

Neptune Energy

Annual Report and Accounts 2022

Neptune Energy is an independent energy company with operations across Europe, North Africa and Asia Pacific.

We aim to store more carbon than is emitted from our operations and the use of our sold products by 2030.

Visit our website at *neptuneenergy.com*

Strategic report

02 At a glance
04 Executive Chairman's message
06 Chief Executive Officer's message
08 Transforming the business
10 The global context

12 Our business

14 Business model and strategy
16 Our values
17 Environmental, social and governance
20 Our key performance indicators
22 Designed for the energy transition
26 Climate-related financial disclosures

32 Our society

34 Our people
39 Our safety
42 Our partners and suppliers
44 Our communities
48 Our local environmental impacts

50 Our operations

58 Norway and the UK
62 The Netherlands
64 Germany
66 Algeria and Egypt
68 Indonesia and Australia
70 Financial review
76 Risk management
85 Section 172(1) statement

Governance

91 Corporate governance and Directors' report

Financial statements

104 Independent auditor's report
106 Consolidated income statement
106 Consolidated statement of other comprehensive income
107 Consolidated statement of financial position
109 Consolidated statement of changes in equity
110 Consolidated cash flow statement
112 Notes to the consolidated financial statements
163 Supplementary information gas and oil – unaudited
164 Glossary of terms
IBC General information
IBC Get in touch

Except as otherwise noted, the figures in this report are stated in US dollars or euros. All references to dollars or $ are to the US currency. We use adjusted profit measures, which exclude the impact of exceptional items and remeasurements. These are used by management to assess the underlying performance of the business.

Except as the context otherwise indicates, Neptune or Neptune Energy, Group, we, us, and our, refers to the group of companies comprising Neptune Energy Group Midco Limited (the Company) and its consolidated subsidiaries and equity-accounted investments.

Designed for the energy transition

Our portfolio is gas-weighted and lower carbon. We have a visible growth path with significant projects under way and an inventory of discoveries for future development. Our focus is on producing lower carbon gas and oil safely and efficiently, and utilising existing infrastructure to integrate energy systems.

Read more about Our business on pages 12-31.



Helping people thrive

Our activities enable economic growth, helping to create jobs, support local supply chains and contribute to national tax reserves. We support a just energy transition that delivers decent, safe work and quality jobs, advances diversity and inclusion and improves the livelihoods of local communities.

Read more about Our society on pages 32-49.



Generating value

Our strong operational and financial performance in 2022 was underpinned by higher production, stronger prices and tight cost control. We focused on maximising safe and efficient operations to support energy security in our key markets, while progressing low carbon developments.

Read more about Our operations on pages 50-75.



At a glance

Geographically diverse and gas-weighted

Neptune Energy is one of the most diversified independent European exploration and production companies. We provide secure energy supplies, via our OECD-focused, ~75% gas-weighted portfolio.

What we do

Explore
Focus exploration on shorter-term, material value-creating prospects, targeted around existing infrastructure.

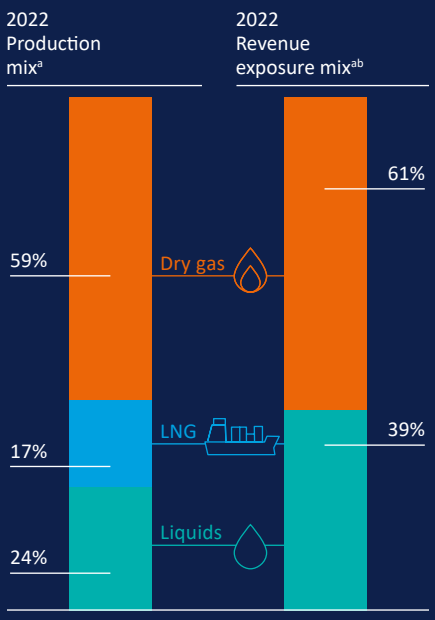
Develop
Develop fields at pace, preferably as operator, with innovative low cost solutions.

Integrate
Work to integrate gas, oil, electrification, carbon capture and storage and hydrogen into energy systems.

Produce
Produce fields safely and efficiently to maximise recovery, lower unit costs and reduce carbon intensity.

Repurpose
Repurpose existing infrastructure to accelerate the energy transition.

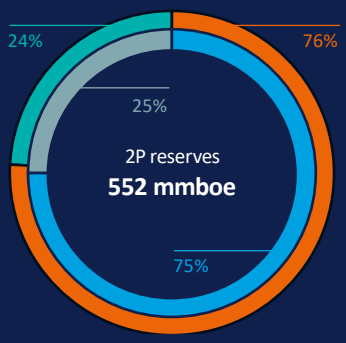
Gas-weighted by volume, balanced by revenue



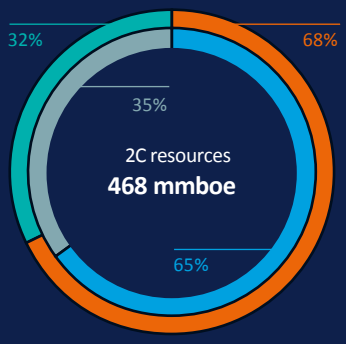
a. Includes wholly owned affiliates and equity-accounted affiliates.
b. Calculated based on revenue from commodity sales net of hedging impact, excludes other income and production-equivalent insurance income.

Long life, material growth potential

Three-quarters of our proved and probable reserves are located in well-established markets in Europe while 35% of our contingent resources are in existing areas of operation across North Africa and Asia Pacific. Our 2P reserves life is 11 years.



~1 billion barrels of 2P reserves and 2C resources



Gas
Oil
Europe
North Africa and Asia Pacific

Europe

01 Norway (43%)*
The Gjøa gas and oil field is powered using low carbon hydroelectricity and we have interests in another six producing fields. We brought Njord onstream in 2022 and expect to start-up Fenja in 2023.

02 UK (11%)
Our Cygnus field is capable of supplying energy to the equivalent of two million UK homes. Seagull is an oil field in the Central North Sea and will come onstream in 2023. We also have a working interest in the Isabella discovery.

03 The Netherlands (14%)
We are the largest gas producer in the Dutch North Sea, with key infrastructure providing scalable hubs for lower carbon opportunities.

04 Germany (13%)
With a presence in the country for more than 130 years, we operate and develop gas and oil fields with our partners in the northwest, east and south of Germany.

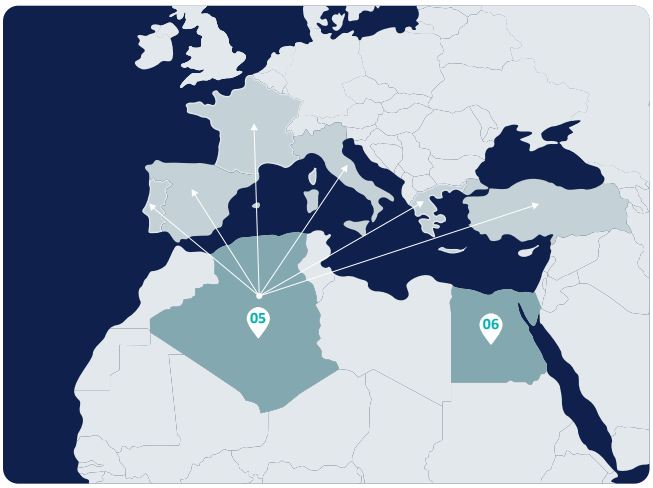


* Proportion of production from each country.
Arrows shown in the maps indicate the typical export destinations of our products only.

North Africa

05 Algeria (2%)
As part of a joint venture with Sonatrach and ENGIE, we produce gas from the Touat plant, which is an important source of supply for mainland Europe.

06 Egypt (2%)
We have interests in oil and gas fields in the Western Desert and an operated exploration licence in the Gulf of Suez.



Asia Pacific

07 Indonesia (15%)
Working with Eni and Indonesian partners, we produce liquefied natural gas for export to the region under long-term contracts as well as gas for the domestic market to help meet the country's growing energy needs.

08 Australia
We are evaluating development concepts for Petrel, a large gas field located in the Timor Sea, which is one of the main gas-producing regions in Australia.



Executive Chairman's message

> We have been on quite the journey since our inception in 2018... we have invested around $7 billion to transform the business."



The economic and geopolitical upheaval that has followed the pandemic has created challenges for us all.

A year of change

Volatile and uncertain energy markets have brought public attention to our sector more than ever. Governments have rightly questioned where their energy comes from, and how much it is costing households and businesses.

This has made our purpose even clearer: produce the energy needed to meet increasing global demand, while also transitioning to a lower carbon future.

The last 12 months have seen a dramatic shift in the geopolitical environment that shapes how energy is produced and used. The war in Ukraine has resulted in the move by European nations to end their reliance on Russian oil and gas. Domestic production and the flexibility of international markets have combined to help Europe achieve this.

While we cannot predict the outcome of Russia's war in Europe, it is undeniable that the redrawing of political allegiances marks a generational shift. It is something that we have responded to, maximising production in response to global supply uncertainty.

We also acted quickly to support humanitarian relief efforts, with a $2 million donation to aid organisations. I'm grateful to our teams, who showed, once again, their dedication to support those most in need.

An accelerating energy transition

There will be other consequences from the last year. An acceleration towards a lower carbon future is one of them. While the international focus on climate change has shifted towards energy security, the energy transition itself only gathers pace.

Investment in clean energy is becoming a new technology race – the US, China and Europe all vying to get ahead of each other. However, innovation and falling technology costs are offset by rising import costs, policy and permitting uncertainty and fractured global alliances, which will make progress uneven.

Our business is prepared for these changes. Despite the uncertainties of the years ahead, our focus on operational excellence, leveraging our competencies and asset base, means we are ahead of the curve in positioning for the transition.

A transforming business

As a company, we have been on quite the journey since our inception in 2018. I want to take this opportunity to highlight some of the achievements from our collective endeavour.

Energy prices have been anything but linear. Low commodity prices of the last decade have been replaced by surging prices and marked volatility. Despite this, we have invested around $7 billion to drive transformation efforts across the business.

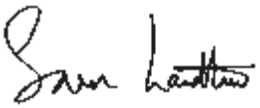
The world is demanding more energy. We have increased our production, while improving our operational efficiency. Investment has enabled seven new developments, all of which will be in production in 2023.

As we prepare for the energy transition, we have progressed 15 low carbon projects and achieved industry leading ESG ratings.

Operational excellence underpins our success – we cannot be complacent in an ever-changing world. We have improved our health and safety performance, and our financial position. Operating cash flow has risen from $1.2 billion in 2018 to more than $2.3 billion, while our leverage has reduced to a historically low level.

A positive outlook

I am thankful to the Board and the whole Neptune team, not only for their contribution to our success in 2022, but also for what we have achieved over the company's history. Our shared commitment, strong economic performance, and vision for the energy transition mean that we will continue this success.



Sam Laidlaw
Executive Chairman
8 March 2023

Chief Executive Officer’s message

“

The next five years will see a further transformation of our business, as we pursue new growth opportunities, aligned closely with our lower carbon strategy.”



In early 2023, we celebrated our fifth anniversary. Since our formation, we have transformed the business and navigated successfully the unprecedented challenge of COVID-19 and the extremes of price volatility.

Among our achievements is the delivery of seven projects, 10 transactions, 14 discoveries, 15 low carbon opportunities and, most importantly, a material improvement in health and safety. We have invested around $7 billion and contributed an average of $3.1 billion each year in economic benefits to the four European countries where we work since 2018. Neptune and all those involved in the business can be proud of the difference we have made.

The next five years will see a further transformation of our business, as we pursue new growth opportunities, aligned closely with our lower carbon strategy. This includes the electrification of additional infrastructure in Norway and start-up of our first carbon capture and storage (CCS) projects, setting us on course to achieve our ambitious net zero ambition by 2030.

Delivering growth

As we progress through 2023, we will realise the benefits of our investment programme, delivering material growth in production to around 180 kboepd by the end of the year, while maintaining a significantly lower carbon intensity than our peers. Not only does this growth reflect investment, but also the hard work and dedication of our teams.

Investment priorities

Our focused strategy continues to deliver new growth opportunities, with exploration activity and new licences adding value to our existing hubs. Within our global portfolio we are maturing a large number of investment opportunities.

While the UK, the Netherlands and Germany remain prospective, windfall profit taxes introduced in 2022 and political uncertainty make further development opportunities challenging, with projects requiring higher returns to be sanctioned. These decisions by governments are contrary to national concerns on energy security and further exacerbate reliance on imports and commodity market volatility.

Despite higher commodity prices in 2022, our financial framework remains unchanged, and we maintain a disciplined approach to capital allocation, prioritising value over volume, and near-term returns. New investment must also align with our lower carbon strategy.

Lower carbon projects approaching key milestones

While we are already well positioned for the energy transition, with a gas-weighted portfolio and a lower carbon intensity than our peers, our ambitions are to go further and faster with our lower carbon plans.

In 2022, we made important progress, focusing on electrification and CCS, which are most aligned with our skill set and experience, and have lower execution risk.

While hydrogen will make a contribution in time, the technology and infrastructure is not yet there on a commercial scale.

In 2022, we approved new electrification projects, which will increase the proportion of our Norwegian production that is fully or partly powered from shore to 100% by 2028. The electrification of our infrastructure will help maintain our low carbon intensity, in what is our largest producing region – and will support the development of integrated energy hubs.

Development of CCS projects is crucial to our net zero ambitions, and we have expanded our pipeline of opportunities significantly, with progress made in Norway, the UK and the Netherlands. Across our portfolio we are pursuing around 15 low carbon opportunities and, as we move through 2023, we aim to mature several of these ahead of possible sanction in 2024.

Strengthening our health and safety culture

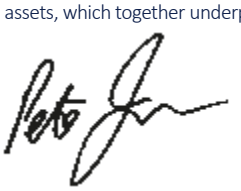
Health and safety remains our highest priority. While we continued to make progress in 2022, with fewer injuries and strengthened process safety, further improvement is essential. Increasing the 'human factor' focus with collaboration and training across the organisation, enhancing our 'speak-up' culture and continuing to work closely with our contractors will make an important difference as we strive to be the best.

We are also making progress on equality, diversity and inclusion and have set an ambitious goal to achieve gender parity across the Group.

Outlook for 2023

Following a strong operational and financial performance in 2022, we head into 2023 with a positive outlook, supported by higher production and robust commodity prices. Our financial outlook is balanced by significantly higher taxes and inflationary pressures, which we will continue to mitigate where we can.

We expect to mature our upstream growth and New Energy pipeline, supported by our strong balance sheet, low leverage and declining committed capex. We will also focus on delivering further operational and safety improvements. Success in these endeavours will reflect the positive changes implemented in our transformation and the quality of our people and assets, which together underpin our positive future.



Pete Jones
Chief Executive Officer
8 March 2023

Transforming the business

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. We now have a greater proportion of developed reserves, are better capitalised and have developed significant new growth opportunities that will deliver both energy security and support the energy transition.

2017/18

The formation of Neptune

- **Backed by strong sponsors** Carlyle, CIC and CVC.
- **Completed EPI acquisition,** with further growth via VNG Norge, Seagull and Isabella acquisitions.
- **Strengthened management team,** systems and processes to establish standalone energy platform.

2019

Building the business for long-term growth

- **Focused growth in core hubs.**
- **Awarded West Ganal licence** and acquired interests in the East Sepinggan and East Ganal licences in Indonesia.
- **Sanctioned Seagull, Duva and Gjøa P1** operated developments in the UK and Norway.
- **Exploration success** at Echino South and Sigrun East in Norway.

2020

Demonstrating resilience

- **Maintained free cash flow generation** through cost savings and deferrals of $350 million.
- **Further material resource growth** through Isabella and Dugong discoveries in the UK and Norway.
- **ESG strategy launched**, with ambitious carbon and methane intensity targets.
- **Established a New Energy team** to accelerate lower carbon opportunities.

Safer
Improved TRIR[1]



1. Number of total recordable injuries per million hours worked.

More profitable
Higher operating cash flow ($m)[2]



2. 2018 operating cash flow adjusted to exclude business combination expenses.

Equitable dividends
Investment in the business

$1.32

invested (development capex) for every

$1

paid in dividends in the past five years

Strong ESG profile
Industry leading ratings

ESG INDUSTRY TOP RATED

GOLD 2022 ecovadis Sustainability Rating

Ambitious targets

Net production electrified in Norway (%)



CO_2 stored for third-party emitters (million tonnes)



Greater reserve base
More 2P reserves and 2C resources (mmboe)



Higher credit ratings
Continued improvement

	2018	2022
Moody's	Ba3 (Stable)	Ba2 (Stable)
S&P	BB- (Stable)	BB (Stable)
Fitch	–	BB+ (Stable)

Note: 2018 numbers are for the period from 15 February 2018 to 31 December 2018.

2021

Establishing a solid track record

- **Delivered pipeline of projects** with Gjøa P1, Duva (Norway) and Merakes (Indonesia) onstream.
- **Sustained low cost growth** with Blasto exploration discovery (Norway) and bolt-on M&A in Germany and the UK.
- **Achieved industry leading ESG ratings** from Sustainalytics and EcoVadis.
- **Joined UN Global Compact** and aligned with the Task Force on Climate-related Financial Disclosures.

2022

Strong performance, delivering growth

- **Strong earnings and cash flow.**
- **New ambition to store more carbon** than is emitted from our operations and the use of our sold products by 2030.
- **Successful start-up of Njord** in Norway.
- **Exploration success** with discoveries at the Hamlet, Ofelia and Calypso prospects in Norway.
- **Fenja and Seagull projects** in Norway and the UK on schedule.
- **Low carbon technology projects** progressing to plan.



The global context

A global energy crisis highlights security of supply vulnerabilities

2022 proved to be another year where world events transformed the outlook for energy markets. As the EU, US and others cut purchases of Russian energy in response to the invasion of Ukraine, prices for liquefied natural gas (LNG) and European gas and power, which were already rising, reached unprecedented levels. These energy market shocks have in turn driven inflationary pressures, causing negative outlooks for growth and living standards in economies that were just starting to recover from COVID-19-related disruptions. This year's events have been a stark reminder of the fragility of the current energy system and the imperative to ensure secure, resilient supplies and adequate storage.

Soaring commodity prices drives economic uncertainty

Pressures in global energy markets were already building before the conflict in Ukraine, driven by strains on multiple global supply chains as economic recovery from the pandemic gathered pace. But the curtailments of natural gas supply to Europe and sanctions on imports of oil and coal from Russia disrupted one of the key arteries of the global energy trade.

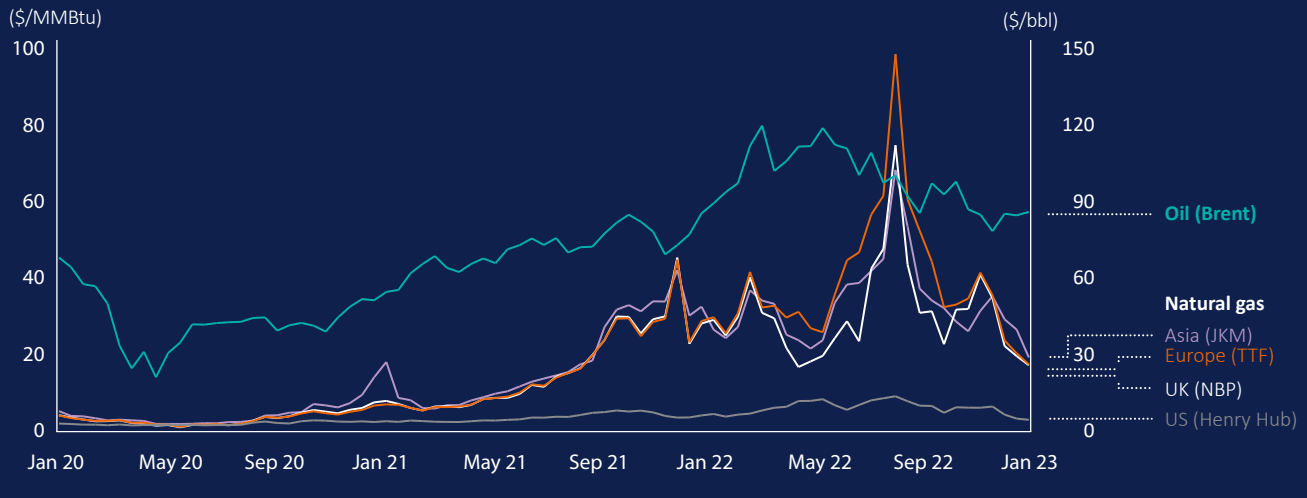
This has affected all fuels as well as many other commodities. Natural gas was at the epicentre of this crisis with spot prices peaking in Europe at more than €300/MWh in August 2022. Coal prices also hit record levels, but the oil market remained relatively well supplied. Brent crude fell back from more than $120 a barrel in June to $80 at the end of 2022. The close link between gas and electricity markets has been highlighted as high marginal gas prices, in addition to rising coal prices, have accounted for 90% of the upward pressure on electricity costs around the world. The impact would have been even greater had energy demand from China not been held back by lockdowns and subdued economic growth.

Higher energy prices have slowed global growth and increased the risk of economic recessions and food insecurity, with the worst impact on poorer households who spend a larger proportion of their income on energy and food. Faced with energy shortfalls and high prices, governments have so far committed more than $500 billion, mainly in advanced economies, to shield consumers from the immediate effects. Waking up to the importance of security of supply and resilience, they have also rushed to try to secure alternative fuel supplies and ensure adequate gas storage.

The European energy system has been placed under severe stress but has so far proven more resilient than initially feared, with gas storage around 65% full in February 2023. Events in 2022 have shone a spotlight on the link between storage and energy security; in a future energy system that is more dependent on renewable energy, we are going to need greater storage capacity.

LNG has also played an increasingly critical role, allowing markets to respond flexibly to price signals. European LNG imports in 2022 more than doubled from the previous year, while Germany brought its first LNG terminal online in just 200 days. European natural gas prices fell back to pre-invasion levels at around €60/MWh in January 2023. However, having fallen by 22% in 2022, China's LNG imports are likely to rebound when they reopen in 2023, increasing competition for LNG cargoes in the second half of the year.

Oil and gas prices 2020-2023



Finding a new balance for the energy trilemma

A key takeaway from the COP27 meeting in Sharm el-Sheikh, Egypt, was a growing concern that greenhouse gas (GHG) emissions appear to be on a trajectory that makes the 1.5°C target unrealistic. So, although the immediate call on the industry has been for more oil and gas supply, longer-term net zero scenarios continue to call for an accelerated shift away from hydrocarbons. These mixed messages on longer-term fossil fuel demand have been exacerbated by the introduction in several jurisdictions of 'windfall' taxes on energy companies. This amplifies the challenge for oil and gas operators to invest in long-term security of supply while also recycling returns into decarbonisation.

Under the IEA's Stated Policies Scenario, investment in upstream oil and gas of almost $650 billion a year until 2030 is required to balance demand projections, a rise of more than 50% from recent years. But in 2022, upstream spending remained below pre-COVID-19 levels and, if this underinvestment continues, the spare supply capacity will not be in place to avoid further fuel price volatility. As many governments seek to fund expanding budget gaps, fiscal policy must work alongside energy policy to ensure energy resilience by, for example, incentivising investment in future supply capacity via tax allowances. Investment in oil and gas cannot be taken for granted, especially as rising tax rates, as well as green investment criteria, are increasingly constraining oil and gas investors' access to capital.

This is especially important since investment in clean technology remains far below the levels needed to transform the energy system. However, there have been encouraging signs of progress in 2022 in stepping up the policy support necessary to boost investment in low carbon energy supply where business models remain uncertain. In particular, the extended and expanded tax credits and subsidies offered to low carbon energy under the US Inflation Reduction Act may well unlock new business opportunities across the globe as other countries introduce enhanced incentives to remain competitive with those available in the US.

An opportunity for carbon capture and storage

Carbon capture and storage (CCS) is vital under all scenarios to meet global climate goals. With the right policy framework, those oil and gas companies with advantaged positions will be able to progress CCS hub developments and offer carbon capture as a service.

According to Wood Mackenzie, the global CCS project pipeline increased by more than 50% during 2022 to more than one billion tonnes per year. This would result in a sixfold increase in storage capacity by 2030. However, the IEA's *World Energy Outlook 2022* estimates that this planned increase would still only cover around 20% of the CO_2 storage capacity that will be needed by 2030 under its Net Zero Emissions Scenario.

50%

annual increase in global CCS pipeline

Energy outlook to 2050

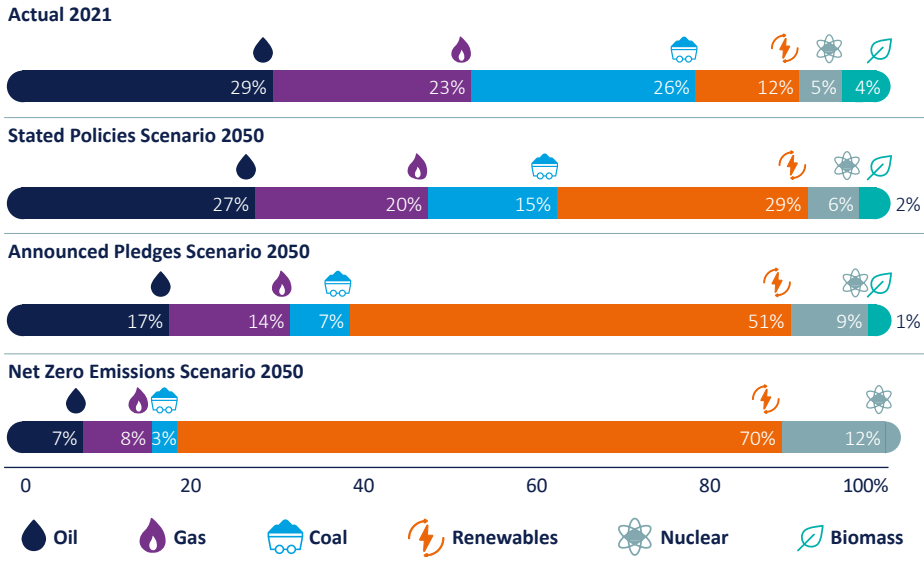
The market volatility seen in 2022 underlines the fact that energy will remain inseparable from the livelihoods of a global population that is set to grow by two billion people by 2050. Natural gas will continue to play an important role as increasing populations and rising incomes sustain growing consumption in emerging market and developing economies in Asia over the next decade. Long-term, oil-indexed gas import contracts, as well as domestic subsidies in some cases, have offered partial protection to Asian consumers from high and volatile gas prices. A growing population, robust economic development and a move away from coal to reduce emissions provide a strong foundation for growth. As a result, the IEA predicts gas demand in emerging Asian markets will rise by 20% to 120 bcm in 2030, with around 70% of this growth met by imported LNG.

Globally, the IEA's Stated Policies Scenario predicts natural gas demand rising by around 5% until reaching a plateau of around 4,400 bcm by 2030. Beyond this point, demand projections become subject to large uncertainty ranges depending on the assumptions made around the speed and scale of the transition to renewable energies. For example, the total share of natural gas in the energy mix by 2050 is 20% in the Stated Policies Scenario (from 23% in 2021) but just 8% in the Net Zero Emissions Scenario.

In any case, reductions in the share of gas in the overall energy mix may not mean that less gas is consumed, as demand for energy continues to grow in the coming decades.

Under all scenarios, existing gas infrastructure and industry experience will be critical to progress the deployment of technologies such as green hydrogen and CCS. The costs of these technologies are coming down, but prudent policy support, access to financing and an entrepreneurial spirit from both incumbent and new industry players will be needed if these technologies are to reach the scale required to meet global climate targets.

World energy supply – 2050 scenarios



Stated Policies Scenario
Does not assume that governments will reach all announced climate commitments. Instead, it explores where the energy system might go without additional policy implementation.

Announced Pledges Scenario
Takes account of all the climate commitments made by governments around the world and assumes that they will be met in full and on time.

Net Zero Emissions Scenario
Sets out a pathway for the global energy sector to achieve net zero CO_2 emissions by 2050, with the emissions trajectory consistent with limiting global temperature rise to 1.5°C.

Source: *World Energy Outlook 2022.*
Note: The sum of the energy shares may not equal 100% due to rounding.

Our business

Designed for the energy transition

Our portfolio is gas-weighted and lower carbon. We have a visible growth path with significant projects under way and an inventory of discoveries for future development. Our focus is on producing lower carbon gas and oil safely and efficiently, and utilising existing infrastructure to integrate energy systems.

Gas-weighted

76%

... of our production and 2P reserves is gas



ESG rating

Top 3%

... of all global oil and gas companies rated by Sustainalytics



Carbon intensity

6.5 kg CO_2/boe

... more than 60% lower than the industry average



Business model and strategy

Focused, lower carbon strategy

We made good progress delivering our strategy set out at the beginning of 2022 to produce lower carbon energy and develop integrated energy hubs. We are working on a pipeline of 15 lower carbon opportunities, mainly in carbon capture and storage (CCS).

Our vision

Our vision is to be the leading independent exploration and production company by meeting society's changing energy needs and creating value for our stakeholders. Our strategy sets out how we will do this and is underpinned by our sound governance, and a responsible approach.

1 Lower carbon energy production

We continue to target new production opportunities in areas that are close to our core hubs, while maintaining our gas-weighted portfolio and lower carbon intensity. We expect to deliver further reductions in carbon emissions through the electrification of assets.

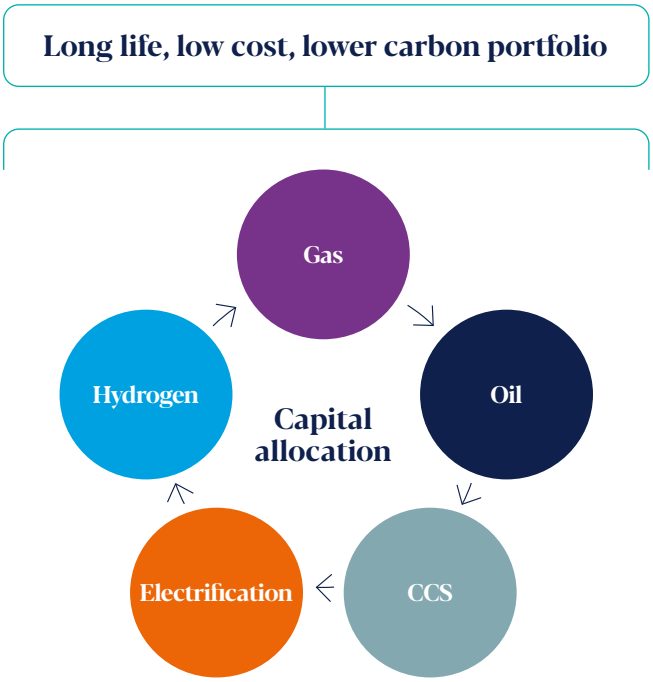
2 Integrated energy hubs

Our integrated energy hub strategy provides an excellent opportunity to drive decarbonisation through utilising existing infrastructure to facilitate CO_2 storage and hydrogen production, using domestic, lower carbon intensive gas or wind power.

Our aims	Delivering our strategy in 2022
• Maintain our gas-weighted portfolio.	• 76% gas-weighted portfolio.
• 6 kg CO_2/boe carbon intensity by 2030.	• 6.5 kg CO_2/boe carbon intensity.
• Zero methane emissions by 2030.	• 0.02% methane intensity.
• 100% of net production in Norway fully or partially electrified by 2028.	• Electrification of assets in Norway progressed, with Gudrun electrification project under way and expected to start-up in 2023 and plans for Njord and Snøhvit submitted.
• Store more carbon than is emitted from our operations and the use of our sold products by 2030.	• Signed cooperation agreement with Horisont Energi for a large-scale CCS opportunity in Norway. • Three CCS licence applications submitted in the UK. • L10 CCS project progressed towards front-end engineering design readiness.
• Assess opportunities to develop integrated energy hubs.	• Signed Memorandum of Understanding on powering integrated energy hubs in the UK with offshore wind. • Submitted lithium production licence in Germany and assessed potential for geothermal projects.

Our difference

We provide secure supplies of gas and oil, with a long life, lower cost portfolio. We are focused on delivering the low carbon projects that are essential for the energy transition. Our strong balance sheet and cash flow generation from our upstream business are integral to delivering our strategy, as we use higher returns from gas and oil to invest incrementally in lower carbon technologies.



Creating value for our stakeholders

Shareholders

We have built a solid track record, delivering strong returns for our shareholders.

Employees

We have an innovative culture, with more than 1,350 employees in Europe, North Africa and Asia Pacific.

Partners

We build strong relationships with our partners and suppliers that help drive excellence and safe operations.

Governments

We engage with our host governments and contribute to national tax reserves.

Communities

Our activities enable economic growth and we support programmes that create long-lasting benefits.

$2.7bn
total distributions to our ultimate shareholders since 2018

80%
employee engagement (see page 38)

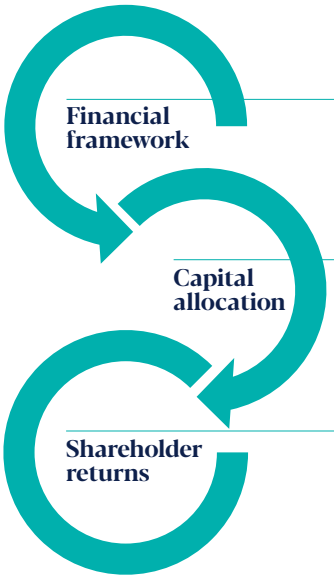
4,500+
suppliers

$1.2bn
taxes paid in 2022

$4.8bn
gross value added contribution to the GDPs of our European countries in 2022 (see page 47)

Delivering near-term returns within a disciplined financial framework

- Upstream capex to focus on shorter-cycle projects for nearer-term value creation.
- Focused exploration spend, adding reserves around existing hubs.
- Spend on lower carbon developments to prioritise electrification and CCS.
- M&A focused on production and adding value around our existing hubs.
- Strong capital structure provides liquidity to support growth, while maintaining low leverage.



