial statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with ISAs (UK) will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

Explanation as to what extent the audit was considered capable of detecting irregularities, including fraud

Irregularities, including fraud, are instances of non-compliance with laws and regulations. We design procedures in line with our responsibilities, outlined above, to detect irregularities, including fraud. The risk of not detecting a material misstatement due to fraud is higher than the risk of not detecting one resulting from error, as fraud may involve deliberate concealment by, for example, forgery or intentional misrepresentations, or through collusion. The extent to which our procedures are capable of detecting irregularities, including fraud is detailed below. However, the primary responsibility for the prevention and detection of fraud rests with both those charged with governance of the entity and management.

- We obtained an understanding of the legal and regulatory frameworks that are applicable to the Group and determined that the most significant are those that relate to the reporting framework (International Accounting Standards and the Companies Act 2006) and the relevant tax compliance regulations in the jurisdictions in which the Group operates. In addition, the Group has to comply with laws and regulations relating to its domestic and overseas operations, including those related to health and safety, employee matters, data protection, environmental and anti-bribery and corruption practices;

- We understood how the Group is complying with those frameworks by making inquiries of those charged with governance, management, internal audit and those responsible for legal and compliance procedures. We corroborated our inquiries through reading Board minutes, papers provided to the Audit and Risk Committee and correspondence received from regulatory bodies and noted there was no contradictory evidence;

- We assessed the susceptibility of the Group's financial statements to material misstatement, including how fraud might occur inquiring of management to understand where they considered there was susceptibility to fraud. We also considered performance targets and their propensity to influence efforts made by management to manage earnings. Where this risk was considered to be higher, we performed audit procedures to address each fraud risk or other risk of material misstatement. These procedures included those on revenue recognition and testing journal entries and were designed to provide reasonable assurance that the financial statements were free from material fraud or error; and

- Based on this understanding we designed our audit procedures to identify noncompliance with such laws and regulations. Our procedures involved inquiries of both Group and local management; inquiries of those charged with governance; and journal entry testing, with a focus on journals meeting our defined risk criteria.

INDEPENDENT AUDITOR'S REPORT TO THE MEMBERS OF NEPTUNE ENERGY GROUP HOLDINGS LIMITED (Continued)

A further description of our responsibilities for the audit of the financial statements is located on the Financial Reporting Council's website at https://www.frc.org.uk/auditorsresponsibilities. This description forms part of our auditor's report.

Use of our report

This report is made solely to the company's members, as a body, in accordance with Chapter 3 of Part 16 of the Companies Act 2006. Our audit work has been undertaken so that we might state to the company's members those matters we are required to state to them in an auditor's report and for no other purpose. To the fullest extent permitted by law, we do not accept or assume responsibility to anyone other than the company and the company's members as a body, for our audit work, for this report, or for the opinions we have formed.

Ernst & Young LLP

Mark Woodward (Senior statutory auditor)
for and on behalf of Ernst & Young LLP,
Statutory Auditor
London
8 March 2023

Consolidated income statement - Group

Group In millions of US$	Notes	Year ended 31 December 2022	Year ended 31 December 2021
Revenue	3	4,640.1	2,490.1
Other operating income	4	7.2	128.6
Revenue and other income		**4,647.3**	**2,618.7**
Cost of sales	6	(1,278.9)	(1,067.2)
GROSS PROFIT		**3,368.4**	**1,551.5**
Exploration expenses	6	(32.7)	(67.7)
General and administration expenses	6	(78.6)	(78.4)
Share of net income from investments using equity method	15	24.5	61.1
OPERATING PROFIT AFTER EQUITY-ACCOUNTED INVESTMENTS	5	**3,281.6**	**1,466.5**
Net impairment reversals	5	-	113.6
Other operating losses	8	(101.0)	(65.4)
OPERATING PROFIT BEFORE FINANCIAL ITEMS		**3,180.6**	**1,514.7**
Finance income	9	89.1	53.1
Finance costs	9	(175.3)	(176.7)
PROFIT BEFORE TAX		**3,094.4**	**1,391.1**
Taxation	11	(2,171.5)	(1,005.2)
NET PROFIT		**922.9**	**385.9**

All profits and losses arise as a result of continuing operations. The accounting policies on page 47 to 61 together with the notes on page 61 to 103 form part of these accounts.

Consolidated statement of other comprehensive income - Group

Group In millions of US$	Notes	Year ended 31 December 2022	Year ended 31 December 2021
Profit for the year		**922.9**	**385.9**
Other comprehensive income/(loss):			
Items that may be reclassified to the income statement:			
Hedge adjustments net of tax (1)	24	488.5	(681.8)
Share of hedge adjustments within equity-accounted investments (2)	24	7.2	(4.2)
Foreign currency translation (3)		(283.5)	(101.9)
		212.2	(787.9)
Other items not reclassified to the income statement:			
Remeasurement of defined pension obligations, net of tax (4)	29	(27.5)	14.8
Net loss on equity instruments designated at fair value through other comprehensive income (5)	24	(1.5)	(4.3)
Foreign currency translation		(0.9)	(1.6)
		(29.9)	8.9
OTHER COMPREHENSIVE INCOME/(LOSS)		**182.3**	**(779.0)**
TOTAL COMPREHENSIVE INCOME/(LOSS) FOR THE YEAR, NET OF TAX		**1,105.2**	**(393.1)**

1. Income tax related to hedge adjustments is $219.7 million debit (2021: $480.2 million credit) and is shown net of amounts reclassified to profit or loss or included in finance costs.
2. Income tax related to share of hedge adjustments within equity-accounted investments is $nil (2021: $2.4 million credit).
3. The foreign currency translation loss arises on the revaluation of subsidiaries with a non-USD functional currency, the losses in 2022 were due to the change in the USD exchange rate with the NOK, EUR and GBP.
4. Income tax related to defined benefit obligations is $14.8 million credit (2021: $4.3 million debit).
5. Within the net loss on equity instruments designated at fair value through other comprehensive income is $nil (2021: $0.2 million) of deferred tax charge.

Consolidated statement of financial position – Group

Group In millions of US$	Notes	31 December 2022	31 December 2021
NON-CURRENT ASSETS			
Goodwill	12	549.6	610.0
Intangible assets	13	371.1	282.0
Property, plant and equipment	14	4,322.6	4,748.8
Derivative instruments	24	-	21.0
Investments in entities accounted for using the equity method	15	629.4	606.3
Other non-current assets	24	99.4	69.5
Non-current income tax receivable		6.5	-
Equity instruments	24	13.0	15.4
Deferred tax assets	11	702.1	852.3
TOTAL NON-CURRENT ASSETS		**6,693.7**	**7,205.3**
CURRENT ASSETS			
Derivative instruments	24	120.8	60.7
Trade and other receivables	17	1,285.0	1,384.8
Inventories	16	103.8	83.0
Cash and cash equivalents	18	234.1	125.5
Income tax receivable		26.7	33.4
		1,770.4	**1,687.4**
Assets held for sale	19	-	134.9
TOTAL CURRENT ASSETS		**1,770.4**	**1,822.3**
TOTAL ASSETS		**8,464.1**	**9,027.6**
Share capital	26	677.2	1,977.2
Hedging reserve	24	(212.9)	(708.6)
Foreign currency translation		(350.4)	(66.9)
Fair value reserve of financial assets at FVOCI		(8.3)	(5.9)
Retained earnings/(deficit)		593.8	(454.8)
TOTAL EQUITY		**699.4**	**741.0**
NON-CURRENT LIABILITIES			
Provisions	23	1,446.1	1,778.0
Long-term borrowings	20	2,024.9	2,269.4
Derivative instruments	24	-	169.7
Income tax payable		165.4	82.5
Other non-current liabilities	21	93.1	95.2
Deferred tax liabilities	11	1,430.3	1,357.1
TOTAL NON-CURRENT LIABILITIES		**5,159.8**	**5,751.9**
CURRENT LIABILITIES			
Provisions	23	142.6	123.5
Short-term borrowings	20	-	60.0
Derivative instruments	24	501.3	1,029.3
Trade and other payables	21	299.5	329.4
Income tax payable		1,126.1	378.8
Other current liabilities	21	535.4	512.8
		2,604.9	**2,433.8**
Liabilities directly associated with the assets held for sale	19	-	100.9
TOTAL CURRENT LIABILITIES		**2,604.9**	**2,534.7**
TOTAL EQUITY AND LIABILITIES		**8,464.1**	**9,027.6**

The accounts on page 41 to 103 were approved by the Board and signed on its behalf by:

Armand Lumens, Chief Financial Officer

Statement of financial position – Company

Company In millions of US$	Notes	31 December 2022	31 December 2021
NON-CURRENT ASSETS			
Property, plant and equipment	14	4.7	1.6
Investments	15	4,271.2	3,992.6
TOTAL NON-CURRENT ASSETS		**4,275.9**	**3,994.2**
CURRENT ASSETS			
Trade and other receivables	17	474.4	499.8
TOTAL CURRENT ASSETS		**474.4**	**499.8**
TOTAL ASSETS		**4,750.3**	**4,494.0**
Share capital	26	677.2	1,977.2
Hedging reserve	24	-	-
Retained earnings		416.1	120.0
TOTAL EQUITY		**1,093.3**	**2,097.2**
NON-CURRENT LIABILITIES			
Provisions	23	1.7	1.0
Inter-company loan payable	21	2,117.7	938.7
Long-term borrowings	20	1,082.8	1,330.7
Other payables	21	47.2	87.7
TOTAL NON-CURRENT LIABILITIES		**3,249.4**	**2,358.1**
CURRENT LIABILITIES			
Provisions	23	3.4	0.1
Trade and other payables	21	404.2	38.6
Derivative instruments	24	-	-
TOTAL CURRENT LIABILITIES		**407.6**	**38.7**
TOTAL EQUITY AND LIABILITIES		**4,750.3**	**4,494.0**

As permitted by Section 408 of the Companies Act 2006, no income statement or statement of comprehensive income is presented for the Company. Profit for the year was $142.9 million (2021: $389.5 million).

Consolidated statement of changes in equity – Group

Group In millions of US$	Share capital	Hedging reserve[1][3]	Foreign currency translation[2]	Fair value reserve of financial assets at FVOCI[4]	Retained earnings/(deficit)	Total
At 1 January 2021	**1,977.2**	**(22.6)**	**35.0**	**-**	**(510.8)**	**1,478.8**
Profit for the year	-	-	-	-	385.9	385.9
Other comprehensive (loss)/income[5]	-	(686.0)	(101.9)	(5.9)	14.8	(779.0)
Total comprehensive (loss)/income	-	**(686.0)**	**(101.9)**	**(5.9)**	**400.7**	**(393.1)**
Transactions with owners of the Company:						
Dividends declared (note 10)	-	-	-	-	(344.7)	(344.7)
At 31 December 2021	**1,977.2**	**(708.6)**	**(66.9)**	**(5.9)**	**(454.8)**	**741.0**
Profit for the year	-	-	-	-	922.9	922.9
Other comprehensive income/(loss)[5]	-	495.7	(283.5)	(2.4)	(27.5)	182.3
Total comprehensive income/(loss)	-	**495.7**	**(283.5)**	**(2.4)**	**895.4**	**1,105.2**
Transactions with owners of the Company:						
Capital reduction (note 26)	(1,300.0)	-	-	-	1,300.0	-
Dividends declared (note 10)	-	-	-	-	(1,146.8)	(1,146.8)
Balance 31 December 2022	**677.2**	**(212.9)**	**(350.4)**	**(8.3)**	**593.8**	**699.4**

1. The hedging reserve represents gains and losses on derivatives classified as effective cash flow hedges stated net of tax.
2. The foreign currency translation reserve represents exchange gains and losses arising on translation of foreign currency subsidiaries.
3. Included in the hedging reserves is $7.2 million of other comprehensive income (2021: $4.2 million loss) net of tax related to hedging undertaken by associated entities.
4. The fair value reserve of financial assets at fair value through OCI (FVOCI) represents the fair value movements in the year associated with the non-listed equity investments classified as equity instruments designated at fair value through other comprehensive income, refer to note 24.
5. As at 31 December 2022, the $495.7 million (2021: $686.0 million loss) other comprehensive income recognised in the hedging reserve relates to the effect of the significant change in commodity prices on the Group's hedging positions.

Statement of changes in equity – Company

In millions of US$	Share capital	Hedging reserve	Retained earnings/(deficit)	Total
At 1 January 2021	**1,977.2**	**(3.7)**	**75.2**	**2,048.7**
Profit for the year	-	-	389.5	389.5
Other comprehensive income	-	3.7	-	3.7
Total comprehensive income	-	**3.7**	**389.5**	**393.2**
Transactions with owners of the Company:				
Dividends declared (note 10)	-	-	(344.7)	(344.7)
Balance 31 December 2021	**1,977.2**	-	**120.0**	**2,097.2**
Profit for the year	-	-	142.9	142.9
Other comprehensive income	-	-	-	-
Total comprehensive income	-	-	**142.9**	**142.9**
Transactions with owners of the Company:				
Capital reduction (note 26)	(1,300.0)	-	1,300.0	-
Dividends declared (note 10)	-	-	(1,146.8)	(1,146.8)
Balance 31 December 2022	**677.2**	-	**416.1**	**1,093.3**

Consolidated cash flow statement – Group

Group In millions of US$	Notes	Year ended 31 December 2022	Year ended 31 December 2021
Cash flows from operating activities			
Profit before taxation		3,094.4	1,391.1
Adjustments to reconcile profit before tax to net cash flows:			
Depreciation and amortisation	6	539.7	575.1
Unsuccessful exploration costs written off	6	7.2	32.2
Impairment (reversals)/losses		-	(113.6)
Finance costs	9.2	175.3	176.7
Finance income	9.1	(89.1)	(53.1)
Share of net income from equity investments		(24.5)	(61.1)
Other non-cash income and expenses(1)		19.4	1.3
Mark-to-market on currency and commodity contracts	8	100.2	73.8
Movement in provisions including decommissioning expenditure	23	(228.4)	(98.4)
Working capital movements(2)		(66.6)	(283.4)
Income tax (paid)/received (net)		(1,153.0)	57.6
Net cash flows from operating activities		**2,374.6**	**1,698.2**
Cash flows from investing activities			
Expenditure on exploration and evaluation assets		(110.1)	(127.7)
Expenditure on property, plant and equipment		(523.3)	(619.4)
Proceeds from sale of assets and subsidiary		23.1	20.9
Dividends received		0.9	1.4
Finance income received		4.8	0.9
Net investment made in equity-accounted investments	15	8.0	(0.5)
Net cash flows used in investing activities		**(596.6)**	**(724.4)**
Cash flows from financing activities			
Loan advanced to parent company	17	-	(455.3)
Proceeds from loans and borrowings	20	2,667.0	2,959.5
Repayment of loans and borrowings	20	(2,987.0)	(2,667.4)
Repayment of obligations under leases		(85.8)	(107.4)
Finance costs paid		(122.4)	(125.2)
Dividends paid to parent company	10	(1,146.8)	(544.7)
Net cash flows used in financing activities		**(1,675.0)**	**(940.5)**
Net increase in cash and cash equivalents		103.0	33.3
Cash and cash equivalents at 1 January		125.5	92.5
Net foreign exchange differences		5.6	(0.3)
Cash and cash equivalents at 31 December	**18**	**234.1**	**125.5**

1. Other non-cash income and expenses mainly includes restructuring provision costs, release of contingent consideration and other losses and gains, see note 8.
2. Working capital movements include movements in trade and other receivables, trade and other payables, and inventory.

Cash flow statement – Company

Company In millions of US$	Notes	Year ended 31 December 2022	Year ended 31 December 2021
Cash flows from operating activities			
Profit before taxation		142.9	389.5
Adjustments to reconcile profit before tax to net cash flows:			
Depreciation, amortisation and provisions		1.3	2.4
Impairment losses	15	54.8	855.9
Finance costs		146.9	139.0
Finance income	9	(356.9)	(1,399.3)
Movement in provisions		0.3	0.6
Working capital movements		339.6	(1,021.4)
Net cash flows generated/(used) in operating activities		**328.9**	**(1,033.3)**
Cash flows from investing activities			
Dividends received from subsidiaries		356.8	1,399.3
Return of capital from investments		842.2	475.3
Capital injection to subsidiary	15	(1,175.6)	-
Net cash flows from investing activities		**23.4**	**1,874.6**
Cash flows from financing activities			
Proceeds from loans and borrowings		1,960.0	2,095.0
Repayment of loans and borrowings		(2,220.0)	(1,805.0)
Loan advanced from subsidiary company		1,175.6	-
Repayment of loan to parent company		-	(7.9)
Loan made to parent company	17	-	(455.3)
Repayment of obligations under leases		(1.1)	(1.3)
Dividends paid to parent company	10	(1,146.8)	(544.7)
Finance costs paid		(120.0)	(122.1)
Net cash flows used in financing activities		**(352.3)**	**(841.3)**
Net movement in cash and cash equivalents		-	-
Cash and cash equivalents at 1 January		-	-
Cash and cash equivalents at 31 December		**-**	**-**

The notes on page 47 to 103 form part of these accounts.

General information
Neptune Energy Group Holdings Limited is a limited company, incorporated and domiciled in the United Kingdom. The registered office is located at Nova North, 11 Bressenden Place, London SW1E 5BY.

The consolidated financial statements of Neptune Energy Group Holdings Limited and its subsidiaries (collectively, the Group) for the year ended 31 December 2022 were authorised for issue in accordance with a resolution of the Board on 8 March 2023.

The Group is principally engaged in oil and gas exploration and production, including energy transition projects.

1. Basis of preparation
The consolidated financial statements for the year ended 31 December 2022 have been prepared in accordance with UK adopted International Accounting Standards, which, for the accounting policies adopted by the Group, also remain fully aligned with EU IFRS.

The preparation of financial statements requires the use of certain critical accounting estimates. It also requires 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 statements, are disclosed below in note 1.3.

The Group has early adopted amendments to IAS 1 and IAS 8 (note 1.1).

Going concern

Given the total available liquidity as at 31 December 2022 of $1.2 billion, comprising our cash balance ($234.1 million) and available and undrawn headroom under the RBL facility ($995.0 million), and capital resources arrangements in place (see note 20), the consolidated accounts have been prepared on a going concern basis. As disclosed in the Group Overview section, the RBL is due to mature in the final quarter of the going concern period to 30 June 2024. The Group continues to work with the bank syndicate with a view to refinancing the RBL facility in the first half of 2023, however it is acknowledged that this is currently not committed. As such the going concern analysis reflects the RBL maturing in the final quarter of the going concern period, and no assumption has been made with respect to a refinancing of the facility.

The going concern basis is supported by future cash flow forecasts which project the Group's available liquidity and compliance with covenants through to 30 June 2024. The going concern cash flow forecasts reflect forecast production consistent with our Board-approved plans and externally published guidance, and commodity prices which reflect current market conditions.

In reaching the conclusion that the going concern basis is appropriate, stress testing of going concern cash flow forecasts and covenant compliance for the Group has been performed to evaluate the impact of plausible downside scenarios. These include scenarios that assume current commodity price levels as of early March 2023 are sustained through to 30 June 2024, which are significantly below the range of current market expectations for the going concern period. In addition, these scenarios consider the impact of unforeseen production outages. A reverse stress test has also been performed, which demonstrated that the Group is resilient to sustained low commodity prices more than 20% lower than those applied in the going concern cash flow forecast.

Under all plausible scenarios, it was concluded that the Group retains sufficient liquidity and headroom over its covenant ratios, and that the going concern basis remains appropriate. The likelihood of the circumstances identified in the reverse stress test materialising is considered remote on the basis of market consensus for short-term commodity prices.

1.1 New standards, interpretations and amendments adopted by the Group

Certain amended accounting standards and interpretations have been applied by the Group for the first time for the annual reporting period commencing on 1 January 2022. These have not had any material impact on the disclosures or on the amounts reported in these Consolidated Financial Statements, nor are they expected to significantly affect future periods. The adoptions made are as follows:

- Amendments to IAS 1 Presentation of Financial Statements issued February 2021 due to be effective for accounting periods commencing 1 January 2023. This amendment replaces the requirement for entities to disclose their 'significant' accounting policies with the requirement to disclose their 'material' accounting policies. The Group has early adopted this amendment.
- Amendments to *IAS 8 Accounting Policies, Changes to Accounting Estimates and Errors* issued February 2021 due to be effective for accounting periods commencing 1 January 2023. The amendments introduced a new definition of 'accounting estimates' and clarify the distinction between changes in accounting estimates, changes in accounting policies and the correction of errors. The Group has early adopted this amendment.

Several other financial reporting amendments and interpretations apply for the first time in 2022, but do not have a significant impact on the consolidated financial statements of the Group.

Furthermore, as at the date of authorisation of these financial statements there are certain other new and revised IFRS Standards that have been issued but are not yet effective. None of these items are expected to have a material impact on the financial statements of the Group in the future.

1.2 Measurement and presentation basis

The consolidated financial statements have been prepared on a historical cost basis, except for derivative financial instruments, debt and equity financial assets and contingent consideration that have been measured at fair value. The carrying values of recognised assets and liabilities that are designated as hedged items in fair value hedges that would otherwise be carried at amortised costs are adjusted to recognise changes in the fair value attributable to the risks that are being hedged in effective hedge relationships.

The consolidated financial statements are presented in US dollars and rounded to millions, except where otherwise indicated.

1.3 Significant judgements and estimates

Estimates and judgements are continually evaluated and are based on historical experiences and other factors, including expectations of future events that are believed to be reasonable under the circumstances.

1.3.1 Estimates

Accounting estimates are monetary amounts in financial statements that are subject to measurement uncertainty. The preparation of consolidated financial statements requires the use of estimates and assumptions to determine the value of assets and liabilities and contingent assets and liabilities at the reporting date, as well as revenues and expenses reported during the period.

The key estimates used in preparing the Group's consolidated financial statements relate mainly to:

- measurement of the recoverable amount of property, plant and equipment, other intangible exploration assets and goodwill;
- calculations of depreciation and amortisation which involve estimates of volumes of commercial reserves of oil and gas;
- measurement of provisions, particularly for decommissioning, pensions and post-employment obligations;
- measurement of recognised tax loss carry-forwards; and
- measurement of volume banking arrangements.

Each of these categories of key estimates are described further below. Due to uncertainties inherent in the estimation process, the Group regularly revises its estimates in light of currently available information. Final outcomes could differ from those estimates.

Recoverable amount of intangible assets and property, plant and equipment and goodwill

The recoverable amounts of intangible assets and property, plant and equipment and goodwill are based on estimates and assumptions, regarding in particular the expected market outlook (including future commodity prices) used for the measurement of cash flows, estimates of the volume of commercially recoverable reserves and resources of oil and gas future production rates and costs to develop reserves and resources, and the determination of the discount rate. Where relevant these estimates are based on life of field projections and generally only include sanctioned fields and projects.

Any changes in these assumptions may have a material impact on the measurement of the recoverable amount and could result in adjustments to any impairment losses to be recognised.

See notes 12, 13 and 14 for further information.

Commercial reserves and depreciation of oil and gas production assets
Charges for depreciation and amortisation of oil and gas producing properties are calculated on a unit of production rate based on production as a proportion of estimated quantities of proved and probable oil and gas reserves. The Group has adopted the definitions and guidelines presented in the Petroleum Resources Management System (SPE-PRMS 2018) for the classification and reporting of commercial reserves and resources of oil and gas. Commercial reserves are those in the proved and probable categories of reserves. See note 14 for further information on the depreciation and amortisation of the Group's assets.

Estimates of reserves is a subjective process involving estimating underground resource accumulations and recovery rates, and is a function of many factors, such as the properties of the reservoir rock and petroleum fluid. Changes in the estimates of commercial reserves will consequently impact depreciation and amortisation expense. Changes in factors or assumptions used in estimating reserves could include:

- changes due to revised estimates of volumes in place and recovery factors;
- the effect on proved and probable reserves of differences between actual commodity prices and assumptions;
- unforeseen operational issues; and
- see Supplementary Information Gas and Oil (unaudited) on page 104 for further information on reserves replacement.

Estimates of decommissioning provisions
Parameters having a significant influence on the amount of provisions for decommissioning costs include the forecast of costs to be incurred to decommission facilities, plug wells and restore sites used for production and drilling, the anticipated scope of such decommissioning obligations, which may depend on laws and regulation in force at the time, the timing of such expenditure and the discount rate applied to forecast cash flows. These parameters are based on information and estimates deemed to be appropriate by the Group at the current time.

The modification of certain parameters could involve a significant adjustment to these provisions.

See note 23 for further information.

Pensions and post–employment benefit obligations
Pension commitments are measured on the basis of actuarial assumptions. These include assumptions in respect of mortality rates and future salary increases, as well as appropriate discount rates. The Group considers that the assumptions used to measure its obligations are appropriate and documented. However, any changes in these assumptions may have a material impact on the resulting calculations.

Pension costs for interim periods are calculated on the basis of the actuarial valuations performed at the end of the prior year. If necessary, these valuations are adjusted to take account of curtailments, settlements or other major non-recurring events that have occurred during the period.

See note 29 for further information.

Measurement of recognised tax loss carry-forwards
Deferred tax assets are recognised on tax loss carry-forwards when it is probable that taxable profit will be available against which the tax loss carry-forwards can be utilised. The estimates of the taxable profit that will be available against which the unused tax losses can be utilised, are based on taxable temporary differences relating to the same taxation authority and the same taxable entity and estimated future taxable profits. These estimates are based on life of field projections and generally only include sanctioned fields and projects. Unsanctioned wells and fields may be included if future profits are considered to be probable in the relevant circumstances. The estimates use underlying assumptions on prices, capital and operating expenditure and reserves which are consistent with those used for asset impairment review. For example, oil and gas prices are based on internal view of management expectations derived from a market consensus for current prices transitioning to a long-term price in 2026 of $65/bbl for Brent crude oil and 75p/therm for NBP gas thereafter inflated by 2% per annum. See note 11 for further information.

Volume banking collaborative arrangements
The Group entered into arrangements with other oil and gas businesses which have resulted in the Group losing production as a result of the tie-in of new infrastructure to host facilities. Compensation for such disruption is provided by means of a non-monetary exchange of assets by the counterparty in the form of an entitlement to future produced volumes. In estimating the loss in volume, complex technical estimates have to be made to model the adverse effect on future reservoir performance due to the tie-in. These estimates are then refined over a number of periods as actual reservoir performance data becomes available.

Climate change
The Group recognises that there may be potential financial implications in the future from changes in legislation and regulation implemented to address climate change risk. While these changes will result in intended benefits, they are likely to increase associated costs and administration requirements and could potentially also reduce the investment capital available to the industry. Over time these changes may well have an impact across a number of areas of accounting including asset impairment, increased costs, onerous contracts and contingent liabilities. However, as at the balance sheet date, the Group believes there is no material impact on balance sheet carrying values of assets or liabilities. Although this is an estimate, it is not currently considered a critical estimate.

We have considered climate-related estimates and assumptions in assessing the recoverable amounts of intangible assets, property, plant and equipment and goodwill, which includes costs for CO_2 emission allowances and satisfying current regulatory requirements. The Group constantly monitors the latest government legislation in relation to climate related matters. At the current time, no legislation has been passed that will further impact the Group. The Group will adjust the key assumptions used in the fair value less cost of sales calculation and sensitivity to changes in assumptions should a change be required.

1.3.2 Judgements
As well as relying on estimates, the Directors make judgements to define the appropriate accounting policies and decisions to apply to certain activities and transactions, including when the effective IFRS standards and interpretations do not specifically deal with the related accounting issues. Key areas of judgement include:

Carrying value of intangible exploration and evaluation assets: the amounts capitalised for exploration and evaluation assets represent cost in respect of active exploration and appraisal projects. These amounts will be written off to the income statement as exploration expense unless commercial reserves are established or the determination process as to the success or otherwise of the activity is not yet completed and there are no indications of impairment in accordance with the Group's accounting policy. The process of determining whether there is an indicator of impairment or calculating the impairment requires critical judgement, including: the Group's intention to proceed with a future work programme for a prospect or licence; the likelihood of licence renewal or extension; the assessment of whether sufficient data exists to indicate that, although a development in the specific area is likely to proceed, the carrying amount of the exploration and evaluation asset is unlikely to be recovered in full from successful development or by sale; and the success of a well result.

Commercial reserves: the estimation of commercial reserves of oil and gas in accordance with SPE-PRMS guidelines, as outlined above, involves complex technical judgements. These complex technical judgements include estimates of oil and gas in place, recovery factors and future commodity prices which have an impact on the total amount of recoverable reserves. Future development costs are estimated taking into consideration the level of development required based on internal functional specialists or operator assessments, where applicable.

Recognition of income from the call of a performance guarantee: the Group may enter into business relationships with counterparties for specific projects such that the future success of these projects is dependent upon the performance of those counterparties. In these instances, it is common for the Group to agree contractual terms which define the expected future performance of the counterparty and, where a counterparty does not meet the required levels of future performance, monetary compensation is to be provided to the Group. In valuing such compensation judgements are required, these include the likelihood that a call on a performance guarantee will be successful and whether the compensation provided represents income or a repayment of a revenue or capital expenditure. Where the contract specifies a penalty clause for non-performance that is linked to compensation for loss of revenue, any recovery would normally be treated as income, elsewise as a reimbursement of a revenue or capital expenditure.

Material accounting policies

1.4 Basis of consolidation

Subsidiaries and business combinations

Subsidiaries are all entities over which the Group has control. The Group consolidates an entity when it is exposed to, or has rights to, variable returns from its involvement with the entity and has the ability to affect those returns through its power over the entity. Subsidiaries are fully consolidated from the date on which control is transferred to the Group (the acquisition date).

Inter-company transactions, balances and unrealised gains on transactions between Group companies are eliminated. Unrealised losses are also eliminated.

Where necessary, amounts reported by subsidiaries have been adjusted to conform with the Group's accounting policies.

The Group applies the acquisition method to account for business combinations. The consideration transferred for the acquisition of a subsidiary is the fair value of the assets transferred, the liabilities incurred to the former owners of the acquiree, and the equity interests issued by the Group. The consideration transferred includes the fair value of any asset or liability resulting from a contingent consideration arrangement.

Identifiable assets acquired, and liabilities and contingent liabilities assumed in a business combination, are measured initially at their fair value at the acquisition date. The fair value of acquired oil and gas properties is based on the post-tax net present value of expected future cash flows. The fair values of assets and liabilities acquired which are initially recognised at provisional amounts may be adjusted within 12 months of the acquisition date based on the assessment of additional data relating to the conditions of items as at the acquisition date.

Acquisition-related costs of a business combination are expensed as incurred.

Any contingent consideration to be transferred by the Group is recognised at fair value at the acquisition date. Subsequent changes to the fair value of the contingent consideration are recognised in accordance with IFRS 9 in profit or loss.

Goodwill arising in a business combination is recognised as an asset at the acquisition date. Goodwill is measured as the excess of the sum of the consideration transferred over the net of the acquisition-date amounts of the identifiable assets acquired and the liabilities assumed. After initial recognition, goodwill is measured at cost less any accumulated impairment losses. For the purpose of impairment testing, goodwill acquired in a business combination is, from the acquisition date, allocated to each of the Group's cash-generating units (CGUs) that are expected to benefit from the combination, irrespective of whether other assets or liabilities of the acquiree are assigned to those units.

Where goodwill has been allocated to a CGU and part of the operation within that unit is disposed of, the goodwill associated with the disposed operation is included in the carrying amount of the operation when determining the gain or loss on disposal. Goodwill disposed in these circumstances is measured based on the relative values of the disposed operation and the portion of the CGU retained. The carrying value of goodwill is reviewed at least annually at the end of the financial year or following a trigger event.

If the Group's interest in the fair value of the acquiree's identifiable net assets exceeds the sum of the consideration transferred, the excess is recognised immediately in net income.

For the Company, fixed asset investments, including investment in subsidiaries, are stated at cost and reviewed for impairment if there are any indications that the carrying value may not be recoverable.

Investments in joint operations and joint ventures

A Joint Arrangement is one in which two or more parties have joint control and may take the form of a joint operation or a joint venture. Joint control is the contractually agreed sharing of control of an arrangement, which exists when decisions about the relevant activities require the unanimous consent of the parties sharing control.

Most of the Group's activities are conducted through joint operations, whereby the parties that have joint control of the arrangement have rights to the underlying assets, and obligations for the liabilities, relating to the arrangement. The Group reports its share of the assets, liabilities, income and expenses of the joint operation within the equivalent items in the consolidated financial statements, on a line-by-line basis. Certain of the Group's joint operations derive from production sharing contracts (PSCs), entered into with host governments or their agencies. PSCs typically result in economic rights similar to other licence and concession arrangements and are accounted for using the same line-by-line basis, with the Group using an appropriate unit of production basis to recognise its share of production and reserves attributable to the PSC.

A joint venture, which normally involves the establishment of a separate legal entity, is a contractual arrangement whereby the parties that have joint control of the arrangement have the rights to the arrangement's net assets. The results, assets and liabilities of a joint venture are incorporated in the consolidated financial statements using the equity method.

Interests in associates
An associate is an entity over which the Group has significant influence, through the power to participate in the financial and operating policy decisions of the investee, but which is not a subsidiary or a Joint Arrangement. Interests in associates are accounted for using the equity method.

1.5 Foreign currency translation
Presentation and functional currency
Items included in the consolidated financial statements are measured using the currency of the primary economic environment in which each Group company operates (its functional currency). The financial statements are presented in US dollars, which is the Company's presentation and functional currency.

Transactions and balances
Foreign currency transactions are translated into the functional currency using exchange rates prevailing at the dates of the transactions. Monetary assets and liabilities denominated in foreign currencies are remeasured at the end of each accounting period. Foreign exchange gains and losses resulting from the settlement or revaluation of monetary assets and liabilities denominated in foreign currencies are recognised in the income statement, except when deferred in other comprehensive income as qualifying cash flow hedges and qualifying net investment hedges (if applicable). Foreign exchange gains and losses included in net income are presented within 'Foreign exchange gain/loss' as part of financial income/expense.

Group companies
The results and financial position of all of the Group entities (none of which has the currency of a hyper-inflationary economy) that have a functional currency different from the presentation currency are translated into the presentation currency as follows:

- assets and liabilities for each balance sheet presented are translated at the closing rate at the date of that balance sheet;
- income and expenses for each income statement are translated at average exchange rates (unless this average is not a reasonable approximation of the rates prevailing on the transaction dates, in which case income and expenses are translated at the rate on the dates of each transaction);
- the exchange differences arising on translation for consolidation are recognised in other comprehensive income; and
- any goodwill arising on the acquisition of a foreign operation and any fair value adjustments to the carrying amounts of assets and liabilities arising on the acquisition are treated as assets and liabilities of the foreign operation and are translated at the spot rate of exchange at the reporting date.

1.6 Intangible assets
Intangible assets (other than goodwill and exploration and evaluation rights) are carried at cost less any accumulated amortisation and any accumulated impairment losses. These assets principally comprise IT software and are amortised on a straight-line basis over their useful economic lives, typically three to five years.

1.7 Assets relating to the exploration and production of mineral resources

i) Acquisition costs of unproved properties: exploration licences and concessions correspond to licences or rights acquired in areas in which the existence of oil and gas reserves has not yet been demonstrated. The costs of acquiring such exploration licences are capitalised within intangible assets.
ii) Exploration and evaluation costs: the Group adopts the successful efforts method of accounting for exploration and evaluation costs. Costs incurred prior to the award of a licence are expensed in the period in which they are incurred. The costs of geological and geophysical surveys and studies are expensed in the period incurred. Exploration and appraisal drilling costs are capitalised in cost centres by well, field or exploration area, as appropriate, pending the results of the exploration activities. Internal costs are expensed unless directly attributed to drilling operations. Costs are then written off as exploration expense in the income statement unless commercial reserves have been established or if the determination process has not been completed and there are no indications of impairment. When the exploratory phase has resulted in the recognition of commercial reserves, the related

costs are first assessed for impairment and (if required) any impairment recognised, then the remaining balance is transferred to property, plant and equipment.

iii) Property, plant and equipment: expenditure on the acquisition of proved properties and on the construction, installation or completion of facilities such as platforms, pipelines and the drilling of development wells, including any development or delineation wells, is capitalised within oil and gas properties – PP&E. In accordance with IAS 16, the initial cost of assets relating to the exploration and production includes an initial estimate of the costs of decommissioning and restoring the site on which the facilities are located when production operations cease, when the entity has a present legal or constructive obligation for decommissioning or to restore the site. A corresponding provision for this decommissioning obligation is recorded for the amount of the asset component.

iv) Borrowing costs that are directly attributable to the construction of the qualifying asset are capitalised as part of the cost of that asset.

v) Depreciation of production assets: the depreciation of production assets, including decommissioning costs, starts when the oil or gas field is brought into production, and is based on the unit of production method. According to this method, the depletion rate is equal to the ratio of oil and gas production for the period to proved and probable reserves, as applied to the capitalised cost plus future estimated costs to develop those reserves.
Pipeline assets are depreciated on a straight-line basis over a period not exceeding the projected useful economic life of the asset.

vi) Recognition and derecognition of assets: acquired assets are valued at their purchase price and assessed for impairment (if required). An item of property, plant and equipment is derecognised upon disposal or when no future economic benefits are expected to arise from the continued use of the asset. Any gain or loss arising on derecognition of the asset (calculated as the difference between the net disposal proceeds and the carrying amount of the item) is included in the income statement in the period in which the item is derecognised.

1.8 Other property, plant and equipment

Items of property, plant and equipment are recognised at cost and are subsequently carried at their historical cost less any accumulated depreciation and any accumulated impairment losses.

1.9 Depreciation

Property, plant and equipment, other than assets related to exploration and production of mineral resources, is depreciated using the straight-line method over the following useful lives:

Main depreciation periods (years)	
Office and computer equipment	3 to 5 years
Freehold and leasehold improvements [1]	up to 50 years
Plant and machinery	5 to 40 years

1. Leasehold improvements are depreciated over the shorter of the useful life and lease term.

1.10 Impairment of property, plant and equipment and intangible assets including goodwill and equity-accounted investments

In accordance with IAS 36, impairment tests are carried out on items of property, plant and equipment and intangible assets where there is an indication that the assets may be impaired. Such indications may be based on events or changes in the market environment, or on internal sources of information.

Impairment indicators

Property, plant and equipment and intangible assets with finite useful lives are only tested for impairment when there is an indication that they may be impaired. This is generally the result of significant changes to the environment in which the assets are operated or when asset performance is worse than expected.

The main impairment indicators used by the Group are described below:

- external sources of information:
  - significant changes in the economic, technological, political or market environment in which the entity operates or to which an asset is dedicated;
  - fall in demand; and
  - changes in energy prices and exchange rates.
- internal sources of information:
  - evidence of obsolescence or physical damage not budgeted for in the depreciation/amortisation schedule;

- worse-than-expected production or cost performance;
- reduction in reserves and resources, including as a result of unsuccessful results of drilling operations;
- pending expiry of licence or other rights; and
- in respect of capitalised exploration and evaluation costs, lack of planned future activity on the prospect or licence.

Measurement of recoverable amount
In order to review the recoverable amount in an impairment test, the assets are grouped, where appropriate, into cash-generating units and the carrying amount of each unit is compared with its recoverable amount.

For operating entities that the Group intends to hold on a long-term and going concern basis, the recoverable amount of an asset corresponds to the higher of its fair value less costs to sell and its value in use. The recoverable amount is primarily determined based on the fair value less cost of disposal method. Standard valuation techniques are used based on the discount rates based on the specific characteristics of the operating entities concerned; discount rates are determined on a post-tax basis and applied to post-tax cash flows. The recoverable amounts calculated on the basis of these discount rates are the same as the amounts obtained by applying the pre-tax discount rates to cash flows estimated on a pre-tax basis, as required by IAS 36.

Any impairment loss is recorded in the consolidated income statement under 'Impairment losses'.

Impairment losses recorded in relation to property, plant and equipment may be subsequently reversed if the recoverable amount of the assets subsequently increases above carrying value. The increased carrying amount of an item of property, plant or equipment attributable to a reversal of an impairment loss may not exceed the carrying amount that would have been determined (net of depreciation/amortisation) had no impairment loss been recognised in prior periods. Impairment losses in respect of intangible assets may not be reversed on a future change in circumstances that led to the impairment.

Goodwill
Goodwill is not amortised but is reviewed for impairment at least annually. For the purpose of impairment testing, goodwill is allocated to each of the Group's cash-generating units (CGUs) expected to benefit from the business combination. Country groups of CGUs to which goodwill has been allocated are tested for impairment annually, or more frequently when there is an indication the unit may be impaired. If the recoverable amount of the group of CGUs is less than the carrying amount of the unit, the impairment loss is allocated first to reduce the carrying amount of any goodwill allocated to the unit and then to the other assets of the unit pro-rata on the basis of the carrying amount of each asset in the unit. An impairment loss recognised for goodwill is not reversed in a subsequent period.

On disposal of a subsidiary, the attributable amount of goodwill is included in the determination of the profit or loss on disposal.

1.11 Leases
The Group assesses at contract inception whether a contract is, or contains, a lease. That is, if the contract conveys the right to *control the use of an identified asset for a period of time in exchange for consideration.*

Group as a lessee
The Group applies a single recognition and measurement approach for all leases, except for short-term leases and leases of low-value assets. The Group recognises lease liabilities to make lease payments and right-of-use assets representing the right to use the underlying assets.

1.11.1a Right-of-use assets
The Group recognises right-of-use assets at the commencement date of the lease (i.e. the date the underlying asset is available for use). Right-of-use assets are measured at cost, less any accumulated depreciation and impairment losses, and adjusted for any remeasurement of lease liabilities. The cost of right-of-use assets includes the amount of lease liabilities recognised, initial direct costs incurred, and lease payments made at or before the commencement date less any lease incentives received. Right-of-use assets are depreciated on a straight-line basis over the lease term, as follows:

Right-of-use assets depreciation periods (years)	
Land	up to 23 years
Buildings	2 to 10 years
Transportation	2 to 5 years
Property, plant and equipment	5 years

The right-of-use assets are also subject to impairment.

1.11.1b Right-of-use assets - assets within Joint Arrangements
The Group recognises the gross value of any right-of-use assets within Joint Arrangements where it is the sole signatory of the lease unless the arrangement between the Group and the joint operation represents a sub-lease. Where a sub-lease exists, and the Joint Arrangement receives substantially all the risks and rewards incidental to ownership then the Group derecognises the portion of the right-of-use asset that is sublet and recognises a Joint Arrangement receivable. Where the Group is a co-signatory to a Joint Arrangement, the Group recognises the Group's Joint Arrangement share of the right-of-use-asset. Where the Group is not a signatory to a Joint Arrangement lease, the Group recognises the Group's Joint Arrangement share of the right-of-use-asset only when it has a right to control the use of the asset. Where the Group has no control then no Joint Arrangement asset is recognised.

1.11.2a Lease liabilities
At the commencement date of the lease, the Group recognises lease liabilities measured at the present value of lease payments to be made over the lease term. The lease payments include fixed payments (including in substance fixed payments) less any lease incentives receivable, variable lease payments that depend on an index or a rate, and amounts expected to be paid under residual value guarantees. The lease payments also include the exercise price of a purchase option reasonably certain to be exercised by the Group and payments of penalties for terminating the lease, if the lease term reflects the Group exercising the option to terminate. Variable lease payments that do not depend on an index or a rate are recognised as expenses in the period in which the event or condition that triggers the payment occurs. In calculating the present value of lease payments, the Group uses its incremental borrowing rate at the lease commencement date because the interest rate implicit in the lease is not readily determinable. After the commencement date, the amount of lease liabilities is increased to reflect the accretion of interest and reduced for the lease payments made. In addition, the carrying amount of lease liabilities is remeasured if there is a modification, a change in the lease term, a change in the lease payments (e.g. changes to future payments resulting from a change in an index or rate used to determine such lease payments) or a change in the assessment of an option to purchase the underlying asset. The Group's lease liabilities are included in note 22.

1.11.2b Lease liability - Joint Arrangement liabilities
The Group recognises the gross value of any right-of-use Joint Arrangement lease liability where it is the sole signatory. Where the Group is a co-signatory to a lease in a Joint Arrangement, the Group recognises the Group's Joint Arrangement share of the right-of-use lease liability. Where the Group is not a signatory to a Joint Arrangement lease, the Group recognises the Group's Joint Arrangement share of the right-of-use lease liability only when it has a right to control the use of the lease. Where the Group has no control, then no right-of-use lease liability is recognised.

1.11.3 Short-term leases and leases of low-value assets
The Group applies the short-term lease recognition exemption to its short-term leases of machinery and equipment (i.e. those leases that have a lease term of 12 months or less from the commencement date and do not contain a purchase option). It also applies the lease of low-value assets recognition exemption to leases of office equipment that are considered to be low value. Lease payments on short-term leases and leases of low-value assets are recognised as an expense on a straight-line basis over the lease term.