Financial framework

- Strong liquidity, low leverage.
- Maintain or improve current credit ratings.
- Cash flow protection through hedging and insurance.

Capital allocation

- Near-term returns, balanced with investment.
- Invest in profitable lower carbon production and integrated energy hubs.
- Full cycle break-even pre-tax costs of <$30/bbl.

Shareholder returns

- Create near-term value for stakeholders.
- Maintain track record of free cash flow generation.
- Grow distributions in line with value creation.

Our values

Our values provide the foundations for how we act and the decisions we make. They articulate our spirit and help guide our actions.



Living our values in 2022

- **83%** of our employees agreed that Neptune is a place they can be themselves.
- **99%** of our employees completed Code of Conduct training.
- **25%** improvement in total recordable injury rate since 2018.
- **300+** employees participated in psychological safety awareness sessions.

Excellence in health, safety and the environment

Health, safety and the environment (HSE) are at the heart of our business. Our goal is to ensure our activities are accident-free and do not result in any harm to people or to the environment. We are committed to achieving best-in-class standards, maintaining safe and reliable operations and contributing to a lower carbon future.

Integrity

Integrity underpins how we work at Neptune, and we are committed to ethical operations and an inclusive culture. Trust is a key element in all our internal and external relationships. Our refreshed Code of Conduct, which we rolled out in 2022, sets out our expectations and commitment to act with the highest degree of ethics and integrity.

Accountability

We take ownership of our actions and results. We are personally committed to Neptune's success and make well-timed and informed decisions. We have a flat structure, where our people feel empowered to make decisions and take action.

Teamwork

We grow together and succeed in partnership. We promote a 'One Neptune' approach and a collective ambition. Together, we are able to create a high-performance culture across the business, attracting top industry talent and creating an environment where our employees can flourish.

Environmental, social and governance

We updated our ESG strategy and roadmap in 2022, building on the solid progress we've already made. We also set our priorities to 2025.



Our L10 project in the Netherlands will help us meet our ambition to store more carbon than we emit by 2030

Our refreshed ESG strategy and roadmap (see page 18) takes into account our strategic ambitions, stakeholder expectations, macro trends and regulatory changes.

Our ESG Committee – whose members include our Executive Chairman, CEO and CFO – approved the strategy and roadmap in September 2022. See page 99 for more information on our ESG Committee and actions in 2022.

SUSTAINALYTICS ESG INDUSTRY TOP RATED 2023

Top 3% of all global oil and gas companies rated by Sustainalytics

GOLD 2022 ecovadis Sustainability Rating

Top 5% of all 95,000 global companies assessed by EcoVadis

Our material issues

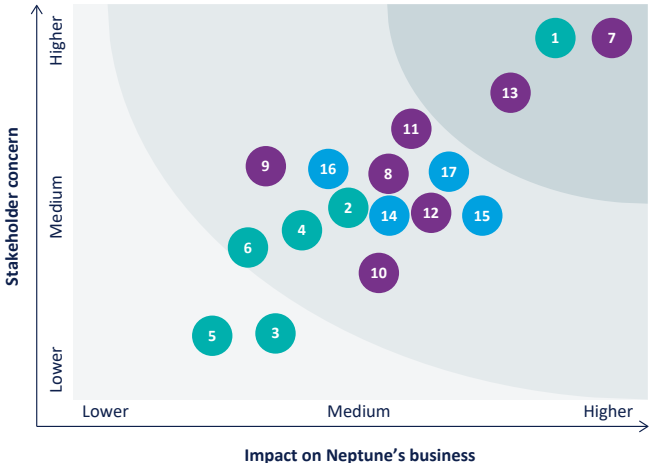
We carry out a materiality assessment every year to identify the ESG issues that have the greatest impact on our business and are of greatest concern for our stakeholders. We used insights from our assessment to inform our refreshed strategy and roadmap.

We talked to a range of internal and external stakeholders, including our ultimate shareholders, bondholders, non-governmental organisations, partners and government officials, to assess our key issues. For example, in May 2022, we held an ESG roadshow with our bondholders, during which we discussed the 'energy trilemma' – the need to balance energy security, affordability and sustainability, in light of macro events.

We also analysed upcoming regulation and sustainability frameworks, such as the International Sustainability Standards Board standards, the Corporate Sustainability Reporting Directive, the Global Reporting Initiative, the UN Global Compact and the Task Force on Climate-related Financial Disclosures (TCFD).

We prioritised the issues according to the impact on our business and level of stakeholder concern. Our ESG strategy and Annual Report contain the issues that we have assessed as high/medium importance. We publish additional data, for example on air emissions and waste, on our website.

Overall, our key issues in 2022 remained broadly consistent with those in 2021. We have included energy security and geopolitics as a new material issue, and some issues have risen in prominence, such as biodiversity, equality, diversity and inclusion, and skills development.



Environmental

1. Climate change and the energy transition
2. Biodiversity
3. Other air emissions
4. Water
5. Waste
6. Decommissioning

Social

7. Safety
8. Equality, diversity and inclusion
9. Social investment
10. Community engagement
11. Economic impact
12. Skills development
13. Energy security and geopolitics (NEW)

Governance

14. Corporate governance
15. Ethical conduct
16. Human rights
17. Supply chain

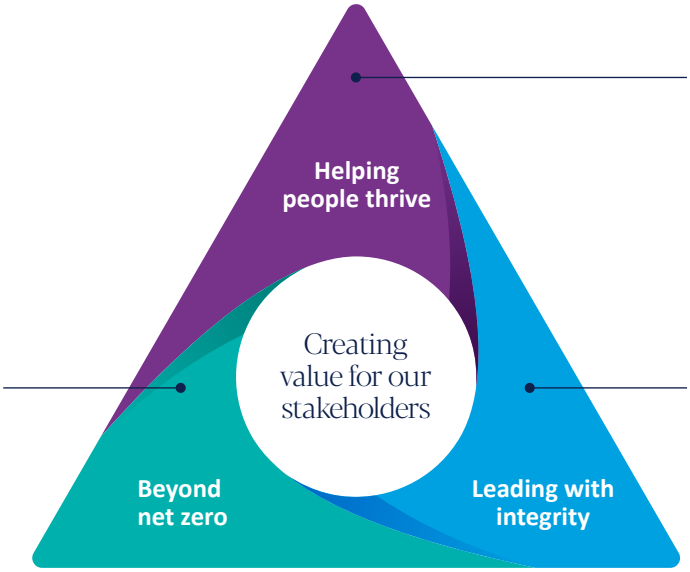
Environmental, social and governance
continued

Our ESG strategy

We focus on three overarching objectives that are aligned with the UN Sustainable Development Goals. Our ESG Committee oversees the delivery of our strategy and roadmap. We'll continue to review our actions regularly, taking account of portfolio changes, societal expectations, technological advances and other factors.

Contribute to meeting global net zero goals, produce secure supplies of lower carbon gas and oil, and enhance biodiversity.





Support a just transition that delivers decent, safe work and quality jobs, advances diversity and inclusion and improves the livelihoods of local communities.



Conduct our business with integrity and good governance, respecting human rights and driving responsible practices in our supply chain.



Our ESG roadmap

Our new three-year ESG roadmap sets out our near-term plans to 2025, complementing our 2030 ambitions. We will focus on specific priorities during each year of the roadmap to help us deliver our ESG strategy.

2023

Embedding ESG at a local level

- Implement emission reduction opportunities.
- Develop country-level ED&I action plans.
- Create a net positive impact on biodiversity.

2024

Working with our partners

- Reduce emissions in our supply chain.
- Deliver our human rights roadmap.
- Evaluate the impact of community programmes.

2025

Demonstrating tangible progress

- Progress low carbon projects to development.
- Maintain low carbon and methane intensities.
- Advance towards Group-wide gender parity.

Our performance against our aims

	Our aims	What we did in 2022	What we plan to do in 2023
Beyond net zero	Develop integrated energy hubs to facilitate CO_2 storage and hydrogen production	• Progressed L10 CCS project in the Netherlands towards concept selection. • Submitted three applications for CCS licences in the UK. • Signed agreement for a large-scale CCS opportunity (Errai) in Norway. • Made progress electrifying assets in Norway. • Signed Memorandum of Understanding with Ørsted and Goal7 on powering integrated energy hubs in the UK with offshore wind.	• Submit storage licence application for L10 and progress into front-end engineering design (FEED). • Conduct survey of appraisal well in the UK CCS licence area, subject to award. • Progress Errai into FEED, subject to licence award. • Work towards achieving 100% net production in Norway fully or partially electrified by 2028. • Progress concept with Ørsted and Goal7 to feasibility and concept selection stage.
	Reduce operational emissions and maintain low carbon and methane intensities	• On track to meet 2030 targets at 6.5 kg CO_2/boe and 0.02% methane intensity. • Identified emission reduction opportunities in the UK. • Achieved ISO 50001 certification in Norway and continued certification in the UK and Germany. • Awarded Gold Standard status from the Oil and Gas Methane Partnership 2.0. • Joined the Aiming for Zero Methane Emissions Initiative.	• Develop carbon reduction plans for each of our operated countries to meet our carbon intensity target of 6 kg CO_2/boe by 2030. • Work towards our net zero methane emissions by 2030 and 0.015% methane intensity by 2025 targets. • Implement measures to achieve zero routine flaring by 2030.
	Enhance biodiversity at our sites to create a net positive impact	• Initiated partnerships to support biodiversity in countries where we work. • Helped fund a new rehabilitation centre for stranded dolphins and porpoises, as part of our partnership with the SOS Dolfijn Foundation. • Supported the SEATRACK project in Norway, which tracks the movements and migration routes of seabirds.	• Use the Integrated Biodiversity Assessment Tool to evaluate our impacts and progress our plans. • Enhance scientific understanding of marine biodiversity.
	Use resources responsibly, reducing water, waste and NOx emissions	• Continued ISO 14001 certification in the UK. • Used the World Resources Institute Aqueduct Water Risk Atlas to assess operated sites in water scarce areas. • Worked with Oil Spill Response Limited on response readiness in the event of any unplanned events.	• Review plans to certify all operated countries to ISO 14001 by 2024. • Implement water management plans. • Target zero spills.
Helping people thrive	Enhance the safety and wellbeing of our people	• Achieved ISO 45001 certification in the UK. • Improved our process safety event rate, total recordable injury rate and lost time injury frequency rate. • Increased our focus on psychological safety, with more than 300 people participating in awareness sessions.	• Achieve top quartile safety performance in our operated regions. • Review plans to extend ISO 45001 certification to our remaining operated countries. • Roll out human factors safety training across the organisation.
	Improve workforce diversity and build an inclusive workplace	• Launched new ambition to achieve gender parity. • Held second global ED&I month, with almost 600 employees participating. • Established Women in Neptune network and LGBTQ+ affinity group. • Achieved highest employee engagement to date at 80% (2021: 73%).	• Work towards gender parity across the business. • Ensure equal representation for internal promotions and external hires. • Establish early careers affinity group. • Maintain employee engagement of at least 80%.
	Build skills needed for the energy transition	• 170 people signed up to mentoring platform. • Launched reverse mentoring programme. • Partnered with schools in the UK and Norway to support science, technology, engineering and maths (STEM) subjects. • 200+ employees attended awareness session on low carbon technologies.	• Implement local skills development programme in Algeria. • Expand partnerships with schools on STEM subjects to other countries where we work.
	Deliver socio-economic benefits that improve the livelihoods of local communities	• $4.8 billion gross value added (GVA) contribution to the GDPs of our European countries, and $510 million GVA contribution to the GDP of Indonesia. • $3.7 million spent on social investment programmes. • Initiated partnership with The Childhood Trust and provided new employee volunteering opportunities.	• Establish key performance indicators (KPIs) for social investment programmes. • Establish employee volunteering programmes in each of the countries where we work. • Implement internship programme in Indonesia for people with a disability.
Leading with integrity	Live our Code of Conduct and values	• Rolled out our new Code of Conduct. • 99% of employees completed Code of Conduct training and annual certification.	• Promote whistleblowing channels in our workforce and supply chain. • Achieve 100% Code of Conduct training and certification.
	Demonstrate our accountability through good governance and transparent disclosure	• Continued to adhere to the Wates Principles. • Received industry leading ESG ratings from Sustainalytics and EcoVadis. • Progressed TCFD, UN Global Compact and GRI reporting.	• Evolve TCFD reporting, including a financial assessment of physical climate risks. • Maintain industry leading ESG ratings.
	Embed respect for human rights into our policies and practices	• Implemented new Grievance Procedure. • Progressed our human rights roadmap. • Introduced human rights and modern slavery training for key functions.	• Continue to align with the UN Guiding Principles on Business and Human Rights. • Enhance monitoring of human rights and modern slavery with suppliers and partners.
	Work with suppliers and partners to drive sustainable practices	• Completed assessment of Scope 3 emissions from purchased goods and services. • Awarded contracts for concept engineering work for a feasibility study for our green hydrogen project in the Netherlands. • Signed agreement with CHC Helicopter to optimise flight times and reduce emissions.	• Develop ESG supply chain KPIs. • Expand Scope 3 disclosure to purchased goods and services.

Our key performance indicators

We assess our performance using a range of operational, ESG and financial metrics that are consistent with our strategy. We use these metrics to evaluate our performance and to inform our decision making.

Operational

1 Production[a] (kboepd)

135.0

(2021: 130.0)

Description The volume of oil, gas and other natural gas liquids produced at Neptune's operations, including equity-accounted entities. We measure production on an oil equivalent basis and it is shown as an average rate per day.

Performance Production increased in 2022 due mainly to the restart of Snøhvit and a full-year's contribution from Duva, which started up in 2021.

2 Production efficiency (%)

85

(2021: 82)

Description Production efficiency is a measure of actual production relative to maximum production potential and includes our operated assets in Norway, the Netherlands, the UK and Germany. Actual production is affected by both planned and unplanned production interruptions.

Performance Production efficiency improved as fewer third-party related issues impacted our UK operations and less downtime was required for development activity in Norway.

See page 50 for more information on our operational performance.

ESG

5 Total recordable injury rate (TRIR)[a] (number)

1.94

(2021: 2.07)

Description TRIR measures the total number of recordable employee and contractor injuries per one million hours worked.

Performance Our TRIR improved in 2022 but was higher than our target of 1.64.

6 Process safety event rate (PSER)[a] (number)

1.13

(2021: 1.28)

Description We introduced PSER as a key performance indicator in 2019. This measures the number of process safety events per one million hours worked and includes tier 1, 2 and 3 events. 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.

Performance We saw an improvement in 2022, with no tier 1 events and one tier 2 event occurring in just one of our countries.

See page 19 for more information on our ESG performance.

Financial

10 Opex[a] ($/boe)

12.3

(2021: 11.3)

Description This is the average operating cost per barrel of oil equivalent produced (excluding levies).

Performance Operating costs increased in 2022 due to industry cost inflation and higher CO_2 emissions taxes and royalties.

11 Operating cash flow[a] ($m)

2,373

(2021: 1,697)

Description This includes cash flow from operations, after tax and working capital movements.

Performance Operating cash flow increased due to higher production, strong oil and gas realisations and good cost control. The increase in cash flow was mitigated partially by higher taxes.

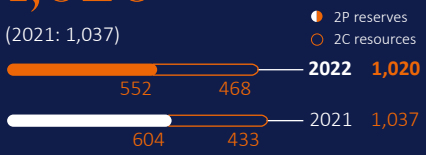
See page 70 for more information on our financial performance.

a. Metrics used in our performance scorecards for the Executive Team and all employees.

3 2P reserves and 2C resources (mmboe)

1,020

(2021: 1,037)



Description Our 2P reserves is the best estimate of proved plus probable reserves. 2C resources is the best estimate of contingent resources and includes projects within the 'development pending', 'on hold' and 'unclarified' categories. See page 163 for an explanation of the inherent uncertainties surrounding 2C resources reporting.

Performance We achieved a strong increase in 2C resources in 2022 due to successful exploration and the acquisition of new licences in Norway and the Netherlands. The reduction in our 2P reserves reflects production in the year and the disposal of non-core assets in Norway.

4 Reserves life (years)

11

(2021: 13)

Description This includes our 2P reserves life.

Performance Our reserves life decreased to 11 years due to the reduction in 2P reserves and higher production.

7 Carbon intensity[a] (kg CO_2/boe)

6.5

(2021: 6.4)

Description This includes Scope 1 and 2 emissions and is calculated on an operational control basis. This includes Germany, the Netherlands, Norway and the UK.

Performance Our carbon intensity remained stable in 2022 and we are on track to meet our 2030 target. Our carbon intensity is 60% lower than the International Association of Oil & Gas Producers industry average.

8 Methane intensity (%)

0.02

(2021: 0.02)

Description This refers to methane emissions from our production operations as a percentage of the volume of the total gas exported.

Performance Our methane intensity was stable in 2022 and remained lower than the Oil and Gas Climate Initiative industry average of 0.17%.

9 Economic impact ($bn)

4.8

(2021: 3.3)

Description This includes our direct impact (employment and GDP generated from our activities), indirect impact (supply chain spend and employment) and induced impact (wage consumption in the wider economy) to the economies of Norway, the UK, the Netherlands and Germany.

Performance Our total economic impact in Europe increased in 2022, primarily due to higher earnings and operating cash flow, driven by higher commodity prices and good cost control.

12 Capex ($m)

537

(2021: 636)

Description This includes development capex, including equity-accounted entities.

Performance Development capex declined in 2022 due to projects completed and brought onstream in 2021. Investment was mainly in Norway and the UK.

13 EBITDAX ($m)

3,854

(2021: 2,109)

Description This comprises net income for the period before income tax expense, financial expenses, financial income, impairment reversals/losses, other operating gains and losses, exploration expenses and depreciation and amortisation. EBITDAX, as defined by the RBL, includes our share of net income from Touat.

Performance EBITDAX increased strongly due to higher commodity prices and good cost control.

14 Net debt to EBITDAX (times)

0.44

(2021: 1.00)

Description This includes net debt (excluding the Subordinated Neptune Energy Group Limited Loan) to a 12-month rolling EBITDAX, as defined by the RBL.

Performance Our leverage ratio continued to decline as we increased EBITDAX and net debt declined. Leverage is well below our target of 1.50 times.

Designed for the energy transition

We are well positioned for the energy transition. Our portfolio is gas-weighted and has a significantly lower carbon and methane intensity than the industry average. We aim to store more carbon than is emitted from our operations and the use of our sold products by 2030.



The electrification of Njord is expected to reduce net CO_2 emissions by around 28,000 tonnes a year from 2027

We support the goals of the Paris Agreement and net zero targets set by governments around the world. While these goals look to 2050, we are focusing on what we can do in the short to medium term, recognising that actions in the next 10 years will be crucial in curbing global temperature rises.

Our two areas of strategic focus are:

1. **Lower carbon energy production**
2. **Integrated energy hubs**

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

We continue to target new production opportunities in areas that are close to our core hubs, while maintaining our gas-weighted portfolio and lower carbon intensity.

Due to the already lower carbon intensity of our portfolio, we expect to deliver further reductions in carbon emissions through the electrification of assets, while improving operating emissions where we see opportunities.

Electrification

The electrification of offshore platforms can help reduce emissions, as gas turbines used to generate heat and power are replaced with an electricity supply. A total of 22% of our net production is already electrified. In Norway, our Gjøa field uses electricity delivered via a submarine power cable from shore. We are looking at ways to increase the capacity of the power cable to electrify the platform fully, eliminating the need for its gas turbine.

Our electrification strategy targets our highest producing assets in areas where it is economic and where the regulatory regime is supportive. Electrification of our hubs will lower the future carbon impact of our pre-development projects and help extend the life of key infrastructure. In 2022, we sanctioned electrification projects at Njord and Snøhvit and expect these to come online in 2027 and 2028, respectively.

By 2028, we expect 100% of our net production in Norway to be from hubs that have been fully or partially electrified, resulting in an annual Scope 1 CO_2 emissions saving of more than 220,000 tonnes.

In the Netherlands, our Q13a-A platform is powered using renewable electricity from Europe, saving around 16,500 tonnes of CO_2 in 2022. In 2023, we will use Dutch-produced electricity, which will have no associated CO_2 emissions.

We continue to evaluate further electrification opportunities in the UK and the Netherlands.

Carbon intensity

While we currently have one of the lowest carbon intensities in the industry at 6.5 kg CO_2/boe (around 60% lower than the industry average), this will naturally increase as our assets mature. This is because more energy is needed to extract more mature gas and oil reserves. Without action, our carbon intensity would increase to 19 kg CO_2/boe in 2030. That is why we have set an ambitious target of 6 kg CO_2/boe by 2030.

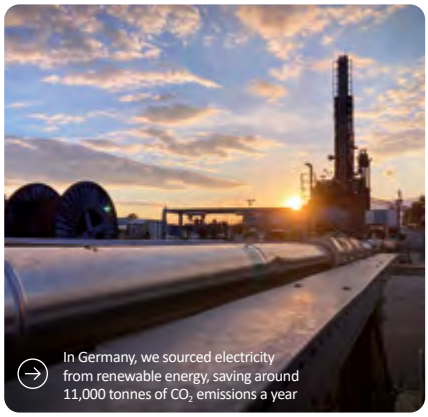
We expect our near-term carbon intensity to rise moderately in 2023 due to compression at Cygnus in the UK and additional power generation requirements at the Altmark gas field in Germany.

Methane intensity

Methane makes up 5% of our total greenhouse gas (GHG) emissions on a CO_2e basis. Reducing methane emissions is recognised as one of the most effective ways of limiting near-term climate change. This is because, although short-lived in the atmosphere, methane is a potent greenhouse gas, retaining more than 80 times more heat than CO_2 in a 20-year timeframe. That is why we have set an ambitious target to achieve net zero methane emissions by 2030.

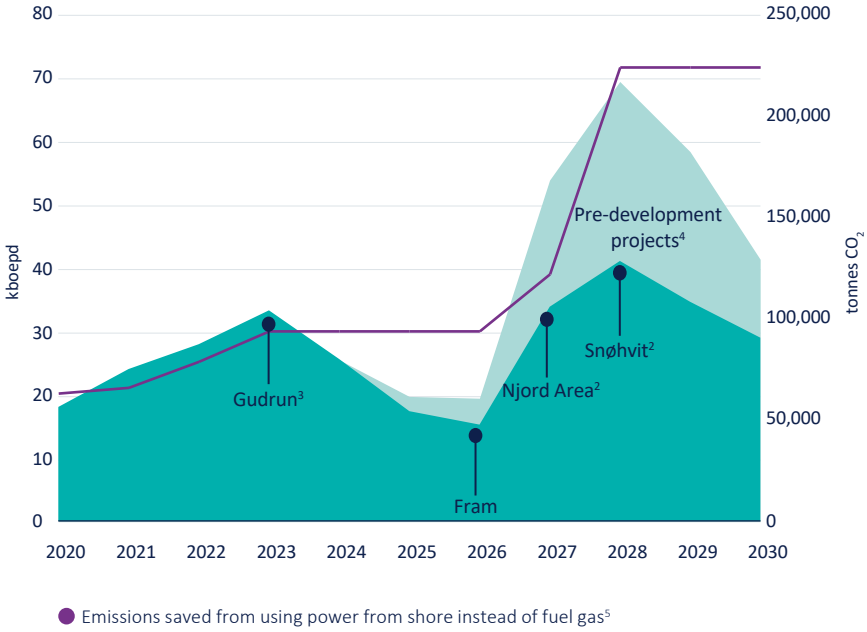
Our methane intensity, which refers to methane emissions from our operated assets as a percentage of gas exported, was 0.02% in 2022. We remain on track to reach our 2030 target and have set an interim target of 0.015% by 2025.

During 2022, scientists working for the Environmental Defense Fund completed evaluation of methane emissions data gathered from our Cygnus platform in the UK in 2021. The evaluation found 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.


In Germany, we sourced electricity from renewable energy, saving around 11,000 tonnes of CO_2 emissions a year

Lower carbon energy production

100% electrification of production in Norway by 2028[1]



1. By 2028, 100% of our production in Norway is expected to be from hubs that have been fully or partially electrified.
2. Plan submitted for electrification of Njord (including Hyme, Bauge and Fenja) and Snøhvit.
3. Gudrun electrification project is due to start-up in mid-2023.
4. Potential pre-development projects include Hamlet, Ofelia, Blasto, Dugong, Calypso and Grosbeak.
5. Calculated on an equity share basis, excluding Fram.

We were awarded Gold Standard status for our reporting to the Oil and Gas Methane Partnership 2.0 framework in 2022. This achievement recognises our robust plans to report and reduce methane emissions for our operated and non-operated assets by 2024 and 2026, respectively.

Energy efficiency and emission reduction

Our Energy Policy sets out our commitment to improve energy efficiency across the organisation. Our operations in the UK, Norway and Germany are certified to the ISO 50001 energy management standard, and we are progressing plans to extend this to the Netherlands. As part of this, we are reviewing energy savings opportunities across our operations.

In 2022, actions to improve energy efficiency led to a reduction of 2,249 MWh. The majority of this was from Germany, with energy saved from using a combined heat and power unit at our Rühlertwist field.

In Germany, we also began sourcing electricity for our assets from renewable energy, saving around 11,000 tonnes of CO_2 emissions a year.

In the UK, we assessed emission reduction opportunities at our Cygnus field and selected initiatives for further evaluation. These include replacing diesel with biofuels for power generation, measures to reduce flaring and moving gas compression 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_2e a year by 2028, equivalent to more than a third of our projected UK Scope 1 emissions for that year.

Zero Routine Flaring by 2030

We are committed to implementing economically viable solutions to eliminate routine flaring at our existing sites as soon as possible, and by no later than 2030. We are also committed to designing new projects with no routine flaring and venting of gas. We endorse the World Bank's Zero Routine Flaring by 2030 initiative. This initiative brings together governments, companies and development institutions to eliminate routine gas flaring from oil production no later than 2030.

Two of our assets in Germany and one in the Netherlands require further action to meet this target. In 2023, we will install micro gas turbines at selected assets in Germany to reduce routine flaring. In the Netherlands, we are starting a project at our F3 platform in 2023 to assess measures to help us achieve zero routine flaring.

Integrated energy hubs

2 Integrated energy hubs: using existing infrastructure to integrate energy systems

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

Carbon capture and storage

Reaching net zero will be virtually impossible without carbon capture and storage (CCS), according to the IEA. In addition, CCS technologies offer strategic value in the transition to net zero, since they can help offset emissions in industries where the technical challenges or cost of decarbonisation are currently prohibitive, such as steel and cement manufacturing. CCS can balance the priorities of climate mitigation, energy security and affordability. It is also a proven technology that has been in safe operation for more than 45 years, according to the Global CCS Institute.

We have significant experience in CCS, having carried out a 14-year project on our K12-B platform offshore in the Netherlands, reinjecting CO_2 into the gas field. We are also a member of industry bodies, such as the Global CCS Institute and the CCSA, which are working to accelerate the deployment of CCS.

We made good progress expanding our CCS opportunities in 2022 in line with our ambition to store more carbon than is emitted from our operations and the use of our sold products by 2030.

We have identified suitable reservoirs in Norway and the UK that support current applications and future planned acreage nominations.

Norway

We announced a partnership with Horisont Energi to develop the Errai CCS project in August 2022. Errai is the first commercial CO_2 storage project in Norway and could store between 4-8 million tonnes of CO_2 a year.

As part of the project, we are planning a proposed onshore receiving terminal on the west coast of Norway. CO_2 from European and domestic customers would then be transported through a pipeline to the North Sea, where it would be injected and permanently stored in an offshore reservoir. The Errai partners submitted a CO_2 storage licence application to the Norwegian Ministry of Petroleum and Energy in 2022, with Neptune proposed as operator.



The Errai CCS project could store between 4-8 million tonnes of CO_2 a year from 2026

In February 2023, together with Horisont Energi, we signed a Memorandum of Understanding with E.ON with the aim of developing a European CCS value chain, covering development, financing and funding. E.ON's participation will further contribute to the linking of CO_2 projects on the Norwegian Continental Shelf with development of a CO_2 offtake market in Europe.

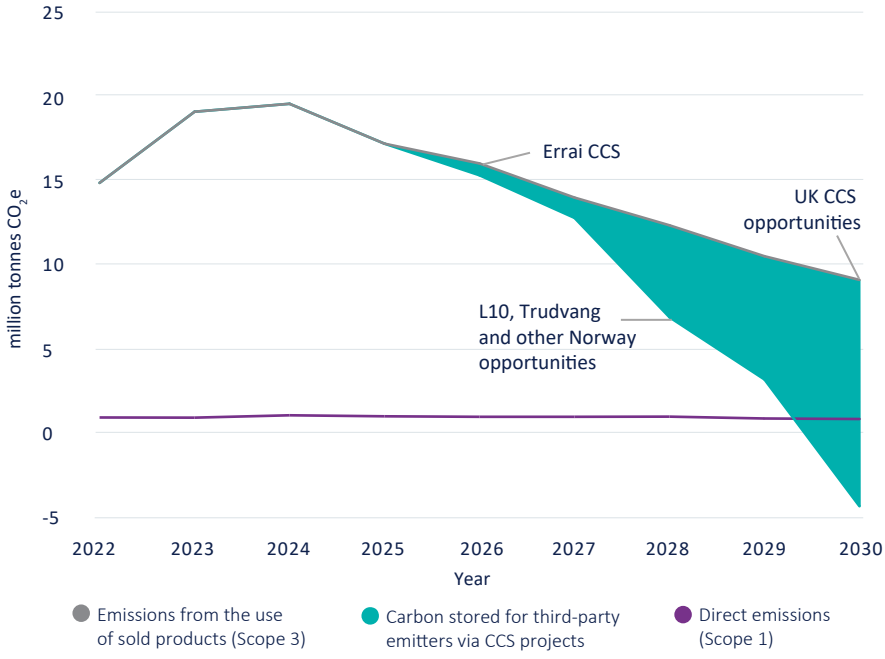
Also in February 2023, together with Sval and Storegga, we applied for a CO_2 storage licence in the Norwegian North Sea. Securing the licence would enable the companies to proceed with the Trudvang project which has the potential to store up to 9 million tonnes of CO_2 a year, equivalent to about 20% of Norway's total annual emissions.

The Trudvang project comprises capture of CO_2 by multiple industrial emitters in Northern Europe and the UK, shipping of liquid CO_2 from export terminals to an onshore receiving terminal in the southwest of Norway and transport via a purpose-built pipeline to the Trudvang location for injection and permanent storage.

The UK

We submitted three applications for CCS licences in 2022. Securing the licences would allow us to develop future proposals for integrated energy hubs in the UK North Sea.

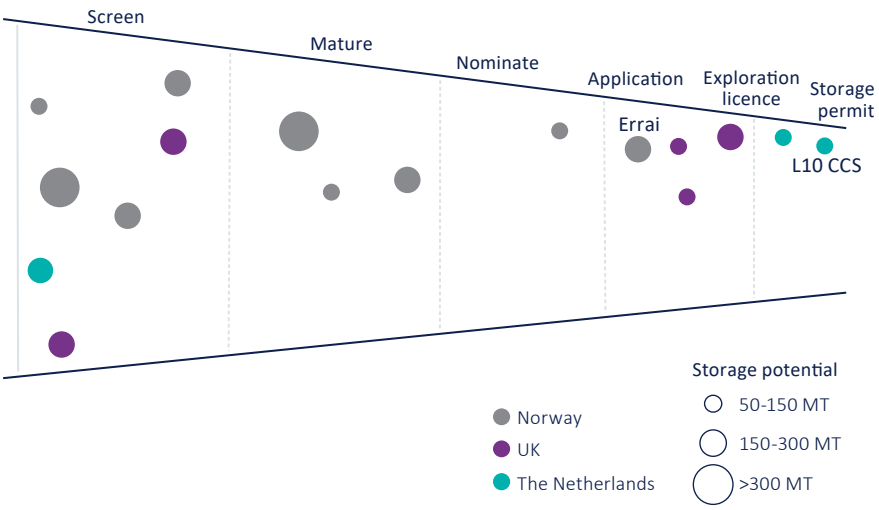
Indicative emissions trajectory – aiming to store more carbon than is emitted from our operations and the use of our sold products by 2030



- Conditional to reaching agreements with key emitters.
- Based on estimated equity share of CCS projects.
- Our calculation methodology for Scope 1 emissions follows the IPIECA/API/IOGP Petroleum Industry Guidelines for Reporting GHG Emissions. These emissions are calculated on an equity share basis.
- Emissions from the use of sold products are Scope 3 category 11 emissions. This includes 2P reserves.

Expanding our CCS pipeline

We are currently looking at large-scale offshore CCS projects that use existing infrastructure in line with our ambition to store more carbon than is emitted from our operations and the use of our sold products by 2030. We made good progress expanding our CCS opportunities in 2022.



The Netherlands

At our L10 CCS project, our most advanced CCS project, we finalised a cooperation agreement with our partners in 2022 and continued to mature the project towards concept selection. We expect to submit a storage licence application in April 2023 and commence front-end engineering design in the second quarter of 2023. The project has the potential to store between 4-9 million tonnes of CO_2 a year for third-party industrial customers into depleted gas fields. We continue to engage with emitters and progress the commercial framework.

In February 2023, with infrastructure owner CapeOmega, we announced NoordKaap, a project concept for a cross-border CO_2 storage solution for industrial emitters across Europe. NoordKaap would involve transporting CO_2 via vessels suitable for directly injecting the CO_2 at offshore locations and for terminal offloading. RWE has signed a Letter of Intent with CapeOmega and Neptune to assess the possibility of shipping CO_2 from its biomass Eemshaven facility for offshore storage in the Dutch North Sea.

Hydrogen

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 our PosHYdon pilot project in the Netherlands to transfer learnings into more commercial-scale projects.

On behalf of the PosHYdon consortium, we are in discussions with the authorities regarding regulatory changes that would be required for the project to proceed.

At our H_2opZee green hydrogen project, a consortium agreement was signed in June 2022 and a feasibility programme is under way. The study is evaluating an initial 300-500 MW of generating capacity, with a pipeline to enable a future increase in capacity to 10-12 GW. The review covers concept designs and engineering for platform, pipeline and wind turbine generator systems and is expected to be completed in mid-2023.

We are a member of the European Clean Hydrogen Alliance, which supports the large-scale deployment of clean hydrogen technologies by 2030. We also chair two Energy Institute working groups on hydrogen:

- Hy2003 – this group is assessing the environmental impacts of deploying hydrogen at scale.
- Hy2006 – this group is developing guidance to minimise the asset integrity risks associated with hydrogen transport.

Together with RWE Renewables, we were awarded an Environmental Excellence Award from Power Technology for the H_2opZee project in December 2022. This recognised the project's role in supporting the development of a hydrogen economy in the Netherlands and the country's energy transition.

Powering integrated energy hubs with offshore wind

Integrated energy hubs have the potential to combine multiple energy systems, including existing gas and oil production assets, carbon storage and hydrogen production facilities. They could extend the life of producing fields and support the economic case for electrification with renewable energy, to keep carbon emissions low.

We signed a Memorandum of Understanding with Ørsted and Goal7 in December 2022 to explore powering new integrated energy hubs in the UK North Sea with offshore wind-generated electricity. The companies will examine the potential to supply renewable energy from Ørsted's Hornsea offshore wind farm to carbon storage facilities, as well as to gas and oil assets to help decarbonise production. They will also look at opportunities for using wind energy for hydrogen production.

The development of integrated energy hubs is an important part of our strategy to store more carbon than is emitted from our operations and the use of our sold products by 2030. Bringing wind power to integrated energy hubs could help reduce emissions associated with gas and oil production, while providing secure supplies of energy and supporting jobs.


Turbines at Ørsted's Hornsea wind farm

Lithium and geothermal

In Germany, we are pursuing opportunities for lithium production and geothermal energy generation. In the Saxony-Anhalt region, we have applied for a lithium production licence, which would allow us to evaluate the extraction of lithium from produced water. In the Rhine Valley, we are exploring the potential for geothermal projects and are in discussions with a potential strategic partner.

Climate-related financial disclosures

The recommendations of the Task Force on Climate-related Financial Disclosures (TCFD) have informed our climate-related disclosures. We will continue to evolve these, in readiness to meet the UK Government's requirements for large private companies.



TCFD index table

Recommended disclosures	Page reference
Governance Disclose the organisation's governance around climate-related risks and opportunities.	
a) Describe the board's oversight of climate-related risks and opportunities.	27
b) Describe the management's role in assessing and managing climate-related risks and opportunities.	27
Strategy Disclose the actual and potential impacts of climate-related risks and opportunities on the organisation's business, strategy and financial planning where such information is material.	
a) Describe the climate-related risks and opportunities the organisation has identified over the short, medium and long term.	27-28
b) Describe the impact of climate-related risks and opportunities on the organisation's businesses, strategy and financial planning.	22, 28-29, 114
c) Describe the resilience of the organisation's strategy, taking into consideration different climate-related scenarios, including a 2°C or lower scenario.	29
Risk management Disclose how the organisation identifies, assesses and manages climate-related risks.	
a) Describe the organisation's processes for identifying and assessing climate-related risks.	29-30
b) Describe the organisation's processes for managing climate-related risks.	29-30
c) Describe how processes for identifying, assessing and managing climate-related risks are integrated into the organisation's overall risk management.	29-30
Metrics and targets Disclose the metrics and targets used to assess and manage relevant climate-related risks and opportunities where such information is material.	
a) Disclose the metrics used by the organisation to assess climate-related risks and opportunities in line with its strategy and risk management process.	
– Focused, lower carbon strategy.	14
– Metrics and targets.	30-31
– Water and biodiversity metrics.	49
b) Disclose Scope 1, Scope 2 and, if appropriate, Scope 3 GHG emissions, and the related risks.	22-23, 31
c) Describe the targets used by the organisation to manage climate-related risks and opportunities and performance against targets.	30

Governance

TCFD recommendation: Disclose the organisation's governance around climate-related issues and opportunities.

We reviewed our strategy in early 2022, a process that reinforced the strengths of our business and increased our ambitions for pursuing lower carbon opportunities. The mainstay of our business remains lower carbon energy production from natural gas, but we are accelerating plans for lower carbon projects, using our existing infrastructure.

The Board oversees our approach to managing climate-related issues and opportunities and considered climate-related matters throughout the year. In 2022, the Board approved our strategy and our ambition to store more carbon than is emitted from our operations and the use of our sold products by 2030. The Board also assessed potential lower carbon projects, reviewed our carbon and methane intensity performance and our climate-related disclosures, approved major capital expenditures and endorsed our business plans and budgets.

The Audit and Risk Committee (ARC) and the Remuneration Committee (RemCo) carry out governance responsibilities with respect to the risks and opportunities associated with climate change and the energy transition. In 2022, as part of the Group's risk management processes, the ARC reviewed Neptune's enterprise risks, including those related to climate change. The RemCo discussed and agreed the carbon intensity measure in the annual performance scorecards for all employees and the Executive Team.

See page 93 for more information on the Board's activities in 2022 on climate-related risks and opportunities.

The Executive Team is responsible for assessing and reviewing climate-related matters and is supported by our ESG Committee (see page 99), Investment Committee and Operational Integrity Committee. The Executive Team monitors our carbon and methane intensity performance each month, as well as our progress on lower carbon technology projects. The Executive Team also reviewed the development of our strategy and lower carbon ambitions, ahead of the Board's review, in early 2022.

Governance of climate-related risks and opportunities



The Board and the Executive Team are supported by senior leaders within the Group with expertise on local climate-related risks and opportunities, such as national carbon prices and regulatory requirements. They report performance and progress against our climate targets on a monthly basis to the Executive Team and focus on delivering Neptune's ambitions at a country level.

Information on our climate ambitions and progress against our targets is shared with our people through monthly outlook calls, IT dashboards, annual and quarterly financial updates, town halls, intranet articles and via our CEO's blog.

Strategy

TCFD recommendation: Disclose the actual and potential impacts of climate-related risks and opportunities on the organisation's business, strategy and financial planning where such information is material.

We recognise the potential impacts of climate-related risks and opportunities on our ability to deliver our strategy and monitor these across three time periods:

1) Short term – three years. Our business plans include financial projections and measures to enable us to progress our climate ambitions in the near term.
2) Medium term – three to 10 years. We use tools, such as our emissions forecasting tool, to assess risks and opportunities. This helps us review our performance and ability to deliver our 2030 targets. We will include the costs of future low carbon technology projects in the medium and long term, once projects have been sanctioned.
3) Long term – beyond 10 years. We consider a range of scenarios for the energy transition out to 2050, using outputs from IEA models and physical risk assessments. See page 29.

TCFD distinguishes between 'transition' and 'physical' risks associated with climate change and we have used this distinction for the purposes of our climate-related financial disclosures.

We have identified four principal risks related to climate change (see page 28), three of which are associated with transition risks and one with physical risk.

See page 114 for information on potential financial implications related to climate change.

Climate-related financial disclosures
continued

Transition risks

1. Host country and investor policy and regulation changes in response to climate change

Time horizon

Short ✓
Medium ✓
Long ✓

Host country energy policies may undermine Neptune's strategy, add cost and reduce profit margins. They may ultimately challenge the economic viability of projects/assets. Governments may decide not to sanction new licences for gas and oil exploration in order to reach their climate goals. This may affect a country's licensing policies and lead to more stringent regulatory regimes that could negatively affect Neptune's ability to grow, fund and sustain its business.

Changes in host country regulations in response to climate change could reduce demand for our products and lead to gas and oil prices that are lower than our financial planning assumptions, reducing our profit margins and challenging the economic viability of our projects.

We anticipate regulatory changes and policies aimed at meeting national and international climate goals, such as carbon taxes and emission reduction targets. Additional regulations and policies could affect the value of our assets and access to capital.

Opportunities

We recognise, however, the potential opportunities arising from policy and regulation changes in response to climate change. We are already well positioned, with a portfolio that is gas-weighted and has a significantly lower carbon and methane intensity than the industry average.

Government and investor interest in the need to reduce emissions and meet international climate goals has also helped inform our strategy and ambition to store more carbon than is emitted from our operations and the use of our sold products by 2030.

To deliver our strategy, we are targeting opportunities close to our core hubs where we can drive integration with our lower carbon objectives. We see significant near-term growth potential for gas and oil in Norway and Indonesia, while the Netherlands is a priority for investments that will support our integrated energy hub strategy. Large, complex, higher carbon and higher cost developments with long-time horizons are less likely to meet our investment criteria. A stable fiscal policy is one of the important criteria that we use when deciding on future investments in countries.

2. Ability to access competitive low carbon technology projects

Time horizon

Short ✓
Medium ✓
Long ✓

The gap between European governments' decarbonisation policies and relevant regulation, plus uncertainty around fiscal/economic regimes for low carbon projects, as well as increased competition from new entrants may reduce the commercial attractiveness of projects. This may, in turn, reduce Neptune's attractiveness to potential investors, increase the cost of financing and undermine Neptune's 2030 carbon ambitions. Given the role of CCS in our low carbon strategy, if we are unable to access decarbonisation projects, we may become less resilient to future changes in climate change-related laws and regulations.

Low carbon technologies, such as CCS and hydrogen, can make a significant contribution to a low carbon energy world but require policy support mechanisms and fiscal incentives. Deploying these technologies also relies on factors such as technology development and customer demand. Insufficient policy support and a strong competitive market for potential customers (emitters) could restrict our ability to deliver our strategy and meet our climate ambitions. This could increase the cost of capital.

In addition, changing and inconsistent government policies on profits generated by energy companies could affect our ability to deploy capital from gas and oil production into low carbon technologies.

Opportunities

Increased demand for low carbon technology solutions and fiscal incentives would represent opportunities for Neptune, enabling a rapid deployment of CCS and hydrogen. Our differentiated position could unlock additional capital, increasing our ability to scale up lower carbon technologies. See pages 14 and 22-25 for more information on our strategy and how we are pursuing lower carbon opportunities.

3. Increased litigation across the oil and gas industry

Time horizon

Short ✓
Medium ✓
Long ✓

Since 2019, there has been a rise in climate-related litigation globally against major carbon emitting corporations, including oil and gas majors and states. Litigation of this kind may increase in frequency with the potential to affect the business, both financially and reputationally.

Globally, several high-profile climate change-related court cases have been brought in recent years in the Netherlands, Germany and the UK. These include cases concerning liability for climate change and the impact on human rights as well as 'greenwashing' claims. While none have involved Neptune, should these cases become common in the industry, this risk could significantly increase our costs, limit our ability to develop new gas and oil reserves, decrease the value of our assets or reduce the demand for our products.

It could also affect our licence to operate and have reputational impacts, limiting our ability to attract and retain the talent we need to support the energy transition.

We do not see any opportunities arising from this type of risk. It does, however, reinforce our approach to sound governance, responsible practices and transparent disclosure.

Physical risks

1. The physical impact of climate change

Time horizon

Short
Medium ✓
Long ✓

The potential for, and adverse impact of, more frequent severe weather conditions, rising sea levels and other physical effects on our operating installations and future projects could rise.

Physical risks, such as those related to the increase in severe weather events, could affect our facilities, employees and supply chain. These could occur as a result of chronic longer-term shifts in climate patterns or from acute physical risks, such as flooding and droughts.

We commissioned an external organisation to conduct a physical climate risk assessment of selected assets in 2022, using low and high emissions scenarios to 2030 and 2050 (see page 29). The assessment found that one of our operated assets in Germany and two of our non-operated sites in Egypt and Algeria were deemed to be at higher risk from physical climate risk in a high emissions scenario to 2030. However, all three sites reach the end of their field life well before 2050. We therefore do not expect significant adaptation costs for these assets but will expand this analysis to quantify potential financial impacts in 2023.

The impact of physical climate change could affect our supply chain and we plan to work with our partners and suppliers to assess and monitor this risk.

Physical climate risks also include the impact on water resources. Based on the World Resources Institute Aqueduct Global Water Risk Atlas, three of our significant operated sites (in Germany) were in areas with high water stress in 2022. See page 49 for more information.

Opportunities

The actions we take to ensure our assets are resilient to physical climate change can help ensure overall business resilience, as well as improving the resilience of our assets. It can also help improve operational efficiencies and costs.

Scenario analysis

To test the resilience of our portfolio, we conduct scenario analysis against IEA scenarios. We use projected commodity and carbon prices out to 2050, given that price is a key variable in how transition risk materialises.

The majority of our operated production is from jurisdictions where there is already a high CO_2 price, and we have a carbon intensity of 6.5 kg CO_2/boe. This is significantly lower than the industry average of 16 kg CO_2/boe. As a result, changes in our net present value are driven almost entirely by the oil and gas price assumptions made in the IEA scenarios.

We use consensus long-term oil and gas prices but also test the robustness of projects at lower prices. In comparison, the IEA's *World Energy Outlook 2022* estimates future real energy prices in 2030 and 2050.

- Under the Stated Policies Scenario (STEPS), which reflects the current policy landscape, the projected 2030 real price is $82/bbl for oil with gas at around 74p/therm.
- The prices are lower under the Announced Pledges Scenario (APS) with oil at $64/bbl and gas 69p/therm.
- They are lower still for the Net Zero Emissions Scenario (NZE), which sets out a pathway for the global energy sector to achieve net zero CO_2 emissions by 2050, with oil at $35/bbl and gas at 40p/therm.

In the period from 2022 to 2030, energy prices are assumed to start at the actual average 2022 level and achieve the 2030 IEA estimate by using three different approaches – linear, forward curve and consensus.

The analysis found that the net present value of our portfolio in both OECD and non-OECD countries was positively affected in STEPS. This is primarily because projected prices under STEPS are higher as supply is constrained faster than consumption.

Under the APS, our non-OECD portfolio is positively affected. This is because projected prices in this scenario are also higher. The impact on our OECD portfolio ranges from -10% to +25% and is only negative under the forward curve approach as the current gas curve was below our assumption for the key first few years.

The net present value of our portfolio is most negatively affected in the NZE Scenario. Both OECD and non-OECD portfolios would see a decline in value compared with the APS scenario of 15% to 25%, as pricing in this scenario falls because demand is expected to peak faster than supply.

The findings from this analysis indicate that our focus on producing lower carbon gas and oil efficiently, and using existing infrastructure to integrate energy systems, will continue to strengthen the resilience of our portfolio.

Net present value (NPV) of portfolio	Stated Policies Scenario (STEPS)	Announced Pledges Scenario (APS)	Net Zero Emissions Scenario (NZE)
OECD	0% to +35%	-10% to +25%	-25% to +10%
Non-OECD	+20% to +40%	+5 to +20%	-5% to -20%

Physical risk analysis

We commissioned an external organisation to conduct a physical risk assessment for 10 key assets in 2022 to help inform our assessment of the materiality of potential physical risks on our business. The assessment included the facilities' exposure to environmental conditions such as flooding, extreme weather events and water stress. It used CMIP6 climate model data and Shared Socio-economic Pathway (SSP) scenarios from the Intergovernmental Panel on Climate Change (IPCC) AR6 report to 2030 and 2050:

- **SSP1-1.6 scenario:** a low emissions scenario that stays below 2°C warming by 2100, aligned to current commitments under the Paris Agreement.
- **SSP5-8.5 scenario:** a high emissions scenario that follows a 'business as usual' trajectory, assuming no additional climate policy and seeing CO_2 emissions triple by 2100.

The assessment included operated and non-operated assets in Norway, the UK, Germany, the Netherlands, Algeria and Egypt.

While the study found that all assets are expected to experience some increased risk to most climate hazards by 2050 across the climate scenarios, the sites with the highest overall physical climate risk across time horizons and climate scenarios were three onshore sites in Algeria, Egypt and Germany.

The climate hazards that presented the greatest risk were flooding, extreme heat, water stress and drought.

- The site in Germany was most exposed to risks associated with flooding and extreme heat, particularly under a higher emissions scenario. This could result in additional expenditure required to repair infrastructure.
- The sites in Africa were assessed as being most exposed to the risks associated with water stress, drought and extreme heat, which typically increased across the climate scenarios and time horizons. This could result in additional spend on energy to cool temperature-sensitive equipment and offices, as well as higher water costs in areas with limited supplies. These sites contributed 4% of our total production in 2022.

By comparison, offshore assets were assessed as being of least risk overall. This in part due to their location in the sea, making climate hazards, such as drought and flooding, less relevant.

We will continue to monitor updated projections and plan to conduct an assessment of the financial implications of physical climate risk in 2023.

Risk management

TCFD recommendation: Disclose how the organisation identifies, assesses and manages climate-related risks.

Our risk management process and policy are embedded in everything we do, from capital allocation for lower carbon projects to individual operational activities, such as reducing carbon emissions and improving energy efficiency. This allows us to consistently analyse and make appropriate risk-informed decisions.

Our integrated risk management system defines how we manage particular risks, including climate-related risks. Each risk has an owner who is responsible for assessing, controlling and mitigating it, and who is accountable for implementing effective risk reduction actions when required.

All enterprise risk information is stored in a single system and is available to leadership teams in real time via interactive risk dashboards. The Board and Executive Team review our principal risks on a yearly basis and the Audit and Risk Committee reviews these risks on a quarterly basis.

Climate-related financial disclosures
continued

Risk management (continued)

Our focused, lower carbon strategy, which is discussed and approved by the Board, guides the organisation in considering the risks we face when pursuing opportunities. Our Executive Team assesses and manages the delivery of this strategy, taking into account climate-related risks and opportunities.

Transition risk

TCFD outlines various risks related to transition risk, including policy and legal risks, technology risk, market risk and reputational risk.

Policy and legal risks

Our corporate affairs team monitors existing and emerging regulations and policies related to climate change and the energy transition. Information is shared with country teams and the Executive Team and informs policy planning and engagement with our host countries. Our ESG Committee monitors emerging ESG issues, including climate-related disclosures and emerging risks.

We monitor climate change-related litigation and have obtained legal advice to help inform our assessment of its potential future impact on the industry and our business.

Technology risk

Our New Energy team has established a pipeline of projects in line with our lower carbon strategy. The team has identified opportunities in areas such as CCS and hydrogen, which will play a key role in the energy transition. The team provides regular briefings to the Board and Executive Team on progress. In 2022, this included reviewing the pipeline of CCS opportunities to meet our ambition to store more carbon than is emitted from our operations and the use of our sold products by 2030. While we have significant experience in deploying CCS technology (see page 24), our ability to meet our target is also dependent on the availability of licences, which face increased competition from new entrants. In 2022, we submitted three CCS licence applications in the UK and signed an agreement with Horisont Energi in Norway to progress a large-scale CCS project.

Market risk

We consider market risks and opportunities in our business planning. For example, we use an internal carbon price in our investment decisions. We operate in countries that already have well-established carbon pricing systems, such as Norway, and monitor potential changes in regulation to assess the likely impact on our portfolio. In 2022, for example, we assessed electrification projects in Norway, with higher carbon prices having a positive impact on their economic viability.

Reputation risk

We engage with the financial community to share our lower carbon strategy and get feedback. We track our reputational sentiment and monitor key emerging issues. We work with industry groups, regulators and other external stakeholders to further their understanding of our approach and climate ambitions, and gain their insights.

Physical risk

Our physical climate risk assessments are based on the geographical location of our facilities. They are managed at a country level through processes such as our emergency response and business continuity plans. Our assessments consider acute physical risks, such as the increased severity of extreme weather events, and chronic physical risks, which relate to longer-term shifts in climate patterns that may cause a rise in sea levels or chronic heat waves. We assess these effects as we develop our projects to help inform the design phase. All new projects need to comply with regulatory requirements, which include provisions for climate change and may evolve over time. For information on the external assessment of physical risk conducted in 2022, see page 29.

Our targets

Our overarching ambition is to store more carbon than is emitted from our operations and the use of our sold products by 2030 (see pages 22-25). Our 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 in the Netherlands and Norway.

Target	Our 2022 performance and opportunities
13 Mte CO_2 stored for third-party emitters by 2030	• We signed an agreement with Horisont Energi in Norway to progress a large-scale CCS project. • We submitted three CCS licence applications in the UK. • We progressed the pipeline of CCS opportunities required to meet our 2030 ambition. • At our L10 project in the Netherlands, front-end engineering design work is due to commence in 2023.
100% of net production in Norway fully or partially electrified by 2028	• We sanctioned electrification projects at Njord A and Snøhvit in 2022. • The Gudrun electrification project is close to completion, with start-up expected in mid-2023. • We expect to have around 43% of our net production in Norway electrified in 2023.
6 kg CO_2/boe carbon intensity by 2030	• 6.5 kg CO_2/boe carbon intensity. • Our carbon intensity remained stable in 2022 and we are on track to meet our 2030 target. • We expect our near-term carbon intensity to rise moderately in 2023 due to compression at Cygnus in the UK and additional power generation requirements at the Altmark field in Germany.
Zero methane emissions by 2030	• 0.02% methane intensity. • Our methane intensity remained stable in 2022 and we are on track to meet our target. • We joined the CEO-led Aiming for Zero Methane Emissions Initiative to promote further industry action. • We were awarded Gold Standard status from the Oil and Gas Methane Partnership 2.0 in recognition of our robust plans to report and reduce methane emissions.
Zero routine flaring by 2030	• We completed a review of our assets that require action to meet this target. As a result, we are focusing on two assets in Germany and one in the Netherlands. • In 2023, we will install micro gas turbines at the selected sites in Germany to reduce routine flaring. In the Netherlands, we are starting a project at our F3 platform to assess measures to help us achieve zero routine flaring.

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 (as 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.

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 product) (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 CH_4 emissions from combustion for energy, flare, direct hydrocarbon emissions, company cars, fleet vehicles and exclusive contract logistics from operations we own or control.

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 reporting energy use from well testing activities performed by third-party contractors. This is non-routine flaring. The majority of this in 2022 was from well testing activity 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 were 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.

Our society

Helping people thrive

Our activities enable economic growth, helping to create jobs, support local supply chains and contribute to national tax reserves. We increased our community investment spend substantially in 2022, supporting local initiatives, as well as humanitarian relief efforts in Ukraine.

Economic impact

$4.8bn

... total gross value added contribution in Europe



Employees

1,350+

... across Europe, North Africa and Asia Pacific



Social investment

$3.7m

... on community investment and humanitarian aid



Our people

We support a just energy transition that delivers decent, safe work and quality jobs. We have a dynamic and inclusive culture, with more than 1,350 employees in Europe, North Africa and Asia Pacific.



Employees at our Florø logistics operations in Norway

Employee profile[a]

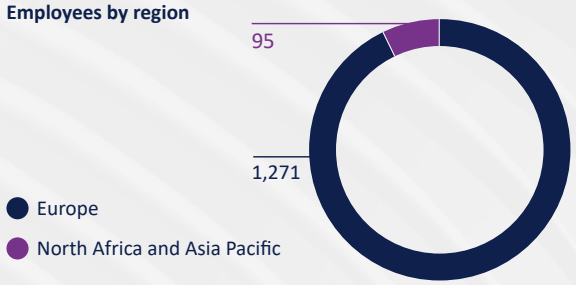
1,366
people

23%
female

40
nationalities

47
average age

Employees by region



a. Based on full-time equivalent as at 31 December 2022.

Attraction and retention

We want to provide a great place to work for everyone. We offer competitive pay and rewards, and our benefit packages include retirement plans, health and medical insurance, life assurance and paid parental leave.

Developing the skills of our existing and future workforce is essential to help us continue to grow and to support a just energy transition.

In the Netherlands, we participate in the Young Energy Officers programme, an initiative launched with the industry association Element NL to encourage new talent into the industry. In 2022, participants discussed repurposing infrastructure, carbon capture and storage and CO_2 reduction targets.

Also in the Netherlands, we held New Energy days with teams from across our functions and operations. During the sessions, we provided updates on our lower carbon projects and discussed how we can attract new people and talent to help us progress our low carbon ambitions. We plan to hold similar sessions in Norway in 2023.

We support our people to develop their careers at Neptune. Our training programmes focus on building technical skills and developing leadership capabilities. They include a mix of learning opportunities and delivery methods, including on-the-job development, virtual classrooms, face-to-face learning, coaching and mentoring.

Our first line manager training programme is aimed at employees who are new to leadership roles. We also run an online development programme for more experienced leaders which includes 360° feedback and coaching sessions.

Our mentoring platform, which we launched in 2021, gives employees the opportunity to become either a mentor or mentee across any aspect of the business. In 2022, 170 employees were registered on the platform.

In 2022, we introduced 'reverse mentoring', pairing members of the Executive Team with employees who are at the start of their careers. Both the mentees and the mentors are able to gain insights on topics of strategic and cultural relevance.

We also participate in external mentoring programmes run by the Engineering Construction Industry Training Board to share our experience and help mentees develop their skills.

We run multi-year apprenticeship and in-year internship programmes, which help participants develop their skills while bringing new knowledge and different perspectives into the business. We provided apprenticeships and internships to 17 people in 2022. In Norway, for example, five women participated in our summer internship programme, working in our drilling and wells, subsurface and supply chain teams.

We plan to run several internship programmes in the UK, the Netherlands and Norway in 2023. These will include opportunities to build both technical and non-technical skills.

Our voluntary turnover rate remained stable at 5.7% in 2022 (2021: 5.3%) and remains lower than the industry average.

All employees take part in at least two formal performance and development reviews a year, discussing their personal goals, performance, areas for improvement and career development with their manager.

80%

employee engagement

587

people participated in equality, diversity and inclusion (ED&I) awareness sessions

8.0

average annual training hours per person[1]

1. Includes employees and contract staff completing HSEQ, cyber security, ethics and ED&I training.



Our Group HR Director, Amanda Chilcott (second from left), visiting our Altmark site in Germany

Our people
continued

Equality, diversity and inclusion

We want our 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, we have made good progress in building a diverse and inclusive workplace. One of the ways we measure this is through our annual employee engagement survey (see page 38). In our 2022 survey, scores on being treated fairly and with respect increased to 79% (2021: 69%). A total of 83% of employees agreed that Neptune is a place they can be themselves (2021: 77%).

Targeting gender parity

We recognise, however, that we need to take additional action to make progress at the scale and pace needed to ensure greater diversity and inclusion. For example, we are not where we want to be on gender diversity, with women making up only 23% of our global workforce in 2022. Following consultation with internal and external stakeholders, 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, which applies across our bands, functions and locations.

By setting out our ambition we believe we can drive progress at greater pace and scale.

We 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, we will continue to look for ways to encourage broader diversity and inclusion in all aspects of our organisation.

Our commitment to equal opportunities

From recruitment and career development to reward and promotion, we aim to ensure equal opportunities for all employees, regardless of age, gender, sexual orientation, ethnicity, marital status, religion or belief, disability or political views. It is our policy that people with disabilities should be given fair consideration for all vacancies against the requirements for the role. See 'Attract' and 'Select' sections to the right for information on how we are supporting neurodiverse engineers and people with chronic physical conditions.

We are committed to treating everyone with dignity and respect, and to providing a workplace that is free from discrimination, harassment and bullying. We expect our partners and suppliers to do the same.

Our ED&I charter

Our ED&I Committee oversees Group-wide progress on our ED&I charter, which sets out our seven focus areas. Eko Lumadyo took over the role of executive sponsor of the ED&I Committee in 2022, succeeding Andrea Guerra, our VP, Subsurface. Eko will bring a country perspective from his position as Managing Director, Asia Pacific. He will build on Andrea's work over the past two years. Meanwhile, Andrea has become executive sponsor of our newly established Women in Neptune (WIN) network.

Build
Grow capability that drives conscious inclusion

Attract
Encourage women and minorities into STEM careers

Select
Promote equal hiring practices

Support
Implement policies that support inclusion

Develop
Increase diverse representation at all levels

Measure
Communicate progress and celebrate success

Belonging
Build networks that promote new connections

Build

Build
Grow capability that drives conscious inclusion

Throughout the year, we delivered focused communications to raise awareness of ED&I, including an ED&I month (see page 37), CEO blogs, town halls and Yammer discussions. We also held inclusive leadership training for senior leaders in Norway and sessions on the importance of psychological safety for more than 300 people across the organisation.

As well as helping our people develop their skills, our new mentoring platform aims to strengthen understanding among our people, helping them share new perspectives and build better connections.

Attract

Attract
Encourage women and minorities into STEM careers

In Indonesia, we held a webinar to celebrate Kartini Day, which commemorates Indonesia's national heroine of women's empowerment. The webinar was led by Janet Hann, our Managing Director, Australia, and held with Enerka, an online learning platform focused on developing the skills needed for the energy transition.

In the Netherlands, two of our female employees became mentors in 2022 as part of our partnership with Klapstoel Academy. This institution connects women at the start of their careers with women working in senior-level roles. In 2023, five of our young female employees under the age of 36 will participate in the career coaching programme.

We signed a partnership agreement in 2022 with Emma at Work, a non-governmental organisation that supports young people with a chronic physical condition. The organisation focuses on training young people to ensure they get a fair chance in the labour market. We will provide placement opportunities and coaching as part of the partnership.

See page 45 for information on how we are working with local schools to engage young people in science, technology, engineering and maths subjects.

Select

Select
Promote equal hiring practices

To help attract diverse candidates into Neptune, we make our commitment to ED&I clear in our recruitment processes. We aim to use neutral language in our job descriptions to reduce unconscious bias and make sure we don't inadvertently discourage diverse candidates from applying.

For roles in specialisations where we tend to find it difficult to access diverse candidates, we will move to evergreen job postings, with the role listed ahead of a vacancy becoming available.

We challenge our leaders, HR teams and external recruitment agencies to ensure we have access to a diverse pool of candidates. This diversity can take many forms, such as age, race, gender, sexual orientation, belief and cognitive diversity. We are working with the Foothold charity (see page 45) to support neurodiverse engineering students and apprentices to complete their studies and start their careers.

We tailor our approach depending on the role. For example, we may be looking for stronger female representation for operational roles or

stronger local national representation for rotational roles in our joint venture operations. In every case, we seek to ensure that both long and short lists for candidates include a diverse pool before we proceed to the interview stage.

Support

Implement policies that support inclusion

We rolled out our refreshed ED&I Policy in 2022, which highlights our key commitments and aligns with our charter. We also launched our Anti-Bullying, Harassment and Discrimination Standard.

Our WIN affinity group (see below) highlighted the need for consistent provision of female-sized personal protective equipment and sanitary products at our offshore and onshore sites and offices. We are working with our suppliers to ensure there are sufficient supplies. For example, we introduced free-to-vend sanitary products in our Aberdeen office in 2022.

We continue to support flexible and part-time working, recognising family and caring commitments. In 2022, we reviewed our parental leave policies in the Netherlands and increased parental pay to nine weeks at 100% of the salary, up from 70%.

Develop

Increase diverse representation at all levels

We want our senior leaders to represent the communities in which we work, which is why our country operations are largely led by Managing Directors who are nationals of their countries.

To check that equality exists in jobs of equal value, we conducted reviews across our countries in 2022 and took action where necessary to ensure fair pay. Our assessment confirmed that we have a strong commitment to equal pay principles. We will continue to conduct these reviews on an annual basis.

We plan to publish our first gender pay data for the UK in March 2023, which considers average pay across the employee population. Our analysis indicates that we have a gender pay gap driven by two key factors. First, our workforce is predominantly male. Second, we have more men than women in senior leadership roles, and more women than men in junior roles.

Additionally, most of our offshore and onshore technical and operational roles are carried out by men. These roles tend to attract higher levels of pay, with added premiums and allowances, which result in higher pay rates compared with office-based work.

Our bonus gender pay gap reflects our predominantly male leadership, as our leadership roles have a higher proportion of variable pay in the form of bonuses, which are tied to individual and company performance.

Our gender diversity target will help us address our gender imbalance. We are working to ensure our women all have structured development plans and to identify high-potential female talent at middle management levels to encourage progression into senior roles. Women made up 18% of those identified as potential successors for executive-level roles in 2022.

To view our gender pay gap report and further actions we are taking to close this gap, see *neptuneenergy.com*

Measure

Communicate progress and celebrate success

Going forward, we will assess our performance against our new gender parity goal and communicate the progress we make.

We held our second global ED&I month in November 2022, running a range of activities to showcase and promote ED&I topics. A total of 587 people participated in the sessions (2021: 352). We invited external and internal speakers who spoke on issues such as belonging, neurodiversity, cultural awareness, LGBTQ+ and gender equity. We also partnered with training provider AKD Solutions, for a second year to offer employees game-based ED&I learning. In the sessions, participants worked in teams to discuss real-life scenarios and consider dilemmas.