1.12 Inventories
Inventories of equipment and materials are measured at the lower of cost and net realisable value. Cost is determined based on the first-in, first-out method or the weighted average cost formula.

An impairment loss is recognised when the net realisable value of inventories is lower than their weighted average cost.

Hydrocarbon inventories are stated at net realisable value with movements in value recognised in the profit and loss account. Net realisable value corresponds to the estimated selling price in the ordinary course of business, less the estimated costs of completion and the estimated costs necessary to make the sale.

See also 1.20 'Revenue', regarding volumes of under and over lifted entitlement to production.

1.13 Financial instruments
Financial instruments are recognised and measured in accordance with IFRS 9.

1.14 Financial assets

Financial assets comprise loans and receivables carried at amortised cost, including trade and other receivables and receivables from joint venture partners, and financial assets measured at fair value through income, including certain derivative financial instruments. Financial assets are analysed into current and non-current assets in the consolidated statement of financial position.

Loans and receivables carried at amortised cost

This item primarily includes loans and advances to associates or non-consolidated companies, guarantee deposits, trade and other receivables.

On initial recognition, these loans and receivables are recorded at fair value plus transaction costs. At each statement of financial position date, they are measured at amortised cost using the effective interest rate method.

Leasing guarantee deposits are recognised at their nominal value.

On initial recognition, trade and other receivables are recorded at fair value, which generally corresponds to their nominal value. Impairment losses are recorded based on the estimated risk of non-recovery. Trade receivables are stated net of provisions. The Group has used the simplified approach in calculating expected credit losses for trade receivables that do not contain a significant financing component. Trade receivables are generally settled on a short time frame and the Group's other financial assets are due from counterparties without material credit risk. The Group applies the practical expedient to calculate expected credit losses using a provision matrix considering how current and forward-looking information may affect our customers' historical default rates and, consequently, how the information would affect their current expectations and estimates of expected credit losses.

Financial assets are derecognised when the rights to receive cash flows from the financial assets have expired or have been transferred and the entity has transferred substantially all the risks and rewards of ownership. If the entity neither retains nor transfers substantially all the risks and rewards, but has not retained control of the financial assets, it also derecognises the assets.

The Group considers a financial asset to be in default when internal or external information indicates that the Group is unlikely to receive the outstanding contractual amounts in full before taking into account any credit arrangements held by the Group. A financial asset is written off when there is no reasonable expectation of recovering the contractual cash flows.

1.15 Derivatives and hedge accounting – Assets and Liabilities

Derivative financial instruments are contracts: (i) whose value changes in response to the change in one or more observable variables; (ii) that do not require any material initial net investment; and (iii) that are settled at a future date. Derivative instruments include swaps, options, futures and swaptions, as well as forward commitments to purchase or sell listed and unlisted securities, and firm commitments or options to purchase or sell non-financial assets that involve physical delivery of the underlying.

The Group uses derivative financial instruments to manage and reduce its exposure to market risks arising from fluctuations in interest rates, foreign currency exchange rates and commodity prices including emissions, mainly for oil and gas. The use of derivative instruments is governed by a Group policy for managing interest rate, currency and commodity risks.

The Group's hedging policy is to ensure that in relation to its debt facilities and the borrowing base assets, the Group has:

a) appropriate controls governing its use of financial derivative transactions; and
b) a prudent and cost-efficient approach to mitigating its exposure to fluctuations in:
    i) commodity prices in energy markets; and
    ii) foreign exchange and interest rates in capital markets.

Hedging instruments: recognition and presentation

Derivative instruments qualifying as hedging instruments are recognised in the consolidated statement of financial position within current assets or liabilities if expiry is less than 12 months, or as non-current items if expiring after 12 months and measured at fair value.

Cash flow hedges

A cash flow hedge is a hedge of the exposure to variability in cash flows that could affect the Group's profit or loss. The hedged cash flows may be attributable to a particular risk associated with a recognised financial or non-financial asset or a highly probable forecast transaction.

The portion of the gain or loss on the hedging instrument that is determined to be an effective hedge is recognised directly in other comprehensive income (OCI), net of tax, while the ineffective portion is recognised as part of 'other operating losses/gains' in the consolidated income statement. The gains or losses accumulated in OCI are reclassified to the consolidated income statement under the same caption as the loss or gain on the hedged item – i.e. within current operating income for operating cash flows and financial income or expenses for other cash flows – in the same periods in which the hedged cash flows affect profit or loss.

If the hedging relationship is discontinued, the cumulative gain or loss on the hedging instrument remains recognised in OCI until the forecast transaction occurs. However, if a forecast transaction is no longer expected to occur, the cumulative gain or loss on the hedging instrument is immediately recognised in the consolidated income statement.

Identification and documentation of hedging relationships
The hedging instruments and hedged items are designated at the inception of the hedging relationship. The hedging relationship is formally documented in each case, specifying the risk management strategy, risk management objective, the hedged risk, sources of hedge ineffectiveness and the methods used to assess hedge effectiveness. Sources of hedge ineffectiveness include mismatch in payment dates and off-market hedges for acquired hedges. Only derivative contracts entered into with external counterparties are considered as being eligible for hedge accounting.

The Group establishes its hedge ratio by considering hedging items as a proportion of post-tax production. Hedge effectiveness is assessed and documented at the inception of the hedging relationship and on an ongoing basis throughout the periods for which the hedge was designated. Hedge effectiveness is demonstrated prospectively using various methods, based mainly on a qualitative assessment of the critical terms of the hedging instrument and the hedged item as to whether their values will generally move in the opposite direction because of the same risk being hedged. Methods based on a regression analysis of statistical correlations between historical price data are also used.

Upon the designation of option instruments as hedging instruments, the intrinsic and time value components are separated, with only the intrinsic component being designated as the hedging instrument and the time value component is deferred in OCI as a cost of hedging.

Derivative instruments not qualifying for hedge accounting: recognition and presentation
These items mainly include derivative financial instruments used in economic hedges that have not been or are no longer documented as hedging relationships for accounting purposes.

When a derivative financial instrument does not qualify or no longer qualifies for hedge accounting, changes in fair value are recognised directly in net income as 'Mark-to-market on derivative instruments' in 'Other operating gains/losses'.

Derivative instruments not qualifying for hedge accounting and other derivatives expiring in less than 12 months are recognised in the consolidated statement of financial position in current assets and liabilities, while derivatives expiring after this period are classified as non-current items.

Fair value measurement
The fair value of instruments listed on an active market is determined by reference to the market price. In this case, these instruments are presented in Level 1 of the fair value hierarchy.

The fair value of unlisted financial instruments for which there is no active market, and for which observable market data exist, is determined based on valuation techniques such as option pricing models or the discounted cash flow method.

Models used to evaluate these instruments take into account assumptions based on market inputs:
- the fair value of interest rate swaps is calculated based on the present value of future cash flows. Cash flows are discounted using standard valuation techniques and observable market-based inputs, including interest rate curves, having regard to the timing of the cash flows; and
- commodity derivatives contracts are valued by reference to observable market-based inputs based on the present value of future cash flows (commodity swaps or commodity forwards) or option pricing models (options), which factor in market price volatility. Contracts with maturities exceeding the depth of transactions for which prices are observable, or which are particularly complex, may be valued based on internal assumptions.

These instruments are presented in level 2 of the fair value hierarchy except when the evaluation is based mainly on data that are not observable; in this case they are presented in level 3 of the fair value hierarchy.

Equity investments are valued using the market approach based on a multiple of EBITDA consistent with the valuation obtained for transactions involving investments similar in nature.

To comply with the provisions of IFRS 13, the Group incorporates credit and/or debit valuation adjustments to reflect appropriately both its own non-performance risk and the respective counterparty's non-performance risk in the fair value measurements. In adjusting the fair value of its derivative contracts for the effect of non-performance risk, the Group has considered the impact of netting and any applicable credit enhancements, such as collateral postings, thresholds, mutual puts, and guarantees.

Equity investments held at fair value through OCI
Where the Group holds an equity investment primarily for strategic purposes, the Group may on initial recognition elect to recognise any change in the fair value through OCI. Under this method, changes in the valuation of the investment are never reclassified to profit and loss, even if the asset is impaired, sold or otherwise derecognised. Where the Group holds an equity investment that is not for strategic purposes, following its initial recognition, any subsequent change in the valuation is recognised through fair value profit and loss.

1.16 Financial liabilities
Financial liabilities include borrowings, trade and other payables, derivative financial instruments and other financial liabilities. Financial liabilities are broken down into current and non-current liabilities in the consolidated statement of financial position. Current financial liabilities primarily comprise:

- financial liabilities with a settlement or maturity date within 12 months after the reporting date;
- financial liabilities in respect of which the Group does not have an unconditional right to defer settlement beyond 12 months after the reporting date;
- derivative financial instruments qualifying as fair value hedges where the underlying is classified as a current item (see note 1.15); and
- commodity trading derivatives not qualifying as hedges (see note 1.15).

Measurement of borrowings
Borrowings are measured at amortised cost using the effective interest rate method. On initial recognition, any issue or redemption premiums and discounts and issuing costs are added to/deducted from the nominal value of the borrowings concerned. These items are taken into account when calculating the effective interest rate and are therefore recorded in the consolidated income statement over the life of the borrowings using the amortised cost method.

1.17 Cash and cash equivalents
Cash and cash equivalents in the statement of financial position comprise cash at banks and on hand, short-term deposits with a maturity of three months or less and highly liquid investments which are subject to an insignificant risk of changes in value. For the purpose of the consolidated statement of cash flows, cash and cash equivalents consist of cash and short-term deposits, as defined above, net of outstanding bank overdrafts, as they are considered an integral part of the Group's cash management.

1.18 Non-current assets held for sale and discontinued operations
The Group classifies non-current assets and disposal groups as held for sale if their carrying amounts will be recovered principally through a sale transaction rather than through continuing use. Non-current assets and disposal groups classified as held for sale are measured at the lower of their carrying amount and fair value less costs to sell. Costs to sell are the incremental costs directly attributable to the disposal of an asset (disposal group), excluding finance costs and income tax expense. The criteria for held for sale classification is regarded as met only when the sale is highly probable, and the asset or disposal group is available for immediate sale in its present condition. Actions required to complete the sale should indicate that it is unlikely that significant changes to the sale will be made or that the decision to sell will be withdrawn. Management must be committed to the plan to sell the asset and the sale expected to be completed within one year from the date of the classification. Property, plant and equipment and intangible assets are not depreciated or amortised once classified as held for sale. Assets and liabilities classified as held for sale are presented separately as current items in the statement of financial position.

1.19 Provisions

1.19.1 General

Provisions are recognised when the Group has a present obligation (legal or constructive) as a result of a past event, it is probable that an outflow of resources embodying economic benefits will be required to settle the obligation and the amount of the obligation can be estimated reliably.

Provisions are reviewed at the end of each reporting period and adjusted to reflect the current best estimate. If it is no longer probable that an outflow of economic resources will be required to settle the obligation, the provision is reversed. If the effect of the time value of money is material, provisions are discounted using a current pre-tax rate that reflects, where appropriate, the risks specific to the liability. When discounting is used, the increase in the provision due to the passage of time is recognised as a finance cost.

1.19.2 Provisions for post-employment benefit obligations and other long-term employee benefits

Depending on the laws and practices in force in the countries where the Group operates, Group companies have obligations in terms of pensions, early retirement payments, retirement bonuses and other post-employment benefit plans.

The Group's obligations in relation to pensions and other employee benefits are recognised and measured in compliance with IAS 19. Accordingly:

- the cost of defined contribution plans is expensed based on the amount of contributions payable in the period. The Group's legal or constructive obligation for these plans is limited to the contributions paid; and
- the Group's obligations concerning pensions and other employee benefits payable under defined benefit plans are assessed on an actuarial basis using the projected unit credit method. These calculations are based on assumptions relating to mortality, staff turnover and estimated future salary increases, as well as the economic conditions specific to each country or subsidiary of the Group. Discount rates are determined by reference to the yield, at the measurement date, on high-quality corporate bonds in the related geographical area (or on government bonds in countries where no representative market for such corporate bonds exists).

Provisions are recorded when commitments under these plans exceed the fair value of plan assets. Where the value of plan assets (capped where appropriate) is greater than the related commitments, the surplus is recorded as an asset under 'Other assets' (current or non-current).

As regards post-employment benefit obligations, actuarial gains and losses are recognised in other comprehensive income. Where appropriate, adjustments resulting from applying the asset ceiling to net assets relating to overfunded plans are treated in a similar way. The Group's net obligation in respect of long-term employee benefits is the amount of future benefit that employees have earned in return for their service in the current and prior periods. That benefit is discounted to determine its present value. Remeasurements are recognised in profit or loss in the period in which they arise.

Net interest on the net defined benefit liability/(asset) is presented in net finance cost/(income).

1.19.3 Decommissioning costs

A provision is recognised when the Group has a present legal or constructive obligation to plug wells, dismantle facilities or to restore a site. An asset is recorded simultaneously by including this decommissioning obligation in the carrying amount of the facilities concerned. Adjustments to the provision due to subsequent changes in the expected outflow of resources, the decommissioning date or the discount rate are deducted from or added to the cost of the corresponding asset. The impact of unwinding the discount (accretion) is recognised as finance cost for the period.

Provisions with a maturity of over 12 months are discounted when the effect of discounting is material. The discount rate (or rates) used reflect current market assessments of the time value of money, based on the relevant risk-free rate, adjusted if appropriate for any risks specific to the liability concerned.

1.20 Revenue

Revenue is recognised when the Group satisfies a performance obligation by transferring oil and gas to a customer. The title to oil and gas typically transfers to a customer at the same time as the customer takes physical possession of the commodity, which is when the performance obligation is fully satisfied.

Differences may arise in a joint operation between the Group's share of production entitlement from an oil or gas field and the volume which has been lifted and sold. Such 'under or over lift' entitlements are recognised in current assets or liabilities, respectively, at net realisable value, with a corresponding adjustment through production costs. As a result, the reported operating result for each period reflects the Group's share of actual sales of production in that period.

The Group recognises its share of LNG revenues in respect of its Indonesian production sharing contracts based on its contractual share of actual liftings. Revenues include volumes allocated to the Group for sale as reimbursement of costs of operation of the LNG processing facility, with corresponding costs included as operating expenses.

The Group enters into take-or-pay arrangements where customers have a right to take make-up product in the future. The Group recognises deferred revenue equal to the amount paid for the 'undertake' as it represents an obligation to provide the product in the future. The Group only recognises revenue once the product has been taken by the customer. Only once the make-up period has expired or it is clear that the purchaser has been unable to take the product, would the liability be eliminated and revenue recognised.

Under IFRS 15, if the Group expects to be entitled to a breakage amount, the expected 'breakage' would be recognised as revenue in proportion to the pattern of rights exercised by the customer. Otherwise, breakage amounts would be recognised when the likelihood of the customer exercising its right becomes remote.

Gas banking represents volume banking collaborative arrangements which arise within the ordinary course of business during the tie-in of new infrastructure to host facilities. This results in the deferral of production from the field disrupted by the tie-in and can also result in a permanent loss of recoverable volume. Where there is a loss in volume that is to be compensated, other revenue is recorded applying IAS 37 when recovery is considered to be virtually certain as entitlement to recover those volumes arises, along with a corresponding other receivable. For lost volumes, when the allocated production is delivered and sold, the other receivable is derecognised. For deferred volumes, when the volumes are produced and sold, the Group recognises revenue as per the revenue recognition policy as described above.

Other operating income includes income that is associated with a company's activities but that falls outside the definition of revenue. Amounts shown in other operating income are typically incidental to the main activities of the company or are different in nature from amounts included in revenue. These include loss of production and gas banking. Loss of production insurance proceeds are recognised as other operating income when their recovery is deemed to be virtually certain.

Further information regarding segmental analysis is contained in note 5.

1.21 Consolidated cash flow statement

The consolidated statement of cash flows is prepared using the indirect method starting from profit before tax. 'Interest received on non-current financial assets' is classified within investing activities because it represents a return on investments. 'Interest received on cash and cash equivalents' is shown as a component of financing activities because the interest can be used to reduce borrowing costs. This classification is consistent with the Group's internal organisation, where debt and cash are managed centrally by the treasury department.

Cash flows relating to the payment of income tax are presented on a separate line of the consolidated statement of cash flows.

1.22 Taxation

Current tax, including corporation tax and foreign tax, is provided at amounts expected to be paid (or recovered) using the tax rates and laws that have been enacted or substantively enacted by the balance sheet date. Tax is recognised in the income statement, except to the extent that it relates to items recognised directly in equity. In this case, the tax is recognised in equity. Management periodically evaluates positions taken in the tax returns with respect to situations in which applicable tax regulations are subject to interpretation and establishes provisions where appropriate.

Deferred tax is recognised in respect of all temporary differences identified at the balance sheet date, except to the extent that the deferred tax arises from the initial recognition of goodwill or the initial recognition of an asset or liability in a transaction which is not a business combination and at the time of the transaction affects neither accounting profit nor taxable profit and loss. Temporary differences are differences between the carrying amount of the Company's assets and liabilities and their tax base. Deferred tax assets are recognised only to the extent that the deductible temporary differences will reverse in the future and it is probable that there will be sufficient taxable profit available against which the temporary differences can be utilised. The amount of deferred tax provided is using tax rates that have been enacted or substantively enacted at the balance sheet date. Deferred taxes are reviewed at least annually at the end of the financial year to take into account factors including the impact of changes in tax laws and the prospects of recovering deferred tax assets arising from deductible temporary differences. Deferred tax assets and liabilities are not discounted.

Current and deferred income tax expense for interim periods is calculated at the level of each tax entity by applying the average estimated annual effective tax rate for the current year to the taxable income for the interim period, with the exception of significant exceptional items. Significant exceptional items, if any, are recognised using their specific applicable taxation rates.

1.23 Dividends
The Group and Company recognise a liability to pay a dividend when the distribution is authorised and the distribution is no longer at the discretion of the Group and Company. As per the corporate laws of England and Wales, a distribution is authorised when it is approved by the shareholders. A corresponding amount is recognised directly in equity.

2. Financial risk management

Group financial risk factors
The Group's activities expose it to a variety of financial risks: market risk (e.g. foreign exchange risks), credit risk and liquidity risk. The Group's overall risk management programme focuses on the unpredictability of financial markets and seeks to minimise potential adverse effects on the Group's financial performance.

Market risk (foreign exchange risk)
The Group operates internationally and is therefore exposed to foreign exchange risk arising from various currency exposures, primarily with respect to the Pound Sterling (GBP), Norwegian Krone (NOK) and Euro (EUR). Foreign exchange risk arises from future commercial transactions, recognised assets and liabilities and net investments in foreign operations.

Credit risk
Currently credit risk only arises from cash and cash equivalents, sales receivables and hedging derivatives. For banks and financial institutions, only independently rated parties with a minimum rating of 'BBB' are accepted.

Liquidity risk
Liquidity risk is the risk that the Group might not have sources of funding to meet its business needs. The Directors believe that the Group has sufficient cash, undrawn committed funds under its borrowing base facility and expected sources of liquidity to meet the business's forecast requirements.

Capital risk
The Company and/or affiliates will continue to explore opportunities to optimise and strengthen its capital structure by refinancing debt, repaying (vendor) loans and/or potentially repurchasing its bonds. The Group and its shareholders continue to explore strategic options for the business to support further development and growth, including the possibility of an IPO.

Management's financing strategy is to manage Neptune's capital structure with the aim that, across the business cycle, net debt (excluding vendor loans) to 12-month rolling EBITDAX, as defined by the RBL, remains below 1.5 times. This ratio, as at 31 December 2022, was 0.44 times. The RBL covenants require this ratio to remain below 3.5 times.

Climate change risk
Climate change risk is the risk that the Group fails to manage the impact of climate change due to evolving regulatory policies. Subsequent related commodity price volatility or access to markets could affect portfolio commerciality, our licence to operate and impact Neptune's access to capital funding.

Please refer to our Risk disclosure in the Neptune Annual Report and Accounts, see pages 28-31, 77 and 79-83.

3. Revenue

Set out below is the reconciliation of the revenue from contracts with customers with the amounts disclosed in note 5.

Group In millions of US$	Year ended 31 December 2022	Year ended 31 December 2021
Gas	4,203.0	2,115.2
Oil	1,027.7	591.3
LNG	817.3	253.6
Other liquids	176.1	151.7
Total production revenue from contracts with customers	**6,224.1**	**3,111.8**
Loss on realisation of cash flow hedges	(1,662.1)	(666.0)
Total production revenue by origin	**4,562.0**	**2,445.8**
Volume banking	15.3	-
Sale of surplus capacity bookings[1]	22.5	-
Other	40.3	44.3
Total other revenue	**78.1**	**44.3**
Revenue	**4,640.1**	**2,490.1**

1. Capacity bookings relate to the right to transport hydrocarbons through third-party owned infrastructure.

There are no right of return assets and refund liabilities held within the Group and costs to obtain contracts are negligible.

Included in revenue from contracts with customers are revenues of $1,324.9 million, $1,295.0 million and $622.5 million (2021: $910.6 million, $456.9 million and $327.7 million) relating to the Group's customers who each contribute more than 10% of total production revenue from contracts with customers. As sales of oil and gas are made on global markets and are highly liquid, the Group does not place reliance on the largest customers mentioned above.

Volume banking income relates to volume banking collaborative arrangements which arise within the ordinary course of business activities in the oil and gas industry due to the loss of production during the tie-in of new infrastructure to host facilities. This is recorded as it is considered virtually certain that the volumes owing to Neptune will be delivered when production commences with the counterparty, anticipated in 2023.

3.1 Performance obligations

Oil and gas sales

The performance obligation is satisfied by the delivery of the product at an agreed delivery point in the distribution chain, often either at the well head or delivery terminal. Payment is generally due within 30 days from delivery or offtake but can be as much as 90 days. Variation in the specification of the product is reflected in the contract price as an increase or decrease against a quoted benchmark product such as Brent (oil) or NTS (gas).

4. Other operating income

Group In millions of US$	Year ended 31 December 2022	Year ended 31 December 2021
Loss of production insurance	7.2	128.6
Total	**7.2**	**128.6**

Neptune is recovering losses via business interruption insurance in relation to the closure of the Equinor operated Hammerfest LNG facility from 26 October 2020 following an incident. The plant processes production from the Snøhvit, Albatross and Askeladd fields. The facility was brought back online on 1 June 2022 and Snøhvit has returned to plateau production since.

5. Segmental information

5.1 Net operating profit after equity-accounted investments

Neptune Energy's reportable segment is that used by the Group's Board and management to run the business. The Board is responsible for allocating resources and assessing performance of the segment.

The Group's activities consist of a single class of business (upstream), representing the acquisition, exploration, development and production of the Group's own oil and gas reserves and resources and is focused on seven areas: UK, Norway, Netherlands, Germany, North Africa, Asia Pacific and Corporate.

	Year ended 31 December 2022							
In millions of US$	**UK**	**Norway**	**Netherlands**	**Germany**	**North Africa**	**Asia Pacific**	**Corporate**	**Total**
Production revenue by origin	295.2	2,727.9	417.1	631.6	28.9	461.3	-	4,562.0
Other revenue	4.5	38.6	17.1	6.1	-	-	11.8	78.1
Revenue	**299.7**	**2,766.5**	**434.2**	**637.7**	**28.9**	**461.3**	**11.8**	**4,640.1**
Other operating income	-	7.2	-	-	-	-	-	7.2
Revenue and other income	**299.7**	**2,773.7**	**434.2**	**637.7**	**28.9**	**461.3**	**11.8**	**4,647.3**
Current operating profit/(loss)	**168.4**	**2,285.9**	**196.5**	**395.6**	**3.4**	**222.8**	**(15.5)**	**3,257.1**
Share of net income from investments using equity method	-	-	3.4	-	21.1	-	-	24.5
Net operating profit/(loss) after equity-accounted investments	**168.4**	**2,285.9**	**199.9**	**395.6**	**24.5**	**222.8**	**(15.5)**	**3,281.6**
Mark-to-market on commodity contracts other than trading instruments (note 8)								(100.2)
Restructuring release								0.1
Other gains								(0.9)
Profit before financial items								**3,180.6**
Financial income								89.1
Finance costs								(175.3)
Profit before tax								**3,094.4**

	Year ended 31 December 2021							
In millions of US$	**UK**	**Norway**	**Netherlands**	**Germany**	**North Africa**	**Asia Pacific**	**Corporate**	**Total**
Production revenue by origin	239.1	1,160.4	363.4	333.0	30.4	319.5	-	2,445.8
Other revenue	6.7	(0.6)	25.5	2.0	-	-	10.7	44.3
Revenue	**245.8**	**1,159.8**	**388.9**	**335.0**	**30.4**	**319.5**	**10.7**	**2,490.1**
Other operating income	-	128.6	-	-	-	-	-	128.6
Revenue and other income	**245.8**	**1,288.4**	**388.9**	**335.0**	**30.4**	**319.5**	**10.7**	**2,618.7**
Current operating profit/(loss)	**81.7**	**974.0**	**155.8**	**131.4**	**2.7**	**78.0**	**(18.2)**	**1,405.4**
Share of net (loss)/income from investments using equity method	-	-	(1.3)	-	62.4	-	-	61.1
Net operating profit/(loss) after equity-accounted investments	**81.7**	**974.0**	**154.5**	**131.4**	**65.1**	**78.0**	**(18.2)**	**1,466.5**
Net impairment reversal								113.6
Mark-to-market on commodity contracts other than trading instruments (note 8)								(73.8)
Restructuring release								0.5
Other gains								7.9
Profit before financial items								**1,514.7**
Financial income								53.1
Finance costs								(176.7)
Profit before tax								**1,391.1**

5.2 EBITDAX by country

EBITDAX as a non-GAAP measure is the group performance metric used to measure our ability to produce income from our operations in any given year. The Group uses the 12-month rolling EBITDAX as it is a principal key performance metric under the Group's RBL borrowing facility.

	Year ended 31 December 2022							
In millions of US$	UK	Norway	Netherlands	Germany	North Africa	Asia Pacific	Corporate	Total
EBITDAX (including equity-accounted affiliates)	237.9	2,451.9	282.4	469.3	38.4	388.4	(14.3)	**3,854.0**

	Year ended 31 December 2021							
In millions of US$	UK	Norway	Netherlands	Germany	North Africa	Asia Pacific	Corporate	Total
EBITDAX (including equity-accounted affiliates)	159.8	1,168.2	256.3	220.7	82.5	237.5	(15.7)	**2,109.3**

Reconciliation of EBITDAX as a non-GAAP measure to profit/(loss) before tax, after financial items:

In millions of US$	Year ended 31 December 2022	Year ended 31 December 2021
Profit before tax, after financial items	3,094.4	1,391.1
Add back:		
Net financing expenses	86.2	123.6
Other operating losses	101.0	65.4
Net impairment reversals	-	(113.6)
Exploration expense	32.7	67.7
DD&A	539.7	575.1
EBITDAX	**3,854.0**	**2,109.3**

5.3 Net impairment reversal/(loss) by country

There were no impairment losses or impairment reversals for the year ended 31 December 2022.

	31 December 2021							
In millions of US$	UK	Norway	Netherlands	Germany	North Africa	Asia Pacific	Corporate	Total
Intangible assets (note 13)	(6.7)	(0.9)	-	-	-	-	-	(7.6)
Property, plant and equipment (note 14)	-	-	77.8	-	-	43.4	-	121.2
Total impairment reversal/(loss)	**(6.7)**	**(0.9)**	**77.8**	**-**	**-**	**43.4**	**-**	**113.6**

5.4 Net assets

	31 December 2022							
In millions of US$	UK	Norway	Netherlands	Germany	North Africa	Asia Pacific	Corporate	Total
Balance sheet								
Assets	1,495.4	3,143.7	707.1	642.5	706.0	1,114.3	655.1	8,464.1
Liabilities	(623.7)	(3,003.6)	(891.4)	(740.1)	(19.8)	(371.4)	(2,114.7)	(7,764.7)
Net assets/(liabilities)	**871.7**	**140.1**	**(184.3)**	**(97.6)**	**686.2**	**742.9**	**(1,459.6)**	**699.4**

	31 December 2021							
In millions of US$	**UK**	**Norway[(1)]**	**Netherlands**	**Germany**	**North Africa**	**Asia Pacific**	**Corporate**	**Total**
Balance sheet								
Assets	1,465.5	3,534.8	937.7	648.8	692.2	1,203.9	544.7	9,027.6
Liabilities	(916.3)	(2,651.7)	(1,315.4)	(715.9)	(34.6)	(227.5)	(2,425.2)	(8,286.6)
Net assets/(liabilities)	**549.2**	**883.1**	**(377.7)**	**(67.1)**	**657.6**	**976.4**	**(1,880.5)**	**741.0**

1. As at 31 December 2021, Norway segment net assets included assets held for sale of $134.9 million and liabilities directly associated with the assets held for sale of $100.9 million. This sale concluded on 31 March 2022, see note 19.

Corporate net liabilities includes amounts of a corporate nature and not specifically attributable to a reportable segment. The liabilities comprise the Group's external debt and other non-attributable corporate liabilities.

5.5 Net capital investment

	Year ended 31 December 2022							
In millions of US$	**UK**	**Norway**	**Netherlands**	**Germany**	**North Africa**	**Asia Pacific**	**Corporate**	**Total**
Investments accounted under equity method (note 15)	-	-	(1.6)	-	24.7	-	-	23.1
Capital expenditure	195.1	225.1	46.8	89.0	13.7	61.1	4.4	635.2
Total	**195.1**	**225.1**	**45.2**	**89.0**	**38.4**	**61.1**	**4.4**	**658.3**

	Year ended 31 December 2021							
In millions of US$	**UK**	**Norway**	**Netherlands**	**Germany**	**North Africa**	**Asia Pacific**	**Corporate**	**Total**
Investments accounted under equity method (note 15)	-	-	(12.3)	-	61.0	-	-	48.7
Capital expenditure	134.7	537.7	62.9	165.4	11.0	131.5	-	1,043.2
Total	**134.7**	**537.7**	**50.6**	**165.4**	**72.0**	**131.5**	**-**	**1,091.9**

5.6 Underlying operating profit

Underlying operating profit as a non-GAAP measure is the group performance metric used to measure our ability to produce income from our operations in any given year. The Group uses underlying operating profit as it removes the effects of non-business as usual events, such as impairment losses/reversals, restructuring costs, curtailment gains/losses and certain one-off costs that might otherwise distort comparability between periods. For the Group's single class of business (upstream), the underlying operating profit is as below:

In millions of US$	**Year ended 31 December 2022**	**Year ended 31 December 2021**
Operating profit before financial items and tax	3,180.6	1,514.7
Adjusted for:		
Other income - equity method investments (see note 15)	(29.3)	-
Net restructuring (release)/cost	(0.1)	(0.5)
Impairment (reversal)/loss in share of net income/(loss) from investments using equity method	-	(32.2)
Impairment (reversals)/ losses	-	(113.6)
Legacy licence cost	-	4.0
Pension scheme curtailment credit	-	(4.1)
Underlying operating profit before financial items and tax	**3,151.2**	**1,368.3**

6. Operating profit before financial items

Included within the Group's operating costs were the following items:

Group In millions of US$	Year ended 31 December 2022	Year ended 31 December 2021
Cost of sales		
Net movements in over/under lift balances	54.3	(92.0)
Production, insurance and transportation costs	545.3	507.4
Depreciation of property, plant and equipment	536.7	570.1
Amortisation of intangible assets	3.0	5.0
Other operating costs	139.6	76.7
Exploration expenses		
Exploration and evaluation expenditure	25.5	35.5
Unsuccessful exploration expenditure written off	7.2	32.2
General and administration expenses include		
Employee costs	45.8	41.9

Auditors' Remuneration

Group In millions of US$	Year ended 31 December 2022	Year ended 31 December 2021
Fees payable to the Company's auditor for the audit of the Company's annual accounts	2.0	2.0
Audit of the accounts of subsidiary companies	0.5	0.5
Non-audit fees	0.4	0.6
Total	**2.9**	**3.1**

Ernst & Young LLP has served as Neptune Energy's independent external auditor for the six-year period ended 31 December 2022. The external auditor is subject to reappointment at the year-end Board meeting and has been reappointed for the 2023 period end.

7. Staff costs

Group In millions of US$	Year ended 31 December 2022	Year ended 31 December 2021
Wages and salaries	196.1	200.1
Social security costs	22.0	26.6
Pension costs - defined benefit schemes	3.9	5.0
Pension costs - defined contribution schemes	17.1	16.0
Other long-term benefits	3.6	3.9
Total	**242.7**	**251.6**

The average number of persons employed globally during the year (including Directors) was 1,332 (2021: 1,300).

The Group operates defined contribution pension schemes for staff. The contributions are payable to external funds which are administered by independent trustees. Contributions during the year amounted to $17.1 million (2021: $16.0 million).

7.1 Total Directors' remuneration

The total Directors' remuneration is:

Company In millions of US$	Year ended 31 December 2022	Year ended 31 December 2021
Short-term employee benefits	5.0	5.2
Other long-term benefits – post-employment benefits	0.1	0.1
Total	**5.1**	**5.3**

Highest paid Director's remuneration

Company In millions of US$	Year ended 31 December 2022	Year ended 31 December 2021
Short-term employee benefits	2.0	2.3
Total	**2.0**	**2.3**

8. Other operating losses/(gains)

Other operating losses/(gains) are those that need to be disclosed separately by virtue of their nature, size or incidence. These include certain remeasurements, pension change costs or credits and asset impairments.

Group In millions of US$	Year ended 31 December 2022	Year ended 31 December 2021
Mark-to-market on derivative instruments:		
Loss on commodity derivative instruments at fair value through profit and loss	74.8	84.3
Loss/(gain) on emissions derivative instruments at fair value through profit and loss	0.5	(19.1)
Loss/(gain) on foreign exchange forward at fair value through profit and loss	5.1	(5.9)
Loss on foreign exchange options at fair value through profit and loss	0.5	-
Gain on ineffectiveness on commodity contracts designated as hedges	(0.2)	-
Loss on excluded components on commodity contracts designated as hedges	19.5	14.5
	100.2	**73.8**
Net movement in inventory provisions	(2.1)	1.0
Gain on disposal of asset (note 19)	(2.8)	-
Restructuring release (note 23)	(0.1)	(0.5)
Pension schemes curtailment credit (note 29.4)	-	(4.1)
Release of contingent consideration	(1.8)	(2.5)
Irrecoverable indirect taxation	13.0	-
Other gains	(5.4)	(2.3)
Total other operating losses	**101.0**	**65.4**

9. Finance income and costs

9.1 Finance income

Group In millions of US$	Year ended 31 December 2022	Year ended 31 December 2021
Interest income	5.0	3.4
Interest income from Joint Arrangements for right-of-use assets	1.0	1.5
Dividend income(1)	0.9	1.4
Net foreign exchange gain	82.2	46.8
Total finance income	**89.1**	**53.1**

1. Dividend income relates to a Level 3 non-listed equity instrument.

In the Company, finance income of $356.9 million (2021: $1,399.3 million) includes dividend income of $356.8 million (2021: $1,399.3 million).

9.2 Finance cost

Group In millions of US$	Year ended 31 December 2022	Year ended 31 December 2021
Interest expense	118.9	120.7
Commitment fees	17.2	14.9
Unwinding of discount on decommissioning and other provisions(1)	35.4	35.4
Interest expense lease liabilities	3.8	5.7
Total finance costs	**175.3**	**176.7**

1. During the year ended 31 December 2022, $0.6 million of unwinding of discount related to decommissioning and other provisions for assets held for sale.

In the Company, finance costs totalled $146.9 million (2021: $139.0 million).

10. Dividend

	Group		Company	
In millions of US$	31 December 2022	31 December 2021	31 December 2022	31 December 2021
Aggregate amount of dividend declared in the year	1,146.8	344.7	1,146.8	344.7
Aggregate amount of dividend paid in the year	1,146.8	544.7	1,146.8	544.7

On 8 December 2022, the Board of Directors of Neptune Energy Group Holdings Limited declared and paid an interim dividend of $1,146.8 million ($1.69 per fully paid ordinary share).

The Board of Directors of Neptune Energy Group Holdings Limited declared a 2021 Interim dividend of $80.0 million on 24 February 2021 (4.05 cents per fully paid ordinary share registered) which was initially settled by the issue of an $80.0 million promissory note. The $80.0 million promissory note was settled in full for cash on 15 December 2021. On 10 December 2021 the Board of Directors of Neptune Energy Group Holdings Limited declared a second 2021 interim dividend of $264.7 million (13.39 cents per fully paid ordinary share registered) which was settled on 15 December 2021 by the Company.

11. Taxation

The major components of income tax expense are:

Group In millions of US$	Year ended 31 December 2022	Year ended 31 December 2021
Current taxation:		
Charge for the period	2,050.8	418.1
Adjustment in respect of prior years	3.5	9.7
	2,054.3	**427.8**
Deferred taxation:		
Origination and reversal of temporary differences	117.2	577.4
Total income tax expense recognised in income statement	**2,171.5**	**1,005.2**

11.1 Reconciliation between theoretical income tax expense and actual tax expense

Group In millions of US$	31 December 2022	31 December 2021
Profit before taxation	3,094.4	1,391.1
Expected tax charge	2,267.9	886.7
Effects on tax charge of:		
Expenses taxed at rates different to the headline statutory rate	57.8	15.4
Non tax-deductible expenditure	32.9	20.7
Income not subject to taxation	(33.1)	(23.1)
Utilisation of previously unrecognised deferred tax assets	(2.5)	-
Adjustments in respect of prior years	3.5	9.5
(Recognition)/derecognition of deferred tax assets	(285.8)	56.3
Non-recognition of deferred tax assets	49.2	46.5
Effect of change in tax rates	89.4	-
Other items	(7.8)	(6.8)
Total income tax charge	**2,171.5**	**1,005.2**

The Group operates in a number of jurisdictions. Across these jurisdictions, there is a broad variation in statutory tax rates. The Group's expected tax charge reflects the applicable rates for the countries in which the Group earned profits. The tax charge will vary depending on several factors, such as the geographic mix of profits and changes to tax rates. During the year, the Group has earned profits in the operating countries applying higher statutory tax rates, especially Norway where the statutory tax rate applicable is 78%. In addition, the introduction of the EU Solidarity Contribution in Germany and the Netherlands and the Energy Profits Levy (EPL) in the UK, has resulted in a higher statutory tax rate for these countries in the year.

The effective tax rate for the Group for 2022 was 70.2% (2021: 72.2%). The effective tax rate in 2022 excluding recognition of the deferred tax asset is 79.4%. The Group's total tax charge for 2022 is $2,171.5 million compared with the Group's expected tax charge of $2,267.9 million.

The main reasons for the difference between the expected tax charge and the actual tax charge are:

- Expenses/(income) taxed or relieved at rates different to the headline statutory rate of $57.8 million of which the main component is the Norway hedging results.
- Net recognition of deferred tax asset of $(285.8) million relating primarily to recognition of UK tax losses (as further described below) and recognition of the interest deductions for the Netherlands.
- Deferred tax asset not recognised of $49.2 million relating mainly to Norway onshore tax losses and tax losses not recognised, mainly in the UK.
- Effect of change in tax rates of $89.4 million relating to the UK Energy Profits Levy and the EU Solidarity Contribution.

11.2 Analysis of deferred tax income/expense recognised in other comprehensive income, by type of temporary difference

Group In millions of US$	31 December 2022	31 December 2021
Difference type		
Actuarial losses/(gains)	14.8	(4.3)
Cash flow hedges	(219.7)	480.2
Net deferred tax (expense)/income	**(204.9)**	**475.9**

11.3 Changes in deferred taxes

The net movement in deferred tax assets and (liabilities) is shown below:

Group In millions of US$	PP&E	Asset retirement obligations	Pensions	Tax losses	Unrealised hedging losses	Other	Total
At 1 January 2022	**(1,784.3)**	**362.6**	**43.5**	**580.1**	**479.9**	**(186.6)**	**(504.8)**
Credit/(charge) for the year	(411.5)	6.1	(0.5)	257.1	-	31.6	(117.2)
Credit/(charge) to equity and other comprehensive income	-	-	14.8	-	(119.9)	-	(105.1)
Currency translation adjustments	207.3	(43.6)	(3.3)	(82.7)	(99.8)	21.0	(1.1)
At 31 December 2022	**(1,988.5)**	**325.1**	**54.5**	**754.5**	**260.2**	**(134.0)**	**(728.2)**

Deferred tax asset	702.1
Deferred tax liabilities	(1,430.3)
Deferred tax liabilities net	**(728.2)**

Group In millions of US$	PP&E	Asset retirement obligations	Pensions	Tax losses	Unrealised hedging losses	Other	Total
At 1 January 2021	**(1,580.1)**	**432.3**	**49.4**	**787.2**	**(0.3)**	**(100.0)**	**(411.5)**
Reclassification	94.8	-	-	(94.8)	-	-	-
Transfers to assets held for sale (note 19)	45.2	(67.8)	-	-	-	-	(22.6)
Credit/(charge) for the year	(405.1)	13.4	1.3	(97.2)	-	(89.9)	(577.5)
Charge to equity and other comprehensive income	-	-	(4.3)	-	496.9	-	492.6
Currency translation adjustments	60.9	(15.3)	(2.9)	(15.1)	(16.7)	3.3	14.2
At 31 December 2021	**(1,784.3)**	**362.6**	**43.5**	**580.1**	**479.9**	**(186.6)**	**(504.8)**

Deferred tax asset	852.3
Deferred tax liabilities	(1,357.1)
Deferred tax liabilities net	**(504.8)**

The Group's net deferred tax liability has increased from $504.8 million as at 31 December 2021 to a deferred tax liability of $728.2 million as at 31 December 2022. The main reasons for the movement are described below, in addition to the deferred tax charge in the year on the unrealised hedging losses.

The deferred tax charge in relation to PP&E for the year ended 31 December 2022 is $411.5 million. The significant contributors to the deferred tax charge of $411.5 million are:

- The change in the petroleum tax regime in Norway, now allowing immediate tax deduction on investments in the special tax base. This immediate expense replaces the current depreciation and uplift deductions which will be discontinued. The change only applies to new investments from 2022, and not to investments covered by the temporary rules introduced in 2020. The new tax regime was approved by the Norwegian parliament in June 2022 and is effective retroactively from 1 January 2022.
- The restatement of the deferred tax liability for the UK Energy Profits Levy.

The deferred tax credit of $257.1 million for 2022 for the tax losses is the deferred tax asset recognised for the UK tax losses, offset by tax losses utilised in the period for UK and Germany. The recognition of the deferred tax asset in relation to the UK tax losses is based on the forecast assumptions in the corporate model used to calculate the future taxable profits. The deferred tax asset recognised on the UK tax losses would be the same if the price assumptions in the corporate model increase or decrease by 10%.

We have also considered the climate related estimates and assumptions in assessing the recoverability of the deferred tax asset. Since the future taxable profits used to calculate the deferred tax asset recognised on the UK tax losses are based on the corporate model, which includes costs for CO_2 emission allowances, the relevant climate related assumptions are already factored in the deferred tax asset recognition.

The deferred tax credit of $31.6 million for 2022, under 'Other', primarily relates to the deferred tax credit for the movement in over/underlift and the deferred tax asset recognised for the Netherlands interest deductions. This is offset by the deferred tax charge on exploration costs.

There were no net deferred tax assets and liabilities recognised in the Company for 2022 or 2021.

11.4 Temporary differences for which no deferred tax asset has been recognised

Group In millions of US$	31 December 2022	31 December 2021
Unused tax losses	2,106.7	2,315.0
Other deductible temporary differences	781.6	808.7
Total temporary difference for which no deferred tax asset is recognised	**2,888.3**	**3,123.7**

The above unrecognised deductible temporary differences are not subject to time limits for utilisation. Other deductible temporary differences not recognised relate predominantly to the UK investment allowances not fully recognised, Norway onshore tax losses not recognised, and Netherlands interest deductions not recognised.

12. Goodwill

Group In millions of US$	31 December 2022	31 December 2021
Cost at 1 January	624.5	664.5
Derecognition	(5.7)	-
Transfers to assets held for sale (note 19)	-	(14.4)
Currency translation adjustments	(60.4)	(25.6)
Cost at 31 December	**558.4**	**624.5**
Impairment losses at 1 January	(14.5)	(14.8)
Derecognition	5.7	-
Currency translation adjustments	-	0.3
Impairment losses at 31 December	**(8.8)**	**(14.5)**
Net book value at 31 December	**549.6**	**610.0**

In 2021, the transfer of goodwill to assets held for sale was in relation to an element of the VNG Norge AS assigned goodwill following the initial acquisition in 2018.