Belonging

Build networks that promote new connections

Our ED&I Committee meets every two weeks and has representatives from all our countries. In 2022, the committee reviewed Neptune's global gender diversity targets, country-level initiatives and the focus areas for our ED&I month. We also have ED&I groups in each country to drive diversity and inclusion at a local level. Each of these employee-led groups have country-specific actions that are aligned with our ED&I charter.

We established our WIN and LGBTQ+ affinity groups in 2022. Both groups are led by executive sponsors and provided feedback on Neptune's new gender diversity target. We have also established country-level women's networks. Our affinity groups create a broader sense of belonging within Neptune and provide a space to discuss ideas, share stories and provide advice. We plan to establish an early careers affinity group in 2023.

Gender diversity[a]

Board

Female	Male
2	3

40%
(2021: 40%)

Executive Team

Female	Male
3	13

19%
(2021: 21%)

Senior leaders

Female	Male
34	151

18%
(2021: 17%)

All employees

Female	Male
310	1,056

23%
(2021: 22%)

New hires

Female	Male
49	155

24%
(2021: 29%)

a. Based on full-time equivalent as at 31 December 2022.


Celebrating cultural diversity in Indonesia

Our people
continued

Employee engagement

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 (see page 36), 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 maintain regular communication between our leadership teams and staff through town halls, webinars, weekly CEO blogs and vlogs, Yammer, extended leadership meetings and many employee forums. Our leaders visit our sites regularly to talk directly to those who are working in front-line roles.

We engage proactively with works councils or employee forums in all our operated locations, as well as with safety committees for both onshore and offshore sites.

We are members of the IOGP and Energy Institute's safety committees and hold frequent safety meetings, working with operational leaders and safety supervisors to implement safety campaigns. Our country Managing Directors and Heads of HR and HSEQ are the main contacts for these groups.

The Neptune European Employee Engagement Forum is chaired by our Group HR Director and attended by our CEO and other members of the Executive Team as needed. The forum creates opportunities for direct communication between employee representatives and our Executive Team. It meets twice a year to discuss topics such as health and safety, business performance, career development and employee engagement.

As set out in our Human Rights Policy, we are committed to freedom of association and work with the trade unions and works councils that our employees wish to be represented by, within the appropriate national laws. A total of 24% of our employees were covered by a collective bargaining agreement in 2022.



Employees in Indonesia took part in Wear It Pink day in October 2022 to raise awareness of breast cancer



Code of Conduct

Our Code of Conduct sets out our expectations and commitment to act with the highest degree of ethics and integrity. It contains five principles:

- Acting in accordance with law and regulations.
- Establishing a culture of integrity.
- Behaving fairly and honestly.
- Respecting others.
- Speaking up.

We rolled out our revised code in 2022. It includes examples and scenarios that help make it easier for our people to apply its principles in their daily work and reiterates our speak-up culture. We require our people to complete an annual e-learning on the code, together with a certification that they have read and understood the code and associated procedures.

A total of 99% of our employees completed the training and certification in 2022. The code applies to all employees, directors and officers of Neptune Energy worldwide, as well as to contract staff.

We also expect our suppliers and those working on behalf of Neptune to adopt equivalent standards. We ended the contract of a contract staff member in 2022 who was deemed to have breached our behavioural expectations.

We review business ethics risks once a quarter as part of our periodic risk reviews. We also conduct specific ethics and compliance risk assessments every two years. In 2022, Indonesia and Australia completed these risk assessments, with our remaining countries due to complete these assessments in the first half of 2023.

Speaking up

We encourage our people to speak up if they are concerned about any inappropriate, illegal or corrupt behaviour in relation to our activities, as well as any actions that are, or could be, harmful to our business. We rolled out our new Grievance Procedure in 2022, which sets out our commitment to investigate any formal grievances raised, and the ways in which our people can raise concerns.

If a member of staff has a concern, they can raise it via one of several channels, including their line manager, local Ethics Champion, legal counsel or HR representative, as well as the Head of Global Ethics and Compliance, or their local employee union or safety representative. They can also raise it via the Vault Platform app.

The Vault Platform allows our people, and those working for our suppliers, to report any concerns of unethical or unfair behaviour in our business anonymously. The platform is certified to the ISO 27001 information security standard.

During 2022, 17 grievances and whistleblowing reports were received via the Vault Platform and other channels (2021: 11). The majority of these related to alleged inappropriate behaviour, unfair conduct, bullying or harassment. All reported matters were assessed, and then, depending on that assessment, followed by an informal or a formal investigation.

Of the 17 reports as at 31 December 2022, 15 have been closed. The remaining two, which were reported in December 2022, are under investigation. All but one of the cases have been, or are being, investigated by Neptune. The remaining case was investigated by a supplier company and related to a claim made by its employee.

Where a claim is investigated, and substantiated, we take action. Possible courses of action range from coaching to formal warnings to dismissals.

We do not tolerate retaliation in any form against any individual who speaks up in good faith. We aim to promote a culture and environment for people to feel psychologically safe to speak up and voice concerns or opinions.



Our safety

Safety underpins all our business activities. We aim to be safer every day, ensuring our people always go home safely.

We saw an improvement in the number of health and safety events reported in 2022. During the year we had no tier 1 process safety events and no serious injuries. Our process safety event rate (PSER)[e] improved to 1.13 (2021: 1.28) but remained higher than our target of 1.04.

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 also improved to 0.97 (2021: 1.09) but was higher than our target of 0.60, again driven by slips, trips and falls.

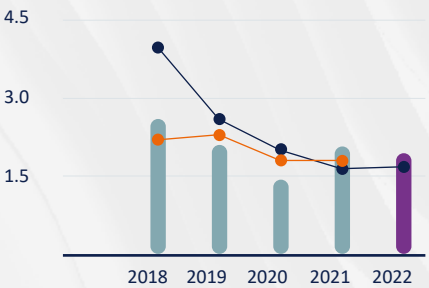
We achieved improvements in performance by delivering safety training and conducting audits of our systems and activities. We take a restorative justice approach to support continual improvement. This means we do not simply investigate what happened when an incident occurred, but how it happened. Understanding the decisions and actions that led to a near miss, for example, helps us learn and improve, so we can prevent more serious events from occurring.

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.

Our Executive Team conducted site visits in 2022 to talk to people working at our onshore and offshore facilities who oversee the safety of our operations and hear their views. They also took part in a three-day process safety training course in 2022. This focused on the effect of major hazards and accidents, with demonstrations of fires and explosions, enabling a greater understanding of the physical impact that these hazards can have.

We include safety performance as a factor in determining employee bonuses for our employees and Executive Team. This includes targets for our TRIR and PSER.

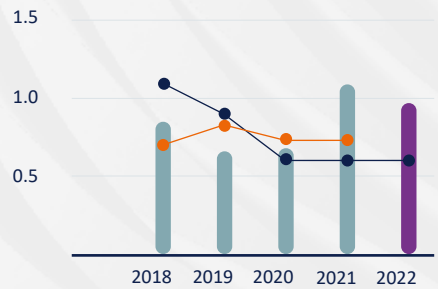
Total recordable injury rate[a]



	2018	2019	2020	2021	2022
Workforce	2.60	2.10	1.43	2.07	1.94
Employees[b]	–	4.08	0.44	0.92	2.62
Contractors[b]	–	1.30	1.67	2.38	1.72

Target TRIR IOGP average[c]

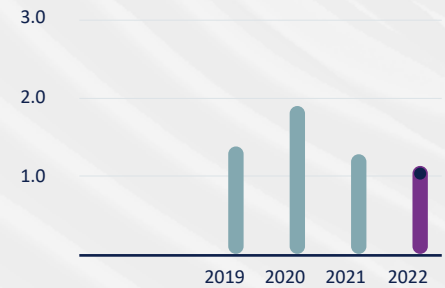
Lost time injury frequency rate[d]



	2018	2019	2020	2021	2022
Workforce	0.85	0.66	0.68	1.09	0.97
Employees[b]	–	0.45	0.00	0.46	1.74
Contractors[b]	–	0.61	0.83	1.26	0.72

Target LTIF IOGP average[c]

Process safety event rate[e]



	2019	2020	2021	2022
PSER	1.38	1.90	1.28	1.13
Tier 1 events	0	0	0	0
Tier 2 events	1	2	1	1
Tier 3 events	28	25	16	11

Target PSER

a. The number of recordable injuries (fatalities, lost work day cases, restricted work day cases and medical treatment cases) per one million hours worked.
b. We began reporting this data from 2019.
c. IOGP – European average. 2022 data is not available until May 2023.
d. The number of lost time injuries (fatalities and lost work day cases) per one million hours worked.
e. The total number of tier 1, 2 and 3 process safety events per one million hours worked. This is a Neptune metric and is therefore not comparable to industry benchmarks. We first started reporting this metric in 2019. In 2022, we changed our PSER to be a weighted metric, with more severe incidents having a higher weighting. We have restated our numbers from 2019 to 2021 accordingly. Due to this change, we are including our PSER target from 2022 only.

Our safety
continued

Having the right culture is key to good safety performance and we reinforce good practice through our Group-led safety culture programme.

Our global operational integrity management standard and integrated management system outline our requirements on issues such as safety, health, emergency preparedness, environmental stewardship and risk management. In 2022, we carried out an audit in Norway focusing on safe operations, risk management and emergency response, as part of our annual audit programme. These audits enable us to monitor compliance with our management system and check we are operating safely.

We identify and assess risks inherent to the oil and gas industry, such as loss of containment, fire, structural failure, helicopter accidents, dropped objects and loss of well control. And we put barriers in place to prevent them.

We celebrate individual and team safety initiatives through our annual HSEQ Awards, which recognise actions that have improved the safety of our people, facilities or processes. In 2022, we received 59 nominations with five winners receiving awards for initiatives that include championing safety during drilling preparations in Egypt and auditing the process safety management system in Algeria to identify opportunities for further improvement.

Speaking up on safety

The responsibility for stopping unsafe work lies with everyone associated with our business. All our employees and contractors must follow the International Association of Oil & Gas Producers' (IOGP) nine life-saving rules, which protect our people from the most common causes of fatal incidents in our industry.

We increased our focus on psychological safety in 2022 and held sessions on the importance of creating a working environment where everyone feels safe to speak up. More than 300 people took part.

We held our first global HSE day in April 2022, bringing together some of our youngest team members, our HSE team and the Executive Team to take a fresh look at safety leadership and how to create a culture of psychological safety within the workplace. A key objective was to help our people feel empowered to speak up if they see or feel that something is not right. Working in teams, participants came up with innovative ideas to help drive HSE performance. They then committed to bring the ideas to life following the session, with an executive sponsor assigned to each team.

Sharing safety insights

We work with industry associations such as the IOGP, the Energy Institute and IPIECA (the global oil and gas industry association for advancing environmental and social performance) to share our experience and learn from others.

We are working with worldwide humanitarian landmine clearance organisation The HALO Trust, to share good safety practice and further improve safety performance within both organisations. Members of The HALO Trust attended our process safety course, which gave both organisations a safe space to share their experiences of managing safety in high-risk environments.

Health and safety certification

Our health and safety system is certified to ISO 45001 in the UK. We completed stage 1 verification in the Netherlands and Germany in 2022. We are reviewing opportunities to extend certification across other countries.

Zero
tier 1
process safety events

25%
improvement in total recordable injury rate since 2018

12
months without a recordable injury in the UK



We completed stage 1 verification of ISO 45001 certification in Germany in 2022



We conducted an exercise with the fire brigade in Germany to test our emergency response preparedness

Well integrity

Wells containing hydrocarbons at pressure are a major hazard that require systematic management. Maintaining their integrity is vital in preventing harm to people or damage to the environment. See page 79 for more information on our principal risk related to drilling safety and performance.

Our global operating standards include requirements on well integrity that seek to ensure our wells are managed safely and with care for the environment throughout their lifecycle from well construction to operations to abandonment. At each phase, we use a combination of physical, operational and organisational barriers to prevent the uncontrolled release of well fluids.

Contractor safety

We are committed to keeping our whole workforce safe. Contractors carry out around 75% of the hours worked at Neptune and are fundamental to the safety of our operations.

Our standard model contracts include health and safety clauses that must be adhered to. Health and safety criteria are included in our contractor pre-qualification and selection processes.

We monitor contractor safety performance throughout the life of the contract, using third-party tools and, where appropriate, our own safety audits. If there is a divergence between our own safety management system and those of our contractors, we put in place formal bridging systems to ensure a strong safety culture.

We also run safety workshops and forums for our contractors. Our CEO met with his counterparts at several of our major contracting companies in 2022 to drive continual improvement and share lessons learned.

Emergency preparedness and response

We do all we can to prevent incidents and have processes in place to enable the earliest detection and a prompt response to emergencies. We operate a four-tier management model for emergency response, which ensures Neptune delivers its duty of care, from an initial site incident to Board-level oversight.

We continue to strengthen our emergency response capabilities, using industry best practice as a guide. In 2022, we conducted training for our people in Algeria, Egypt, Indonesia and the Netherlands on how to talk to family members affected by an incident. We also carried out a joint exercise with local fire brigades in Germany to simulate the rescue and transportation of employees suffering from burns and respiratory injuries to ensure our teams are prepared for such emergencies.

In Norway, we held a seminar with the Operator's Association for Emergency Response. Representatives from the police, fire brigade and the municipality's health services joined the session on emergency evacuation.

Cyber security

To manage the increasing global threat of cyber attacks, we introduced new cyber security emergency response procedures and delivered training and awareness programmes for our employees. A total of 90% of employees completed e-learning on cyber security in 2022. In addition, we held sessions for each of our countries and functions on cyber risks and conducted simulated phishing exercises across the Group. Our digital security team delivered 680 hours of cyber security training in 2022.

Health

We increased our focus on mental health in 2022. This was in direct response to feedback we received in our annual employee engagement survey in 2021, which told us employees would benefit from additional resources. We shared resources from our charity partner, Mental Health UK. We also celebrated World Mental Health Awareness Week and promoted awareness days such as National Schizophrenia Awareness Day and Time to Talk Day. We are also supporting a project to ensure people living with mental illness in remote communities can get online and access the support services they need. See page 45 for more information.

We recognise that mental health is just as important as physical health and initiated mental health first aid training towards the end of 2022. Eight employees are now qualified mental health first aiders in our Aberdeen office, and we will extend this training to other sites in 2023.

Our Thrive wellness portal is available to all our people, providing information on a range of resources in four key areas – physical, mental, social and day-to-day wellbeing.

Our people, and their family members, can access counselling through our Employee Assistance Programme, which is accessible 24 hours a day.

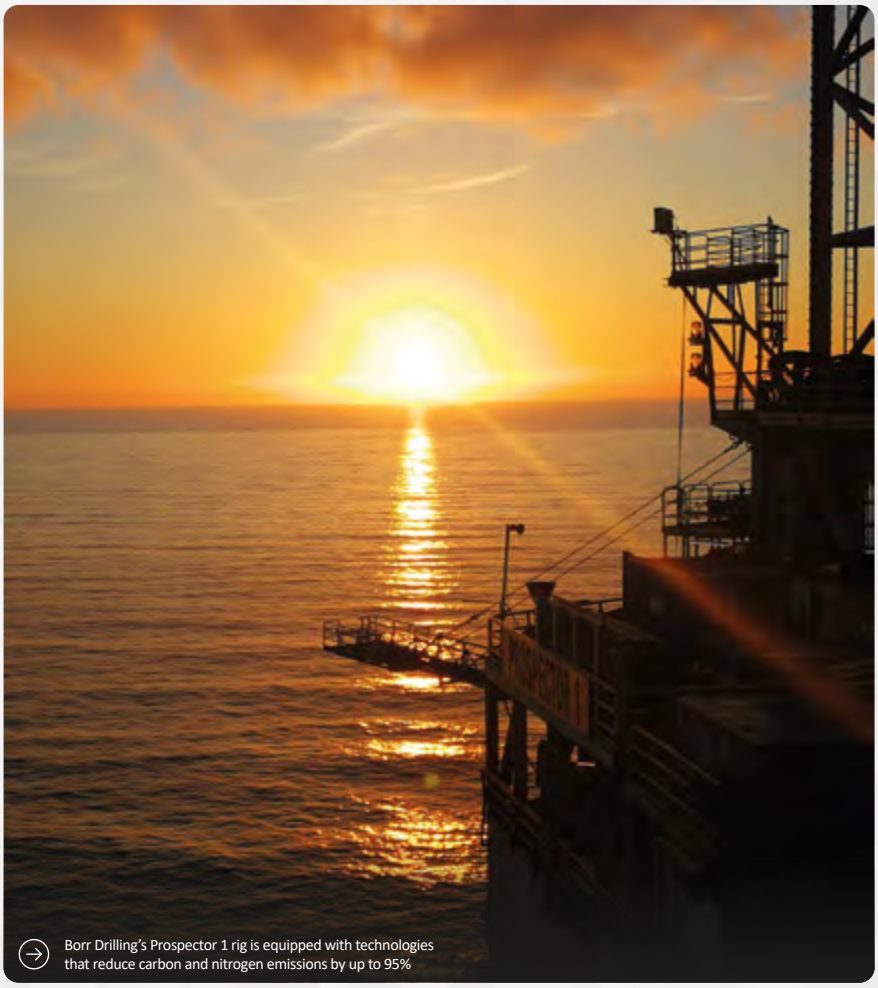
In Norway, we continued our support of a research centre that aims to reduce the number of sudden cardiac arrests by improving diagnostic and monitoring tools. The NEEDED centre opened in September 2021 and conducted its first study in 2022. We are funding several PhD positions to 2024 to help support its research.



We celebrated World Mental Health Awareness Week, focusing on making mental health a priority through a 'power hour' activity

Our partners and suppliers

We build strong relationships with our partners and suppliers that help drive technical excellence and enable us to maintain safe operations.



Borr Drilling's Prospector 1 rig is equipped with technologies that reduce carbon and nitrogen emissions by up to 95%

Our partners and suppliers help us deliver our strategic ambitions. We set out our expectations and commitments to our suppliers in our Supply Chain Policy. The policy includes embedding our health, safety, environment and quality (HSEQ) requirements in our supply chain to create the right conditions and behaviours to protect people and the environment. It also includes our commitment to work with suppliers on ESG matters, such as the energy transition, emission reductions and ethical working practices.

Our Code of Conduct reinforces this, setting out our expectations that our partners and suppliers will adhere to the same ethical standards.

Engaging with our partners

A total of 45% of our production was from non-operated ventures in 2022. We work with our joint venture partners via regular formal meetings, such as joint operating and technical committees, as well as ongoing informal engagements.

Before working with a supplier, we carry out a risk assessment and due diligence. We use a screening platform that identifies issues such as sanctions, human rights abuse, criminal convictions and any adverse media reports in respect of suppliers. The platform allows us to evaluate the results before deciding whether to work with a supplier.

Throughout the contract lifecycle, we aim to maintain open and transparent dialogue with suppliers. We talk to them via one-to-one discussions, as well as through supplier conferences on topics such as health and safety and ethical conduct. We have performance measures in place with all our major suppliers, which are discussed at weekly and monthly calls. We also hold quarterly performance reviews with our suppliers.

We work with our suppliers to help them apply our standards, including in health and safety. This helps set expectations and identify mutual opportunities to learn from one another.

4,500+
suppliers of goods and services

75%
of hours worked at Neptune are by contractors

Sustainable procurement

We are progressing our multi-year sustainable procurement action plan, which includes working with our suppliers to maximise efficiency and reduce operational emissions, as well as enhancing our due diligence procedures on human rights. In 2022, we began assessing emissions from our purchased goods and services and plan to report on outcomes in 2023.

To raise awareness of ESG issues in our supply chain, we held training sessions with our procurement teams in 2022. These included sessions on human rights and our new due diligence screening platform.

We are reviewing our contract standards to ensure agreements comply with our ESG requirements. All new agreements are now subject to our updated standards. We will refresh existing agreements, where required, in 2023. We also plan to introduce a supplier ESG monitoring framework in 2023.

Environmental footprint

A collaborative approach is key in helping us deliver our strategy and supports new ways of working to improve efficiencies and environmental performance. In 2022, we signed an alliance agreement with CHC Helicopter for offshore transport that will optimise flight schedules and routes to improve overall efficiency. This will reduce the total number of offshore flights and associated emissions. As part of the agreement, CHC will provide transport to and from the 29 offshore platforms that we operate in the Netherlands.

We are working with Borr Drilling to consolidate development and exploration work in the Dutch and UK sectors of the North Sea. This helps to reduce costs and operational emissions associated with these activities. In 2022, Borr's Prospector 1 rig was used at our Cygnus field in the UK and at prospective drilling sites in the Netherlands. The rig is equipped with technologies that reduce carbon and nitrogen emissions by up to 95%.

In 2022, we worked with one of our logistics companies to assess the potential use of drone flights for offshore deliveries. This could help lower costs and reduce carbon emissions associated with the transport of goods.

The energy transition

We are working with our partners and suppliers to achieve our ambition to store more carbon than is emitted from our operations and the use of our sold products by 2030. For example, we held a supplier screening day with Horisont Energi, our partner in the Errai carbon capture and storage (CCS) project in Norway, in 2022. More than 30 people participated in the session, which provided information on the project and its requirements.



Ethical conduct

We are a signatory to Offshore Energies UK's Supply Chain Code of Practice. This sets out best practice guidelines on working with suppliers to reach the highest standards of health, safety, ethical and environmental performance.

Suppliers can report any concerns about ethical conduct to their Neptune Energy contract representative or via the Vault Platform at *app.vaultplatform.com/neptune/Open-reporting*

Digital innovation

We have continued to build our relationship with leading UK-based 3D technology specialist Eserv, to increase the use of 'digital twins' for our operated assets. Ten of our assets now have a digital twin. This allows engineers to carry out tasks from onshore locations. For example, our L10-A, L10-B and L10-E drilling and production platforms in the Netherlands have digital twins, which support planning for our major CCS project in the L10 area.

In 2022, we partnered with industrial software provider Cognite, to optimise data from our well operations. We introduced Cognite Data Fusion, which provides contextual data from well operations in real time. This will help inform decisions about maintenance, production and safety. We have used the software for well operations in the UK, initially, and plan to use it at our Gjøa platform in Norway in 2023.

We continued our partnership with PaleBlue in 2022, following a virtual reality pilot at Gjøa. By using a VR headset, teams can visit the facility and build their knowledge of the complex multi-level facility. This allows us to reduce transport emissions and plan work operations more efficiently. We have assessed further use cases for the technology and plan to develop these in 2023.

Assessing modern slavery risk

We are committed to maintaining effective controls to ensure modern slavery is not taking place anywhere in our business or our supply chain. Our commitments are outlined in our Anti-Slavery and Human Trafficking Policy.

We are opposed to all forms of modern slavery and do not tolerate child, forced or bonded labour in our operations or by contractors working for us, as stated in our Code of Conduct.

As part of our pre-contractual due diligence, we ask our suppliers to confirm that they comply with legislation relating to modern slavery.

We make every effort to prevent our activities having a negative impact on human rights and take steps to remedy situations when they arise.

We carry out periodic ethics-related risk assessments throughout our business, including assessing the risk of slavery and human trafficking.

Following a human rights assessment that we commissioned in 2021, we took several supply chain-related actions to align with the UN Guiding Principles on Business and Human Rights in 2022. These included:

- Implementing a new due diligence screening platform, where, for high-risk business partners, we carry out due diligence on labour and human rights risks.
- Developing our approach to contractual management including assessing compliance with the terms and conditions of the contract, including the human rights and modern slavery clause.
- Conducting awareness training sessions on the risk of modern slavery in key functions such as supply chain and HR. A total of 146 people attended these sessions in 2022.

See *neptuneenergy.com* for our Anti-Slavery and Human Trafficking Statement.

Our communities

We want to deliver long-term opportunities for the communities where we work. We increased our community investment spend substantially in 2022, supporting local initiatives, as well as humanitarian relief efforts in Ukraine.

Supporting humanitarian relief efforts

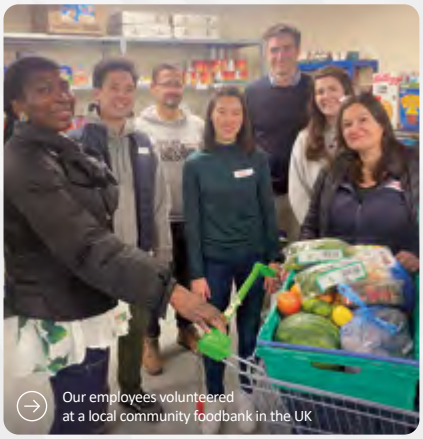
We consulted with international and local non-governmental organisations (NGOs), as well as our employees and Board, to assess how we could best support those affected by the humanitarian crisis in Ukraine and the cost of living crisis in the UK.

As a result, we donated $2 million to charities to help with relief efforts in Ukraine. Our $1 million donation to the International Rescue Committee, for example, helped provide essentials like food and blankets, health services, emergency cash assistance and access to safe healing and learning spaces for families affected by the crisis.

In addition, our employees raised more than $20,000 for the Ukraine Crisis Appeal.



We supported aid efforts in Ukraine



Our employees volunteered at a local community foodbank in the UK

To help support those affected by the cost of living crisis in the UK, where we are headquartered, we partnered with London child poverty charity The Childhood Trust.

We donated $617,000 to the charity's appeal to help vulnerable children get practical and emotional support.

We also partnered with the charity to collect food for a local foodbank, where some of our employees also volunteered to support those most in need.

Our social investment framework

Our social investment programmes take into account local community needs and contribute to the UN Sustainable Development Goals (SDGs). We partner with NGOs and local community groups to support programmes that have long-lasting benefits in the areas of health, local economic development, education and environment.

We are working with our community partners to develop key performance indicators so we can measure the impact of the initiatives over their lifetime. Our social investment standard includes an assessment of how the projects contribute to the SDGs, along with our ethics and compliance requirements.

Social investment spend ($m)



Health

We want to promote healthy lives and improve the wellbeing of people in our communities.

As well as improving awareness of the importance of health and wellbeing in our workplace (see page 41), we are working to increase access to support in the wider community.

We entered the third year of our partnership with Mental Health UK in 2022. We are supporting a project that provides individuals in rural communities with the skills, access and assistance to find the help they need to manage their mental health.

As part of the project, the charity delivered mental health awareness training to 121 rural workplace and community organisations in Scotland in 2022. Following the training, 94% of participants said they felt more confident to talk about their mental health with their colleagues.

This was also our second year supporting Sheltersuit UK, a not-for-profit organisation that creates products to protect rough sleepers from the elements. In November 2022, ahead of the European winter, we donated funds that helped provide around 1,500 Shelterbags. These portable sheltered beds are made from recycled materials and can be rolled up into a bag. They are insulated, waterproof, lightweight and have a built-in pillow. Our donation also supported the salaries of two Sheltersuit employees who came to the UK as refugees.

Local economic development

We contribute to the social and economic development of the countries where we work.

In Egypt, we supported an initiative led by the Ministry of Petroleum and Mineral Resources to help rebuild the Khor Awada village in Aswan, which was destroyed by flooding in November 2021. The funds raised by the project helped provide homes with electrical equipment and furniture, and the villagers received support for livestock initiatives to secure a sustainable income.

In the UK, we are partnering with the Foothold charity to support the development of the Differently Wired hub, which will provide support and advice to those in the engineering community who live with neurodiverse conditions. As part of the multi-year partnership, we will provide educational tools and resources to support engineers and their families.

Education

We support programmes that encourage young people to consider careers in science, technology, engineering and mathematics (STEM).

We have worked closely with the Scottish Schools Education Research Centre over the past two years to establish a partnership project to enhance STEM learning in Aberdeen. The project helps companies link with local schools and colleges to engage teachers and students on STEM. Our employees mentor secondary school students and support them through a tailored programme of STEM activities and learning.

We also support Developing the Young Workforce North East, which helps young people prepare for the world of work. In 2022, our employees conducted mock interviews with students and hosted workshops on problem solving, team working and communication skills.

In Norway, we support a summer school programme, run by social enterprise Forskerfabrikken, that aims to get more young people interested in natural science. We supported 10 courses, with around 200 school children participating in 2022.

We also participate in initiatives to help young people share their views and ideas on the energy transition. See page 35 for more information.



We support a summer school programme in Norway which aims to increase interest in natural sciences

10

courses run by social enterprise Forskerfabrikken

200

school children participated in 2022



We supported a reforestation project in 2022, donating fruit trees to a local community in Central Java

Environment

We want to have a net positive impact on biodiversity.

Our biodiversity strategy sets out our commitment to restore, preserve and enrich biodiversity and ecosystems. We work with environmental NGOs to deliver our ambitions. For example, we partnered with the SOS Dolfijn Foundation, which rescues stranded dolphins, porpoises and whales on the Dutch coast and surrounding countries. See page 49 for more information on the partnership and our biodiversity strategy.

In the UK, we supported the River Dee Trust, a charity that focuses on improving the biodiversity and ecosystem of the river and preserving it for future generations, helping provide education programmes across Aberdeen. We also launched a partnership with the North East Scotland Biodiversity Partnership, which works with local government, agencies and NGOs to tackle threats to biodiversity and facilitates conservation action in the region.

In Indonesia, we supported a reforestation project with a local community organisation, by donating fruit trees, including starfruit, guava and rambutan trees, to communities in Central Java. The area is prone to flash floods and landslides, so this project aims to help communities put measures in place to protect themselves against natural disasters, as well as conserve nature and improve community welfare. Residents participate directly by maintaining and caring for the trees.

Our communities
continued

Community engagement

We build strong relationships with the communities where we work and consult with them throughout the different stages of our operations to understand their priorities and address their concerns. This enables us to generate value for local communities and contribute to their economic and social development.

We are committed to having open dialogue with local communities and host governments and to ensuring there are channels for local communities to provide feedback. Our engagement is guided by our Code of Conduct, which sets out our expectations on community involvement. This is backed up by our stakeholder engagement framework, which sets out our process for identifying key stakeholders and implementing engagement plans for our projects and operations.

We also have guidance on specific topics. For example, our biodiversity strategy requires us to work with local stakeholders to identify any risks to habitats and species that our activities may present.

While the majority of our production is offshore, we have dedicated stakeholder and community liaison managers in countries where we have onshore operations.

In Germany, for example, we have a dedicated local stakeholder manager for each region where we operate. Stakeholders can also raise any concerns or questions via a telephone hotline or by email.

The majority of concerns raised in 2022 related to noise, transport and light during drilling operations. We are committed to addressing these concerns by informing local communities of timings well in advance of activities taking place. We conduct site visits and participate in public consultations to inform the community about planned activities and hear their views. In 2022, for example, the local mayor and council in Hoogstede visited our Scheerhorn oil field and talked to us about environmental conservation. As a result, we are supporting a project that aims to restore shallow waters and heathland to enhance the habitat for native bird species.

At our Touat gas plant in Algeria, we engage with local authorities and community members to understand local needs. In 2022, we worked with local labour authorities to develop a programme to support local employment. We will provide secondments for entry-level positions to members of the local community in 2023 and 2024. The first cohort of secondees will join in the first quarter of 2023.

Human rights

We respect individual human rights as set out in the United Nations Universal Declaration of Human Rights and the core conventions of the International Labour Organization.

We have been working to align with the UN Guiding Principles on Business and Human Rights and have progressed actions in our human rights roadmap. We are using the outcomes from the independent human rights assessment that we commissioned in 2021 to guide us.

Following the introduction of our new third-party screening platform, we have a more rigorous process in place for assessing potential third parties before working with them. For example, for types of services where there is a higher risk of human rights abuse or bribery and corruption, we issue a detailed questionnaire to the third party so that we can assess the steps they have taken to mitigate the risk.

We ran training sessions on human rights in 2022 to build greater understanding across our business. The training covered the identification of human rights issues, what we do at Neptune to avoid human rights abuses within our supply chain and how to report concerns. A total of 142 people, from key functions such as HR and supply chain, participated.

See pages 42-43 for more information on human rights and our supply chain.

Tax and transparency

We are committed to acting with honesty and integrity in respect of tax laws and regulations, and to paying our taxes in the countries where we work. We report payments to governments on a country-by-country and project basis under the UK's national reporting regulations.

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.

We support the Extractive Industries Transparency Initiative (EITI), which is designed to improve accountability for the revenues paid and received for a country's oil, gas and mineral resources. We submitted data for publicly available EITI reports in the UK, Germany, the Netherlands and Indonesia in 2022.



Economic impact

Our contribution to the communities and countries where we operate extends well beyond the provision of heat, light, mobility and power. Our work helps create jobs, supports local supply chains and contributes to national tax reserves.

We quantify our total economic impact using modelling from Oxford Economics. This modelling uses three core channels (direct, indirect and induced impact), which together represent the economic footprint of our assets.

We supported an estimated $4.8 billion gross value added (GVA) contribution to the gross domestic product of our European countries – Germany, the Netherlands, Norway and the UK – in 2022, and some 9,251 jobs. For every Neptune employee in Europe, around six additional jobs are supported elsewhere in the economy.

Our total economic impact in Europe increased in 2022, primarily due to higher earnings and operating cash flow, driven by higher commodity prices and good cost control.

Generating value in Indonesia

Oxford Economics also assessed our economic impact in Indonesia, where we work with Eni and other partners to produce LNG for export to the region as well as gas for the domestic market. 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.