The goodwill from business combinations is reviewed for impairment prospectively at each reporting date, or earlier if there are indications of impairment. For the purpose of impairment testing, goodwill is allocated to groups of cash-generating units (CGUs); these represent the lowest level at which goodwill is monitored. The recoverable amounts are determined based on the fair value less cost of disposal method. The key assumptions in estimating the recoverable amounts are disclosed in note 1.3.1.

The goodwill assigned to Norway is $473.2 million. The discount rate applied in determining the recoverable amount is 8%. No reasonable possible change in any of the key assumptions would cause Norway's carrying amount to exceed its recoverable amount.

The Group uses the fair value less cost of disposal method to calculate the recoverable amount of the CGUs consistent with a Level 3 fair value measurement as defined in note 24.1. In determining the fair value, the Group has used a post-tax discount rate of 8% (31 December 2021: 8%) based on a country-based weighted average cost of capital. Oil and gas prices are based on an internal view of management expectations derived from a market consensus for current prices transitioning to a long-term price in 2026 of $65/bbl (31 December 2021: 2025 at $65/bbl) for Brent crude oil and 75p/therm (31 December 2021: 2025 at 50p/therm) for NBP gas thereafter inflated by 2% per annum.

The Group has run sensitivity analysis on the key assumptions including oil and gas prices outlined above. No reasonable possible change in any of the key assumptions would cause the carrying amount of the CGU to exceed its recoverable amount.

13. Intangible assets

Group **in millions of US$**	**Exploration and evaluation**	**Other**	**Total**
Cost at 1 January 2021	**184.1**	**32.0**	**216.1**
Additions	131.5	1.7	133.2
Disposals	(2.6)	(0.2)	(2.8)
Unsuccessful exploration expenditure	(32.2)	-	(32.2)
Impairment loss	(7.6)	-	(7.6)
Transfers from property, plant and equipment	6.9	-	6.9
Currency translation adjustments	(5.4)	(1.1)	(6.5)
Cost at 31 December 2021	**274.7**	**32.4**	**307.1**
Additions	120.4	0.3	120.7
Asset derecognition	-	(1.4)	(1.4)
Unsuccessful exploration expenditure	(7.2)	-	(7.2)
Transfers from property, plant and equipment	(0.1)	-	(0.1)
Currency translation adjustments	(20.6)	(2.9)	(23.5)
Cost at 31 December 2022	**367.2**	**28.4**	**395.6**
Amortisation at 1 January 2021	-	**(21.2)**	**(21.2)**
Charge for the year	-	(5.0)	(5.0)
Elimination on disposals	-	0.2	0.2
Currency translation adjustments	-	0.9	0.9
Amortisation at 31 December 2021	-	**(25.1)**	**(25.1)**
Charge for the year	-	(3.0)	(3.0)
Asset derecognition	-	1.4	1.4
Currency translation adjustments	-	2.2	2.2
Amortisation at 31 December 2022	-	**(24.5)**	**(24.5)**
Net book value at 31 December 2022	**367.2**	**3.9**	**371.1**
Net book value at 31 December 2021	**274.7**	**7.3**	**282.0**

Unsuccessful exploration expenditure relates to costs associated with licence relinquishments and uncommercial well evaluations.

There were no impairment losses or impairment reversals for the year ended 31 December 2022. The impairment charges for 2021 are shown below:

Country of CGU In millions of US$	Trigger for 2021 impairment	2021 Impairment	Post-tax discount rate assumption	2021 CGU Remaining recoverable amount
Denmark (a)	a	0.9	8%	-
UK (b)	b	6.7	8%	-
Total		7.6		-

a. Due to the sale of the CGU (note 8).
b. Licence relinquishment.

14. Property, plant and equipment

Group In millions of US$	Oil and gas properties	Other fixed assets	Total
Cost at 1 January 2021	**6,721.8**	**94.6**	**6,816.4**
Additions	891.7	18.3	910.0
Asset derecognition[1]	-	(5.7)	(5.7)
Disposals	(0.7)	(8.9)	(9.6)
Transfers to intangible assets	(6.9)	-	(6.9)
Transfers	(4.2)	4.2	-
Transfers to assets held for sale (note 19)	(133.7)	-	(133.7)
Currency translation adjustments	(236.2)	(4.3)	(240.5)
Cost at 31 December 2021	**7,231.8**	**98.2**	**7,330.0**
Additions	507.3	7.2	514.5
Asset derecognition[2]	(35.2)	(3.9)	(39.1)
Disposals	(11.1)	(0.8)	(11.9)
Transfers from intangible assets	0.1	-	0.1
Currency translation adjustments	(502.6)	(6.6)	(509.2)
Cost at 31 December 2022	**7,190.3**	**94.1**	**7,284.4**
Accumulated depreciation at 1 January 2021	**(2,223.9)**	**(26.3)**	**(2,250.2)**
Charge for year [3],[4]	(591.9)	(9.7)	(601.6)
Impairment loss	(18.7)	-	(18.7)
Reversal of impairment loss	139.9	-	139.9
Asset derecognition	-	5.7	5.7
Disposals	-	2.4	2.4
Transfers to assets held for sale (note 19)	56.7	-	56.7
Currency translation adjustments	85.5	(0.9)	84.6
Accumulated depreciation at 31 December 2021	**(2,552.4)**	**(28.8)**	**(2,581.2)**
Charge for year [3],[4]	(555.8)	(9.5)	(565.3)
Transfers	0.1	(0.1)	-
Asset derecognition	22.5	3.9	26.4
Disposals	11.0	0.8	11.8
Currency translation adjustments	144.8	1.7	146.5
Accumulated depreciation at 31 December 2022	**(2,929.8)**	**(32.0)**	**(2,961.8)**
Net book value at 31 December 2022[4]	**4,260.5**	**62.1**	**4,322.6**
Net book value at 31 December 2021	**4,679.4**	**69.4**	**4,748.8**

1. The derecognition of assets arises in Norway in relation to the fire at the non-operated Hammerfest LNG facility.
2. Oil and gas asset derecognition in 2022 are due to lease modifications that resulted in the lease not meeting the IFRS 16 criteria to recognise a right-of-use asset, see note 22.
3. Includes capitalised depreciation of $28.6 million (2021: $31.5 million) related to right-of-use assets in Norway and the UK.
4. Refer to note 22 for depreciation charge and carrying amounts related to right-of-use assets.

The Group uses the fair value less cost of disposal method to calculate the recoverable amount of the cash-generating units (CGU) consistent with a Level 3 fair value measurement. In determining the fair value, the Group has used a post-tax discount rate of 8-10% (2021: 8-10%) based on a country specific weighted average cost of capital. Oil and gas prices are based on an internal view of management expectations derived from a market consensus for current prices transitioning to a long-term price in 2026 of $65/bbl (31 December 2021: 2025 at $65/bbl) for Brent crude oil and 75p/therm (31 December 2021: 2025 at 50p/therm) for NBP gas thereafter inflated by 2% per annum.

The company principally holds a single asset, being the right-of-use asset relating to an office lease. As at 31 December 2022 this item had a net book value of $4.7 million, comprised of cost of $4.8 million and accumulated depreciation of $0.1 million. As at 31 December 2021, the company had a right-of-use asset with a net book value of $1.1 million, comprised of cost of $4.2 million and accumulated depreciation of $3.1 million, and other fixed assets with a net book value of $0.5 million.

There were no impairment losses or impairment reversals for the year ended 31 December 2022. The impairment reversals/charge for 2021 are shown below:

Country of CGU In millions of US$	Trigger for 2021 impairment	2021 Impairment (reversal)/charge	Post-tax discount rate	2021 CGU recoverable amount (post-tax)[d]
Indonesia	a	(43.4)	10%	1,037.2
Netherlands (1)	b	(96.5)	8%	120.4
Impairment reversal total		(139.9)		1,157.6
Netherlands (2)	c	18.7	8%	-
Total		**(121.2)**		**1,157.6**

a. Increase due to updated assumptions on future commodity prices and change in discount rate.
b. Increase due to upward reserves revision.
c. Decrease due to underlying reservoir performance.
d. CGU recoverable amount (post-tax) is calculated as at testing date.

Incremental price and discount rate sensitivity impairment analysis on CGU recoverable amount (post-tax):

Country of CGU In millions of US$	2021 CGU recoverable amount	Oil and Gas price		Post-tax discount rate	
		Plus 10%	Minus 10%	Plus 1%	Minus 1%
Netherlands (1) (a)	120.4	18.6	(24.2)	(1.0)	1.1
Indonesia (b)	1,037.2	108.6	(105.8)	(39.3)	42.2

a. The 10% price increase of $18.6 million and the minus 1% post-tax discount increase of $1.1 million would not have resulted in an additional post-tax impairment reversal.
b. The 10% price increase of $108.6 million would be restricted to an additional impairment reversal of $37.0 million and the minus 1% post-tax discount increase of $42.2 million would be restricted to an additional impairment reversal of $14.5 million.

The Group believes a 1% change in the post-tax discount rate to be a reasonable possibility based on historical analysis of the Group's and a peer group of oil and gas companies' impairment analysis.

For the Netherlands (1) CGU, sensitivity analyses indicate that if reserves were to fall by 10%, the post-tax impairment reversal recognised would have been $24.2 million lower. An increase of reserves by 10% would have increased the recoverable amount by $18.6 million, but would not have resulted in an additional post-tax impairment reversal.

For the Indonesia CGU, sensitivity analyses indicate that if reserves were to fall by 10%, the post-tax impairment reversal recognised would have been $124.0 million lower. An increase of reserves by 10% would have increased the recoverable amount by $120.7 million, but would not have resulted in a full post-tax impairment reversal.

For climate risk emissions sensitivities refer to Note 25.3.

15. Investments

Investments in entities accounted for using the equity method

Group In millions of US$	Total
Carrying amount at 1 January 2021	**557.6**
Net movements	48.7
Carrying amount at 31 December 2021	**606.3**
Net movements	23.1
Carrying amount at 31 December 2022	**629.4**

Interest in joint ventures

The Group has an 18.57% interest in Noordgastransport B.V. and a 54% interest in Neptune Energy Touat B.V. ('Touat').

Group In millions of US$	31 December 2022	31 December 2021
At 1 January	**606.3**	**557.6**
Share of results in the year	24.5	61.1
Hedging recognised in other comprehensive income	7.2	(4.2)
Dividends paid	(4.4)	(2.3)
Equity injection contribution	14.2	19.0
Share capital repayment	(17.8)	(16.2)
Net investment in equity-accounted investments	**(8.0)**	**0.5**
Currency translation adjustments	(0.6)	(8.7)
At 31 December	**629.4**	**606.3**

Neptune Energy Touat B.V. as a material joint venture, has an interest in the Touat production sharing contract in Algeria. The Group's interest in Touat is accounted for using the equity method in the consolidated financial statements. Summarised financial information of the joint venture, based on its IFRS financial statements, and reconciliation with the carrying amount of the investment in the consolidated financial statements are set out below:

Neptune Energy Touat B.V. In millions of US$	31 December 2022	31 December 2021
Non-current assets	1,085.7	1,087.8
Current assets	135.9	132.1
Current liabilities	(40.8)	(71.8)
Non-current liabilities	(29.2)	(42.2)
Equity	**1,151.6**	**1,105.9**
Group's share of equity – 54%	621.9	597.2
Group's carrying amount of the investment	**621.9**	**597.2**

Neptune Energy Touat B.V. In millions of US$	2022	2021
Revenue	61.1	73.9
Other income	79.7	93.4
Cost of sales	(87.9)	(90.3)
Gross profit	**52.9**	**77.0**
General and administration expenses	(3.1)	(4.0)
Operating profit	**49.8**	**73.0**
Impairment reversal	-	59.6
Other operating losses	(17.9)	(3.9)
Operating profit before financial items	**31.9**	**128.7**
Finance income	16.7	3.1
Finance costs	(15.3)	(3.4)
Profit before tax	**33.3**	**128.4**
Taxation	5.7	(12.8)
Profit for the year	**39.0**	**115.6**
Other comprehensive gain/(loss) that may be reclassified to profit or loss in subsequent periods, net of tax	13.4	(7.7)
Total comprehensive income for the year	**52.4**	**107.9**
Group's share of profit for the year - 54%	21.1	62.4
Group's share of other comprehensive income/(loss) - 54%	7.2	(4.2)
Group's share of total comprehensive income - 54%	**28.3**	**58.2**

Included within current assets are cash and cash equivalents of $7.8 million (2021: $11.1 million) and derivative contracts of $nil (2021: $nil).

Included within other income in the year ended 2022 is a $29.3 million performance guarantee (net to Neptune). As it is related to the loss of revenue from the delayed start-up of the Touat project, management's judgement is that this represents income rather than a repayment of part of the construction cost of the asset due to the underlying nature of the performance guarantee being directly linked to compensation for lost production and revenue. This was cash received in full in the period.

Included within cost of sales is depreciation of oil and gas assets of $23.5 million (2021: $39.3 million).
Neptune Energy Touat B.V. had capital commitments of $11.4 million (2021: $4.2 million) for which the Neptune Group has a corresponding commitment of $6.2 million (2021: $2.3 million), as disclosed in note 27.

The investments held in the Company during the year are its direct interest in:

- Neptune Energy Finance Limited
- Neptune E&P UKCS Limited
- Neptune E&P UK Limited
- Neptune Energy Group Resourcing Limited
- Neptune Energy Norge A.S.
- Neptune Energy Holding Netherlands B.V.
- Neptune Energy International S.A.

Company In millions of US$	Total
Cost at 1 January 2021	**5,734.0**
Capital redemption	(475.3)
Cost at 31 December 2021	**5,258.7**
Capital injection[1]	1,175.6
Capital redemption[2]	(842.2)
Cost at 31 December 2022	**5,592.1**
Impairment at 1 January 2021	**(410.2)**
Impairment loss[3]	(855.9)
Impairment at 31 December 2021	**(1,266.1)**
Impairment loss[3]	(54.8)
Cost at 31 December 2022	**(1,320.9)**
Net book value at 31 December 2022	**4,271.2**
Net book value at 31 December 2021	**3,992.6**

1. During 2022, the Company provided funds to its direct subsidiary Neptune Energy Holdings Netherlands B.V. resulting in a capital injection totalling $1,175.6 million..
2. During 2022, the Company received a return of capital from Neptune Energy Finance Limited of $800 million and from Neptune Energy UKCS Limited of $42.2 million resulting in a total of capital redemptions for the period of $842.2 million.
3. A further impairment of the investment held in the direct subsidiary Neptune Energy International S.A. was recognised during 2022 for an amount of $54.8 million (2021: impairment of $855.9 million). This impairment arose subsequent to the subsidiary remitting monies by means of a dividend to the Company, thereby reducing its net asset coverage of the investment value held.

16. Inventories

Group In millions of US$	31 December 2022	31 December 2021
Hydrocarbons stock	6.1	4.9
Raw materials and consumables	97.7	78.1
Total	**103.8**	**83.0**

Included within raw materials and consumables is $10.6 million (2021: $21.5 million) in respect of provisions for deterioration and obsolescence.

The Company held no inventories in 2022 and 2021.

17. Trade and other receivables

Group In millions of US$	31 December 2022	31 December 2021
Amounts falling due within one year		
Trade receivables	461.3	445.9
Under-lift position	93.4	136.9
Other taxes receivable	11.9	8.7
Receivables from joint venture partners	154.7	159.4
Other receivables	105.4	175.5
Loan to parent company	455.3	455.3
Prepayments and accrued income	3.0	3.1
Total	**1,285.0**	**1,384.8**

Trade receivables are stated net of credit loss provisions of $0.6 million (2021: $0.4 million). When management considers the recovery of a receivable to be improbable, a provision is made against the carrying value of the receivable. The movement through the income statement is included in other operating gains and losses (see note 8).

Company In millions of US$	31 December 2022	31 December 2021
Amounts falling due within one year		
Loan to parent company	455.3	455.3
Amounts owed by subsidiaries	11.0	40.3
Prepayments and accrued income	7.4	3.7
Other current assets	0.7	0.5
Total	**474.4**	**499.8**

The loan to parent company, Neptune Energy Group Midco Limited is repayable on demand and is interest free.

18. Cash and cash equivalents

Group In millions of US$	31 December 2022	31 December 2021
Cash at bank and in hand	234.1	107.3
Restricted cash	-	18.2
Total cash and cash equivalents	**234.1**	**125.5**

Cash and cash equivalents comprise cash in hand and deposits with maturity of three months or less. In 2021, restricted cash includes monies held for decommissioning obligations, from 2022 onwards, this was presented as an 'other non-current financial asset'.

The Company held $nil cash and cash equivalents at 31 December 2022 (31 December 2021: $nil).

19. Assets held for sale

On 31 March 2022, the Group completed the disposal of a portfolio of non-core Norwegian assets. The assets the Group divested included the producing Draugen, Brage and Ivar Aasen fields, as well as the Edvard Grieg Oil Pipeline and the Utsira High Gas Pipeline. All decommissioning liabilities were transferred to the buyers. The gain on the disposal of $2.8 million is recorded in other operating (losses)/gains (note 8). The Group received $20.3 million on 31 March 2022, including working capital adjustments. A deferred payment of $0.8 million was received on 30 May 2022 and a further $6.5 million will be received by 1 January 2024.

The major classes of assets and liabilities of the Group as held for sale as at 31 December 2022 and 2021, are as follows:

Group In millions of US$	31 December 2022	31 December 2021
Assets		
Goodwill (note 12)	-	14.4
Property, plant and equipment (note 14)	-	77.0
Deferred tax asset (note 11)	-	22.6
Trade receivables and other working capital	-	18.7
Currency translation adjustments	-	2.2
Assets held for sale	-	**134.9**
Provisions (note 23)	-	(89.9)
Trade and other payables	-	(9.3)
Currency translation adjustments	-	(1.7)
Liabilities directly associated with assets held for sale	-	**(100.9)**
Net assets directly associated with disposal group	-	**34.0**

Immediately before the classification of the disposal group as assets held for sale, the recoverable amount was estimated for the disposal group and no impairment loss was identified. The assets in the disposal group are held at the lower of their carrying amount and fair value less costs to sell. As at 31 December 2022 and 2021, there were no further write downs as the carrying amount of the disposal group did not fall below its fair value less costs to sell.

20. Borrowings

Group In millions of US$	Interest rate 2022 %	Interest rate 2021 %	Maturity	31 December 2022	31 December 2021
Non-current interest-bearing loans and borrowings					
Reserve Based Lending facility	7.024	2.857	2024	1,082.8	1,330.7
Subordinated Neptune Energy Group Limited loan	7.750	7.750	2024	100.0	100.0
Subordinated Neptune Energy Group Limited loan 1	6.875	6.875	2025	545.4	543.5
Subordinated Neptune Energy Group Limited loan 2	6.625	6.625	2025	296.7	295.2
Total non-current				**2,024.9**	**2,269.4**
Current interest-bearing loans and borrowings					
DNB uncommitted facility	-	1.800	2022	-	50.0
Citibank uncommitted facility	-	0.874	2022	-	10.0
Total current				-	**60.0**
Total				**2,024.9**	**2,329.4**

The movements in borrowings are described in the table below:

Group In millions of US$	
At 1 January 2022	2,329.4
Associated cash flows	
Repayment of borrowings	(2,987.0)
Drawdown of borrowings	2,667.0
Non-cash movements	
Amortisation of debt arrangement fees	15.5
At 31 December 2022	**2,024.9**

Changes in liabilities arising from financing activities:

Group In millions of US$	1 January 2022	Cash flows	Currency translation adjustments	Additions	Other[1]	31 December 2022
Reserved Based Lending Facility	1,330.7	(260.0)	-	-	12.1	1,082.8
Subordinated Neptune Energy Group Limited loan	100.0	-	-	-	-	100.0
Subordinated Neptune Energy Group Limited loan 1	543.5	-	-	-	1.9	545.4
Subordinated Neptune Energy Group Limited loan 2	295.2	-	-	-	1.5	296.7
Uncommitted facility	60.0	(60.0)	-	-	-	-
Total borrowings	**2,329.4**	**(320.0)**	**-**	**-**	**15.5**	**2,024.9**
Dividends payable (note 10)	-	(1,146.8)	-	1,146.8	-	
Leases	131.7	(85.8)	(10.0)	100.5	(13.8)	122.6
Total liabilities from financing activities	**2,461.1**	**(1,552.6)**	**(10.0)**	**1,247.3**	**1.7**	**2,147.5**

1. Includes amortisation of arrangement fees and derecognition of leases.

Certain subsidiaries within the Group have a Reserve Based Lending facility (RBL) with total aggregate commitments of $2.1 billion at the end of the year. The outstanding debt is repayable in line with the amortisation of bank commitments over the period from 1 April 2022 to the final maturity date of 11 May 2024, or such time as is determined by reference to the remaining reserves of the assets, whichever is earlier. No amounts are repayable within the next 12 months. The maximum amount that the relevant subsidiaries (the RBL Group) can drawdown under this facility (the borrowing base) is subject to a consolidated cash flow and debt service projection, which is subject to an annual redetermination process in March. On this date, there is a redetermination of the available size of the facility, which takes into account, among other things, the most up-to-date forecast of the RBL Group's production. The facility was a multi-currency facility and incurred interest on outstanding debt at US dollar and Sterling LIBOR, EURIBOR or NIBOR plus an applicable margin. Following the March 2022 redetermination, the borrowing base remained at $2.3 billion and will remain at this level until the completion of the next redetermination in April 2023. The facility was also amended during 2021 and now only allows for USD drawdowns priced at USD LIBOR plus an applicable margin. The facility is secured over the shares of certain companies within the RBL Group, and certain of its oil and gas assets.

The Company holds the Reserve Based Lending facility. As at 31 December 2022 the balance was $1,082.8 million (2021: $1,330.7 million).

21. Trade payables and other liabilities

Group In millions of US$	31 December 2022	31 December 2021
Trade and other payables	299.5	329.4
Other current liabilities	422.4	391.9
Lease liabilities	64.2	73.9
Wages and social security	48.8	47.0
Current trade payables and other liabilities	**834.9**	**842.2**
Other non-current liabilities	34.7	37.4
Lease liabilities	58.4	57.8
Other non-current liabilities	**93.1**	**95.2**
Total	**928.0**	**937.4**

Trade payables are usually paid within 30 days of recognition. The carrying amount of financial liabilities approximates their fair value and they are all due within one year.

Other current liabilities in 2022 and 2021 principally related to hedging liabilities and joint venture funding, refer to note 25 for further details on derivatives.