$510m

total gross value added contribution to the gross domestic product of Indonesia

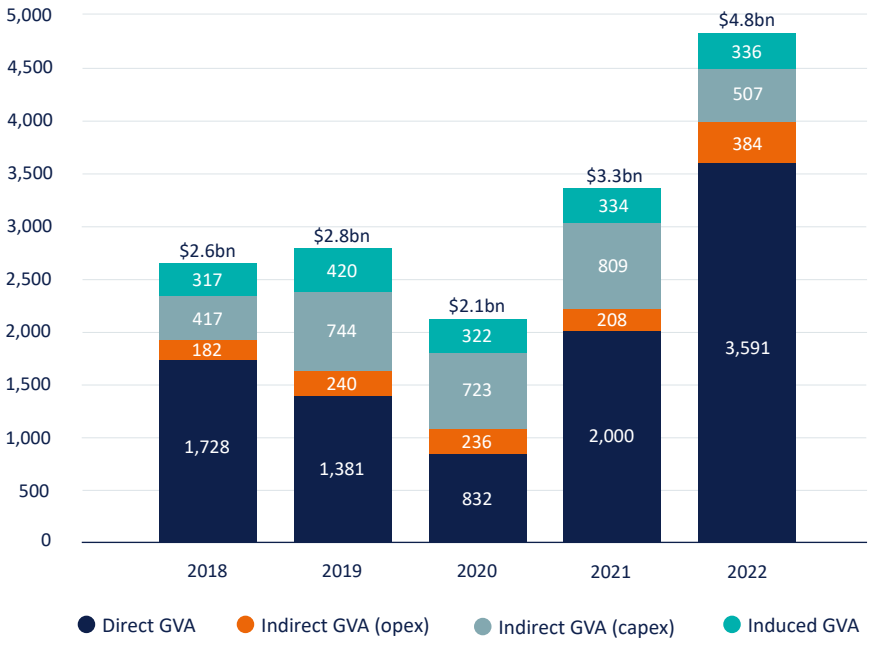
7,856

jobs supported through direct, indirect and induced channels in Indonesia

Our impact on the European economy in 2022

	Our direct impact	Our indirect impact	Our induced impact	Our total impact
	The people we employ + the GDP our operations generate.	The money we spend with suppliers who employ people, generate GDP and use other suppliers.	Wages spent by employees – ours and our suppliers – in the wider economy, generating more GDP and jobs.	Direct + indirect + induced = our total economic impact.
GVA	$3.6bn	+ $891m	+ $336m	= $4.8bn
Employment	1,267	+ 5,067	+ 2,917	= 9,251

Economic impact in Europe ($m)



Our local environmental impacts

We continue to make progress to reduce the impacts that our operations have on the local environment. We prioritise issues set out in our Environmental Policy, such as biodiversity, other air emissions, water and spill prevention.



We have introduced low emission turbines at our assets in the Netherlands to reduce NOx emissions

Our Environmental Policy is supported by our environmental standards, which detail our requirements, ensuring a common understanding throughout our organisation. This includes requirements on consulting with stakeholders who may be affected by our activities. Our CEO is responsible for ensuring that the policy is followed across the business.

We carry out environmental impact assessments when planning new projects. This includes understanding the potential impact our activities could have on biodiversity, fresh water resources and air quality. We use the results to identify the actions we can take and measures we can put in place in our project design and operations to lessen that impact. We monitor the impact of our activities when they move into the operational phase and conduct environmental audits, as appropriate, to ensure compliance with our standards and regulations, and to identify further opportunities for improvement.

We conducted an internal environmental audit of our Cygnus site and Borr Drilling's Prospector 1 drilling rig in the UK in 2022. As a result, we introduced several improvement measures, such as changing the placement of hoses and adding further insulation, to mitigate the risk of leaks and spills.

Our environmental management system is certified to ISO 14001 in the UK. We are progressing our plans to certify all operated countries and expect this to be complete by the end of 2024.

We work with our industry to share and learn from good practice. One of the ways we do this is via our membership of trade associations, such as the International Association of Oil & Gas Producers, the Energy Institute and IPIECA.

We take account of local environmental sensitivities in managing our performance. At sites closer to populations, the most immediate concern may be fresh water management, whereas an offshore site may need to give greater consideration to marine biodiversity. To take account of these differences, we manage performance and set targets at a local level.

Other air emissions

In 2022, our nitrogen oxide (NOx) emissions increased to 980 tonnes (2021: 701 tonnes). We are working to reduce these emissions. In the Netherlands, for example, we are working towards meeting NOx emission reduction targets as set out by national legislation. We have introduced low emission turbines and adjusted their running times. This has led to a reduction in our Dutch NOx emissions of 73% between 2018 and 2022.

Oil spill prevention

Our aim is to have zero operational spills. We regularly assess the risk of spills at each of our assets, considering various spill scenarios. We put in place physical, technical and operational barriers to prevent and mitigate the risk of spills and have contingency plans in place to protect the environment in the event of a spill. We recorded one spill greater than one barrel in 2022. The release occurred in Norway during the start-up of the Nova field and totalled 0.4 tonnes.

We assessed the environmental impact and speed of oil degradation. No oil reached shore and there was no oil on the sea surface. We have shared lessons learned to help us prevent more serious events from occurring.

We are members of Oil Spill Response Limited (OSRL), an industry initiative that has resources located across the world to respond in the event of an oil spill. In 2022, we worked with OSRL on response readiness. Our leaders complete mandatory oil spill response training.

Water

Water is an essential resource and we are committed to using it efficiently and minimising our consumption. We use non-fresh water, such as sea water, in our drilling and production processes. We use fresh water, mainly in our offshore operations, for drinking, cooking and sanitation. We use technologies to minimise fresh water use. For example, at our Cygnus offshore asset in the UK, we use reverse osmosis to convert sea water into drinking water.

In 2022, our total fresh water consumption decreased to 66,337 m^3 in (2021: 94,269 m^3).

We identify water-related impacts as part of our environmental impact assessments. We recognise that managing fresh water use is particularly important in areas of water stress. Based on analysis using the World Resources Institute Aqueduct Water Risk Atlas, three of our significant operated assets (in Germany) were located in areas of high water stress in 2022. These sites withdrew a total of 291 m^3 of fresh water in 2022, equating to around 1% of our total fresh water withdrawal in Germany. We use non-fresh water from our wells at some of our sites in Germany to reduce the amount of water we require from municipal supplies. We will review reduction opportunities and implement water management plans in 2023.

In 2022, we commissioned an independent organisation to conduct a physical climate risk assessment of some of our key assets. The review considered the risk of water stress and drought and found that two of our non-operated sites in Algeria and Egypt have the highest risk exposure for water stress and drought. See page 29 for more information.

We are committed to monitoring and reducing hazardous contaminants in discharges to water. To minimise adverse effects on the environment, we treat produced water prior to discharging. We conduct regular environmental audits at our sites to identify improvements and ensure the appropriate measures are in place.

Biodiversity

Our biodiversity strategy sets out our aim to restore, preserve and enrich biodiversity and ecosystems to achieve a net positive impact on biodiversity. It also commits us to avoid commencing new projects in areas of the highest value, including UNESCO heritage sites and IUCN I-IV protected areas. We participate in restoration projects and enhance biodiversity in each of the countries where we operate. Our strategy is aligned with IPIECA's six biodiversity and ecosystem services management practices, a set of guidelines on the effects, dependencies, risks and opportunities in the oil and gas sector.

Our environmental impact assessments include reviewing whether a site will be located close to or within a protected area. We seek first to avoid and then minimise, restore and offset any potential impact with appropriate site selection, project design and scheduling. We monitor our impact throughout the operation's lifespan.

In total, 17 of our operated assets are located within a protected area. We report on locations that are designated Ramsar, Natura 2000, IUCN I-IV and World Heritage sites. We identify the species under threat within these protected areas to shape the development of our plans. For example, our Cygnus site in the UK is in a designated protected area due to the presence of harbour porpoises. To mitigate any potential negative impact from drilling campaigns, we work within strict guidelines and avoid excessive noise during breeding seasons.

In 2023, we will use the Integrated Biodiversity Assessment Tool, developed by an alliance of environmental non-governmental organisations. This will enable us to gain further insights into biodiversity-related risks and to identify additional actions to achieve a net positive impact on biodiversity.

In Norway, we support the SEATRACK project, which tracks the movements of seabirds, taking into account migration routes and wintering grounds. The data can be used to assess our environmental impacts and to help us plan activities in less sensitive areas or time periods.

As part of our partnership with the SOS Dolfijn Foundation, we provided funding to support a rehabilitation centre for injured marine mammals, which opened in April 2022. We also worked with the foundation in planning the H_2opZee green hydrogen project to ensure we avoid known migration routes.

Decommissioning

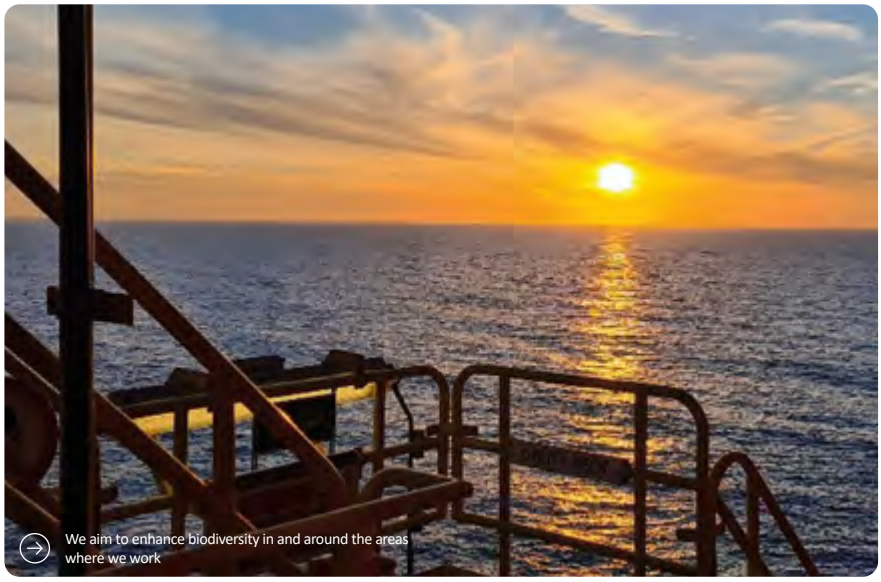
We consider environmental factors when decommissioning and closing a site. When onshore decommissioning wells, for example, we fill them in and dismantle the extraction and processing equipment. Well sites are cleared and refilled with topsoil to return the land to its original condition.

We support initiatives to promote economic development after site closure. We spent $29.1 million on decommissioning depleted fields and site restoration in 2022. We developed a conservation area at our Anzing 5 well site in Germany after site closure, in cooperation with the Bavarian State Forest. The area includes a meadow orchard and wetlands for amphibians.

Waste

We manage waste at all stages of our activities, from initial project planning to decommissioning. We require our projects and operations to establish waste management plans to prevent waste as the first priority, followed by options for reuse, recycling, treatment and disposal. We conduct inspections to ensure appropriate maintenance of waste storage, handling and disposal processes. Reusing infrastructure is a key part of our integrated energy hub strategy, which aims to drive decarbonisation by extending the life of assets and repurposing them to facilitate CO_2 storage (see page 24).

For full environmental performance data see *neptuneenergy.com/esg*



We aim to enhance biodiversity in and around the areas where we work

Our operations

Generating value

Our strong operational and financial performance in 2022 was underpinned by higher production, stronger prices and tight cost control. We focused on maximising safe and efficient operations to support energy security in our key markets, while progressing low carbon developments.

Production

135.0 kboepd

... reflecting restart of Snøhvit and a full-year's contribution from Duva



Reserves

~1 billion

... barrels of 2P reserves and 2C resources



Free cash flow

$1.7 billion

... up from $862.7 million in 2021



Our progress in 2022

Strong operating performance in 2022, materially higher production in 2023

- Good HSE performance, with lower total recordable injury rate and process safety event rate. Targeting further improvements in personal and process safety in 2023.
- Carbon intensity from operated production stable at 6.5 kg CO_2/boe, methane intensity of 0.02%. On track to hit 2030 targets.
- FY 2022 production increased to 135.0 kboepd, reflecting restart of Snøhvit and a full-year's contribution from Duva. Njord successfully brought onstream in December. Further improvement in production efficiency to 85%.
- Production guidance of 150-165 kboepd in 2023, supported by Njord ramp-up, start-up of Fenja (April) and Seagull (Q2) projects, and the restart of gas exports from Touat.

Lower carbon portfolio, low carbon developments

- Total investment since 2018 of more than $4 billion, delivering a material increase in total reserves and resources and production, and supporting energy security in Europe.
- 2P reserves of 552 mmboe at 31 December 2022, with a higher proportion of reserves developed. 2C resources increased to 468 mmboe, reflecting new licences and exploration success, and providing future growth opportunities.
- Reducing operational emissions through electrification. Gudrun project to be brought online in mid-2023. Submitted plans in December 2022 to electrify Snøhvit and Njord, increasing proportion of production electrified in Norway to 100% in 2028.
- Continuing to advance CCS opportunities in Norway, the Netherlands and the UK. FEED expected to commence at L10 CCS project in 2023, submitted CO_2 storage licence applications in the UK and Norway.

Growing cash flow, strong balance sheet

- Post-tax operating cash flow of $2.4 billion, EBITDAX of $3.9 billion and operating profit of $3.2 billion. Strong performance enabled dividend and capital distributions totalling $1.1 billion by Neptune Energy Group Limited.
- Total tax charge for 2022 of $2.2 billion, representing an effective tax rate of 70%.
- Net debt to EBITDAX of 0.44 times at 31 December 2022. RBL refinancing expected to be completed in the first half of 2023. Credit rating upgrades in 2022 from Fitch, Moody's and S&P.
- Guidance for post-tax operating cash flow of ~$2.0 billion in 2023 as higher production is offset by lower expected oil and gas prices and higher cash taxes.

Disciplined capital allocation, near-term growth

- Disciplined investment in 2023, guidance for development capex of ~$450 million and exploration and pre-development spend of ~$200 million. Further increase in spend on lower carbon projects.
- Focus on shorter cycle projects and near-term returns. Maturing new growth projects in Norway, the Netherlands and Indonesia.
- Exploration wells to be drilled at Cerisa, Yakoot and Geng North in 2023. Successful completion of Isabella appraisal well, evaluating results to establish commerciality.
- Higher cash taxes of ~$2.0 billion in 2023, reflecting the timing of our tax payments and impact of windfall taxes. Cash windfall taxes and royalties in the UK, the Netherlands and Germany are expected to total $105 million in 2023.

Leading ESG performance, socio-economic impact

- Strong ESG ratings received in 2022 from Sustainalytics and EcoVadis.
- New three-year roadmap to 2025 includes actions to meet our 2030 climate targets, along with actions to support a just energy transition.
- Estimated $4.8 billion of gross value added to GDPs in our European countries of operation, underlining the positive economic contribution from our investments, supporting jobs, supply chains and national tax revenues.
- Focus on delivering on our ambitious plans to store more carbon than is emitted through our operations and the use of our sold products by 2030.



99%

five-year reserves replacement ratio

Financial summary

Neptune Energy	2022	2021
Revenue ($m)	**4,640.1**	2,490.1
Operating profit before financial items ($m)	**3,180.6**	1,514.7
Profit before tax ($m)	**3,095.9**	1,392.4
Net profit after tax ($m)	**924.4**	387.2
Net cash flows from operating activities ($m)	**2,373.2**	1,696.8
Non-GAAP measures		
Total daily production (kboepd) (note a)	**135.0**	130.0
Total daily production (kboepd) including production-equivalent insurance income (note a, b)	**135.6**	148.3
Operating costs ($/boe) (note c)	**12.3**	11.3
EBITDAX ($m) (RBL basis) (note d)	**3,854.0**	2,109.3
Underlying operating profit ($m) (note e)	**3,151.2**	1,368.3
Adjusted development cash capital expenditure ($m) (note f)	**537.2**	635.8
Free cash flow ($m) (note g)	**1,685.1**	862.7
Net debt ($m) (book value) (RBL basis) (note h)	**1,690.8**	2,103.9
Net debt/EBITDAX (RBL basis) (note h)	**0.44x**	1.00x

a. Production figures are for wholly owned affiliates and equity-accounted affiliates.
b. Including business interruption insurance income, converted to a net entitled production equivalent.
c. 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 abandonment costs incurred on non-producing fields.
d. 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. EBITDAX, as defined by the RBL, includes our share of net income from Touat.
e. Underlying operating profit is calculated as operating profit/(loss) before the impact of impairment reversals/losses, restructuring costs and pension settlements or curtailments. A full calculation is shown below.
f. 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.
g. Free cash flow is calculated as net cash flow from operating activities less net capital investments during the period including repayments under leases. A full calculation is shown to the right.
h. 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 million and less the cash balance at 31 December 2022 of $234.1 million.

Underlying operating profit is calculated before the impact of impairment reversals/losses, restructuring costs, pension curtailment credits and certain one-off costs, as follows:

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)**	–
Impairment (reversal)/loss in share of net income/(loss) from investments using equity method	**–**	(32.2)
Impairment (reversals)/losses	**–**	(113.6)
Net restructuring (release)/cost	**(0.1)**	(0.5)
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

Free cash flow calculated as net cash flow from operating activities less net capital investments during the period including repayments under leases:

In millions of US$	Year ended 31 December 2022	Year ended 31 December 2021
Net cash flows from operating activities	**2,373.2**	1,696.8
Adjusted for:		
Expenditure on exploration and evaluation assets	**(110.1)**	(127.7)
Expenditure on property, plant and equipment	**(523.3)**	(619.4)
Net investment made in equity-accounted investments	**8.0**	(0.5)
Repayment of obligations under leases	**(85.8)**	(107.4)
Proceeds from sale of assets and subsidiary	**23.1**	20.9
Free cash flow	**1,685.1**	862.7



$3.2bn
underlying operating profit

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 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%.

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 carbon capture and storage (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.

Production

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

	2022	2021
Norway	**58.3**	45.7
UK	**15.4**	15.1
Netherlands	**18.4**	21.2
Germany	**17.5**	18.8
North Africa	**5.0**	8.7
Asia Pacific	**20.4**	20.5
Total production (kboepd)	**135.0**	130.0

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.



$4bn

investment since 2018*

* Includes development capex, exploration and pre-development spend, opex and abandonment costs.

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.

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, at 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 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.

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 from 50% at the end of 2021 to 55%. 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.



85%
production efficiency



11 years
reserves life

Group overview
continued

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.

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.

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.



14

discoveries since 2019

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 $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 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.



$1.2bn

cash taxes paid in 2022

Norway and the UK



Country overview – Norway

The Gjøa gas and oil field is powered using low carbon hydroelectricity and we have interests in another six producing fields. We brought Njord onstream in 2022 and expect to start-up Fenja in 2023.

Norway daily average production

Gas production
(kboepd)

2022	**25.4**
2021	20.2

Gas production for sale as LNG
(kboepd)

2022	**8.0**
2021	–

Liquid production[1]
(kbpd)

2022	**24.9**
2021	25.5

Total production
(kboepd)

2022	**58.3**
2021	45.7

1. Liquid includes oil and condensate and other natural gas liquids.



Country overview – The UK

Our Cygnus field is capable of supplying energy to the equivalent of two million UK homes. Seagull is an oil field in the Central North Sea and will come onstream in 2023. We also have a working interest in the Isabella discovery.

UK daily average production

Gas production
(kboepd)

2022	**15.1**
2021	14.8

Liquid production[1]
(kbpd)

2022	**0.3**
2021	0.3

Total production
(kboepd)

2022	**15.4**
2021	15.1

Norway and the UK
continued



Odin Estensen
Managing Director,
Norway and the UK

Norway

Production

In Norway, production averaged 58.3 kboepd in 2022, reflecting a strong operational performance, the restart of operations at Snøhvit and a full year of production from Duva, which was brought onstream in 2021. Production was higher at Gudrun, driven by completion of an infill and workover campaign. These gains were offset partially by the disposal of a portfolio of non-core assets, which was completed in March 2022 and accounted for 3.7 kboepd in the first quarter and contributed 0.9 kboepd as a full-year average.

In April 2022, we agreed with the Norwegian authorities to increase gross gas production from the Duva field by 6.5 kboepd to support energy security in Europe. The agreement has been extended until mid-2023.

Excluding planned shutdowns, production efficiency in Norway was 95% in 2022 and was our strongest performing region. Our process safety event rate remained better than target in 2022.

Since restarting operations in June, Snøhvit has performed well, averaging around 16 kboepd in the second half of the year. Plateau production will be prolonged by volumes from the Askeladd field, which was brought onstream in December 2022. The first phase of the Askeladd development was originally completed in 2020, however, start-up was delayed by the outage at the Hammerfest LNG facility. Development of the Askeladd Vest field will add further production capacity from 2025 and includes the drilling of two development wells.

In late December 2022, Njord was brought onstream, adding around 8 kboepd of net production to Neptune. The Hyme (March) and Bauge (April) tie-backs to Njord are due to start-up shortly, with net production from the Njord area expected to increase to plateau rates of around 20 kboepd at around the end of the year. The Neptune-operated Fenja field is expected to increase net production by an initial 6 kboepd, before increasing to plateau rates of 10 kboepd in the fourth quarter of 2023.

With start-up of Njord and Fenja and a full year of operations at Snøhvit, we expect production in Norway to average around 75 kboepd in 2023. Natural decline at Gjøa will be offset partially by improved production availability, following shutdowns in 2022 related to the third-party Nova tie-back, and higher deferral volumes. An infill well is planned to be drilled at Fram in the third quarter of 2023.

Our shutdown plans in 2023 include an extended maintenance programme at Fram in April to align with a shutdown at Troll. Short shutdowns are planned at Gjøa in March and September and at Gudrun in October.

Operating costs in Norway remained stable at $8.6/boe in 2022, as higher production in the period was offset by increased transportation costs, tariffs and CO_2 emissions taxes. We expect opex to remain around similar levels in 2023.

Development

In 2022, we completed development activities at our remaining two sanctioned projects at Njord and Fenja, with both projects expected to contribute to materially higher production in Norway in 2023. Our pre-development projects continue to mature as we progress several new opportunities towards sanction, which will help support longer-term growth.

At our Njord Future project, hook-up and commissioning activities were completed in the fourth quarter of 2022 and the field was brought onstream in late December. The Hyme tie-back is due to start-up in March and the Bauge tie-back in April. The Njord Future project includes the reactivation of eight existing production wells, previously shut-in, and the drilling of 10 additional development wells to help maintain plateau production. Three of the new wells are due to be drilled and brought onstream in 2023. The refurbishment of Njord is expected to extend the life of the facility until the 2040s, providing a potential hub for discoveries within tie-back distance.

We completed the development programme at our operated Fenja project in the third quarter of 2022. Production is scheduled to commence in April 2023 from both oil producing wells and has been delivered on budget. Fenja has been developed as a 36 km tie-back to Njord A.

In Norway, development capex declined to $252 million in 2022, reflecting completion of our remaining development projects during the year. We expect development spending to fall further in 2023, with investments mainly at Njord and Snøhvit.

Future growth in production is expected to be driven by our pre-development projects, particularly around our existing hubs. During 2022, we continued to evaluate recent discoveries, prioritising potential projects that create the most value and can offer shorter-cycle returns. Our key pre-development projects include Dugong, Echino South and Blasto, along with the recent discoveries at Hamlet and Ofelia.

At Gudrun, planning has commenced for the phase three infill programme, which is expected to commence in 2024. The Gudrun electrification project is close to completion and scheduled to start-up in mid-2023. The project is expected to reduce gross CO_2 emissions by approximately 60,000 tonnes per year.

The first phase of the Troll electrification project is due to commence in 2024, with full electrification planned in 2026, resulting in Fram also being electrified.

In December 2022, Equinor submitted plans for both Snøhvit Future Phases and the electrification of Njord. The Njord electrification project will be implemented in collaboration with OKEA, which is also electrifying Draugen. OKEA will develop the power infrastructure from shore to Draugen and Equinor will install a power cable connecting Draugen to Njord. On completion, approximately 60% of Njord A's and 100% of Njord Bravo's power requirements will be supplied by electricity. The project, which is expected to be completed in 2027, also includes Fenja and is expected to reduce gross CO_2 emissions by around 125,000 tonnes per year.

The Snøhvit Future Phases includes installation of onshore compression and full electrification of Snøhvit from 2028. The onshore compression project extends Snøhvit's plateau production for four years and is expected to be followed by offshore compression towards 2035.

The Snøhvit electrification project will connect Melkøya Island to the Hyggevatn substation and includes grid capacity upgrades. Electrification of the Hammerfest LNG facility, which is already one of the world's most efficient LNG plants, is expected to reduce gross CO_2 emissions by around 850,000 tonnes per annum from 2028, equivalent to 2% of Norway's annual emissions. The project will help extend the life of the LNG facility to around 2050.

Our electrification projects are expected to increase the proportion of our Norwegian production fully or partly powered from shore to 100% by 2028 from around 43% in 2023, contributing materially to our lower carbon energy production ambitions. At the Neptune-operated Gjøa platform, the carbon intensity is already low at 2.5 kg of CO_2/boe, substantially lower than the industry average. Electrification of our hubs will also lower the future carbon impact of our pre-development projects and help extend the life of key infrastructure.

In August 2022, we announced a partnership with Horisont Energi to develop the Errai CCS project. The project aims to store 4-8 million tonnes of CO_2 annually, with the potential to store more in later phases. An onshore receiving terminal for intermediate storage of CO_2 will be located in Gismarvik, on the west coast of Norway. CO_2 will be shipped from European and domestic customers, before being transported offshore through pipeline for permanent storage offshore. The Errai partners submitted a CO_2 storage licence application to the Norwegian Ministry of Petroleum in late 2022, with Neptune proposed as operator.

In February 2023, together with Horisont Energi, we signed an MoU with E.ON with the aim of developing a European CCS value chain, covering development, financing and funding. E.ON's participation will further contribute to the linking of CO_2 projects on the Norwegian Continental Shelf with development of a CO_2 offtake market in Europe.

Also in February 2023, together with Sval and Storegga, we applied for a CO_2 storage licence in the Norwegian North Sea for the Trudvang CCS project. Securing the licence would enable the companies to proceed with the Trudvang project which has the potential to store up to 9 million tonnes of CO_2 a year, equivalent to about 20% of Norway's total annual emissions.

Exploration

In 2022 we drilled three exploration wells, resulting in discoveries at the Hamlet, Ofelia and Calypso prospects. All three discoveries are located within tie-back distance to our hubs, providing fast-track development potential and lower operating and development costs.

In April, we announced an oil and gas discovery at the Hamlet prospect, with a side-track confirming the oil-water contact. Preliminary estimates of the size of the Hamlet discovery are 8-24 mmboe. In August, we announced a further discovery at the Ofelia prospect. The primary discovery is estimated at 16-39 mmboe, with an additional 10 mmboe of gas resources identified in the shallower Kyrre Formation. The discoveries at Hamlet and Ofelia confirm the significant resource potential of the Agat Formation in the Gjøa area, which had been proven initially in the nearby Neptune-operated Duva field.

In December 2022, we announced a new oil and gas discovery at the Calypso exploration well. The well encountered an 8 m gas column and a 30 m oil column with reservoir quality ranging from good to very good. Preliminary estimates of the size of the discovery are 6-22 mmboe and initial analysis indicates commercial potential. The joint venture has commenced a development study, which could include a tie-back to either Draugen or Njord A.

In 2023, we plan to drill four exploration and appraisal wells, including two further wells in the Gjøa area. An appraisal well at the Ofelia discovery will be drilled in the third quarter, followed by a well targeting the Cerisa prospect. The Cerisa prospect is located to the northeast of Gjøa and is targeting a similar play to Hamlet and Ofelia. Successful results from Ofelia and Cerisa will support fast-track developments of these discoveries.

In early 2023, we plan to drill the Eirik prospect, which is targeting the Brae Formation sands onlapping the Gudrun structure. The Mulder prospect is located close to Fram and is due to be drilled in June. Both wells are non-operated.

In January 2023, Neptune was awarded two licences in the APA 2022 licensing round, strengthening our positions around Gjøa and Fram.

The UK

Production

Production in the UK averaged 15.4 kboepd in 2022, reflecting higher production efficiency during the period, which improved to 84% from 72% in 2021. An annual shutdown was completed safely in August. During the second quarter, the Cygnus gas compression project started up and the system is being monitored to optimise future performance. In the UK, our HSE performance across the year was very strong with no recordable injuries.

In August we commenced a two well infill programme at Cygnus. The 10th Cygnus well was brought onstream successfully at the end of January 2023, with the 11th well due to start-up at the end of March. The new wells will help support production from the field in 2023, with further wells planned to offset natural decline and increase ultimate recovery. With the Seagull project due to start-up in May, we expect production from the UK to increase significantly in 2023, with further upside in 2024 as additional wells at Seagull are brought onstream.

An annual maintenance shutdown at Cygnus is planned in August, with a field outage due in April to coincide with hook-up of the 11th Cygnus well. We have identified several emission reduction opportunities at Cygnus, including fuel replacement and flare gas recovery, which are expected to deliver an annual reduction of up to 30,000 tonnes of CO_2 by 2028.

We continue to support plans for a permanent change in UK gas entry specifications, which is required to maintain reliable indigenous gas supplies into the UK and to unlock additional potential reserves and resources from the Southern North Sea.

Unit operating costs in the UK increased slightly to $9.6/boe in 2022, reflecting tariffs, National Transmission System charges and CO_2 emissions taxes. Operating costs are expected to remain around similar levels in 2023.

Development

We continued to make good progress at our Seagull project in 2022 and start-up remains on schedule. During 2022, the first development well was completed and tested successfully. Operations to complete the second well are ongoing. The two remaining development wells are expected to be drilled in 2023 and brought onstream in 2024. Initial production from Seagull is expected to be 12 kboepd net to Neptune from the first two wells, increasing to peak rates of 17 kboepd in 2024.

In the fourth quarter of 2022, a subsea campaign was completed, including installation of the subsea control module and flowmeter, umbilical hook-up and testing, pipeline tie-in and leak tests. The topside programme is now close to completion, with the final major equipment package installed on the ETAP platform and the Flotel demobilised. Topside completion is scheduled for the first quarter of 2023.

In September 2022, we submitted three applications for carbon capture and storage licences as part of a recent Carbon Dioxide Appraisal and Storage Licensing Round. Licence awards are expected by the end of the first quarter of 2023.

During 2022, we invested $109 million in development activities in the UK, with most of the investment at our operated Seagull project. We expect development capex to increase in 2023, reflecting the ongoing development of Seagull and our Cygnus drilling programme. We expect an increase in decommissioning activities at our non-operated CMS assets in 2023.

Exploration

At the end of 2022 we completed appraisal drilling at the Isabella discovery. Hydrocarbons were encountered in the Upper Jurassic and Triassic sandstone reservoirs and logs were acquired within each zone. Results from the well are being analysed to determine commerciality of the reservoir.

The Netherlands



Country overview

We are the largest gas producer in the Dutch North Sea, with key infrastructure providing scalable hubs for lower carbon opportunities.

Daily average production

Gas production
(kboepd)

2022	**17.4**
2021	19.9

Liquid production[1]
(kbpd)

2022	**1.0**
2021	1.3

Total production
(kboepd)

2022	**18.4**
2021	21.2

1.. Liquid includes oil and condensate and other natural gas liquids.



Lex de Groot
Managing Director,
The Netherlands

Production

Production from the Netherlands averaged 18.4 kboepd in 2022, reflecting expected declines from some of our mature fields and stable production efficiency. During the period strong performances were achieved at L5a-D, L15b, Q13 and the G blocks. The K2b-A8 side-track, brought onstream in September, continues to perform at better-than-expected rates. Output was lower than planned at E17a and F3. Our process safety event rate improved compared with 2021, with further progress targeted in 2023.

In 2023, we expect production to average slightly lower rates due to natural field decline. Workovers are planned at G14, K12, K2b, L10 and F3. We continue to mature potential infill opportunities, which could be drilled in 2024 and 2025. Planned shutdowns at the G blocks and L10-A Hub will result in seasonally lower production in May, with maintenance also planned at the L5-A platform in September and F3-FB in October.

Operating costs increased to $19.5/boe in the Netherlands in 2022, reflecting lower production volumes in the period. We expect opex per barrel to increase in 2023 due to lower production and industry cost inflation.

Development

Neptune operates several key hubs in the Netherlands, providing opportunities to add reserves and production through near field exploration and infill drilling. Discoveries at F17, Turkoois and Clover provide near-term growth projects, which we aim to mature during 2023. Our infrastructure also supports our longer-term lower carbon plans.

We continue to work with our partners to progress a development concept for the F17 development. Several development options are being considered, including a tie-back to the Neptune-operated F3 Hub. Concept selection is expected to be taken in 2023.

In 2022, we were awarded the L7 licence containing the Rhone gas discovery, which was originally discovered in 1974. An integrated field study identified significant potential in place resources and reservoir characteristics analogous to nearby producing fields. An appraisal well is due to be drilled in the second quarter of 2023, which will help reduce volumetric uncertainty and prove reservoir productivity prior to a development decision.

At the non-operated Turkoois discovery, an appraisal well drilled in 2022 helped narrow the potential resource range. The joint venture is considering a possible fast-track development option, along with an alternative joint development. A number of exploration prospects are being matured for drilling.

At the non-operated Clover discovery, we are evaluating a possible fast-track development concept, which could enable first gas in 2024. The development concept includes the reuse of an existing mini-platform tied back to a host platform nearby. Possible host locations include the Neptune-operated L15b-A and L10-A platforms.

We invested $30 million in development capex in the Netherlands in 2022 as we continued to focus on growth around our existing infrastructure. We expect investment to remain modest in 2023, before increasing in 2024 as we progress new development opportunities.

At our L10 CCS project, we finalised a cooperation agreement with our partners in June 2022 and continued to mature the project towards concept selection. We expect to submit a storage licence application in April 2023 and commence front-end engineering design in the second quarter of 2023. We continue to engage with emitters and progress the commercial framework.

In February 2023, with infrastructure owner CapeOmega, we announced NoordKaap, a project concept for a cross-border CO_2 storage solution for industrial emitters across Europe. NoordKaap would involve transporting CO_2 via vessels suitable for directly injecting the CO_2 at offshore locations and for terminal offloading. RWE has signed a Letter of Intent with CapeOmega and Neptune to assess the possibility of shipping CO_2 from its biomass Eemshaven facility for offshore storage in the Dutch North Sea.

The PosHYdon green hydrogen project continues to make progress, however, regulatory changes are required for the project to proceed. On behalf of the PosHYdon consortium, we are in discussions with the authorities regarding how these changes could be implemented.

In 2022, we prepared for a multi-well decommissioning programme starting in 2023. The Well-Safe Protector will be mobilised in the second quarter to commence a plug and abandonment campaign, extending into 2024, covering at least 21 wells located in Dutch and UK waters.

Exploration

We participated in three exploration wells in the Netherlands in 2022, resulting in new discoveries at the Clover and Pollux prospects. The F5-A well was unsuccessful. The N04-04 appraisal well targeting the Turkoois discovery encountered a separate gas column.

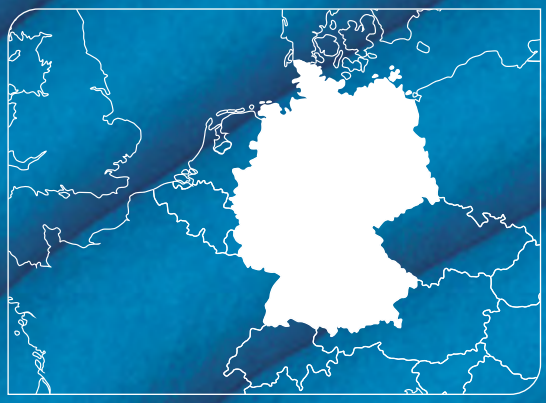
The Clover exploration well, which was drilled in the second quarter of 2022, encountered gas in good quality reservoir. The discovery is considered commercial and has fast-track development potential. A number of analogous prospects have been identified in the surrounding acreage, potentially adding considerable value to the development of Clover. In 2023, we plan to reprocess further 3D seismic covering the L10/L11 area, with additional wells likely to be drilled in 2024.

We are continuing to evaluate results from the Pollux exploration well, which encountered oil and gas within two reservoir intervals.

In 2023, we plan to participate in two wells, including an appraisal well at the L7-Rhone gas field and an exploration well targeting the E15-Maple prospect. The Rhone appraisal well, which is due to be drilled in the second quarter of 2023, will help narrow the resource range and prove reservoir productivity prior to possible development.

The Maple exploration well is due to be drilled in the first quarter of 2023 and is targeting a large shallow water Triassic target. A discovery could unlock further exploration potential in the surrounding area.

Germany



Country overview

With a presence in the country for more than 130 years, we operate and develop oil and gas fields with our partners in the northwest, east and south of Germany.

Daily average production

Gas production
(kboepd)



Liquid production[1]
(kbpd)



Total production
(kboepd)



1. Liquid includes oil and condensate and other natural gas liquids.



Andreas Scheck
Managing Director, Germany

Production

Production in Germany averaged 17.5 kboepd in 2022, reflecting a strong performance from the Adorf, Husum and Georgsdorf fields. Output was impacted negatively by the cessation of gas sales from the Altmark field in April. A gas-to-power project commenced at Altmark in May, but at lower equivalent rates. Production efficiency in Germany declined slightly to 88% in 2022. Our process safety event rate was better than our target level, however, several minor injuries led to an increase in our total recordable injury rate.

In 2023, production is expected to increase slightly as new production from wells drilled at the Adorf, Ringe and Römerberg fields is offset partially by natural decline at our mature fields. A workover programme is also planned at the Römerberg and Rühlermoor fields.

Operating costs, excluding royalties, increased slightly to $15.2/boe in 2022, reflecting lower production volumes during the period. Opex per barrel is expected to increase in 2023 due to inflationary pressures, as well as higher transportation tariffs, electricity costs, blend gas costs and planned workover activity. In 2022, we benefitted from renewable energy supplies for our operated production in Germany, reducing emissions by more than 11,000 tonnes of CO_2 per year.

Development

In 2022, we continued development of the Adorf field, with construction of a new well pad and the drilling of the Adorf-Z17 well. We expect to complete installation of the new gas processing plant in May 2023, enabling production to commence from Adorf-Z17 in the second quarter. The Adorf-Z18 well commenced drilling in January and is expected to be brought onstream in the third quarter of 2023, increasing output from the field to around 8 kboepd. We also plan to drill a new well at the Ringe field and two further wells at the Rühlermoor field.

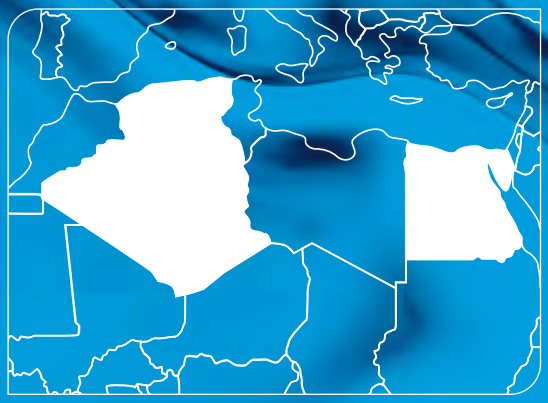
At our Römerberg field, the mining authority approved an increase in the production limit, allowing us to increase oil output to approximately three times the existing limit. We continued to mature plans for full development of the Römerberg field, which will include additional wells and an upgrade of the surface facilities. The plans will support increased production and the elimination of routine flaring. The Römerberg-6 well was brought onstream at the end of 2022 and tested at rates of up to 1,800 boepd. Planning is under way for the Römerberg-10 well, which is expected to be drilled in 2024.

Development capex in Germany increased to $61 million in 2022 as we continued to invest in development wells and infrastructure programmes. Investment in 2023 is expected to increase further as we continue to develop the Adorf, Ringe, Römerberg and Rühlermoor fields.

In 2023, our main decommissioning spend will be at the Reitbrook Alt, WEK, Emsland and Bentheim fields. Our mud pit reclamation programme is also continuing.

In the Saxony-Anhalt region, we have applied for a lithium production and exploration licence, which would enable us to evaluate the extraction of lithium from produced water. We are also exploring the potential for geothermal energy projects in the Rhine Valley and are in discussions with a potential strategic partner.

Algeria and Egypt



Country overview

As part of a joint venture with Sonatrach and ENGIE, we produce gas from the Touat plant in Algeria, which is an important source of supply for mainland Europe.

In Egypt, we have interests in oil and gas fields in the Western Desert and an operated exploration licence in the Gulf of Suez.

Daily average production

Gas production
(kboepd)

2022	**4.6**
2021	8.1

Liquid production[1]
(kbpd)

2022	**0.4**
2021	0.6

Total production
(kboepd)

2022	**5.0**
2021	8.7

1. Liquid includes oil and condensate and other natural gas liquids.



Mehdi Bouguetaia
Managing Director, Algeria



Alexandra Thomas
Managing Director, Egypt

Algeria

Production

The Touat processing facility remained shut-in throughout 2022 following the decision in November 2021 to stop operations as a precaution to enable 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.

A phased remediation strategy is being pursued, which will enable gas exports to recommence in April 2023. Additional upgrades to facilities will allow ramp-up to full production capacity in the third quarter of the year.

The construction of permanent facilities is expected to be completed in 2024 and will include additional mercury removal capacity in parallel with the existing facility. A further polishing unit will be located at export to guarantee the correct gas specification. As part of this process the cold box will be redesigned to ensure long-term operational integrity.

During 2022, considerable work has been undertaken to clean, inspect and repair the gas processing plant. A number of issues, which had previously impacted the performance of the plant, have been resolved. The organisational structure has also been enhanced to improve operational performance.

Reported production of 2.3 kboepd in 2022 reflects compensation for gas produced from the Sbaa field.

We achieved significant improvements in our health and safety performance in Algeria, embedding good practices and stronger leadership. We are targeting further improvements in 2023 through raising risk awareness and compliance.

Development

Capital expenditure associated with Touat was $15 million in 2022, reflecting repairs to the mercury removal unit. Investment in 2023 is expected to increase as we execute plans for permanent facilities to improve the performance and reliability of the plant and to commence FEED for the phase two development plan, including debottlenecking and other plant upgrades. The phase two development plan will extend plateau production until the 2030s and includes drilling 16 new production wells.

Egypt

Production

In Egypt, production averaged 2.7 kboepd in 2022, reflecting delays to the planned oil infill programme and Karam gas well, in addition to lower than expected gas production from the Karam-11 well. The Karam-12 oil well, which was brought onstream in September, demonstrated strong productivity from the ARG formation, contributing to higher production in the fourth quarter. Six other wells were brought onstream in 2022 and we continued to deliver positive results from our workover programme.

In October 2022, we accelerated the switch of Karam gas to medium pressure operation to enable new light oil wells to be tied into our gas manifold, minimising flaring. We plan to maintain production in 2023 through an active programme of new wells and workovers.

Our health and safety performance in Egypt was excellent, with no total recordable injuries.

Operating costs in Egypt increased to $9.6/boe in 2022, reflecting lower production volumes and higher production and diesel costs. Operating costs are expected to remain at similar levels in 2023.

Development

We invested $13 million of development capex in 2022 and expect expenditure to remain at similar levels in 2023. As part of our programme, we expect to drill up to 10 development wells at our Assil, Bahga, Magd and Karam fields.

Exploration

In mid-2023 we plan to drill the Yakoot prospect, which is located in the North West El Amal Concession in the southern Gulf of Suez. This is Neptune's first operated well in Egypt and is targeting a structural trap located in shallow water. A number of other leads and prospects have been identified within the licence, providing further upside potential.

In the Alam El Shawish West Concession, we plan to drill the Assil C104 prospect in the third quarter of 2023.

Indonesia and Australia



Country overview

In Indonesia, working with Eni and other partners, we produce LNG for export to the region under long-term contracts, as well as gas for the domestic market to help meet the country's growing energy needs.

In Australia, we are evaluating development concepts for Petrel, a large gas field located in the Timor Sea, which is one of the main gas-producing regions in Australia.

Daily average production

Gas production
(kboepd)

2022 5.5
2021 5.4

Gas production for sale as LNG
(kboepd)

2022 14.6
2021 14.7

Liquid production[1]
(kbpd)

2022 0.3
2021 0.4

Total production
(kboepd)

2022 20.4
2021 20.5

1. Liquid includes oil and condensate and other natural gas liquids.



Eko Lumadyo
Managing Director,
Asia Pacific

Indonesia

Production

Production in Indonesia remained stable in 2022, averaging 20.4 kboepd. During the year we continued to manage output from the Jangkrik and Merakes fields, maintaining gas throughput at close to capacity of the Jangkrik FPU. Gas demand in the region remains strong, enabling several spot cargoes to be sold in the period.

In the second half of 2022, we commenced a three well side-track programme, which is expected to help maintain gas exports at similar levels in 2023. The Jangkrik-12ST was successfully brought onstream in October, followed by the Merakes-7ST in December and the Merakes-6ST in February 2023. All three wells are performing as expected. Additional workover activity is expected to reduce production slightly in the first quarter of 2023, with further downtime planned in the third quarter for maintenance.

Our health and safety performance in Indonesia was excellent with no total recordable injuries.

Operating costs increased slightly to $10.9/boe in 2022, reflecting good cost control in the period. At the Bontang LNG facility, technical adjustments implemented in the second quarter of 2022 have helped reduce requirements for C3/C4 blending, partially mitigating industry cost inflation. We expect an increase in opex in 2023 due to the execution of maintenance projects and ROV operations.

Development

We continued to progress development plans for the Maha and Merakes East fields in 2022, with both fields due to be developed as tie-backs to the Jangkrik FPU. The plan of development for the Merakes East project was approved in December 2022, with first gas anticipated in 2025.

At the Maha project, we expect to submit a plan of development in the first half of 2023, subject to finalisation of the unitisation agreement. Geotechnical studies and FEED are due to commence in the second half of 2023. First gas is anticipated in 2026.

The Jangkrik booster compression project has been deferred.

Development capex in Indonesia decreased to $58 million in 2022, reflecting completion of the Merakes project in 2021. Investment levels are expected to increase in 2023 and 2024 due to the start of development activities at Merakes East and Maha.

Exploration

In mid-2023 we plan to drill the Geng North exploration well, located in the North Ganal licence. The deep water well will target a large multi-Tcf gas prospect, with standalone development potential in a success case. The prospect is de-risked by amplitude anomalies showing good conformance to structure and consistent with gas-bearing sand. A number of follow-on prospects provide further upside potential in the surrounding area.

Australia

Exploration

We continue to evaluate opportunities to enhance the Petrel project and improve project economics. The East Coast and Northern Territories gas markets strengthened in 2022 and a number of parties have expressed appetite for gas from the Petrel field, particularly given that adjacent gas fields are showing high depletion rates. An ROV survey of the Petrel wells was completed in November. An application for the renewal of the Petrel Titles was submitted for a further five-year term and the renewals are pending a joint authority decision.

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	**3,095.9**	1,392.4
Taxation charge	**(2,171.5)**	(1,005.2)
Net profit after tax	**924.4**	387.2
EBITDAX (RBL basis) (note c)	**3,854.0**	2,109.3
Net cash flows from operating activities	**2,373.2**	1,696.8
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 72.

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 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.

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 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

Financial review
continued

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 $84.7 million (2021: $122.3 million) for the year and main components include $117.4 million (2021: $119.4 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 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 $3,095.9 million (2021: $1,392.4 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	**3,095.9**	1,392.4
Add back:		
Net financing expenses	**84.7**	122.3
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 70.1% (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 $2,268.1 million and the actual tax charge of $2,171.5 million.

Net profit after tax for the year ended 31 December 2022 was $924.4 million (2021: $387.2 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.

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.

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 $2,373.2 million (2021: $1,696.8 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.

Financial review
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.
- $850 million 6.625% senior notes, maturing in 2025.
- $100 million 7.250% Subordinated Neptune Energy Group Limited vendor loan with ENGIE E&P International S.A., 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 $2,373.2 million (2021: $1,696.8 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 $1,673.6 million (2021: $939.1 million) primarily consists of:

- The settlement of $1,146.8 million of dividends to parent company.
- Net repayment of borrowings of $526.8 million (2021: $60.9 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 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.

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 risk management section (see pages 79-83).

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 parent company and 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 9 December 2022, the Board of Directors of Neptune Energy Group Midco Limited declared and paid an interim dividend of $1,146.8 million to its immediate and ultimate parent, Neptune Energy Group limited (NEGL). This enabled NEGL on 12 December 2022 to declare and settle both an interim preference dividend of $96.8 million and a capital redemption settlement of $1,049.9 million to the ultimate shareholders of NEGL.

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

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 the 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.



Armand Lumens
Chief Financial Officer
8 March 2023

Risk management

Maintaining business resilience in a volatile external environment

High external volatility, whether geopolitical, economic, fiscal or regulatory, continues to pose new challenges to our business. Under such circumstances, maintaining business resilience is a strategic imperative and structured risk management enables us to understand ongoing and new threats, while continuing to deliver our vision and strategy. Effective risk management helps us to identify potential hazards, uncertainties and scenarios, and take them into account when we make decisions. Our risk approach allows us to balance the way we identify and understand emerging risks with a relentless focus on ongoing risks, such as the health and safety of our workforce and process safety of our installations.

Our strategy, which is discussed and approved by the Board, guides the organisation in considering the risks we face when pursuing business opportunities. This helps us decide which risks to take to increase business value, which to avoid as they destroy value, and which to mitigate.

Summary of developments in Neptune's risk profile in 2022

At the start of 2022, the risks associated with the COVID-19 pandemic began to ease after successful national vaccination roll-outs. However, this was quickly disrupted by the Russian invasion of Ukraine in February. Neptune Energy was not exposed directly to Russia and the impact on Neptune was limited. However, our resilience was tested again as we faced increased volatility in commodity and financial markets, supply chain disruption, cost inflation and increased fiscal burden, as well as greater geopolitical instability. We also navigated various changing economic sanctions imposed primarily by the US, EU and UK on Russian entities and individuals, which had the potential to affect Neptune indirectly.

Fast-paced changes in fiscal and energy policies introduce significant uncertainty around future returns in a capital-intensive business like Neptune. While security of oil and gas supplies overtook green recovery and transition concerns in the short term, we remained focused on climate change-related risks to ensure we understand and manage potential physical and transition consequences to our business.

Rallying oil and gas prices in 2022 significantly reduced inherent risks to our liquidity position. However, commodity price volatility increased business planning and hedging risks. On the other hand, higher hydrocarbon prices improved joint venture partner resilience and eased host country fiscal pressures, reducing our counterparty exposures.

Our principal risks

For details on particular risks please see pages 79-83.



Improve

1. Host country and investor policy and regulation changes in Europe in response to climate change/energy security
2. People competence and capability gap
3. Drilling safety and performance
4. Malicious damage to Neptune assets or critical third-party infrastructure in Europe

Manage

5. Replenishment of reserves
6. Production loss impairing external market outlook
7. Adverse outcome from LNG contract renegotiations
8. Cyber attack on information systems
9. Ability to access competitive low carbon technology projects
10. Breach of ethics and compliance requirements
11. Business continuity preparedness
12. Market inflation and supply shortages

Monitor

13. Significant oil/gas price volatility
14. Health, safety or environmental incident
15. Inability to access capital markets
16. Liquidity
17. Climate change class action/litigation
18. Unfavourable changes in fiscal regimes

Operate

19. Physical impact of climate change

Despite external volatility, Neptune remained resilient throughout 2022 and we were able to address ongoing risks around safety, production, reserves replenishment, exploration and projects.

We keep our risk register current and in 2022 added a number of new risks to our enterprise risk register, while moving a number of risks down as their relative significance reduced. Such risks are moved into functional or country risk registers and monitored at that level. In 2022, these were risks associated with the COVID-19 pandemic due to reduced inherent exposure, external financial reporting errors as a result of adequate mitigation, and political instability in North Africa due to the reduction of risk to tolerable levels.

Climate change-related risks

Climate change-related risks remained a significant and important part of Neptune's risk profile. These risks are essential elements of Neptune's strategic, stakeholder, people, health, safety, environment and quality (HSEQ) and compliance risk categories.

Despite the current focus in Europe on energy security and affordability, the Board recognises the strategic importance of risks relating to climate change, as well as the opportunities presented by the energy transition. We identify, assess and manage climate-related risks through our enterprise risk management system. We will continue to review and develop the risks and opportunities resulting from climate change beyond 2022. This will include a particular focus on our strategic ambition of storing more carbon than is emitted from our operations and the use of our sold products by 2030.

In 2022, we maintained four risks relating to climate change:

1) Risks relating to host country and investor policy and regulation changes in response to climate change.
2) Risks relating to the ability to access competitive low carbon technology markets.
3) Risk of increased litigation across the oil and gas industry.
4) Risks associated with the physical impact of climate change.

We provide more detailed descriptions of these risks in the principal risks section and elaborate on them on page 28.

Emerging risks

In 2022, we continued to monitor the risk of inflation in the cost of materials, caused by the Russian war against Ukraine and ongoing major disruptions, triggered by events such as the COVID-19 pandemic and the Suez Canal blockage in 2021.

We recognise that there is still a potential threat of global political and security instability with more conflict areas opening up or older disputes re-emerging – all of which can cause further damage to commodity prices, financial markets and supply chains.

We have previously identified that, over the medium term, our ability to attract and retain talent may be adversely affected by changing sentiment towards the oil and gas industry. With the ramp-up in oil and gas activity globally and historic underinvestment in oil and gas, we have identified the risk of losing capability in the industry. There is also potential for increased competition for talent in the medium to longer term. As well as affecting our business delivery, this could have an impact on the safety of that delivery. As such, it is treated with the utmost importance at all levels of Neptune leadership and has been added to our enterprise risk register (see page 79).

While we may not always be able to prevent or influence emerging risks, we recognise the importance of sound risk governance, organisational culture and risk management processes to help us to tackle emerging risks if they materialise.

Emerging risk	Description	Response
Deterioration of geopolitical and security environment	The Russian invasion of Ukraine resulted in significant shifts in the global political and security environment. We recognise there is potential for the conflict to further escalate, as well as the opening up of new, or revival of past, conflict areas – all of which may create further global instability, and, in turn, affect markets and supply chains.	We monitor the situation and maintain business resilience, keeping safety as the top priority, always.
Hybrid workforce disparities	We see a shift in working patterns across the business with more of our people moving to hybrid working arrangements. This flexibility adds to Neptune's attractiveness as an employer of choice. However, in the longer term, it may have a potential negative impact on people development, inclusion and capability, particularly among recent hires.	We provide clear guidance in all locations for hybrid working arrangements. We run an annual engagement survey to assess staff sentiment and perceptions towards Neptune. We also monitor the situation in larger organisations, which are more susceptible to those risks, in order to learn from their experiences.
Changes to requirements for decommissioning security arrangements (DSA)	In certain jurisdictions, regulator attitudes towards DSA requirements are subject to change and require bank guarantees or cash collateral in lieu of parent company guarantees. This could increase the financial costs of such securities, but also damage credit facilities that Neptune maintains with banks, limiting banks' funding capacity.	We engage with relevant regulatory bodies and governments to provide Neptune's perspective on the impact that the change in DSA arrangements may have on our ability to invest.
Increased scrutiny on climate change disclosures	With the focus on climate change rising every year, disclosure requirements and scrutiny also increase. Some of the disclosures may introduce additional complexity, increasing the risk of error, which may result in future liabilities.	Our published Basis of Reporting and Assurance of Non-Financial Data states the parameters for our non-financial disclosures. It also defines the levels of assurance the Board requires with regard to these disclosures. All disclosures are required to be assured internally by respective Functional VPs. Furthermore, disclosures required by law need to be audited externally, while voluntary disclosures are assured by Group internal audit on a three-year rolling basis. Any new disclosure requirements are monitored and assessed for impact both for data collection and validation as well as independent assurance.

How we manage risk
continued

Our risk management approach

Risk management is integrated in the way we think, plan and act as a business. Our common risk management process is embedded in everything we do, from capital allocation to individual operational activities, which allows us to continuously and consistently analyse and make appropriate risk-informed decisions.

The Board exercises its oversight of risks and the risk management process via our Audit and Risk Committee. The committee oversees and discusses key enterprise risks at a strategic level and monitors the effectiveness of Neptune's enterprise risk management process. In 2022, Group internal audit assessed the maturity of our enterprise risk management process using Gartner's benchmarking methodology. It confirmed that our risk management process and systems are designed to meet business needs and provide leadership teams and individual risk owners with analysis that helps them identify and manage their respective business risks. Neptune's culture supports the risk process by promoting speaking up and diversity of thought, which contribute to the identification and assessment of potential threats, allowing us to take optimal risk response action.

The Audit and Risk Committee regularly reviews Neptune's enterprise risk portfolio following a review by the executive-level Enterprise Risk Committee. This enables the committee to better understand the risk profile and interdependencies between the risks, and to get assurance over alignment between the Board, our Executive Team and risk owners.

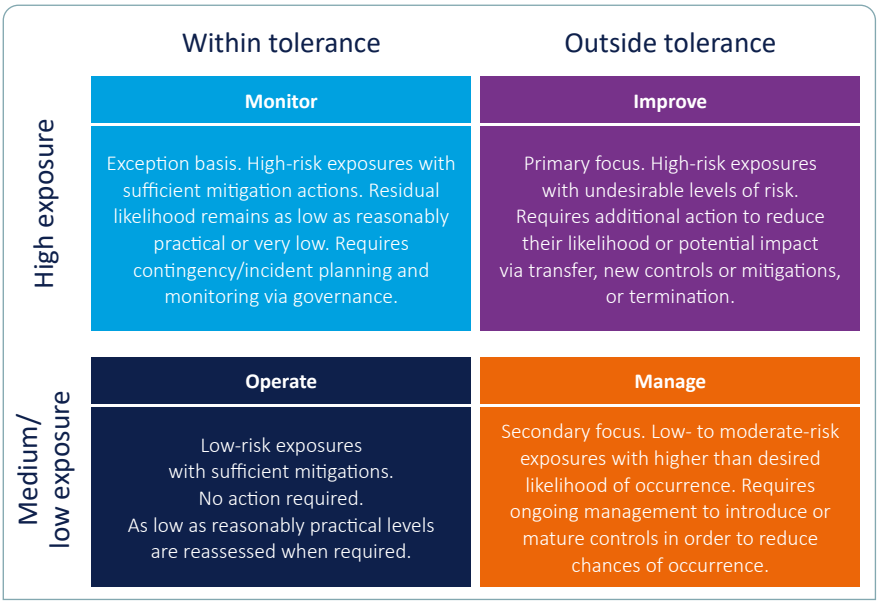
At a country level, each business maintains its top country risk registers, which country leaders review regularly. These registers are also embedded in our business planning and business performance reviews, during which they are also reviewed and challenged by the Executive Team.

Top country risk registers are based on functional, asset and project-level risk registers, which are fundamental to effective bottom-up risk identification.

Oversight responsibilities for other Group-wide risks are delegated to other committees or cross-functional teams to ensure the right level of expertise and focus. For information on these committees, see pages 94-95 and 99.

The regular conversations in these committees are key to keeping the organisation focused on the risks that matter both in the short term and over a longer-term planning horizon. They are also fundamental to ensuring we consider diverse views on risk in order to reduce personal bias or groupthink.

How we prioritise risk conversations across Neptune



A risk management calendar is supported by a network of risk coordinators who support their Country Managing Directors and Functional VPs in ensuring a strong focus on risk is maintained.

While it is essential that our leaders focus on risk management, we expect everyone at Neptune to manage risks in their respective areas of responsibility.

The Risk Management Policy and the Group Risk Management Standard set out the Board's expectations on sound risk management processes, as well as common risk management principles. These provide the foundation for Neptune's integrated management system, which defines how we manage particular risks.

Each risk is owned by an individual who is responsible for assessing, controlling and mitigating it. Risk owners are accountable for implementing effective risk reduction actions when required.

Risk owners follow a common risk management process to identify risks and the effectiveness of existing risk mitigations.

Using our common risk assessment criteria, risk owners assess the current level of probability and potential impact of each risk. If a risk is assessed as too high, then we identify further risk reduction measures to bring the risk to the target/acceptable level.

We classify risks into one of four categories: improve, manage, monitor and operate (as shown above). On one dimension, our improve and manage categories represent risks that are outside our risk tolerance and require action to be taken to either reduce their probability or impact to a tolerable level. Our monitor and operate categories are risks that are at tolerable levels and have sufficient levels of mitigation and controls in place. On another dimension, improve and monitor risks are more significant than the risks in our operate and manage categories. This categorisation helps us prioritise risk discussions and help leaders focus their time on the risks that require their attention, support or awareness.

All enterprise risk information is stored in a single system and is available to leadership teams in real time, via interactive risk dashboards. This allows them to perform relevant risk analyses and generate additional functional or business risk insights. We monitor further risk reduction actions through the system and report on them to the Audit and Risk Committee regularly to ensure we act on opportunities to reduce Neptune's risk exposure.

Principal risks and uncertainties

Risk	Risk category	Link to KPIs	Mitigation	Risk change during 2022
Improve **Primary focus. High-risk exposures with undesirable levels of risk. Requires additional action to reduce their likelihood or potential impact via transfer, new controls or mitigations, or termination.**				
① **Host country and investor policy and regulation changes in Europe in response to climate change/ energy security** Host country energy and fiscal policies may undermine Neptune's strategy, add cost and reduce profit margins. They may ultimately challenge the economic viability of projects/assets. Governments may decide not to sanction new licences for gas and oil exploration in order to reach their climate goals. This may affect a country's licensing policies and lead to more stringent regulatory regimes that could negatively affect Neptune's ability to grow, fund and sustain its business.	Stakeholder/Country and government	1, 3, 7, 8, 9, 11, 12	Our gas-weighted portfolio supports the energy transition, while our 2030 ambitions align with longer-term global targets. We engage with respective host countries and investors to ensure the right balance between security, affordability and low carbon intensity of energy supplies.	➡ Security and affordability of oil and gas supply in the short term took over green recovery in light of the Russian invasion of Ukraine and the economic sanctions imposed by the EU, US and UK, including restrictions on imports of Russian oil and gas. The profitability of the industry, and attractiveness to potential investors, was challenged by rapidly changing fiscal and regulatory regimes, which increased risk for new developments. However, the energy transition creates opportunities for investments in electrification, CCS and hydrogen.
② **People competence and capability gap** A gap in people competence and capability in our operated assets and among key subcontractors may hinder growth and safety performance. Global industry growth may increase competition for talent and lead to a loss of capability and/or supplier competence, exacerbating the risk further.	People	1, 5, 9	We have in-country hiring and competency assessments for staff, and contractual vendor competency and performance management, in place.	**NEW** We developed a Group-wide competency assurance management standard covering all operational activities. An overall competence improvement roadmap was put in place. We evaluated gaps associated with competency attainment and developed dedicated country-specific plans. We reviewed tendering and sourcing standard and supplier management standard to address competence evaluation of third parties specifically.
③ **Drilling safety and performance** The rapid ramp-up of drilling activities across Neptune, use of multiple drilling contractors and the move into higher-risk drilling activities create a risk of a safety incident, including a major well incident.	Health, safety, environment, climate	5, 6	We have in-country drilling barrier management and emergency preparedness planning in place. We conduct operational readiness assurance.	**NEW** We are enhancing our drilling and wells assurance framework for future drilling activities, with targeted risk assurance on rig start-up and operational readiness. We will conduct a global drilling and wells activity risk assessment as the basis for further risk reduction measures.
④ **Malicious damage to Neptune assets or critical third-party infrastructure in Europe** Following the damage to the Nord Stream pipeline and power supply disruption in Germany, there is a risk of a major security incident at our operated and non-operated assets, or critical third-party infrastructure, as a consequence of increased geopolitical instability. In the worst case, this could result in catastrophic damage to an installation and loss of life.	Health, safety, environment, climate	1, 6	We follow state response plans to prevent, detect and respond to any security threat onshore and offshore. We have insurance policies in place. However, under certain common exclusions, cover may be restricted.	**NEW** We seek assurances from the respective state agencies on their preparedness. We seek similar assurances from non-operated ventures and critical third-party infrastructure providers. We manage employee communications and engagement proactively to reduce potential anxiety.

How we manage risk
continued

Risk	Risk category	Link to KPIs	Mitigation	Risk change during 2022
Manage **Secondary focus. Low- to moderate-risk exposures with higher than desired likelihood of occurrence. Requires ongoing management to introduce or mature controls in order to reduce chances of occurrence.**				
⑤ **Replenishment of reserves** We may be unable to replenish our resource base and reserves, which may prevent sustained levels of production in the longer term and, therefore, affect Neptune's strategic targets.	Business/Portfolio	1, 3, 4	We have a strategic country focus on reserves replacement. Our Investment Committee selectively approves best development opportunities. We screen opportunities continuously for selective acquisitions.	➡ We continued to increase reserves through the acquisition or maturation of resources. At the end of 2022, our 2P reserves were 552 mmboe. Over a five-year period, from the inception of Neptune, our reserves replacement ratio is 99%. Our 2023 exploration budget provides capital for several opportunities in the pipeline and participation in new acreage licensing rounds to refill our exploration portfolio.
⑥ **Production loss impairing external market outlook** We may be unable to meet the production target range advised to stakeholders.	Business/Operational	1, 2, 10, 11, 13, 14	We have loss of production insurance in place for key production assets, applicable under insurance industry standards. We carry out regular production monitoring and reporting.	➡ We increased production to 135.0 kboepd, reflecting 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 was at the lower end of guidance. Neptune was, however, able to recover part of the lost value and cost through its insurance cover.
⑦ **Adverse outcome from LNG contract renegotiations** Our LNG contracts, particularly in Indonesia, Algeria and Norway (Snøhvit) are renewed from time to time and, depending on expected market conditions, may expose Neptune to price reviews, which may result in lower prices.	Stakeholder/ Customers	11	The Board monitors LNG contract management. In case of renewals, we ensure early planning and negotiation strategy preparations are in place with regular Steering Committee oversight and reporting to the Board. We have senior stakeholder engagement with relevant counterparties.	⬇ High volatility of gas prices contributed to the complexity and uncertainty of outcomes of the price renegotiation, mediation and arbitration processes.
⑧ **Cyber attack on information systems** Malicious attacks on information systems, networks or operating systems may lead to their unavailability, lack of access to systems, loss of data and outages.	Information systems/ System security	1, 2, 6, 10	Security standards are defined and used by Group-wide assets. We conduct regular risk assessments and vulnerability scanning. We review and refine the effectiveness of our cyber security barriers continuously. Our cyber security team carries out an ongoing programme to assure compliance with the respective cyber security standards.	➡ General level of cyber awareness in Neptune has risen. However, the level of underlying threat remained high against the backdrop of the Russian invasion of Ukraine.