Company In millions of US$	31 December 2022	31 December 2021
Trade payables	1.0	0.6
Lease liabilities	0.1	1.2
Amounts owed to parent companies (note 28)	14.3	14.4
Amounts owed to subsidiaries (note 28)	367.0	0.1
Accruals and other creditors	16.6	18.8
Other current liabilities	5.2	3.5
Current trade and other payables	**404.2**	**38.6**
Amounts falling due after one year		
Lease liabilities	4.1	-
Other non-current liabilities[1]	43.1	87.7
Inter-company loan payable to subsidiary	1,175.6	-
Inter-company loans payable to parent company	942.1	938.7
Other non-current liabilities	**2,164.9**	**1,026.4**
Total	**2,569.1**	**1,065.0**

1. Other non-current liabilities of $43.1 million (2021: $87.7 million) relate to meeting the future obligations of a subsidiary company and are held at the fair value of the future expected liability.

Inter-company loan payable to subsidiary of $1,175.6 million relates to a $1,800 million borrowing facility the Company entered into with its wholly owned subsidiary Neptune Energy Finance Limited on 30 November 2022, it is due for repayment on 31 December 2027. The loan has a fixed interest rate of 8.92%. Also on 30 November, the Company drew down $1,175.6 million on the new facility to finance a Euro 1,134.1 million further investment in capital in its wholly owned subsidiary Neptune Energy Holding Netherlands B.V. (see note 15).

The inter-company loans payable to parent company of $942.1 million due as at 31 December 2022 (2021: $938.7 million) relate to separate loans provided by the Company's parent (Neptune Energy Group Midco Limited).

For terms and conditions relating to related party payables, refer to note 28.

22. Leases

Group as a lessee

The Group has lease contracts for land, buildings, plant, equipment and transportation assets used in its operations. Leases of land and buildings have lease terms between three and 42 years, PP&E leases are less than three years, while transportation assets have leases between two and 13 years. The Group's obligations under its leases are secured by the lessor's title to the leased assets.

The Group also has certain leases of machinery with lease terms of 12 months or less and leases of office equipment with low value. The Group applies the 'short-term lease' and 'lease of low-value assets' recognition exemptions for these leases and these costs are expensed in the profit and loss statement.

Set out below are the carrying amounts of right-of-use assets recognised (included within property, plant and equipment) and the movements during the period:

Group In millions of US$	Oil and gas properties	Other fixed assets	Total
At 1 January 2021	**67.7**	**38.5**	**106.2**
Additions	19.2	15.8	35.0
Depreciation expense	(45.4)	(7.3)	(52.7)
Currency translation adjustments	(1.9)	(2.3)	(4.2)
At 31 December 2021	**39.6**	**44.7**	**84.3**
Additions	39.7	6.0	45.7
Derecognition[1]	(12.7)	-	(12.7)
Depreciation expense	(36.9)	(6.0)	(42.9)
Currency translation adjustments	(3.3)	(3.2)	(6.5)
At 31 December 2022	**26.4**	**41.5**	**67.9**

1. Lease derecognition in 2022 is due to a lease modification that resulted in the lease not meeting the IFRS 16 criteria to recognise a right-of-use asset.

Set out below are the carrying amounts of lease liabilities (included under trade payables and other liabilities) and the movements:

Group In millions of US$	2022	2021
At 1 January	(131.7)	(188.1)
Additions	(100.5)	(52.9)
Modification	14.0	0.7
Interest expense[1]	(4.2)	(6.0)
Payments[2]	90.0	113.4
Other	(0.2)	0.2
Currency translation adjustments	10.0	1.0
At 31 December	**(122.6)**	**(131.7)**

1. Includes $0.4 million (2021: $0.3 million) of capitalised interest.
2. The payments include $4.2 million (2021: $6.0 million) relating to interest and $85.8 million (2021: $107.4 million) relating to principal repayments.

Group In millions of US$	31 December 2022	31 December 2021
Within one year	64.2	73.9
Current trade payables and other liabilities (note 21)	**64.2**	**73.9**
Between two and five years	42.1	37.5
More than five years	16.3	20.3
Non-current trade payables and other liabilities (note 21)	**58.4**	**57.8**

The following are the amounts recognised in profit or loss:

Group In millions of US$	31 December 2022	31 December 2021
Depreciation expense of right-of-use assets	(42.9)	(52.8)
Interest income from Joint Arrangements for right-of-use assets	1.0	1.5
Interest expense	(4.2)	(6.0)
Expense relating to short-term leases	(0.1)	(0.1)
Expense relating to variable lease payments	(0.5)	(1.3)
Expense relating to leases of low-value assets	(0.5)	(0.7)
Total amount recognised in profit and loss	**(47.2)**	**(59.4)**

The Group has total cash outflows for leases of $90.0 million (2021: $113.4 million). The future cash outflows relating to leases that have not yet commenced are disclosed in note 27.1.

Company as a lessee

The Company has a lease liability balance of $4.2 million (2021: $1.2 million) pertaining to the lease of a building that has a remaining lease term of 5 year (2021: 1 year). The extension of this lease term arose as a result of the Company electing not to trigger a break clause in the lease which had originally been expected to be activated in September 2022. The revised remaining term of the lease runs to March 2028.

23. Provisions

Group In millions of US$	Decommissioning	Restructuring	Total employee benefit obligations	Other	Total
At 1 January 2022	1,681.7	22.3	184.5	13.0	1,901.5
Charge for the year	26.3	-	7.8	-	34.1
Unwinding of discount	33.1	-	1.7	-	34.8
Additions	78.1	-	-	0.5	78.6
Change in discount rate	(125.4)	-	42.3	-	(83.1)
Utilisation/paid[1]	(29.1)	(17.2)	(179.4)	(2.7)	(228.4)
Unused provisions released to income statement	(8.7)	(0.1)	(0.2)	-	(9.0)
Currency translation	(120.9)	(1.1)	(17.7)	(0.1)	(139.8)
At 31 December 2022	**1,535.1**	**3.9**	**39.0**	**10.7**	**1,588.7**

1. Included in the $179.4 million relating to employee benefit obligations is a one-off insurance premium of $168.6 million paid to Allianz Pensionsfonds AG to insure the past service benefits of the ENGIE E&P Deutschland GmbH pension scheme. For further details see note 29.

Group In millions of US$	31 December 2022	31 December 2021
Current		
Restructuring	2.6	20.1
Post-employment benefit and other long-term benefits (see note 29)	8.2	9.7
Decommissioning	122.1	86.4
Other	9.7	7.3
Current total	**142.6**	**123.5**
Non-Current		
Restructuring	1.3	2.2
Post-employment benefit and other long-term benefits (see note 29)	30.8	174.8
Decommissioning	1,413.0	1,595.3
Other	1.0	5.7
Non-current total	**1,446.1**	**1,778.0**
Total	**1,588.7**	**1,901.5**

The Group makes full provision for the future cost of decommissioning oil production facilities and pipelines on a discounted basis on the installation of those facilities. The decommissioning provision represents the present value of decommissioning costs relating to oil and gas properties, which are expected to be incurred up to the end of operations. These provisions have been created based on the Group internal estimates.

Assumptions, based on the current economic environment, have been made which management believe are a reasonable basis upon which to estimate the future liability. These estimates are reviewed regularly to take into account any material changes to the assumptions. However, actual decommissioning costs will ultimately depend upon future market prices for the necessary decommissioning works required which will reflect market conditions, such as inflation, at the relevant time. The discount rate used for discounting decommissioning liabilities is based on the future timing of decommissioning, expected currency of decommissioning expenditure and was in the range 1.9% to 4.4% (2021: year-end range 0.7% to 3.2%). The oil and gas price assumptions used to determine the field life cessation of production are consistent with those applied for the impairment assessment.

Furthermore, the timing of decommissioning is likely to depend on when the fields cease to produce at economically viable rates. This in turn will depend upon future oil and gas prices, which are inherently uncertain.

This decommissioning provision is matched with an accounting entry to property, plant and equipment. The depreciation charge on this asset is included within current operating profit and the cost of unwinding of discount is included within financial costs.

The restructuring provision is in relation to the decision in 2019 to close the corporate office in France and also in June 2020 to close offices in Oslo in Norway and Lingen in Germany.

Company specific provisions
As at 31 December 2022, the Company recognises an employee benefit provision of $1.4 million (2021: $1.1 million) and an other provision of $3.7 million (2021: $nil).

Company In millions of US$	31 December 2022	31 December 2021
Current		
Post-employment benefit and other long-term benefits	0.2	0.1
Other	3.2	-
Current total	**3.4**	**0.1**
Non-current		
Post-employment benefit and other long-term benefits	1.2	1.0
Other	0.5	-
Non-current total	**1.7**	**1.0**
Total	**5.1**	**1.1**

24. Financial assets and liabilities

Financial risk management objectives
The Group's activities expose it to a variety of financial risks including market risk (commodity price risk, foreign currency risk, interest rate risk), credit risk and liquidity risk. The Group's overall risk management programme focuses on the unpredictability of financial markets and seeks to minimise potential adverse effects on the Group's financial performance. The Group holds a portfolio of commodity, interest rate and foreign currency derivative contracts, with various counterparties. The use of derivative financial instruments is governed by the Group's policy approved by the Board of Directors and exposure limits are reviewed internally on a regular basis. The Group does not enter into or trade financial instruments, including derivatives, for speculative purposes.

Fair values of financial assets and liabilities
With the exception of hedging derivatives, the Group considers the carrying value of all of its financial assets and liabilities to be materially the same as their fair value. Derivatives and contingent consideration are measured at fair value through profit and loss, while equity instruments are designated as fair value through other comprehensive income. All other financial assets and liabilities are measured at amortised cost.

Fair values of derivative instruments

All fair values are recognised at fair value on the balance sheet with changes in valuation recognised immediately in the income statement, unless the derivatives have been designated as a cash flow hedge. Fair value is the amount for which the asset or liability could be exchanged in an arm's length transaction at the relevant date. Fair values, where available, are determined using quoted prices in active markets. To the extent that market prices are not available, fair values are estimated by reference to market-based transactions or using standard valuation techniques for the applicable instruments and commodities involved.

Set out below is an overview of financial assets, other than cash and short-term deposits, held by the Group as at 31 December 2022 including their maturity. For items held at amortised cost there is no significant difference between their fair value and amortised cost value.

	31 December 2022			
Group In millions of US$	Less than one year	Between two and five years	More than five years	Total
Financial assets at fair value				
Commodity derivatives at fair value through profit and loss	5.0	-	-	5.0
Commodity derivatives in qualifying hedging relationships[1]	99.4	-	-	99.4
Foreign exchange forward contracts at fair value through profit and loss	16.4	-	-	16.4
Equity instruments designated at fair value through OCI				
10.58% interest in Erdgas-Verkaufs-Gesellschaft GmbH, Münster	-	-	13.0	13.0
Financial assets at amortised cost				
Trade and other receivables	1,285.0	-	-	1,285.0
Other non-current assets[2]	-	99.4	-	99.4
Total	**1,405.8**	**99.4**	**13.0**	**1,518.2**

1. Of the $99.4 million due under one year as at 31 December 2022, $60.7 million is due within six months.
2. Other non-current assets mainly represents amounts receivable from joint venture partners, pre-funded abandonment cost and deferred consideration.

	31 December 2021			
Group In millions of US$	Less than one year	Between two and five years	More than five years	Total
Financial assets at fair value				
Commodity derivatives at fair value through profit and loss	6.0	5.0	-	11.0
Commodity derivatives in qualifying hedging relationships	48.8	16.0	-	64.8
Foreign exchange forward contracts at fair value through profit and loss	5.9	-	-	5.9
Equity instruments designated at fair value through OCI				
10.58% interest in Erdgas-Verkaufs-Gesellschaft GmbH, Münster	-	-	15.4	15.4
Financial assets at amortised cost				
Trade and other receivables	1,384.8	-	-	1,384.8
Other non-current assets[2]	-	69.5	-	69.5
Total	**1,445.5**	**90.5**	**15.4**	**1,551.4**

1. Of the $48.8 million due under one year as at 31 December 2021, $34.3 million is due within six months.
2. Other non-current assets mainly represents amounts receivable from joint venture partners.

Set out below is an overview of financial assets, other than cash and short-term deposits, held by the Company as at 31 December 2022 and 31 December 2021, including their maturity.

	31 December 2022			
Company In millions of US$	Less than one year	Between two and five years	More than five years	Total
Financial assets at amortised cost				
Loan to parent company	455.3	-	-	455.3
Amounts owed by subsidiaries	11.0	-	-	11.0
Prepayments and accrued income	7.4	-	-	7.4
Other current assets	0.7	-	-	0.7
Total	**474.4**	**-**	**-**	**474.4**

Company In millions of US$	31 December 2021 Less than one year	Between two and five years	More than five years	Total
Financial assets at amortised cost				
Loan to parent company	455.3	-	-	455.3
Amounts owed by subsidiaries	40.3	-	-	40.3
Prepayments and accrued income	3.7	-	-	3.7
Other current assets	0.5	-	-	0.5
Total	**499.8**	**-**	**-**	**499.8**

There are no significant sources of hedge ineffectiveness other than for off-market hedging relationships for hedging instruments as well as for credit risk being included on the hedging instrument and not the hedged item in accordance with IFRS 9.

Set out below is an overview of financial liabilities, held by the Group as at 31 December 2022 including their maturity. The Senior Notes held by the Group have a fair value of $830.3 million, compared with the carrying amount of $842.1 million (2021: a fair value of $871.0 million, compared with the carrying amount of $838.7 million). This financial liability would be classed as Level 1. For all other items held at amortised cost there is no significant difference between their fair value and amortised cost value.

Group In millions of US$	31 December 2022 Less than one year	Between two and five years	More than five years	Total
Financial liabilities at fair value				
Commodity derivatives in qualifying hedging relationships(1)	501.3	-	-	501.3
Contingent consideration	2.8	0.9	-	3.7
Financial liabilities at amortised cost				
Long-term borrowings				
Reserve Based Lending facility	-	1,082.8	-	1,082.8
Subordinated Neptune Energy Group Limited Vendor loan	-	100.0	-	100.0
Subordinated Neptune Energy Group Limited loan 1	-	545.4	-	545.4
Subordinated Neptune Energy Group Limited loan 2	-	296.7	-	296.7
Trade and other payables	299.5	-	-	299.5
Wages and social security	48.8	-	-	48.8
Lease liabilities	64.2	42.1	16.3	122.6
Other liabilities	419.6	33.8	-	453.4
Total	**1,336.2**	**2,101.7**	**16.3**	**3,454.2**

1. Of the $501.3 million, $249.8 million is due within six months.

	31 December 2021			
Group **In millions of US$**	**Less than one year**	**Between two and five years**	**More than five years**	**Total**
Financial liabilities at fair value				
Commodity derivatives in qualifying hedging relationships[1]	1,029.3	169.7	-	1,199.0
Contingent consideration	1.1	4.0	-	5.1
Financial liabilities at amortised cost				
Short-term borrowings				
DNB uncommitted facility	50.0	-	-	50.0
Citibank uncommitted facility	10.0	-	-	10.0
Long-term borrowings				
Reserve Based Lending facility	-	1,330.7	-	1,330.7
Subordinated Neptune Energy Group Limited Vendor loan	-	100.0	-	100.0
Subordinated Neptune Energy Group Limited loan 1	-	543.5	-	543.5
Subordinated Neptune Energy Group Limited loan 2	-	295.2	-	295.2
Trade and other payables	329.4	-	-	329.4
Wages and social security	47.0	-	-	47.0
Lease liabilities	73.9	37.5	20.3	131.7
Other liabilities	390.8	33.4	-	424.2
Total	**1,931.5**	**2,514.0**	**20.3**	**4,465.8**

1. Of the $1,029.3 million, $576.1 million is due within six months.

Set out below is an overview of financial liabilities, held by the Company as at 31 December 2022 and 31 December 2021, including their maturity.

	31 December 2022			
Company **In millions of US$**	**Less than one year**	**Between two and five years**	**More than five years**	**Total**
Financial liabilities at fair value				
Other non-current liabilities	-	43.1	-	43.1
Financial liabilities at amortised cost				
Long-term borrowings				
Reserve Base Lending facility	-	1,082.8	-	1,082.8
Inter-company loan payable to subsidiary	-	1,175.6	-	1,175.6
Inter-company loans payable to parent company		942.1	-	942.1
Trade payables	1.0	-	-	1.0
Lease liabilities	0.1	4.1	-	4.2
Amounts owed to parent companies	14.3	-	-	14.3
Amounts owed to subsidiaries	367.0	-	-	367.0
Accruals and other creditors	16.6	-	-	16.6
Other current liabilities	5.2	-	-	5.2
Total	**404.2**	**3,247.7**	-	3,651.9

	31 December 2021			
Company In millions of US$	Less than one year	Between two and five years	More than five years	Total
Financial liabilities at fair value				
Other non-current liabilities	-	87.7	-	87.7
Financial liabilities at amortised cost				
Long-term borrowings				
Reserve Base Lending facility	-	1,330.7	-	1,330.7
Inter-company loans payable to parent company	-	938.7	-	938.7
Trade payables	0.6	-	-	0.6
Lease liabilities	1.2	-	-	1.2
Amounts owed to parent companies	14.4	-	-	14.4
Amounts owed to subsidiaries	0.1	-	-	0.1
Accruals and other creditors	18.8	-	-	18.8
Other current liabilities	3.5	-	-	3.5
Total	**38.6**	**2,357.1**	-	**2,395.7**

24.1 Fair value measurements

Valuation
All financial instruments that are initially recognised and subsequently remeasured at fair value have been classified in accordance with the hierarchy described in IFRS 13 Fair Value Measurement.

Fair value measurement hierarchy
The fair value hierarchy, described below, reflects the significance of the inputs used to determine the valuation of financial assets and liabilities measured at fair value.

Level 1 fair value measurements are those derived directly from quoted prices (unadjusted) in active markets for identical assets and liabilities.

Level 2 fair value measurements are those including inputs other than quoted prices included within Level 1 that are observable for the asset or liability directly or indirectly. The fair value of the Group's interest rate and currency exchange rate derivatives and the majority of the Group's commodity derivatives are calculated from relevant market prices and yield curves at the balance sheet date and are therefore based solely on observable price information. These instruments are not directly quoted in active markets and are accordingly classified as Level 2 in the fair value hierarchy.

Level 3 fair value measurements are those derived from valuation techniques that include significant inputs for the asset or liability that are not based on observable market data. Where observable market valuations of commodity contracts are unavailable, the fair value on initial recognition is the transaction price and is subsequently determined using the Group's forward planning assumptions for the price of gas, other commodities and indices.

Equity investments are valued using the market approach based on a multiple of EBITDA consistent with the valuation obtained for transactions involving investments similar in nature.

All of the Group's derivatives are Level 2 and 3. There were no financial derivatives held by the Company in 2022 and 2021.

The following table provides the fair value measurement hierarchy of the Group's assets:

Group In millions of US$	Date of valuation	31 December 2022 Total	Significant observable inputs (Level 2)	Significant unobservable inputs (Level 3)
Assets measured at fair value				
Derivative financial assets				
Commodity derivatives in qualifying hedging relationships	31-Dec-22	99.4	99.4	-
Commodity derivatives at fair value through profit and loss	31-Dec-22	5.0	5.0	-
Foreign exchange forward contracts at fair value through profit and loss	31-Dec-22	16.4	16.4	-
Non-listed equity instruments				
10.58% interest in Erdgas-Verkaufs-Gesellschaft GmbH, Münster	31-Dec-22	13.0	-	13.0
Total		**133.8**	**120.8**	**13.0**

Group In millions of US$	Date of valuation	31 December 2021 Total	Significant observable inputs (Level 2)	Significant unobservable inputs (Level 3)
Assets measured at fair value				
Derivative financial assets				
Commodity derivatives in qualifying hedging relationships	31-Dec-21	64.8	64.8	-
Commodity derivatives at fair value through profit and loss	31-Dec-21	11.0	11.0	-
Foreign exchange forward contracts at fair value through profit and loss	31-Dec-21	5.9	5.9	-
Non-listed equity instruments				
10.58% interest in Erdgas-Verkaufs-Gesellschaft GmbH, Münster	31-Dec-21	15.4	-	15.4
Total		**97.1**	**81.7**	**15.4**

The valuation of Neptune's interest in Erdgas-Verkaufs-Gesellschaft GmbH, Münster has been calculated based on an enterprise value/EBITDA multiple taking into account recent transactions involving suitable comparative infrastructure companies.

The following table provides the fair value measurement hierarchy of the Group's liabilities:

Group In millions of US$	Date of valuation	31 December 2022 Total	Significant observable inputs (Level 2)	Significant unobservable inputs (Level 3)
Liabilities measured at fair value				
Commodity derivatives in qualifying hedging relationships	31-Dec-22	501.3	501.3	-
Contingent consideration	31-Dec-22	3.7	-	3.7
Total		**505.0**	**501.3**	**3.7**

Group In millions of US$	Date of valuation	31 December 2021 Total	Significant observable inputs (Level 2)	Significant unobservable inputs (Level 3)
Liabilities measured at fair value				
Commodity derivatives in qualifying hedging relationships	31-Dec-21	1,199.0	1,199.0	-
Contingent consideration	31-Dec-21	5.1	-	5.1
Total		**1,204.1**	**1,199.0**	**5.1**

There were no transfers between fair value levels in the year for either assets or liabilities.

The Company held neither assets nor liabilities measured at fair value for either year ended 31 December 2022 or 31 December 2021.

24.2 Level 3 fair value movements

The movements in the year associated with the non-listed equity investments classified as equity instruments designated at fair value through other comprehensive income in accordance with Level 3 are shown below:

	Group		Company	
In millions of US$	31 December 2022	31 December 2021	31 December 2022	31 December 2021
Fair value at 1 January	15.4	21.1	-	-
Fair value loss on equity instruments designated at FVOCI	(1.5)	(4.1)	-	-
Currency translation adjustments	(0.9)	(1.6)	-	-
Fair value at 31 December	**13.0**	**15.4**	-	-

A 5% change in the EBITDA multiple to the Level 3 instrument above as applied would result in a $0.6 million change in valuation (2021: $0.8 million).

The movements in the year associated with the contingent consideration at fair value through profit and loss in accordance with Level 3 are shown below:

	Group		Company	
In millions of US$	31 December 2022	31 December 2021	31 December 2022	31 December 2021
Fair value at 1 January	(5.1)	(2.6)	-	-
Additions in the period	-	(6.0)	-	-
Utilisation/cash paid	1.1	0.7	-	-
Gains recognised in the income statement	-	2.5	-	-
Gains recognised in other comprehensive income	0.3	0.3	-	-
Fair value at 31 December	**(3.7)**	**(5.1)**	-	-

The contingent consideration at 31 December 2022 relates to assets acquired in Germany from Wintershall Dea AG in 2021. This will be payable based upon satisfaction of certain criteria, of which $1.1 million (2021: $0.7 million) has been settled during 2022. The possible outcome of the remaining contingent consideration ranges from $nil to $6.1 million. The contingent consideration is based on unobservable inputs and are Level 3 in the IFRS 13 hierarchy.