Risk	Risk category	Link to KPIs	Mitigation	Risk change during 2022
⑨ **Ability to access competitive low carbon technology projects** The gap between European governments' decarbonisation policies and relevant regulation, plus uncertainty around fiscal/economic regimes for low carbon projects, as well as increased competition from new entrants may reduce the commercial attractiveness of projects. This may, in turn, reduce Neptune's attractiveness to potential investors, increase the cost of financing and undermine Neptune's 2030 carbon ambitions. Given the role of CCS in our low carbon strategy, if we are unable to access decarbonisation projects, we may become less resilient to future changes in climate change-related laws and regulations.	Strategy/Business model	7, 8, 13, 14	We have a lower carbon strategy in place. We are progressing a pipeline of projects, in line with our strategy, to ensure the long-term viability of projects.	➡ Competition for low carbon projects is increasing, which may reduce their attractiveness. We observed additional interest in Neptune's low carbon projects. We submitted applications for new CCS projects in the UK and Norway and are progressing a number of low carbon opportunities in the Netherlands. See pages 24-25 for more information.
⑩ **Breach of ethics and compliance requirements** A breach of ethics and compliance requirements could lead to reputational loss, financial losses, additional costs and civil and/or criminal liabilities.	Compliance/Ethics and conduct	11	Neptune policies and standards outline our requirements on ethical conduct and compliance. We provide regular compliance training and awareness campaigns for employees, contractors and suppliers. We have third-party due diligence screening in place. We have an ethics whistleblowing hotline and misconduct and loss investigation processes in place.	➡ We have largely implemented a longer-term compliance programme, having deployed our refreshed Company-wide Code of Conduct, e-learning and annual certification.
⑪ **Business continuity preparedness** Current country/site business continuity plans may not be adequate to respond to certain new risk scenarios.	Business/Operational	1, 11	We have agreed our business continuity planning model with the CEO. We have business impact assessments in place with service levels agreed. We carry out periodic scenario testing.	➡ We have been consolidating our Business Continuity Policy and Standard and will finalise that work in 2023.
⑫ **Market inflation and supply shortages** Increased inflationary pressures may lead to increased costs of goods and services, which, in turn, could lead to higher opex and capex. Also, Neptune may suffer from supply shortages due to logistics problems caused by global market disruptions. This may affect the delivery of projects and efficiency of operations.	Stakeholder/Supplier	2, 10, 11, 12	We monitor market intelligence regularly to understand potential inflationary effects. We engage with key suppliers.	⬇ We factor inflation risk into business plans and budgets. However, increased and more unreliable lead times may occur, which can lock up working capital and cause disruption to operations and delays to project timelines.

How we manage risk
continued

Risk	Risk category	Link to KPIs	Mitigation	Risk change during 2022
Monitor **Exception basis. High-risk exposures with sufficient mitigation actions. Residual likelihood remains as low as reasonably practical or very low. Requires contingency/incident planning and monitoring via governance.**				
⑬ **Significant oil/gas price volatility** Profits could be affected by movements in oil and gas prices. If left unmanaged, this has the potential to put the solvency of the Company at risk.	Financial/Market	3, 4, 11, 13, 14	We actively manage this risk by executing our hedging strategy. This is overseen by the Board and targets a minimum hedge ratio of 50%, 30% and 15% for years one, two and three.	⬆ Extreme commodity price volatility continued throughout 2022 with crude fluctuating between $80 and $120. TTF gas averaged €123/MWh but touched a low of €70/MWh and a high of more than €300/MWh over the year. While overall higher commodity prices contributed to a significant reduction in debt, the extreme volatility put pressure on business planning, effectiveness of hedging and use of credit lines with banks.
⑭ **Health, safety or environmental incident** Risk of a health, safety or environmental incident leading to loss of life, loss of reputation and additional costs and liabilities.	HSE/Health, safety and security	5, 6, 10, 11	We have an ongoing programme to maintain and reinforce our safety culture throughout Neptune. We have rolled out a process safety fundamentals programme to employees and contractors.	➡ We observed a decline in HSEQ performance across the industry caused by underinvestment in personnel. We addressed this by enhancing our training and competency arrangements, and maintaining our focus on safety.
⑮ **Inability to access capital markets** Neptune may be unable to access debt capital markets or equity capital markets, which may affect capital structure, funding and financing costs.	Financial/Liquidity and solvency	14	Group Treasury monitors the market continuously in order to remain in a state of preparedness.	➡ The bond markets reopened but were volatile. Margins increased for all credit ratings. ESG considerations continue to increase. This could have an impact on our medium and longer-term access to capital, as well as the cost of capital.
⑯ **Liquidity** Neptune may not be able to service its debt and pay its suppliers as invoices become due.	Financial/Liquidity and solvency	14	We have a Treasury Policy in place. Group Treasury monitors the market continuously to remain in a state of preparedness should new funding needs arise.	⬇ We reduced our net debt. We completed our borrowing base redetermination successfully, with value remaining at $2.3bn until March 2023.

Risk	Risk category	Link to KPIs	Mitigation	Risk change during 2022
⑰ **Climate change class action/litigation** Since 2019, there has been a rise in climate-related litigation globally against major carbon emitting corporations, including oil and gas majors and states. Litigation of this kind may increase in frequency with the potential to affect the business, both financially and reputationally.	Compliance/Legal, Contract/Disputes HSE/Environment/ Climate change	10	We monitor climate change-related litigation and receive legal advice on the potential future impact on the industry and our business.	➡ A number of high-profile climate change-related court cases, unrelated to Neptune, are being pursued in numerous jurisdictions. Any adverse measures introduced in response to the outcomes of such litigations may become common in the industry. This could increase the Group's costs significantly, limit its ability to develop new reserves, decrease the value of its assets, or reduce the demand for hydrocarbons and refined petroleum products.
⑱ **Unfavourable changes in fiscal regimes** Governments in tax jurisdictions introduce changes to the fiscal regimes that govern Neptune's business, resulting in increased taxes, duties and levies.	Stakeholder/Country, government/ Fiscal change	13	We engage with respective governments and industry groups.	**NEW** The risk has been elevated to enterprise level in 2022 and was largely realised with windfall taxes introduced in the UK, the Netherlands and Germany and changes to the temporary tax regime in Norway. The risk remains since governments continue to change their fiscal policies in response to the volatile external market environment.
Operate **Low-risk exposures with sufficient mitigations. No action required. As low as reasonably practical levels are reassessed when required.**				
⑲ **Physical impact of climate change** The potential for, and adverse impact of, more frequent severe weather conditions, rising sea levels and other physical effects on our operating installations and future projects could rise.	HSE/Environment/ Climate change	10	We hired a consultancy to conduct a physical climate change assessment covering 10 key assets.	➡ No significant change in risk to Neptune. See page 29.

How we manage risk
continued

Internal control monitoring and assurance

In order to manage risk, we define and implement internal controls through our integrated management system to ensure our control requirements are consistent and kept live. Our internal control system is linked to our enterprise risk management process and is subject to assurance activities through multiple 'lines of defence'. This confirms that we have implemented our key controls and that they are operating effectively.

The first line of defence is provided by asset-level operational and project teams and in-country functions. Group functions and Group internal audit provide additional layers of monitoring and assurance. For the whole system to work, all assurance levels must be effective.

In 2022, we implemented further changes to the way we plan and deliver business assurance activities across Neptune, which should allow us to ensure greater discipline around their execution and outcomes. We enhanced our systems to allow us to collect more structured assurance data. This will help provide valuable insights for our business leaders.

Our Group internal audit team finalised remaining audits from the 2021 plan and delivered part of its 2022 plan, which was reprioritised due to other corporate priorities. Our Audit and Risk Committee has approved the 2022 Group internal audit plan and agreed that certain parts can be deferred.

In 2022, we have continued to strengthen assurance coverage in three risk areas:

- **Technical assurance** – we have established a new Group-level functional organisation, HSEQ and Technical Services, which reports to the CEO. It provides assurance on technical risks to the CEO and the Board, independently from the business, including risks related to health, safety, environment, projects and engineering, drilling and wells, operations, supply chain management and logistics. In Neptune's assurance model, the new function is positioned as the second line of defence. Each area remains subject to independent Group internal audit assessment from time to time that the functional assurance methods and activities meet Neptune's assurance objectives.
- **Assurance over internal controls for financial reporting** – having carried out substantial work to document key financial controls, our Group finance team has now developed a two-year financial controls roadmap. This aims to embed those internal controls and ensure we maintain sufficient testing to help us develop a certification of financial controls by the end of 2023.
- **Non-financial data assurance** – the overall framework is defined in Neptune's Basis of Reporting and Assurance of Non-Financial Data (see *neptuneenergy.com/esg*). In 2022, Group internal audit followed up actions from the 2021 assurance and continued to help strengthen business and functional assurance. These are key elements of our assurance model for non-financial data. This should prepare Neptune for future independent assurance that the EU's Corporate Sustainability Reporting Directive is expected to require. At the moment, the Board requires data that Neptune publishes for regulatory and compliance purposes to be assured externally. Independent assurance over other data is provided to our Audit and Risk Committee by Group internal audit as part of a three-year rolling audit programme.

Our approach to assurance is flexible to enable us to adapt to the changing risk landscape. We will continue to assess how we can optimise and refine our approach.

Section 172(1) statement

Our Board and Executive Team take into account the views of our stakeholders when making their decisions.

The Directors are required by law to act in a way that promotes the success of the Company for the benefit of its shareholders as a whole. While carrying out this duty, the Directors must also consider the wider consequences of their decisions in the long term and how those decisions might affect other groups of stakeholders, including those listed in section 172(1) of the Companies Act 2006.



The Board sanctioned an electrification project at Njord in Norway in 2022

Long-term strategy and vision

During 2022, the Board's response to Russia's invasion of Ukraine and the tightening of commodity markets as geopolitical uncertainties restricted oil and gas flows in key markets was a priority in securing the long-term success of the Group. To address this, the Board ensured that our Group-operated facilities and offices continued to function, while increasing production in Norway and bringing forward additional energy supplies where possible. The Board also supported those affected by the humanitarian crisis in Ukraine through donations to aid organisations and ongoing support for the Group's employees who were affected. The Board also made it clear to the Group's suppliers and advisers that it expected them to cease conducting business with Russian entities.

With energy supplies remaining tight throughout 2022, the Board continued to focus investment on delivering projects on schedule. While the Board welcomed the publication of the UK Government's Energy Security Strategy, recent changes to the fiscal regime have made this more challenging. The Board also acknowledged the need for further action and policy changes in Europe to diversify oil and gas supplies. It believes more needs to be done to reprioritise investment in indigenous resources in order to reduce energy costs and reduce the need for energy imports. The Board worked with authorities to deliver incremental production, where possible, to support energy security priorities in the UK and Europe.

The Board continued to recognise that specific environmental factors are relevant to the Group's success – factors that grew in prominence during 2022. While our products are essential for societies, by providing power generation, transport and heating, the Board also recognised the need to invest significant time and resources into the Group's lower carbon business. To that end, the Board continued to oversee the Group's progress in pursuing lower carbon opportunities throughout 2022, including a new partnership with Horisont Energi to develop the Errai carbon capture and storage (CCS) project in Norway. In Germany, the Group used its regional knowledge to explore opportunities for geothermal energy as well lithium extraction from produced water.

See pages 24-25 for more information.

During 2022, the Board supported the Group's delivery of its refreshed ESG strategy and three-year ESG roadmap, including approving new gender targets. The Board and Executive Team monitor relationships with stakeholders on an ongoing basis in recognition of their importance to Neptune's long-term success. Overleaf, we set out how the Board and Executive Team considered stakeholders when making their decisions.

Section 172(1) statement
continued

Employees and contractors

Engagement survey

The Group used feedback from our annual Pulse survey to inform its engagement and action plans. For example, as a result of feedback, in 2022, we:

- Increased the amount of leadership training at all our operated locations.
- Communicated our business strategy to employees and discussed the role our teams play in supporting the deliverables.
- Added levels to our position bands to provide more clarity on how employees can progress and develop their career.
- Continued to support flexible working across our business, and improved access to our policies and benefits for new starters and existing employees.
- Increased communications and the resources available on mental health and continued to embed our Employee Assistance Programme.

See pages 38 and 41 for more information.



Interaction with works councils and employee forums

We held regular meetings with representatives of our works councils and employee forums during 2022. The works councils in Germany, the Netherlands and Norway provide a formal setting for our employees to give 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 the Board and the management team, including our CEO, Director of New Energy, VP Business Development and Commercial, Director of Corporate Affairs, Director of Supply Chain and Logistics and Director of Employee Experience.

We also ran 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:

- Career development, including the introduction of an in-role promotion process.
- Safety, including the introduction of 'stop the job' cards and visible contractor commitment.
- Transparency, including 25 webinars delivered on our pay and reward structure.

See pages 35, 38 and 41 for more information.

Visits to operating assets

Members of the Board and Executive Team visit our operating assets and offices to talk to employees and contractors and ensure their views and perspectives are considered when making business decisions. As travel restrictions eased in many countries, the Directors and other members of senior management were, once again, able to visit our onshore and offshore sites in many of the countries where we work. For example, Amanda Chilcott (a Director of the Company and Group Human Resources Director) visited various sites throughout the year, including our onshore operations in Speyer and Salzwedel, Germany, the Cygnus platform in the UK, the K12B platform in the Netherlands, the Touat gas site in Algeria and the Gjøa platform in Norway. During her visits, Amanda spoke to line managers, HSEQ representatives, employees and contractors to hear their experiences of working with Neptune.

As a result of their feedback, we implemented various improvements to the employee experience, including:

- Improved facilities at the Speyer site in Germany.
- A performance review of key contractor suppliers in relation to our UK operations.
- A refreshed commitment to our internship programmes.
- Additional communication on acceptable working environments.
- Improvement actions for our onboarding processes.
- Enhanced communication on incentive plans in Algeria.

See page 35 for more information.

Direct engagement

We resumed face-to-face engagements, while recognising that flexibility remains important to employees.

In line with our hybrid working policies, introduced in 2021, and where possible, we ran hybrid sessions allowing virtual and in-person attendance as appropriate.

Examples of engagement between our senior leaders and employees include:

- Hybrid virtual and in-person town hall meetings for all employees or groups of employees.
- Extended leadership team conference in Stavanger, Norway, with more than 100 senior leaders, where we discussed Neptune's strategy and celebrated our 2022 HSEQ award winners.
- Country Managing Directors led local team events to rebuild relationships with colleagues and make new ones following the challenges posed by the COVID-19 restrictions in the previous year.
- Members of the senior leadership team made regular visits to our European offices.
- Weekly blog from our CEO to all our employees and more webinars on key topics made available to employees.

See page 38 for more information.

Equality, diversity and inclusion (ED&I) awareness sessions

The Group ran events throughout the year to promote its approach to ED&I. This included holding our second global ED&I month in November, with Executive Team members participating in sessions with internal and external speakers on a range of topics.

Our focus on ED&I has led to:

- New gender diversity targets for the Group to support our goal of achieving gender parity for all our employees.
- New affinity groups, including a Women in Neptune network and an LGBTQ+ group, each led by an executive sponsor.
- Partnerships with external organisations, such as Foothold, a charity that provides support to neurodiverse engineers.
- Country-level ED&I groups to drive action at the local level.

See pages 36-37 for more information.



Eko Lumadyo, Managing Director of Asia Pacific and our ED&I executive sponsor, led an ED&I awareness session for our teams in Indonesia and Australia

Suppliers

Direct engagement with suppliers on HSE and low carbon developments

Acknowledging the inherent risks that our industry faces, we held senior management meetings with our logistics service providers and suppliers to discuss operational and health, safety and environmental (HSE) performance.

These conversations reinforced Neptune's expectations on HSE matters and helped us obtain assurance on contractor competency, an increasingly important risk factor for 2022.

We presented our strategy to one of our key offshore drilling contractor companies and discussed ways in which they can support the Group's existing and lower carbon businesses.

To help develop a full CCS value chain, we engaged with potential CO_2 shipping companies. This led to the signing of several memoranda of understanding to help develop transport options.

See pages 42-43 for more information.

Section 172(1) statement
continued

Customers

Provision of vital products and services

Most of our direct customers are large multinational corporations, traders or government entities. The Directors recognise that Neptune's products are vital for the daily lives of the end-consumers served by our customers.

This has been a particularly complex year, with increased political instability across Europe as a result of the conflict in Ukraine and rising gas prices.

Concern for the security of offshore installations has also grown following the Nord Stream pipeline incident. The Board ensured that the Group continued to operate safely and recognised the importance of maintaining stable production during periods of exceptional political and economic volatility during 2022.

See page 93
for more information.

Communities and the environment

Community consultation

We consult with local communities throughout the different stages of our operations to help us understand their priorities and address their concerns. In Germany, for example, we organised a site visit with our Country Managing Director and the local mayor and council in Hoogstede which resulted in an agreement to support a conservation project at our Scheerhorn oil field.

See page 46
for more information.

Environmental consultation

We recognise 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.

See page 27 for more information on the Board's role in overseeing climate-related risks and opportunities.

During 2022, members of our Board and Executive Team:

- Tracked our carbon and methane intensity performance against our 2030 targets.
- Engaged with stakeholders to drive our innovative hydrogen and CCS projects in the UK, Norway and the Netherlands.
- Approved partnerships with environmental non-governmental organisations to support biodiversity and signed up to the CEO-led Aiming for Zero Methane Emissions Initiative.

See pages 22-25 and 48-49
for more information.

Social investment activities

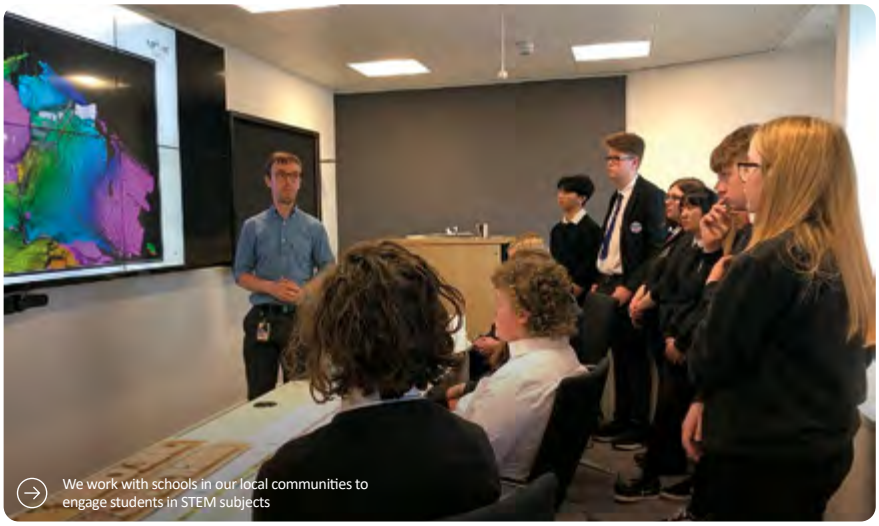
With many societies still recovering from the COVID-19 pandemic, additional pressure on communities around the world came from the humanitarian crisis following Russia's invasion of Ukraine, along with rising inflation. The Board recognised the need for urgent action to help those most affected and approved a substantial increase in our social investment in 2022. This included:

- A $2 million donation to charities to help with humanitarian relief efforts in Ukraine.
- Support for children affected by the cost of living crisis in the UK. This included a financial donation to The Childhood Trust, as well as a food collection for a local community foodbank, where some of our employees also volunteered.

During the year we continued to support our charity partner Mental Health UK, to help people affected by mental health problems. We also supported school children and students in the UK, Norway, the Netherlands and Indonesia, with a focus on science, technology, engineering and mathematics.

Our social investment activities are aligned with the UN Sustainable Development Goals.

See pages 44-45
for more information.



We work with schools in our local communities to engage students in STEM subjects

Joint venture partners

Regular meetings

Almost all of our assets are operated as joint ventures with other industry partners. Depending on the asset and the stage in its lifecycle, we hold weekly, monthly or quarterly meetings with our partners. Our collaboration with joint venture partners allows us to align their expectations with ours (for example, in routine matters such as budgets, maintenance, operations or projects) and to better manage extraordinary situations when they occur. For example, in the UK we worked with stakeholders and other energy companies to consult with the Government on proposed regulatory changes to the country's gas entry specifications. These proposals would allow gas companies, including Neptune via the Cygnus platform, to deliver more domestic gas to households and businesses.

Where we are not the operator of a facility, we seek to work with our partners, sharing our experiences and practices. We do this, for example, through our representation at operating committee meetings, technical committee meetings and board meetings. In 2022, we held board meetings with our joint venture partners in Algeria. These meetings gave us the opportunity to make key decisions about the Touat gas site. We also held meetings with our joint venture partners in Norway (Equinor, Sval, INPEX, Wintershall Dea) and had multiple meetings and direct engagement with Eni in relation to our joint venture cooperation and operations in Indonesia.

See page 42 for more information.

Financial stakeholders

Shareholder engagement

The Company has a single shareholder, Neptune Energy Group Limited, but recognises the need to engage with – and act fairly between – its other financial stakeholders, including its ultimate shareholders, bondholders, banks and other finance service providers.

Members of our Executive Team (which includes members of the Board) held numerous meetings with the Group's ultimate shareholders in 2022 to hear their feedback on matters such as our business plan and budget. For example, during various meetings (including during Neptune Energy Group Limited's Board meetings) we updated shareholders on the Group's business developments and commercial opportunities. Discussions included our low carbon projects, key gas contract price reviews and sales contracts.

In addition, although the Group does not have a formal dividend policy, dividends form part of shareholders' expected returns. As such, the Group's ultimate shareholders (via the Neptune Energy Group Limited Board) were kept informed of the dividend and capital distributions made by the Group in 2022.

See page 93 for more information.

Interactions with banks, credit agencies and insurers

We held regular meetings with the core group of banks that are part of our reserve base lending facility, as well as with other banks and financial advisers. We also met with S&P, Moody's and Fitch to discuss funding arrangements, 2022 company performance and progress on ESG matters.

Our banks advise us on the debt and equity matters that drive value for all of our stakeholders.

The credit agencies provide credit assessments and ratings on Neptune Energy on a regular basis, all of which are publicly available.

During 2022, Moody's, Fitch and S&P all upgraded Neptune Energy Group Midco Ltd's corporate credit rating.

We held multiple meetings with our insurance broker and insurance syndicate throughout 2022 on the business interruptions that occurred at Snøhvit, Norway and Touat, Algeria in 2021. We also continued to provide additional reporting updates to the insurance companies in relation to our loss of production insurance claims. The Snøhvit claim is still in progress.

Meeting our bondholders and other lenders

We hold regular meetings with our bondholders and present formal quarterly results presentations. During 2022, we held approximately 40 virtual or face-to-face meetings with bondholders, potential bondholders and lending banks. The Company guarantees the bonds issued by its subsidiary, Neptune Energy Bondco plc.

The feedback we receive from bondholders ensures that their interests are considered when making decisions that might affect the Group's ability to meet its obligations towards bondholders and other creditors. We also consider our bondholders' views on ESG matters. For example, we held a roadshow with bondholders in May 2022 to hear their views on our ESG strategy and we incorporated this feedback into our new three-year ESG roadmap to 2025.

See page 17 for more information.

Section 172(1) statement
continued

Host governments and regulators

Meetings with representatives and embassies

We engage with all host governments directly and through meetings with representatives of the Group (which includes members of the Board) in the countries where we work. We also engage indirectly through their London embassies and, where relevant, British embassies in country. We play an active role in the development of energy policy in each jurisdiction through meetings, briefings and consultation responses.

In the UK, for example, we held meetings with representatives from the Government's treasury and business departments in 2022 on the British Energy Security Strategy and the Energy (Oil and Gas) Profits Levy. We discussed domestic energy security, decarbonisation initiatives and the levy's impact on potential UK investments.

We also held similar meetings with government departments in the Netherlands on the Solidarity Contribution.

In Indonesia, we were in frequent contact with the country's industry regulator, SKK Migas, throughout the year to help us better understand country risk when making local investment decisions. This included an in-person meeting between senior officials from SKK Migas and our CEO, Executive Chairman and Managing Director of Asia Pacific to discuss Neptune's global strategy, with a particular focus on our current activities in Indonesia. Our CEO also separately met Indonesia's Ambassador to the UK to discuss Neptune's investment plans.



SKK Migas Chairman Dwi Soetjipto with our Executive Chairman, Sam Laidlaw

Maintaining high standards of business conduct

Deloitte carried out a maturity assessment of our ethics and compliance function in 2021. The actions from this assessment, together with our ongoing compliance initiatives, in particular on addressing human rights and modern slavery risk, helped inform our compliance programme for 2022. This included:

- Assessing third-party connections to Russia, to determine Neptune's potential exposure to sanctions-related issues through the third parties that we work with.
- Developing a new e-learning module and annual certification for our new Code of Conduct, which we rolled out in 2022.
- Updating the Group's Privacy Notices (as required by data protection legislation) and Personal Data Protection Policy.
- Updating the Group's Sanctions Policy and developing a new embargoes and sanctions e-learning course, launched in 2022.
- Updating our data protection e-learning course for new joiners, launched in 2022.
- Reviewing all our ethics and compliance policies and procedures, updating where relevant. This included updates to our Gifts and Invitations Policy and our Conflicts of Interest Procedure.
- Focusing on mitigating the risk of human rights and modern slavery, including publishing an updated Anti-Slavery and Human Trafficking Statement, adding a section on human rights in our Code of Conduct e-learning module and internal training sessions on modern slavery. We also developed a new human rights page on the Group's intranet, wrote several management blogs and added questions on human rights to our third-party due diligence process.

See page 100 for more information on our ethics and compliance programme and pages 32-49 for details of the Group's engagement with stakeholders.

The Board delegates day-to-day management of the Group and various stakeholder engagement activities to members of the Executive Team and senior management, who report back to the Board.

The Board regularly reviews the HSE performance of the Group as well as operational and financial performance. The Board also reviews, assesses, challenges and ultimately approves the Group's strategy. It also reviews the Group's approach to matters such as risk management and mitigation, equality, diversity and inclusion, legal, compliance, governance and social responsibility matters.

The Board takes into account these factors when continuing to set and develop the Company's culture. This includes our guiding principle to be 'safer, faster and better' than our peer group and our own past performance while also promoting an inclusive, 'speak-up' culture where psychological safety is at the forefront.

The Board acknowledges that not every decision it makes will benefit all our stakeholders all of the time and evaluates each key decision from the perspective of the stakeholders most affected by that decision. By considering the Company's purpose and values alongside its strategic priorities, and by having a clear process in place to make key decisions, the Board does, however, aim to make sure that its decisions are consistent and predictable.

As a result, the Board has had an overview of engagement with stakeholders and other factors that allow the Directors to understand the nature of their stakeholders' concerns while complying with their duty under section 172 of the Companies Act 2006 to promote the success of the Company. See page 93 for a summary of some of the key decisions made by the Board in 2022.

This Strategic report, consisting of pages 1-90 was approved by the Board on 23 February 2023.

By order of the Board.



Pete Jones
Chief Executive Officer
8 March 2023

Governance

Leading with integrity

We are committed to the highest standards of governance, ethics and integrity throughout our operations.

Contents

Pages 92-101 comprise the Directors' report, including:

92 Corporate governance statement
92 1 Purpose and leadership
93 Board activities during the year
95 2 Board composition
96 Senior management
98 Neptune Energy Group Limited Directors
98 3 Director responsibilities
98 4 Opportunity and risk
99 Audit and Risk Committee
99 ESG Committee
100 Ethics and compliance
100 5 Remuneration
100 Remuneration Committee
100 6 Stakeholders
101 Directors' statements

Governance



“

The welcome easing of pandemic-related restrictions meant we were able to increase our face-to-face Board meetings and engagement with our stakeholders. Throughout the increased volatility seen in 2022, the Group continued to provide vital energy supplies to our host communities and remained committed to the highest standards of corporate governance.”

Sam Laidlaw
Executive Chairman

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 our ultimate 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 Sustainalytics and EcoVadis in 2022. The ratings 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 Gold Standard status by the Oil and Gas Methane Partnership 2.0 (a voluntary initiative launched by the United Nations 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 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: 1.28). 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. This was largely as a result of 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, Group production has the potential 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 make good progress on our lower carbon initiatives, as we aim to store more carbon than is emitted from our operations and the use of our sold products by 2030. At our L10 carbon capture and storage (CCS) project (Netherlands) we continued to progress towards concept selection and front-end engineering design-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 CCS licences as part of a recent Carbon Dioxide Appraisal and Storage Licensing Round.

For more information on our Board, and that of our parent company, see pages 94 to 98.

Board activities during the year

During 2022, the Board of Directors of the Company met frequently, either before or shortly after Neptune Energy Group Limited (NEGL) Board and Audit and Risk Committee meetings. The Board also held numerous ad hoc update meetings with other members of the Executive Team and extended leadership team.

The Group's HSE performance continued to be the main item considered and reviewed by the Board and Executive Team during 2022, with particular focus on how performance could be improved.

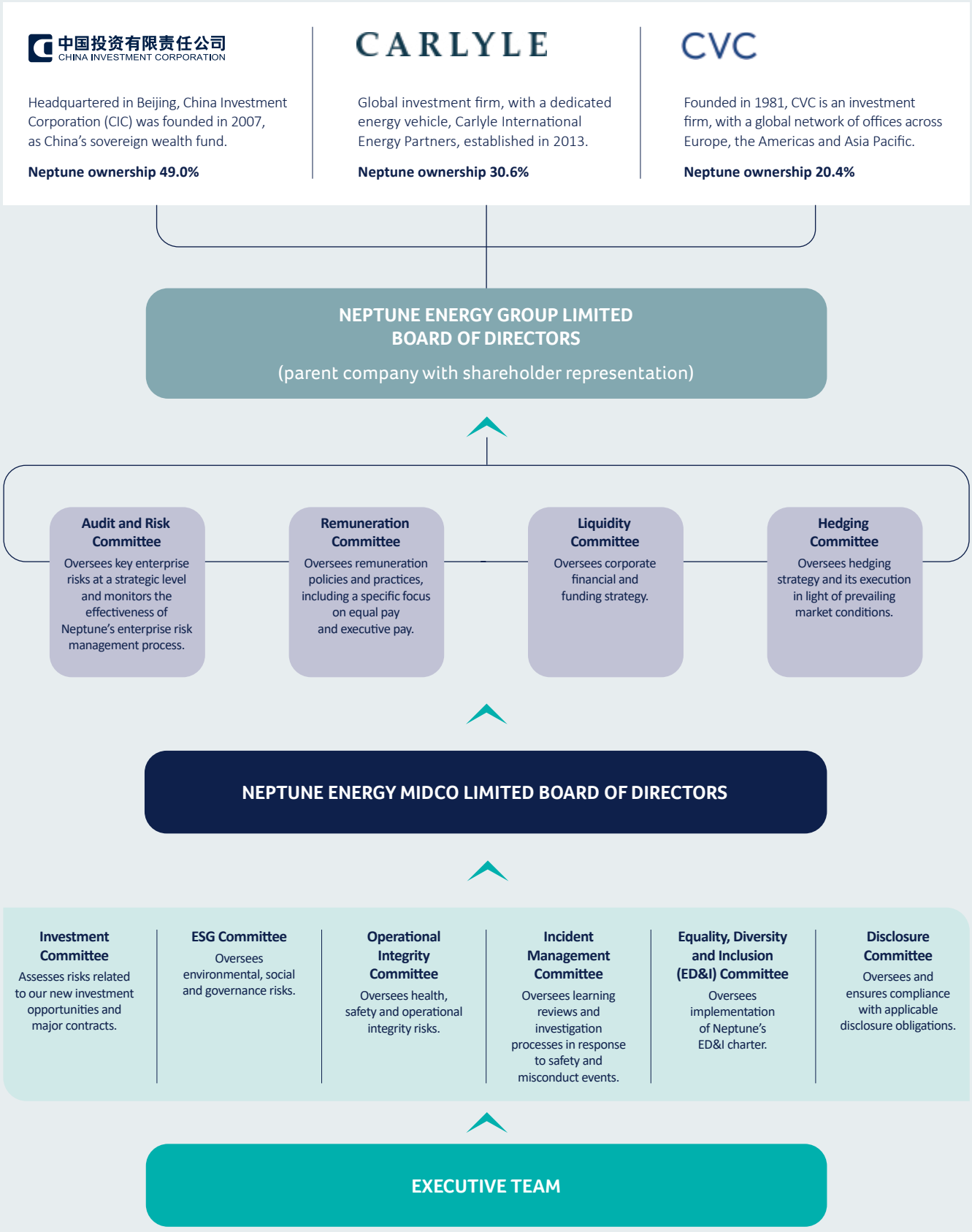
In addition, each of our businesses participated in performance reviews with the Executive Team and other members of the senior leadership team on two occasions in 2022.

Other matters the Board considered in 2022 included:

- Assets coming into production, notably Njord.
- The Group's hedging programme and associated risks in the current volatile commodity price environment.
- The 2023 budget and business plan, including the Group's capital expenditure programme and operating expenditure.
- The Group's financing arrangements, including a review of the Group's liquidity position and repayment of certain debt facilities and its RBL refinancing.
- Various commercial contracts, relating to the sale of commodities produced by the Group.
- The Group's strategy in light of the challenges posed by the ongoing commodity price volatility and political uncertainty caused by Russia's invasion of Ukraine.
- The Group's ESG strategy and external stakeholders' expectations on ESG matters.
- The Group's lower carbon opportunities and the different initiatives to be pursued by the Group, including CCS and hydrogen projects to help the Group achieve its target to store more carbon than is emitted by its operations and the use of its sold products by 2030.
- The impact of climate change on the Group's operations, both directly and indirectly, as a result of changes in law and societal expectations, including TCFD requirements.
- Various employee engagement and retention initiatives, including a review of the results of the 2021 employee engagement survey.
- The 2021 Annual Report and Accounts as well as the quarterly earnings releases in 2022.
- Various M&A opportunities.
- Various disputes to which members of the Group were party as well as various insurance claims.
- Overall strategy, including growth opportunities, commodity pricing, liquidity events and fiscal policy.