The gain on the derecognition of a contingent consideration payable in 2021 related to an asset in Denmark that was part of the VNG acquisition in 2018 that was disposed of during the year.

24.3 Hedging reserve

The hedge reserve represents the portion of deferred gains and losses on hedging instruments deemed to be effective cash flow hedges. The movement in the reserve for the period is recognised in other comprehensive income. The following table summarises the hedge reserve by type of derivative, net of tax effects.

Group In millions of US$	Cash flow commodity hedge reserve	Cost of commodity hedging reserve	Total hedge reserve
At 1 January 2022	**652.0**	**56.6**	**708.6**
Add: costs of hedging deferred and recognised in OCI	941.6	31.7	973.3
Less: reclassified from OCI to profit or loss	(1,662.0)	(19.5)	(1,681.5)
Less: deferred tax	237.6	(17.9)	219.7
Hedge adjustments net of tax	**(482.8)**	**(5.7)**	**(488.5)**
Less: share of hedge adjustments within equity-accounted investments deferred and recognised in OCI	(7.0)	(0.2)	(7.2)
At 31 December 2022	**162.2**	**50.7**	**212.9**

Group In millions of US$	Cash flow commodity hedge reserve	Cost of commodity hedging reserve	Cash flow interest rate hedge reserve	Total hedge reserve
At 1 January 2021	**11.5**	**7.4**	**3.7**	**22.6**
Add: costs of hedging deferred and recognised in OCI	1,761.9	84.4	(3.7)	1,842.6
Less: reclassified from OCI to profit or loss	(666.1)	(14.5)	-	(680.6)
Less: deferred tax	(459.5)	(20.7)	-	(480.2)
Hedge adjustments net of tax	**636.3**	**49.2**	**(3.7)**	**681.8**
Less: share of hedge adjustments within equity-accounted investments deferred and recognised in OCI	4.2	-	-	4.2
At 31 December 2021	**652.0**	**56.6**	**-**	**708.6**

The table above excludes hedge ineffectiveness, this is taken directly into the income statement, in 2022, was a gain of $0.2 million (2021: $nil). The value of any credit valuation adjustment (CVA) and debit valuation adjustment (DVA) for 2022 was $0.2 million (2021: $2.3 million).

There were no financial derivatives held by the Company in 2022 and 2021.

24.4 Fair value reserve of financial assets at Fair Value through Other Comprehensive Income ('FVOCI')

Group In millions of US$	2022	2021
At 1 January	5.9	-
Fair value loss on equity instruments designated at FVOCI	1.5	4.1
Currency translation adjustments	0.9	1.6
Deferred tax	-	0.2
At 31 December	**8.3**	**5.9**

There were no fair value reserve of financial assets at FVOCI in the Company during 2022 and 2021.

25. Financial risk factors

Please refer to our risk disclosure in the Neptune Energy Group Midco Limited Annual Report and Accounts.

The Group did not enter into any enforceable master netting arrangements.

The Group's senior management oversees the management of financial risk. The Group's senior management ensures that financial risk-taking activities are governed by appropriate policies and procedures and that financial risks are identified, measured and managed in accordance with Group policies and risk objectives. All derivative activities for risk management purposes are carried out by specialist teams, both internal and external, that have the appropriate skills, experience and supervision.

Market risk is the risk that the fair value of future cash flows of a financial instrument will fluctuate because of changes in market prices. Market risk comprises three types of risk: commodity price risk, interest rate risk and foreign currency risk. Financial instruments is mainly affected by market risk including loans and borrowings, deposits and derivative financial instruments.

The sensitivity analyses have been prepared on the basis that the amount of financial instruments are all constant. The sensitivity analyses are intended to illustrate the sensitivity to changes in market variables on the composition of the Group's financial instruments at the balance sheet date and show the impact on profit or loss and shareholders' equity, where applicable.

The following assumptions have been made in calculating the sensitivity analyses:

- the sensitivity of the relevant profit before tax item and/or equity is the effect of the assumed changes in respective market risks for the full year based on the financial assets and financial liabilities held at the balance sheet date;
- the sensitivities indicate the effect of a reasonable increase in each market variable. Unless otherwise stated, the effect of a corresponding decrease in these variables is considered approximately equal and opposite;
- fair value changes from derivative instruments designated as cash flow hedges are considered fully effective and recorded in shareholders' equity, net of tax; and
- fair value changes from derivatives and other financial instruments not designated as cash flow hedges are presented as a sensitivity to profit before tax only and not included in shareholders' equity.

25.1 Liquidity risk
Liquidity risk is the risk that the Group might not have sources of funding to meet its business needs. The Group manages its liquidity risk using both short and long-term cash flow projections, supplemented by debt financing and active portfolio management. The Board of Directors, who have ultimate responsibility for liquidity risk management, believe that the Group has sufficient cash, undrawn committed funds under its borrowing base facility and expected sources of liquidity to meet the business's forecast requirements for the short, medium and long-term.

The Group assessed the concentration of risk with respect to refinancing its debt and concluded it to be low. The Group has access to a sufficient variety of sources of funding and debt maturing within 12 months can be rolled over with existing lenders.

25.2 Credit rate risk
Credit risk is managed on a Group basis. Currently, credit risk only arises from cash and cash equivalents, sales receivables, receivables from joint venture partners and hedging derivatives. For banks and financial institutions, only independently rated parties with a minimum rating of 'BBB' are accepted. The Group does not have any significant credit risk exposure to any single counterparty or any group of counterparties. Joint Venture partners are predominantly international oil and gas market participants. Counterparty evaluations are conducted utilising information provided by international credit rating agencies, credit insurance companies and financial assessments. Where considered appropriate, security in the form of trade finance instruments from financial institutions with an appropriate credit rating, such as letters of credit, bank guarantees and credit insurance, are obtained to mitigate the risks.

The Group's maximum exposure to credit risk for the components of the statement of financial position at 31 December 2022 and 2021 is the carrying amounts as illustrated in note 24.

25.3 Climate change risk
Climate change risk is the risk that the Group fails to manage the impact of climate change due to evolving regulatory policies. Subsequent related commodity price volatility or access to markets could affect portfolio commerciality, our licence to operate and impact Neptune's access to capital funding. Please refer to note 1.3.1 *Estimates – Climate change* and Neptune Energy Group Midco Limited Annual Report and Accounts for more information on how the Group is managing climate-related risk and what it is doing to manage ESG matters.

25.4 Market risk
Financial instruments used by the Group that are affected by market risks primarily comprise cash and cash equivalents, borrowings and derivative contracts. Due to the nature of its operations, the Group carries a natural exposure to gas and oil prices, generating commodity-market-related volatility on its earnings.

The Group identifies, governs and manages this market price exposure through a dedicated market risks policy.

One of the elements of the Group market risks policy is to implement a hedging programme on forecasted sales of produced gas and oil products. The hedging programme aims at smoothening the impact of gas and oil price volatility on earnings by reducing exposure to market prices. It thereby improves the earnings predictability of the Group.

The Group's hedging programme is focused on reducing volatility of the net earnings, taking into account the underlying pricing structure of sales contracts, production uncertainties and fiscal impacts of hedging.

Under the Reserves Based Lending (RBL) facility, the aggregate post-tax hedge ratio shall equal 50% for the first rolling 12-month period, 30% for the next rolling 12-month period and 15% for the last 12-month period. The Group currently benefits from a waiver until the period ended 31 March 2023, which allows the Group not to hedge for the last 12-month period.

In 2022, this hedging programme applied to price exposures of the major affiliates of the Group: Neptune Energy Norge AS, Neptune Energy Nederland B.V., Neptune Energy E&P Holdings Netherlands B.V., Neptune Energy Deutschland GmbH, and Neptune E&P UK Ltd.

The Group held the following commodity forward contracts for its wholly owned subsidiaries as at the respective balance sheet date:

			31 December 2022			
Group	Volumes	Swap	Bought put	Sold call	Bought call	Period of hedge
OIL HEDGES VS BRENT	mmbbl	$/bbl	$/bbl	$/bbl	$/bbl	
Put options	5.1	-	47.8	-	-	up to 1 year
Collars	1.3	-	47.8	117.4	-	up to 1 year
Three-ways collars (call-spread)	1.7	-	47.8	117.4	110.2	up to 1 year
Total/(weighted average)	**8.1**	**-**	**47.8**	**117.4**	**110.2**	
GAS HEDGES VS NBP	000's mmbtu	$/mmbtu	$/mmbtu	$/mmbtu	$/mmbtu	
Collars	11,910	-	6.4	21.2	-	up to 1 year
Swaps	4,200	15.6	-	-	-	up to 1 year
Total/(weighted average)	**16,110**	**15.6**	**6.4**	**21.2**	**-**	
GAS HEDGES VS TTF	000's mmbtu	$/mmbtu	$/mmbtu	$/mmbtu	$/mmbtu	
Collars	21,548	-	9.1	35.0	-	up to 1 year
Swaps	5,937	4.7	-	-	-	up to 1 year
Total/(weighted average)	**27,485**	**4.7**	**9.1**	**35.0**	**-**	
EMISSION HEDGES VS EUA	000's tonnes	€/tonnes	€/tonnes	€/tonnes	€/tonnes	
Commodity forward	100	38.7	-	-	-	up to 1 year

			31 December 2021			
Group	Volumes	Swap	Bought put	Sold call	Bought call	Period of hedge
OIL HEDGES VS BRENT	mmbbl	$/bbl	$/bbl	$/bbl	$/bbl	
Put options	7.0	-	47.0	-	-	up to 2 years
Collars	2.8	-	47.0	87.4	-	up to 2 years
Three-ways collars (call-spread)	1.7	-	47.0	87.4	95.4	up to 1 year
Total/(weighted average)	**11.5**	**-**	**47.0**	**87.4**	**95.4**	
GAS HEDGES VS NBP	000's mmbtu	$/mmbtu	$/mmbtu	$/mmbtu	$/mmbtu	
Call options	2,100	-	-	-	15.5	up to 0.5 year
Collars	12,060	-	6.2	15.0	-	up to 2 years
Swaps	27,000	5.7	-	-	-	up to 2 years
Total/(weighted average)	**41,160**	**5.7**	**6.2**	**15.0**	**15.5**	
GAS HEDGES VS TTF	000's mmbtu	$/mmbtu	$/mmbtu	$/mmbtu	$/mmbtu	
Collars	29,164	-	6.2	11.7	-	up to 2 years
Swaps	24,455	5.4	-	-	-	up to 2 years
Total/(weighted average)	**53,619**	**5.4**	**6.2**	**11.7**	**-**	
EMISSION HEDGES VS EUA	000's tonnes	€/tonnes	€/tonnes	€/tonnes	€/tonnes	
Commodity forward	200	33.4	-	-	-	up to 2 years

There were no financial derivatives held by the Company in 2022 and 2021.

Aggregate post-tax hedge ratio

The Group establishes its hedge ratio by considering hedging items as a proportion of post-tax production. Post-tax hedge ratios adjust for different tax rates on physical sales and hedge gains and losses, which means that effective post-tax hedges can be achieved through hedging contracts for volumes, which may be significantly less than anticipated sales.

The Group's hedge ratio for commodity derivatives is calculated after applying a 10% headroom against entitlement forecast production and is designed to protect post-tax revenues.

At 31 December 2022 the aggregate post-tax hedge ratio for the Group's wholly owned subsidiaries was:

	2023	2024	2025
Oil	45%	-	-
Gas	44%	-	-
Total weighted average	**45%**	-	-

At 31 December 2021 the aggregate post-tax hedge ratio for the Group's wholly owned subsidiaries was:

	2022	2023	2024
Oil	37%	23%	-
Gas	62%	30%	-
Total weighted average	**49%**	**26%**	-

Oil price hedges include hedges of realisations for gas production sold as LNG and priced in relation to oil prices.

Sensitivities of the commodity-related financial derivatives portfolio used as part of the portfolio management activities at 31 December, are detailed in the table below and are reasonably foreseeable market movements to the Group's financial instruments. They are not representative of future changes in consolidated earnings and equity, in so far as they do not include the sensitivities relating to the purchase and sale contracts for the underlying commodities, only the effect on the underlying derivative itself.

		31 December 2022		31 December 2021	
Group In millions of US$	Price movement	Pre-tax loss/ (gain) on income	Pre-tax loss/ (gain) on equity	Pre-tax loss/ (gain) on income	Pre-tax loss/ (gain) on equity
SENSITIVITY ANALYSIS Effect on profit before tax and on pre-tax equity					
Gas price	+10% pence/ therm increase	-	78.3	-	163.2
Gas price	-10% pence/ therm decrease	-	(76.3)	-	(163.2)
Brent oil price	+10%/bbl increase	-	5.1	-	12.9
Brent oil price	-10%/bbl decrease	-	(5.6)	-	(12.8)
Carbon dioxide European Union Allowance	+10%/eua increase	(0.9)	-	(1.9)	-
Carbon dioxide European Union Allowance	-10%/eua decrease	0.9	-	1.9	-

25.5 Foreign currency risk

The Group conducts and manages its business predominantly in US dollars, the operating currency of the oil and gas industry. However, as the Group operates internationally it is therefore exposed to foreign exchange risk arising from various currency exposures, primarily with respect to the Euro, Sterling and Norwegian Krone (NOK). Foreign exchange risk arises from future commercial transactions, recognised assets and liabilities and net investments in foreign operations.

The Group is exposed to currency risk, defined as the impact on its statement of financial position and income statement of fluctuations in exchange rates affecting its operating and financing activities. Currency risk comprises: (i) transaction risk arising in the ordinary course of business, (ii) specific transaction risks related to investments, mergers-acquisitions projects, and (iii) the risk arising on the consolidation in USD of subsidiary financial statements with a functional currency other than the USD.

The Group held $1,103.8 million of USD NOK forwards as at 31 December 2022 (2021: $210.0 million), with the key objective to hedge tax payments in Norway for 2023.

The table below illustrates the indicative pre-tax effects on the income statement and other comprehensive income of applying reasonably foreseeable market movements to the Group's currency related financial instruments at the balance sheet date.

	31 December 2022		31 December 2021	
Group In millions of US$	Pre-tax loss/ (gain) on income	Pre-tax loss/ (gain) on equity	Pre-tax loss/ (gain) on income	Pre-tax loss/ (gain) on equity
SENSITIVITY ANALYSIS				
Effect on profit before tax and on pre-tax equity:				
+10% NOK	101.8	-	19.6	-
-10% NOK	(124.5)	-	(24.0)	-

26. Called up share capital

Group and Company	Number	US$ million
Allotted, called up and fully paid $1 shares		
31 December 2021	**1,977,175,201**	**1,977.2**
Capital reduction	(1,300,000,000)	(1,300.0)
31 December 2022	677,175,201	677.2

The capital reduction took the form of two separate events as detailed below.

On 1 September 2022, the Directors of the Company resolved to complete a reduction of share capital. Such reduction took the form of cancelling and extinguishing 1 billion of the issued and fully paid up ordinary shares of $1.0 each. This resulted in the the issued share capital of the Company being reduced from $1,977,175,201, comprising of 1,977,175,201 ordinary shares of $1.0 each, to $977,175,201, comprising of 977,175,201 ordinary shares of $1.0 each.

On 17 November 2022 the Directors of the Company resolved to complete a further reduction of share capital. Such reduction took the form of cancelling and extinguishing 300 million of the issued and fully paid up ordinary shares of $1.0 each. This resulted in the the issued share capital of the Company being reduced from $977,175,201, comprising of 977,175,201 ordinary shares of $1.0 each, to $677,175,201, comprising of 677,175,201 ordinary shares of $1.0 each.

27. Commitment and contingencies

27.1 Lease and financial commitments

The Group has lease contracts that have not yet commenced as at 31 December 2022. The future lease payments for these non-cancellable lease contracts are $6.1 million (2021: $2.8 million) within one year, $2.8 million (2021: $nil) within two to five years and $nil (2021: $nil) in more than five years.

The Group has several lease contracts that include extension and termination options. These options are negotiated by management to provide flexibility in managing the leased-asset portfolio and to align with the Group's business needs.

The Group has financial commitments in respect of leases that do not meet the IFRS 16 criteria to recognise as a right-of-use asset. As at 31 December 2022, the future payments for these contracts are $11.9 million (2021: $0.5 million) within one year, $16.7 million (2021: $0.2 million) within two to five years and $nil (2021: $nil) in more than five years.

The Group has financial commitments in respect of capacity bookings. As at 31 December 2022, the future payments for these contracts are $23.4 million (2021: $30.3 million) within one year, $19.2 million (2021: $39.8 million) within two to five years and $0.4 million (2021: $0.8 million) in more than five years.

The Company has a single lease commitment as detailed in note 22.

27.2 Capital commitments

	Group		Company	
In millions of US$	31 December 2022	31 December 2021	31 December 2022	31 December 2021
Amounts due:				
Within one year	282.6	307.7	-	-
After one year but within two years	56.4	20.0	-	-
After two years but not more than five years	90.0	51.7	-	-
More than five years	-	-	-	-
Total	**429.0**	**379.4**	-	-

1. Values are inclusive of IFRS 16 lease contracts that are yet to commence as disclosed in note 27.1.
2. Includes the Group's share of $6.2 million (2021: $2.3 million) of capital commitments related to Neptune Energy Touat B.V. (see note 15).

As at 31 December 2022, the Group had commitments for future capital expenditure amounting to $429.0 million (2021: $379.4 million). Where the commitment relates to a Joint Arrangement, the amount represents the Group's net share of the commitment. Where the Group is not the operator of the Joint Arrangement, then the amounts are based on the Group's net share of committed future work programmes.

The Company has no capital commitments in 2022 and 2021, other than the lease mentioned above.

27.3 Contingencies

As at 31 December 2022, the Group has no contingent liabilities (2021: $nil). As at 31 December 2022 and 31 December 2021, a contingent asset existed in Norway in relation to loss of production and future recovery through business interruption insurance. At 31 December 2022 and 2021, due to several variable factors, it is not possible to provide an estimate of the amount of the associated contingent assets.

The Company had no contingencies in either 2022 or 2021.

27.4 Legal proceedings

During the normal course of its business, the Group may be involved in disputes, including tax disputes. Where applicable the Group has made accruals for probable liabilities related to litigation and claims based on management's best judgement and in line with IAS 37 and IAS 12.

In 2022 and 2021, the Group has not identified any material contingent liabilities as all are deemed remote in nature.

There are no material pending legal proceedings for the Company as at 31 December 2022 (2021: none).

28. Related party transactions

The note describes the material transactions between the Group and its related parties.

The Group's main subsidiaries are listed in note 30.

GROUP

Related party undertaking	Principal activities	Country of incorporation	% Equity interest
Neptune E&P UK Limited	Management and technical services	UK	100
Neptune Energy International S.A.	Management and technical services	France	100
Neptune Energy Norge A.S.	Management and technical services	Norway	100
Neptune Energy Holding Netherlands B.V.	Management and technical services	Netherlands	100

The ultimate holding parent is Neptune Energy Group Limited, which is based in London, UK.

During 2022 and 2021, the Group undertook the following transactions with related parties:

In millions of US$		2022	2022	2021	2021
Related party undertaking	Nature of transactions	Purchases	Accounts payable	Purchases	Accounts payable
TMF Norway Energy AS (CVC investor)	Services	3.0	-	2.9	0.3
Essential Project Solutions	Services	0.2	-	0.3	-
ONE-Dyas B.V. (Carlyle investor)	Oil and Gas	5.4	-	6.9	-
PA Consulting (Carlyle investor) [1]	Services	-	-	0.1	-

1. PA Consulting ceased to be a related party from March 2021.

In millions of US$		2022	2022	2021	2021
Related party undertaking	Nature of transactions	Sales	Accounts receivable	Sales	Accounts receivable
ONE-Dyas B.V. (Carlyle investor)	Oil and Gas	9.1	0.9	8.4	0.6

Terms and conditions of transactions with related parties
The finance income and expenses from related parties are made on terms equivalent to those that prevail in arm's length transactions. Outstanding balances at the year-end are unsecured. There have been no guarantees provided or received from any related party receivables or payables. For the years ended 31 December 2022 and 31 December 2021, the Group has not recorded any impairment of receivables relating to the amounts owed by related parties. This assessment is undertaken throughout the financial year through examining the financial position of the related party and the market in which the related party operates.

Other transactions with related parties
At 31 December 2022 and 2021, there was a loan receivable balance of $455.3 million due from the parent company Neptune Energy Group Midco Limited, as described in note 17.

Compensation of key management personnel of the Group
Key management includes the Directors of the Company and its subsidiaries. The compensation paid or payable to key management for employee services is shown below:

In millions of US$	2022	2021
Short-term employee benefits	5.1	5.2
Long-term employee benefits – post employment benefits	0.1	0.1
Total compensation to key management personnel	**5.2**	**5.3**

There are no other related party transactions.

COMPANY

There are no related party transactions other than inter-company interest, loans and the promissory note as described in note 10 and note 21.

Terms and conditions of transactions with related parties
The finance income and costs from related parties are made on terms equivalent to those that prevail in arm's length transactions. Outstanding balances at the year end are unsecured. There have been no guarantees provided or received from any related party receivables or payables. For the years ended 31 December 2022 and 31 December 2021, the Company has not recorded any impairment of receivables relating to the amounts owed by related parties. This assessment is undertaken throughout the financial year through examining the financial position of the related party and the market in which the related party operates.

Compensation of key management personnel of the Company
There is no compensation for key management or Directors included in Neptune Energy Group Holdings Limited. There were no other related party transactions.

29. Post employment benefit obligations and other long-term employee benefits

29.1a Post employee benefit obligations – description of the main pension plans

Pension commitments are measured on the basis of actuarial assumptions. These include assumptions in respect of mortality rates and future salary increases, as well as appropriate discount rates. The Group considers that the assumptions used to measure its obligations are appropriate and documented. However, any changes in these assumptions may have a material impact on the resulting calculations.

The Group provides pension benefits to its employees that are in line with common market practice in the countries where Neptune operates. These consist of both defined contribution and defined benefit arrangements. The latter are either career average or final salary based on employee pensionable earnings and length of service. The plan in the UK is a defined benefit contribution plan.

The Group also provides other post-employment benefits and these are mainly end-of-service gratuities and energy price subsidies, commonly provided by the industry in France.

Germany

Neptune Energy Deutschland has seven defined benefit plans and two long-term benefit plans, corresponding to different groups of employees successively incorporated in the Company.

In 2022, the Group paid an insurance premium to Allianz Pensionsfonds AG to insure the past service benefits of the pension scheme (ENGIE E&P Deutschland GmbH). The insurance company has reinsured the risk with Allianz Lebensversicherungs-AG. Neptune Energy Deutschland remains liable should the insurer be unable to meet the benefits as they fall due so the liability and corresponding asset remains on the balance sheet. The premium paid for the insurance contract was $168.6 million in November 2022 with a further $5.5 million due for settlement in 2023. The fair value of the insurance policy is set equal to the value of the IAS 19 liabilities it covers. The premium paid for the policy is over and above the IAS 19 value of the past service liabilities it covers so the difference, $69.7 million, has been recognised through the OCI as an asset experience loss, due to the exchange of one plan asset for another. There were no plan assets in 2021.

The payment of the insurance premium to fund the German pension scheme is the main reason why the Group's net pension liability has reduced from $184.5 million at the end of 2021 to $39.0 million at the end of 2022.

France

Since 1 January 2005, the CNIEG (Caisse Nationale des Industries Électriques et Gazières) has operated the pension, disability, death, occupational accident and occupational illness benefit plans for 'Energy' employees and retirees in electricity and gas industry companies ('IEG'). The CNIEG is a social security legal entity under private law placed under the joint responsibility of the ministries in charge of social security, budget and energy. Energy employees and retirees have been fully affiliated to the CNIEG since 1 January 2005. The Group Company covered by this plan is Neptune Energy International SA. Pension benefit obligations and other 'mutualised' obligations are assessed by the CNIEG.

In 2019, the corporate office in France was closed. As a result of this, except for the ANE (Avantage en Nature Energie) plan, the majority of defined benefit plan liabilities were removed for employees who had been made redundant reflecting the fact that commitments for Neptune only cover employees while on the IEG payroll.

During 2021, it was concluded that Neptune no longer had any liabilities in the Indemnites, Invalidite, Rentes, Retraites, Medailles, Capital Deces or Aide aux Frais d'education plans. The remaining liabilities for these plans were removed from the balance sheet in 2021, resulting in a settlement gain of $3.0 million. The ANE is the only plan now remaining in 2022.

Norway

Neptune Energy Norge is required to have a funded occupational pension scheme in accordance with Norwegian law. This plan is administered by and holds insurance assets with Norwegian financial services firm DNB. There are five other unfunded plans which are also administered by DNB.

Indonesia

2022 is the second year that the Indonesian Labour Law plan has been included in the pension disclosures.

As there is no deep market for high quality corporate bonds in Indonesia, the discount rate has been set by the local actuary with reference to government bonds instead. The benefits in the Plan are not linked directly to inflation but depend on salary growth.

Other

The Group also operates a number of defined contribution plans which receive fixed contributions from Group companies. The Group's legal or constructive obligation for these plans is limited to the contributions paid. Further details of the amounts paid into these arrangements can be found in note 7.

The Group operates a defined benefit scheme in the Netherlands. This closed in 2019 and the liabilities are fully covered by insurance contracts. As such, the liabilities have been treated as fully settled since 2020, and there is no income statement or net balance sheet impact for 2022 and 2021.

29.1b Other long-term employee benefits – description of the long-term incentive plan

A number of employees participate in a long-term incentive plan, under which they can receive cash payments spread over a period of three years dependent on a number of performance criteria having been met over a three year assessment period. There are employees in this plan from several different territories. Awards are made on an annual basis at the discretion of the Board.

29.2 Pension Governance

The Group's externally funded plans are established under trusts, or similar entities such as insurance contracts. The operation of these entities is governed by local regulations and practice in each country as is the relationship between the local country management and the Trustees, or their equivalent, and the composition of these bodies. Where Trustees or their equivalents are in place they generally act on behalf of the plan's stakeholders. Periodic reviews are carried out on the solvency of the plans in accordance with local legislation and play a role in the long-term investment and funding strategy.

29.3 Defined benefits plans

29.3.1 Change in benefit obligations and plan assets

The table below shows the amount of the Group's projected benefit obligations and plan assets, changes in these items during the periods presented, and their reconciliation with the amounts reported in the consolidated statement of financial position:

Group In millions of US$	Pension benefit obligations [1]	Other post-employment benefit obligations [2]	Long-term benefit obligations [3]	Total employment benefit obligations
A – Change in projected benefit obligations				
Projected benefit obligations at 1 January 2022	(187.8)	(0.6)	(9.0)	(197.4)
Transfers	-	-	-	-
Service cost	(3.9)	-	(4.0)	(7.9)
Past service cost	-	-	-	-
Interest cost on benefit obligations	(2.1)	-	-	(2.1)
Financial actuarial gains and losses	34.7	0.1	0.8	35.6
Actuarial gains and losses due to demographic assumptions	-	-	-	-
Actuarial gains and losses due to experience	(6.1)	-	(0.6)	(6.7)
Benefits paid	7.0	-	2.8	9.8
Other including translation adjustments	12.2	0.1	0.1	12.4
Projected benefit obligation at 31 December 2022 (A)	**(146.0)**	**(0.4)**	**(9.9)**	**(156.3)**

Group In millions of US$	Pension benefit obligations (1)	Other post-employment benefit obligations (2)	Long-term benefit obligations (3)	Total employment benefit obligations
B – Change in fair value of plan assets				
Fair value of plan assets at 1 January 2022	12.9	-	-	12.9
Transfers	-	-	-	-
Interest income on plan assets	0.4			0.4
Financial actuarial gain and losses[4]	(71.1)	-	-	(71.1)
Contributions received[5]	176.6	-	2.8	179.4
Benefits paid	(7.0)	-	(2.8)	(9.8)
Other including translation adjustments	5.5	-	-	5.5
Fair value of plan assets at 31 December 2022 (B)	**117.3**	-	-	**117.3**

Group In millions of US$				
C – Funded status (A+B)				
Net benefit obligation	**(28.7)**	**(0.4)**	**(9.9)**	**(39.0)**

1. Pensions and retirement bonuses.
2. Gratuities and other post-employment benefits.
3. Length of service awards and other long-term benefits.
4. Included in the financial actuarial loss for the year is an asset experience loss of $69.7 million related to the difference in the value of insurance premium paid (see footnote 5 below) and the IAS 19 value of the past service liabilities it covered.
5. Included in the $176.6 million relating to pension benefit obligation contributions received is a one-off insurance premium of $168.6 million paid to Allianz Pensionsfonds AG to insure the past service benefits of the ENGIE E&P Deutschland GmbH pension scheme.

Group In millions of US$	Pension benefit obligations (1)	Other post-employment benefit obligations (2)	Long-term benefit obligations (3)	Total employment benefit obligations
A – Change in projected benefit obligations				
Projected benefit obligations at 1 January 2021	(227.4)	(5.4)	(8.8)	(241.6)
Transfers	(0.5)	-	-	(0.5)
Service cost	(5.1)	-	(3.6)	(8.7)
Past service cost	-	-	-	-
Settlements/curtailments[4]	1.8	2.5	1.3	5.6
Interest cost on benefit obligations	(1.5)	-	-	(1.5)
Financial actuarial gains and losses	12.4	0.2	0.1	12.7
Actuarial gains and losses due to demographic assumptions	4.4	-	-	4.4
Actuarial gains and losses due to experience	4.4	1.9	(0.3)	6.0
Benefits paid	8.3	-	2.0	10.3
Other including translation adjustments	15.4	0.2	0.3	15.9
Projected benefit obligation at 31 December 2021 (A)	**(187.8)**	**(0.6)**	**(9.0)**	**(197.4)**

Group In millions of US$	Pension benefit obligations (1)	Other post-employment benefit obligations (2)	Long-term benefit obligations (3)	Total employment benefit obligations
B – Change in fair value of plan assets				
Fair value of plan assets at 1 January 2021	18.6	-	-	18.6
Transfers	-	-	-	-
Interest income on plan assets	0.3	-	-	0.3
Settlement/curtailments[4]	(1.5)	-	-	(1.5)
Financial actuarial gain and losses	(4.2)	-	-	(4.2)
Contributions received	8.7	-	2.0	10.7
Benefits paid	(8.3)	-	(2.0)	(10.3)
Other including translation adjustments	(0.7)	-	-	(0.7)
Fair value of plan assets at 31 December 2021 (B)	**12.9**	-	-	**12.9**

Group *In millions of US$*				
C – Funded status (A+B)				
Net benefit obligation	**(174.9)**	**(0.6)**	**(9.0)**	**(184.5)**

1. Pensions and retirement bonuses.
2. Gratuities and other post-employment benefits.
3. Length of service awards and other long-term benefits.
4. Included in settlement/curtailments in 2021 is the derecognition of liabilities of $4.1 million. Refer to note 29.4 for further details.

At 31 December 2022 and 2021, there were no pre-paid benefit cost.

29.4 Components of net pension cost

Group In millions of US$	31 December 2022	31 December 2021
Current service cost	7.9	8.7
Net interest expense	1.8	1.2
Actuarial gains and losses on long-term benefit obligations	(0.4)	-
Non-recurring items[1]	-	(4.1)
Total	**9.3**	**5.8**

1. Non-recurring items in 2021 includes settlement and curtailment gains of $4.1 million; $3.0 million arising in France, $1.0 million arising in Germany and $0.1 million arising in Norway.

29.5 Reconciliation of balance sheet deficit over the year

Group In millions of US$	2022	2021
Deficit at 1 January	(184.5)	(223.0)
Expense (charge)/credit	(9.3)	(5.8)
Employer contributions[1]	179.4	10.7
Transfers	-	(0.5)
Actuarial (loss)/gain recognised in OCI[2]	(42.4)	19.1
Currency translation gain	17.8	15.0
Deficit at 31 December	**(39.0)**	**(184.5)**

1. Included in the $179.4 million relating to employer contributions is a one-off insurance premium of $168.8 million paid to Allianz Pensionsfonds AG to insure the past service benefits of the ENGIE E&P Deutschland GmbH pension scheme.
2. Included in the actuarial loss for the year is an asset experience loss of $69.7 million related to the difference in the value of insurance premium paid in (1) above and the IAS 19 value of the past service liabilities it covered.

29.6 Funding

The funding of these obligations at 31 December 2022 can be analysed as follows:

Group In millions of US$	Projected benefit obligation	Fair value of plan assets	Total net obligation
Underfunded plans[1]	(123.3)	117.3	(6.0)
Unfunded plans[2]	(33.0)	-	(33.0)
At 31 December 2022	**(156.3)**	**117.3**	**(39.0)**

Group In millions of US$	Projected benefit obligation	Fair value of plan assets	Total net obligation
Underfunded plans[1]	(14.5)	12.9	(1.6)
Unfunded plans[2]	(182.9)	-	(182.9)
At 31 December 2021	**(197.4)**	**12.9**	**(184.5)**

1. An underfunded plan relates to those schemes where resource is set aside in advance to provide the benefit but where the current amount set aside is less than the current value of the liability.
2. An unfunded plan relates to those schemes where no resources are set aside in advance to provide the benefit.

The allocation of plan assets by principal asset category can be analysed as follows:

% of total	31 December 2022	31 December 2021
Insurance contracts	100	100
Total	**100**	**100**

The scheme assets are held in insurances contracts in Germany and Norway (2021: Norway).

29.7 Actuarial assumptions

With the objective of presenting the assets and liabilities of the pension and other post-employment benefit plans at their fair value on the balance sheet, assumptions under IAS 19 are set by reference to market conditions at the valuation date. The actuarial assumptions used to calculate the benefit liabilities vary according to the country in which the plan is situated.

The discount rate applied is determined based on the yield, at the date of the calculation, on top-rated corporate bonds with maturities mirroring the term of the plan.

2022 assumptions:

Eurozone

Group	Pension benefit obligations(1)	Other post-employment benefit obligations(2)	Long-term benefit obligations(3)
Discount rate	3.50%	2.10% to 3.45%	3.00% to 3.55%
Inflation rate	2.10%	2.10%	0.00% to 2.10%

Norway

Group	Pension benefit obligations(1)	Other post-employment benefit obligations(2)	Long-term benefit obligations(3)
Discount rate	3.00%	-	-
Inflation rate	2.00%	-	-

Indonesia

Group	Pension benefit obligations(1)	Other post-employment benefit obligations(2)	Long-term benefit obligations(3)
Discount rate	7.60%	-	-
Inflation rate	3.00%	-	-

2021 assumptions:

Eurozone

Group	Pension benefit obligations(1)	Other post-employment benefit obligations(2)	Long-term benefit obligations(3)
Discount rate	0% to 1.05%	0% to 1.05%	0% to 0.45%
Inflation rate	1.80%	1.80%	1.80%

Norway

Group	Pension benefit obligations(1)	Other post-employment benefit obligations(2)	Long-term benefit obligations(3)
Discount rate	1.90%	-	-
Inflation rate	1.75%	-	-

Indonesia

Group	Pension benefit obligations(1)	Other post-employment benefit obligations(2)	Long-term benefit obligations(3)
Discount rate	7.30%	-	-
Inflation rate	3.00%	-	-

1. Pensions and retirement bonuses.
2. Gratuities and other post-employment benefits.
3. Length of service awards and other long-term benefits.

Discount and inflation rates

Eurozone:

The discount rate applied is determined based on the yields on AA corporate bonds with maturities matching the durations of the plans at 31 December 2022. The inflation assumption is based on the long-term target of the European Central Bank for inflation.

Norway:

The discount rate and inflation assumptions in Norway have been set in line with the Norwegian Accounting Standards Board's guidance as at 31 December 2022.

Indonesia:

The discount rate has been set by the local actuary using a cash flow-weighted approach. As there is no deep market for high quality corporate bonds in Indonesia, government bonds have been used instead. The benefits in the plan are not linked directly to inflation but depend on salary growth. In setting the salary growth assumption an estimate for future inflation has been determined by taking an average of observed inflation over the last seven to eight years.

Pension risk analysis

The main risks the Group faces are:

Some of the defined benefit liabilities are unfunded arrangements, which increases the chance that the benefits cannot be paid as they fall due.

A decrease in bond yields has the effect of increasing plan liabilities. For funded plans any movement in liabilities may not be matched by a movement in assets.

The majority of the plans' obligations are to provide benefits for the life of each retired member and their nominated dependant, so increases in life expectancy result in an increase in the plans' liabilities.

Sensitivity to key assumptions

The table below illustrates how the Group's defined benefit liabilities would change (excluding the impact of inflation rate and interest rate hedging), as at 31 December 2022, in the event of the following changes in the key assumptions.

Sensitivities to key assumptions In millions of US$	31 December 2022
Increase of 0.5% rate in discount assumption	(8.2)
Decrease of 0.5% rate in discount assumption	8.3
Increase of 0.5% rate in inflation assumption	6.3
Decrease of 0.5% rate in inflation assumption	(5.9)
Increase in 1 year of life expectancy	7.5
Decrease in 1 year of life expectancy	(7.6)

Future benefit payments

The aggregate duration of the Group's defined benefit obligations is 14 years at 31 December 2022. The expected future benefit payments are as follows:

Future benefit payments In millions of US$	31 December 2022
Next year: paid from scheme assets	2.1
Next year: paid directly by employer	8.2
Expected in year 2024	11.3
Expected in year 2025	10.0
Expected in year 2026	8.8
Expected in year 2027	7.9
Expected in year 2028 to 2032 (total)	35.7

The amount expected to be paid by the Group in 2022 is $8.2 million. These payments are to meet benefits expected from unfunded plans and also to pay the outstanding premium to Allianz Pensionsfonds AG for the insurance of the past service benefits of the Germany pension scheme (ENGIE E&P Deutschland GmbH).

30. Principal subsidiary undertakings, joint ventures, associates

At 31 December 2022, the principal subsidiary undertakings, joint ventures and associates of the Company were:

Company name	Country of incorporation	Registered office	Holding	Proportion of voting rights and shares held	Main activity
Neptune Energy Australia Pty Ltd	Australia	A	100%	100%	Oil and gas
Neptune Energy Bonaparte Pty Ltd	Australia	A	100%	100%	Oil and gas
Neptune Energy Brasil Participacoes Ltda	Brazil	B	100%	100%	Oil and gas
Neptune Energy France SAS	France	D	100%	100%	Oil and gas
Neptune Energy International SA	France	D	100%	100%	Holding Company
BHKW Manschnow GmbH i.L.	Germany	E	50%	50%	Oil and gas
Gewerkschaft Küchenberg Erdgas und Erdöl GmbH	Germany	F	50%	50%	Oil and gas
Westdeutsche Erdölleitung GmbH	Germany	F	50%	50%	Oil and gas
Neptune Energy Deutschland GmbH	Germany	G	100%	100%	Oil and gas
Neptune Energy Holding Germany GmbH	Germany	G	100%	100%	Holding Company
Neptune Energy Alam El Shawish B.V.	Netherlands	H	100%	100%	Oil and gas
Neptune Energy Arguni I B.V.	Netherlands	H	100%	100%	Oil and gas
Neptune Energy Ashrafi B.V.	Netherlands	H	100%	100%	Oil and gas
Neptune Energy CCUS B.V.	Netherlands	H	100%	100%	Energy
Neptune Energy E&P Holding Netherlands B.V.	Netherlands	H	100%	100%	Holding Company
Neptune Energy East Ganal B.V.	Netherlands	H	100%	100%	Oil and gas
Neptune Energy East Sepinggan B.V.	Netherlands	H	100%	100%	Oil and gas
Neptune Energy Egypt B.V.	Netherlands	H	100%	100%	Oil and gas
Neptune Energy Exploration B.V.	Netherlands	H	100%	100%	Oil and gas
Neptune Energy Facilities Netherlands B.V.	Netherlands	H	100%	100%	Oil and gas
Neptune Energy Germany B.V.	Netherlands	H	100%	100%	Oil and gas
Neptune Energy Holding Netherlands B.V.	Netherlands	H	100%	100%	Holding Company
Neptune Energy Hydrogen B.V.	Netherlands	H	100%	100%	Energy
Neptune Energy Jakarta B.V.	Netherlands	H	100%	100%	Oil and gas
Neptune Energy Muara Bakau B.V.	Netherlands	H	100%	100%	Oil and gas
Neptune Energy Netherlands Administration B.V.	Netherlands	H	100%	100%	Oil and gas
Neptune Energy Netherlands B.V.	Netherlands	H	100%	100%	Oil and gas
Neptune Energy North Ganal B.V.	Netherlands	H	100%	100%	Oil and gas
Neptune Energy North West El Amal B.V.	Netherlands	H	100%	100%	Oil and gas
Neptune Energy Participation Netherlands B.V.	Netherlands	H	100%	100%	Oil and gas
Neptune Energy Touat B.V.	Netherlands	H	54%	54%	Oil and gas
Neptune Energy Touat Holding B.V.	Netherlands	H	100%	100%	Oil and gas
Neptune Energy West Ganal B.V.	Netherlands	H	100%	100%	Oil and gas
Neptune Energy Norge AS	Norway	C	100%	100%	Oil and gas
Neptune E&P UK Ltd	UK	I	100%	100%	Oil and gas
Neptune E&P UKCS Ltd	UK	I	100%	100%	Oil and gas
Neptune Energy Bondco plc	UK	I	100%	100%	Financing Company
Neptune Energy CCS Projects Limited	UK	I	100%	100%	Energy
Neptune Energy Capital Limited	UK	I	100%	100%	Financing Company
Neptune Energy Finance Limited	UK	I	100%	100%	Financing Company
Neptune Energy Group Resourcing Limited	UK	I	100%	100%	Service Company
Neptune Energy Hydrogen Limited	UK	I	100%	100%	Energy
Production North Sea Netherlands Ltd	USA	H	100%	100%	Oil and gas

Registered office addresses

A	Level 2, 5 Mill Street, Perth WA 6000, Australia
B	Avenida Presidente Vargas, No. 309, 21 floor (part), Centro, City and State of Rio de Janeiro, Zip Code 20040-010, Brazil
C	Vestre Svanholmen 6, 4313 Sandnes, Norway
D	c/o REGUS, 191-195 Avenue Charles de Gaulle, 92200 Neuilly-sur-Seine, France
E	Langewahler Straße 60, 15517 Fürstenwalde/Spree, Germany
F	Riethorst 12, 30659 Hannover, Germany
G	Ahrensburger Straße 1, 30659 Hannover, Germany
H	Prinses Beatrixlaan 5, 2595 AK The Hague, the Netherlands
I	Nova North, 11 Bressenden Place, London, SW1E 5BY, UK

31. Events after the reporting period

There were no reportable balance sheet events after the reporting period that require disclosure.

SUPPLEMENTARY INFORMATION
GAS AND OIL (UNAUDITED)

Reserves
The geographical allocation of reserves is as below:

	Proved plus probable reserves (mmboe)		
	Europe	**North Africa and Asia Pacific**	**Total Neptune Energy**
2P reserves at 31 December 2021	451	153	604
Acquisitions	(7)	-	(7)
Revisions, extensions and discoveries	8	(4)	4
Production	(40)	(9)	(49)
2P RESERVES AT 31 DECEMBER 2022	412	140	552

	Contingent resources (mmboe)		
	Europe	**North Africa and Asia Pacific**	**Total Neptune Energy**
2C resources at 31 December 2021	296	137	433
Acquisitions and divestments	15	8	23
Revisions, extensions and discoveries	(5)	17	12
2C RESOURCES AT 31 DECEMBER 2022	306	162	468

Notes:

- The above are management estimates, the majority of which are independently audited by ERCe.
- Numbers may not add up due to rounding differences.
- 2P denotes the best estimate of reserves which is the sum of proved plus probable reserves.
- *Proved reserves* are those quantities of petroleum that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable from known reservoirs and under defined technical and commercial conditions. If deterministic methods are used, the term 'reasonable certainty' is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.
- *Probable reserves* are those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than proved reserves but more certain to be recovered than possible reserves.
- 2C denotes best estimate of contingent resources and it reflects the same level of technical uncertainty as 2P reserves.
- *Contingent resources* are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, by the application of development projects not currently considered to be commercial owing to one or more contingencies.
- At year end 2022, our proved plus probable reserves (2P) were 552 mmboe. Our reserves replacement ratio (RRR) was -6% in 2022 (2021: 39%). Over a five-year rolling period, from the inception of Neptune, our reserves replacement ratio is 99%.