Governance
continued

Our governance structure



Principle 2 – Board composition

The Company's Board of Directors comprises Sam Laidlaw (Executive Chairman), Pete Jones (Group Chief Executive Officer), Armand Lumens (Group Chief Financial Officer), Amanda Chilcott (Group Human Resources Director) and Andrea Guerra (Vice President, Subsurface).

Biographies of the Directors are set out on page 97.

The Board continues to work closely with the Board of its parent company, NEGL, and operates to a similar agenda of standing and extraordinary items.

NEGL is the entity through which our investors own their interests in the Group. The Directors of NEGL are nominated by our investors and are experienced business leaders with the skills necessary to help the business deliver its strategy. For further detail on our investors see page 98. In addition to their roles as Directors of NEGL, certain members of the NEGL Board also sit on the Audit and Risk Committee, Remuneration Committee, Liquidity Committee and Hedging Committee.

The Board and the NEGL Board are supported by the Audit and Risk Committee and the Remuneration Committee. The activities of these committees are described on pages 99 and 100.

The day-to-day management of the Group is delegated to the executive leadership team (the Executive Team).

Audit and Risk Committee

The Group's Audit and Risk Committee (ARC) consists of the members of the NEGL Board as well as members of the Executive Team. The ARC helps the Board (and the NEGL Board) carry out governance responsibilities with respect to external audit, internal audit, risk and internal control. It also oversees the integrity of the Group's financial reporting and associated narrative statements. For details of the ARC's activities in 2022, see page 99.

Remuneration Committee

The Group's Remuneration Committee (RemCo) consists of the members of the NEGL Board as well as our Group Human Resources Director, with our Group CEO attending by invitation. The RemCo's primary purpose is to develop, maintain and implement remuneration policies. For details of the RemCo's activities in 2022, see page 100.

Executive Team

The Group is managed by the Executive Team. This consists of senior management, together with the heads of other functions and the Managing Directors of the countries where 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 cyber security matters. The Investment Committee, ESG Committee, Operational Integrity Committee, Incident Management Committee and Hedging Committee, all comprising members of the Executive Team (and 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.

For information on the Executive Team and their biographies, see page 97.

Senior management

Our depth and breadth of experience

We have a high-quality, highly committed management team that is invested in the business, has deep experience and an excellent track record in the international energy sector.


1


2


3


4


5


6


7


8


9

1 – Sam Laidlaw
Executive Chairman

A C E I R

Sam is a founder of Neptune Energy and became its first Chairman in 2015. He is an experienced energy industry executive, with a strong international operational track record of more than 30 years in the oil and gas sector.

Previously, Sam served as Chief Operating Officer of Hess Corporation, with responsibility for global upstream, CEO of Enterprise Oil Plc, Executive VP of Chevron Corporation and CEO of Centrica Plc.

Sam has also been a member of the UK Government's Energy Advisory Panel, President of the UK Offshore Operators Association, a member of the Prime Minister's Business Advisory Group, the Senior Director for the Department of Transport and a non-executive director of both HSBC Holdings Plc and Hanson Plc.

Sam is a non-executive director of Rio Tinto plc and Chairman of the National Centre for Universities and Business.

2 – Pete Jones
Chief Executive Officer

A C E I

Pete became Neptune's CEO in January 2022 and has more than 25 years' experience in the upstream oil and gas sector. He joined Neptune in 2018 as Managing Director for the UK and was Neptune's VP Operations for Europe from October 2019.

During his tenure in the UK and Europe, Pete transformed the Netherlands and Germany businesses and delivered organic and inorganic growth in Norway and the UK. He also drove an improvement in safety culture, while improving production efficiency.

Pete gained a degree in engineering operational research from the University of Birmingham and joined Marathon Oil, where he spent the first 16 years of his career working in various operational, technical and functional roles across the UK and the US, before being appointed Managing Director of its UK business in 2009. He went on to become the Managing Director of TAQA Europe.

During 2015 and 2016, Pete was on the Board of Oil & Gas UK and a member of the Energy Jobs Taskforce. Between 2017 and 2020, he was Honorary Professor at Aberdeen University's Business School.

Key to committee membership

- A Audit and Risk Committee
- C Company Director of Neptune Energy Group Midco Limited
- E Environmental, Social and Governance Committee
- I Investment Committee
- R Remuneration Committee
- Committee Chair

3 – Armand Lumens
Chief Financial Officer

A C E I

Armand joined as CFO in December 2018. He has worked in the oil and gas sector for more than 25 years and provides Neptune with deep knowledge and experience of energy and capital markets.

Before joining the Company, Armand was Group CFO at Louis Dreyfus Company. Prior to this, he spent more than 20 years with Shell in various senior financial roles, including as CFO of Shell Trading and Supply.

Armand is a non-executive director at Oryx Energies S.A. and V-Labs S.A.

4 – Andrea Guerra
VP Subsurface

C I

Andrea joined Neptune in August 2018 and has more than 20 years' international oil and gas sector experience.

Her extensive knowledge combines both managerial and technical experience addressing portfolio optimisation, prospect generation and maturation, reservoir management as well as exploration, appraisal and development drilling.

She directs the corporate reserve reporting function and is responsible for Neptune's global exploration portfolio.

Previously she worked at Apache, with senior management responsibilities for its North Sea Reservoir Engineering division, South America New Ventures, Corporate International Planning, and Corporate Reserves and Economics.

5 – Julian Regan-Mears
Director of Corporate Affairs

A E I

Julian joined Neptune in September 2018 and is responsible for investor relations, public affairs, media relations, internal communications and ESG.

Julian has more than 15 years' experience leading international corporate communications functions, mostly in the energy and mining sectors, holding senior management positions with Centrica plc and The De Beers Group. Earlier in his career, Julian led communications for Britvic plc's listing.

6 – Ben Walker
General Counsel

A E I

Ben joined Neptune in September 2019 from Vivo Energy plc, a pan-African fuel retailer and distributor, where he was General Counsel and Company Secretary.

Prior to Vivo Energy, he held the roles of Senior Legal Counsel with Centrica plc and Associate with Slaughter and May. Ben is a qualified solicitor in England and Wales and has significant experience in the oil and gas industry.

7 – David Hemmings
VP Business Development and Commercial

I

David joined Neptune in July 2018 with more than 20 years' experience in corporate finance in the oil and gas sector. David has a strong knowledge of capital markets in the energy sector, having advised oil majors, exploration and production companies and national oil companies on mergers and acquisitions and debt and equity financing.

Previously, he was a Managing Director in the energy and power advisory group at Rothschild.

8 – Philip Lafeber
VP HSEQ and Technical Services

I

Philip has more than 30 years' upstream energy experience, predominantly in Europe, the Middle East and West Africa. He joined Neptune from DONG Energy, where he was Country Manager for Norway. As its UK Technical Director, he led the OGA West of Shetland Task Force Work Group.

At Amerada Hess, he was Global Strategic Planning Manager and Pre-Developments Manager for Europe, North Africa and Southeast Asia. He has worked in Oman for Shell International and in West Africa for Schlumberger Wireline.

9 – Amanda Chilcott
Group Human Resources Director

C E R

Amanda joined Neptune in December 2018 and is responsible for the development and delivery of our people strategy. She has been working in human resources for more than 20 years and has significant specialist experience in the areas of organisation design, reward and employee relations.

She has worked with Ford Motor Company, BP and Aggreko in a variety of global roles, including assignments in the UK, continental Europe, China and the US.

Directors' report

Neptune Energy Group Limited Directors

The Board of Directors of our parent company, Neptune Energy Group Limited (NEGL), comprises Directors nominated by the Group's ultimate shareholders and is chaired by our founder, Sam Laidlaw.

The Directors of the NEGL Board are respected industry leaders and provide valuable insight into management and governance matters, working closely with members of the Board and Executive Team.

Sam Laidlaw (Executive Chairman): see page 97 for Sam's biography.

Fang Bo (CIC nominee): Mr Fang serves as Senior Vice President in the Investment Department at CIC. He joined the Board in October 2020. Mr Fang has been an investment professional in various sectors, including energy, infrastructure, telecoms, power and renewables. He graduated from Peking University with a master's degree.

Tai Tin On (CIC nominee): Mr On is a Senior Vice President in the Real Assets Investment Department II at CIC. He joined the Board in July 2022. He is an experienced and dedicated investment banking and asset management professional. Prior to joining CIC, Mr On worked at SINO-CEE Fund, ICBC International and Deutsche Bank. Mr On graduated from Harvard University with a master's degree in statistics.

Tao Mi (CIC nominee): Mr Mi joined the Board in July 2022. He is a Managing Director at CIC. He is responsible for developing CIC's infrastructure strategy and establishing and managing the portfolio. Prior to joining CIC, Mr Mi worked at Ernst & Young, SC Capital Partners and KPMG. Mr Mi is a CFA Charter holder and licensed CPA. He holds an MBA in finance from the University of California, Irvine.

Marcel van Poecke (Carlyle Group nominee): With more than 25 years of experience in the energy sector, Mr van Poecke is Head and Managing Director for Carlyle International Energy Partners (CIEP). He is also Chairman of AtlasInvest, a private holding company he founded in 2007 that is engaged in investments across the broad energy spectrum, and Chairman of ONE-Dyas, which owns and operates oil and gas assets. Mr van Poecke has a degree in agricultural business administration from the University of Wageningen and a master's in business administration from the William E. Simon School of Management of the University of Rochester, US.

Robert Maguire (Carlyle Group nominee): Mr Maguire is a Managing Director and Partner at The Carlyle Group, with responsibility for Carlyle International Energy Partners, L.P., a fund focused on Europe and Africa with $8 billion of assets under management. Mr Maguire has been active in the global energy markets for more than 35 years in a variety of senior roles at Perella Weinberg Partners, Basin Capital Partners and Morgan Stanley. He was involved in numerous significant transactions in the energy space, including mergers such as BP/Amoco, Elf/Total and Equinor/Norsk Hydro, privatisations such as Equinor, Rosneft, Gazprom and Sinopec, acquisitions such as BP/ARCO and Shell/Enterprise and joint ventures such as TNK-BP and LUKArco. He holds an AB from Princeton University, an MA from Oxford University and a JD from the University of Virginia School of Law.

James Mahoney (CVC Capital Partners nominee): Mr Mahoney is a Partner at CVC Capital Partners, a world leader in private equity and credit with €137 billion of assets under management and a global network of 25 local offices. He has responsibilities in both the private equity and strategic opportunities platforms, including the firm's current investments in Neptune Energy, ONTIC and Moto. Mr Mahoney has been active in the private equity industry for more than 20 years, with experience of making and managing equity investments across a range of industries and geographies. Prior to joining, Mr Mahoney was a Managing Director with Investcorp. He has a bachelor's degree in engineering from the University of Auckland.

Principle 3 – Director responsibilities

The Board meets regularly around the time of NEGL Board or ARC meetings. Members of the Board also engage on a regular basis with other members of the Executive Team, including through the weekly Executive Team meeting.

In addition, members of the Board attended two strategic planning meetings with the whole Executive Team in 2022. This kept the Board updated on Group activities, enabling the Directors to discharge their responsibilities.

The Directors bring a wide range of experience to inform Board discussions and discharge those responsibilities. In keeping with best corporate governance practice, the roles of the Chair and CEO are distinct and the functional responsibilities of the other Directors (CFO, Group Human Resources Director and VP Subsurface) ensure that there are diverse viewpoints in Board discussions.

Decisions within the Group are made in accordance with the NEGL shareholders' agreement, as well as the articles of association of the Company and an approved delegation of authority standard.

In reaching their decisions, the Directors considered these arrangements as well as their responsibilities under section 172 of the Companies Act 2006 (see pages 85-90 for further information).

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's approach to strategic opportunities, and the key risks it faces and mitigating actions it has in place to manage them, are set out in our Strategic report on pages 79-83.

The Board 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 Board 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 Board continued to oversee the Group's 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 products 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.

Audit and Risk Committee

The Audit and Risk Committee (ARC) reports to the NEGL Board but also informs the Board. It comprises the Executive Chairman (who chairs the ARC), the other members of the NEGL Board (or their representatives), the CEO, CFO, General Counsel, Director of Corporate Affairs and Director of Internal Audit and Enterprise Risk. The Group's VP HSEQ and Technical Services, Director of External Reporting, Group Financial Controller, Head of Global Ethics and Compliance, as well as the Group's external auditor, also attend ARC meetings.

The ARC works to a standing agenda, which includes updates on reporting, technical accounting, internal controls, internal audit activities, the enterprise risk register, legal disputes and ethics and compliance. The ARC also provides the opportunity for the Director of Internal Audit and the Chairman to provide private feedback to ARC members and the Group's external auditors.

The ARC reviewed the independence of the Group's external auditors, Ernst & Young (EY). The ARC also considered EY's report on audit observations and recommendations in respect of the Group financial statements for 2021, its unaudited interim review update for H1 2022 and EY's 2022 audit plan report.

Financial reporting and technical accounting

As in previous years, ARC meetings coincided with the Group's quarterly results reporting to its bondholders and other stakeholders. ARC meetings provided an opportunity for the results and accompanying presentations to be reviewed and challenged by committee members ahead of publication.

In particular, the ARC reviewed the Group's financial statements and bondholder presentations for the six-month period ended 30 June 2022, which were also reviewed by EY.

During ARC meetings, the financial reporting and technical accounting teams gave updates on the processes for preparing the financial statements and the accounting areas of judgement supporting the positions taken by the Group. This was supported by accounting review papers, for example, in relation to impairments – and reversals thereof – receivables, acquisitions and discount rates.

The ARC also approved an annual update to our Group Accounting Policy Manual – our key reference document for the Group's accounting policies.

Risk management and internal control

Committee members reviewed the Group's enterprise risk register as a standing item at each ARC meeting, as well as specifically reviewing the Group's finance risk register. 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 committee's monitoring of the Group's enterprise risks, it reviewed climate change-related risks, which are discussed in more detail on page 28. The committee also reviewed 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. For more details, please see page 77.

In 2022, a maturity assessment of the Group's enterprise risk management (ERM) process was undertaken, the results of which were reviewed by the committee. The ERM process was rated four out of a five-tier maturity scale – a level which highlights its successful integration into the Neptune organisation and which the committee hopes will be sustained by management going forward. The Group also made improvements to further embed its internal financial control processes, resulting in the risk of external financial reporting errors being downgraded by the end of 2022. This risk will continue to be monitored by the committee as part of the CFO's report on the Group's finance risk register and any financial control incidents will continue to be reported to the ARC in detail.

As another standing item on the ARC agenda, the Director of Internal Audit and Enterprise Risk reported the activities of the internal audit function to the ARC, as well as progress on closing out identified audit actions. During 2022, these included:

- The outcome of the ERM process maturity assessment.
- Audits of hydrocarbon reserves reporting process and hydrocarbon sales.
- Assurance of non-financial data according to the rolling assurance plan.

During the second half of 2022, the internal audit team focused on enhancing internal systems and methodology to help improve the Group's risk and control culture. This included the introduction of new functionality which enabled the committee to monitor business assurance activities in their entirety and improve discipline in respect of the remediation of audit and control issues across the Group.

Disputes and compliance

ARC members received regular updates in relation to the legal disputes to which entities of the Group were party as well as updates on matters relating to the Group's ethics and compliance programme. This included updates on investigations and approval of new policies and procedures as well as training programmes for compliance matters.

The ARC also approved the Group's 2021 Anti-Slavery and Human Trafficking Statement, which was subsequently approved by the Board and the NEGL Board and published on our website.

ESG Committee

In 2022, the Group's Environmental, Social and Governance (ESG) Committee consisted of the Executive Chairman, CEO, CFO, Director of Corporate Affairs (who chairs the committee), Group HSEQ Director, Group Human Resources Director, Head of ESG, Director of Internal Audit and Enterprise Risk, Head of Global Ethics and Compliance, Director of New Energy and the General Counsel.

The ESG Committee continued to implement the Group's ESG strategy and considered a range of matters, including:

- The next phase of the Group's ESG strategy and three-year roadmap to 2025.
- Outcomes of ESG ratings and the link between ESG performance and financial matters.
- Matters related to climate change management and disclosures, including the Group's trajectory to achieve its climate ambitions.
- Outcomes from stakeholder engagement on our ESG strategy and reporting.
- Gender diversity targets and equality, diversity and inclusion initiatives, including on neurodiversity.
- The Group's response to the cost of living crisis and initiatives with non-governmental organisations to support UN Sustainable Development Goal 10: Reduced inequalities.
- Matters related to the internal assurance of non-financial information.

Directors' report
continued

Ethics and compliance

In 2022, the Group continued to enhance its ethics and compliance programme using the six guiding principles for bribery prevention set out in the UK Ministry of Justice's guidance on the Bribery Act 2010, namely: (i) due diligence, (ii) proportionate procedures, (iii) top-level commitment, (iv) risk assessment, (v) communication (including training) and (vi) monitoring and review.

Due diligence

Following the introduction of our new third-party screening platform, hosted by Dow Jones, we have a more rigorous process in place to assess potential third parties before we engage with them. In particular, for types of services where there is a higher risk of bribery, corruption or human rights abuse, we issue a more detailed questionnaire to the third party so that we can review the steps it has taken to mitigate such increased risk in its business.

Proportionate procedures

We also introduced our new Ethics and Compliance Due Diligence Standard, to reflect our more rigorous screening process. Additionally, we updated other ethics and compliance policies and procedures, including the Sanctions Policy, the Conflicts of Interest Procedure, the Personal Data Protection Policy and the privacy notices required in accordance with data protection legislation.

Top-level commitment

The leadership team and the Audit and Risk Committee receive regular updates on the development of our ethics and compliance programme. Senior management proactively communicates on ethics and compliance matters. For example, during 2022, through a 'Spotlights on Ethics' series of management blogs, leadership team members highlighted challenging, ethical situations or circumstances that they have encountered during their careers. In addition, members of the leadership team proactively communicate our requirement to complete the Code of Conduct e-learning module and annual certification to their teams.

Risk assessment

All functions assess their ethics and compliance risks as part of their periodic risk reviews. Every office will carry out a dedicated risk assessment focused purely on ethics and compliance risks by the end of the first quarter of 2023.

Training and communications

We rolled out a new Code of Conduct e-learning programme in September 2022, along with annual certification. As at 31 December 2022, 99% of staff[1] globally had completed the training. We launched a new embargoes and sanctions e-learning module in December 2022, and all new joiners in the supply chain, finance, legal, commercial and business development teams will be required to complete the training. We also launched a new data protection e-learning module in December 2022, which we expect all new joiners to complete. We provided virtual training to staff on a variety of ethics and compliance topics, including international sanctions, modern slavery, data protection, understanding the risks of bribery and corruption, and carrying out of investigations.

Monitoring and review

New processes have been put in place to monitor compliance with certain ethics and compliance policies and procedures. For example, periodic checks are carried out to assess compliance with the Ethics and Compliance Due Diligence Standard, the Gifts and Invitations Policy and the Conflicts of Interest Procedure.

Promoting a speak-up culture

We provide training and awareness sessions continually to encourage people to speak up if they have concerns about unethical practices.

During 2022, we received 17 grievances and whistleblowing reports, the majority of which related to alleged inappropriate behaviour, unfair conduct, bullying or harassment. We have assessed all reported matters and depending on that assessment, followed up with an informal or formal investigation. See page 38 for more information.

Principle 5 – Remuneration

The Group's Remuneration Committee (RemCo) consists of members of the NEGL Board as well as the Group Human Resources Director, with the Group CEO attending by invitation. The RemCo generally meets twice a year and on an ad hoc basis, when required, to review and recommend matters relating to remuneration and benefits. During 2022, the RemCo considered a range of issues, including:

- Output from the 2021 Group scorecard for the purpose of determining the Group performance element for bonuses paid in relation to 2021.
- Bonuses payable to members of the Executive Team.
- Design of the 2022 scorecard.
- The Group's long-term incentive plan.
- Remuneration payable to employees joining or leaving the Group.
- Our gender pay gap and pay ratios and actions to improve in these areas.
- Market data on reward in comparable companies.

In developing, maintaining and implementing remuneration policies, the RemCo's main objective 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 value creation.

The RemCo aims to ensure that levels of remuneration across the Group are sufficiently competitive to retain talent, as well as benchmarking our Executive Team remuneration packages. The RemCo also reviews the Group's performance against diversity and inclusion criteria, including benchmarking against other industry players, while making recommendations on how to improve in these areas.

Principle 6 – Stakeholders

The Directors recognise the need to consider the views of stakeholders when coming to their decisions, particularly in the context of the Group's ambition to be a leading player in the energy transition through its gas-weighted portfolio and lower carbon developments.

We listen to the views and concerns of our stakeholders, which inform the decisions we make – from day-to-day business-level decisions to longer-term strategic matters considered by the Board and our ultimate shareholders. We set out examples of how we engage with our key stakeholders on pages 32-49 and in our Section 172(1) statement on pages 85-90.

1. Training issued to all employees and contract staff included in Neptune's headcount. Percentage excludes any staff on long-term leave.

Directors' 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.

Directors' statement of disclosure of information to the auditor

The Directors who held office at the date of approval of this report confirm that, so far as they are aware, there is no relevant audit information of which the Company's auditors are unaware. They also confirm they have taken all necessary steps as Directors to make themselves aware of 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:

- Dividends, see page 75.
- The financial risk management objectives and policies of the Company and the exposure of the Company to price risk, credit risk, liquidity risk and cash flow risk, see page 73 hedging and note 25 on page 149.
- Likely future developments in the business of the Company, see page 57.
- Research and development activities carried out by the Company, see pages 24-25.
- Employment of disabled persons, see page 36.
- Employee engagement, see page 38.
- Greenhouse gas emissions, energy consumption and energy efficiency, in respect of Streamlined Energy and Carbon Reporting (SECR) requirements, see pages 23 and 31.
- Our engagement with suppliers, customers and others with whom we do business, see pages 42-43.

Conflicts of interest

Directors have a statutory duty to avoid situations in which they may have interests that conflict with those of the Company and complete certification in relation to conflicts of interest on an annual basis.

The Board has adopted procedures as provided for in the Company's articles of association for authorising existing conflicts of interest and for the consideration of and, if appropriate, authorisation of new situations that may arise.

Political donations

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

By order of the Board.



Sam Laidlaw
Executive Chairman
8 March 2023
Company number: 10684661

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) have 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.

Financial statements

Strong financial performance, delivering growth

Contents

104 Independent auditor's report
106 Consolidated income statement
106 Consolidated statement of other comprehensive income
107 Consolidated statement of financial position
109 Consolidated statement of changes in equity
110 Consolidated cash flow statement
112 Notes to the consolidated financial statements
163 Supplementary information gas and oil – unaudited
164 Glossary of terms
IBC General information

Auditor's Report

Independent Auditor's Report to the Members of Neptune Energy Group Midco Limited

Opinion

We have audited the financial statements of Neptune Energy Group Midco 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 101, 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 by 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 identified above. 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.

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.



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

Consolidated financial statements

For the year ended 31 December 2022

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/(losses)	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	**(173.8)**	(175.4)
Profit before tax		**3,095.9**	1,392.4
Taxation	11	**(2,171.5)**	(1,005.2)
Net profit		**924.4**	387.2

All profits and losses arise as a result of continuing operations. The accounting policies on page 112 to 123 together with the notes on pages 123 to 162 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		**924.4**	387.2
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)**	(101.8)
		212.2	(787.8)
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**	(778.9)
Total comprehensive income/(loss) for the year, net of tax		**1,106.7**	(391.7)

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	**1,284.9**	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
		1,770.3	1,687.4
Assets held for sale	19	**–**	134.9
Total current assets		**1,770.3**	1,822.3
Total assets		**8,464.0**	9,027.6
Share capital	26	**1,977.2**	1,977.2
Hedging reserve	24	**(212.9)**	(708.6)
Foreign currency translation		**(350.6)**	(67.1)
Fair value reserve of financial assets at FVOCI		**(8.3)**	(5.9)
Retained deficit		**(699.3)**	(449.4)
Total equity		**706.1**	746.2
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	**528.6**	507.6
		2,598.1	2,428.6
Liabilities directly associated with the assets held for sale	19	**–**	100.9
Total current liabilities		**2,598.1**	2,529.5
Total equity and liabilities		**8,464.0**	9,027.6

The accounts on pages 106 to 162 were approved by the Board and signed on its behalf by:



Armand Lumens, Chief Financial Officer
8 March 2023

Consolidated financial statements

For the year ended 31 December 2022

Statement of financial position – Company

Company In millions of US$	Notes	31 December 2022	31 December 2021
Non-current assets			
Investments	15	**1,977.2**	1,977.2
Inter-company loan receivable	17	**942.1**	938.7
Total non-current assets		**2,919.3**	2,915.9
Current assets			
Trade and other receivables	17	**472.4**	471.8
Total current assets		**472.4**	471.8
Total assets		**3,391.7**	3,387.7
Share capital	26	**1,977.2**	1,977.2
Retained earnings		**2.6**	1.9
Total equity		**1,979.8**	1,979.1
Non-current liabilities			
Inter-company loan payable	21	**942.1**	938.7
Total non-current liabilities		**942.1**	938.7
Current liabilities			
Other current liabilities	21	**469.8**	469.9
Total current liabilities		**469.8**	469.9
Total equity and liabilities		**3,391.7**	3,387.7

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 $1,147.5 million (2021: $345.2 million), this mainly relates to dividend income of $1,146.8 million (2021: $344.7 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 (deficit)/ earnings	Total
At 1 January 2021	**1,977.2**	**(22.6)**	**34.7**	**–**	**(506.7)**	**1,482.6**
Profit for the year	–	–	–	–	387.2	387.2
Other comprehensive (loss)/income[5]	–	(686.0)	(101.8)	(5.9)	14.8	(778.9)
Total comprehensive (loss)/income	**–**	**(686.0)**	**(101.8)**	**(5.9)**	**402.0**	**(391.7)**
Transactions with owners of the Company:						
Dividends declared (note 10)	–	–	–	–	(344.7)	(344.7)
At 31 December 2021	**1,977.2**	**(708.6)**	**(67.1)**	**(5.9)**	**(449.4)**	**746.2**
Profit for the year	–	–	–	–	924.4	924.4
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)**	**896.9**	**1,106.7**
Transactions with owners of the Company:						
Dividends declared (note 10)	–	–	–	–	(1,146.8)	(1,146.8)
Balance 31 December 2022	**1,977.2**	**(212.9)**	**(350.6)**	**(8.3)**	**(699.3)**	**706.1**

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	Retained earnings	Total
At 1 January 2021	**1,977.2**	**1.4**	**1,978.6**
Profit for the year	–	345.2	345.2
Total comprehensive income for the year	**–**	**345.2**	**345.2**
Transactions with owners of the Company:			
Dividends declared (note 10)	–	(344.7)	(344.7)
At 31 December 2021	**1,977.2**	**1.9**	**1,979.1**
Profit for the year	–	1,147.5	1,147.5
Total comprehensive income for the year	**–**	**1,147.5**	**1,147.5**
Transactions with owners of the Company:			
Dividends declared (note 10)	–	(1,146.8)	(1,146.8)
Balance 31 December 2022	**1,977.2**	**2.6**	**1,979.8**

Consolidated financial statements

For the year ended 31 December 2022

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		**3,095.9**	1,392.4
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		**–**	(113.6)
Finance costs	9.2	**173.8**	175.4
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]		**(68.0)**	(284.8)
Income tax (paid)/received (net)		**(1,153.0)**	57.6
Net cash flows from operating activities		**2,373.2**	1,696.8
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		**2,667.0**	2,959.5
Repayment of loans and borrowings		**(2,987.0)**	(2,667.4)
Repayment of obligations under leases		**(85.8)**	(107.4)
Finance costs paid		**(121.0)**	(123.8)
Dividends paid to parent company	10	**(1,146.8)**	(544.7)
Net cash flows used in financing activities		**(1,673.6)**	(939.1)
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		**1,147.5**	345.2
Adjustments to reconcile profit before tax to net cash flows:			
Finance costs		**68.3**	68.6
Finance income	9	**(1,212.4)**	(410.4)
Other non-cash items		**(3.4)**	(3.4)
Working capital movements		**(0.7)**	(0.5)
Net cash flows used in operating activities		**(0.7)**	(0.5)
Cash flows from investing activities			
Dividends received from subsidiary		**1,146.8**	544.7
Finance income received		**65.8**	66.2
Net cash flows from investing activities		**1,212.6**	610.9
Cash flows from financing activities			
Loan made to parent company	10, 17	**–**	(455.3)
Repayment of loan to parent company		**–**	(7.9)
Proceeds from subsidiary loan	21	**–**	455.3
Repayment of loan from subsidiary		**–**	7.9
Finance costs paid		**(65.1)**	(65.7)
Dividends paid to parent company	10	**(1,146.8)**	(544.7)
Net cash flows used in financing activities		**(1,211.9)**	(610.4)
Net increase in cash and cash equivalents		**–**	–
Cash and cash equivalents at 1 January		**–**	–
Cash and cash equivalents at 31 December		**–**	–

The notes on pages 112 to 162 form part of these accounts.

Notes to the consolidated financial statements

General information

Neptune Energy Group Midco 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 Midco 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 parent company and 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 163 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.

Notes to the consolidated financial statements
continued

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.

Notes to the consolidated financial statements
continued

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.

Notes to the consolidated financial statements
continued

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.

Notes to the consolidated financial statements
continued

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.

Notes to the consolidated financial statements
continued

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 on pages 28-31, 77 and 79-83.

Notes to the consolidated financial statements
continued

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.

In millions of US$	UK	Norway	Netherlands	Germany	North Africa	Asia Pacific	Corporate	Total
	Year ended 31 December 2022							
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								**(173.8)**
Profit before tax								**3,095.9**

In millions of US$	UK	Norway	Netherlands	Germany	North Africa	Asia Pacific	Corporate	Total
	Year ended 31 December 2021							
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 income/(loss) 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								(175.4)
Profit before tax								1,392.4

Notes to the consolidated financial statements
continued

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	**3,095.9**	1,392.4
Add back:		
Net financing expenses	**84.7**	122.3
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**	**655.0**	**8,464.0**
Liabilities	**(623.7)**	**(3,003.6)**	**(891.4)**	**(740.1)**	**(19.8)**	**(371.4)**	**(2,107.9)**	**(7,757.9)**
Net assets/(liabilities)	**871.7**	**140.1**	**(184.3)**	**(97.6)**	**686.2**	**742.9**	**(1,452.9)**	**706.1**

	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)	(2,420.0)	(8,281.4)
Net assets/(liabilities)	549.2	883.1	(377.7)	(67.1)	657.6	976.4	(1,875.3)	746.2

1. As at 31 December 2021, Norway segment net assets includes 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

In millions of US$	Year ended 31 December 2022 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**

In millions of US$	Year ended 31 December 2021 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

Notes to the consolidated financial statements
continued

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:

Group In millions of US$	Year ended 31 December 2022	Year ended 31 December 2021
Short-term employee benefits	**6.5**	6.7
Other long-term benefits – post-employment benefits	**0.3**	0.3
Total	**6.8**	7.0

Highest paid Director's remuneration

Group 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 $1,212.4 million (2021: $410.4 million) includes dividend income of $1,146.8 million (2021: $344.7 million).

9.2 Finance cost

Group In millions of US$	Year ended 31 December 2022	Year ended 31 December 2021
Interest expense	**117.4**	119.4
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	**173.8**	175.4

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 $68.3 million (2021: $68.6 million).

Notes to the consolidated financial statements
continued

10. Dividend

In millions of US$	Group		Company	
	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 9 December 2022, the Board of Directors of Neptune Energy Group Midco Limited declared and paid an interim dividend of $1,146.8 million to its immediate and ultimate parent, Neptune Energy Group limited (NEGL) (58.0 cents per fully paid ordinary share). This enabled NEGL on 12 December 2022 to declare and settle both an interim preference dividend of $96.8 million and a capital redemption settlement of $1,049.9 million to the ultimate shareholders of NEGL.

The Board of Directors of Neptune Energy Group Midco 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 Midco 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. Furthermore, the $200.0 million promissory note issued in respect of the final 2019 dividend announced on 11 December 2019 was also settled on 25 February 2021.

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	**3,095.9**	1,392.4
Expected tax charge	**2,268.1**	886.9
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	**(8.0)**	(7.0)
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 70.1% (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 $2,268.1 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.

Notes to the consolidated financial statements
continued

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.

Notes to the consolidated financial statements
continued

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.

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):

	2021 CGU recoverable amount	Oil and Gas price		Post-tax discount rate	
Country of CGU In millions of US$		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**

Notes to the consolidated financial statements
continued

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 interests in Neptune Energy Group Holdings Limited and Neptune Energy Bondco plc.

Company In millions of US$	Total
Cost at 31 December 2021 and 31 December 2022	**1,977.2**

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.

Notes to the consolidated financial statements
continued

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	**105.3**	175.5
Loan to parent company	**455.3**	455.3
Prepayments and accrued income	**3.0**	3.1
Total	**1,284.9**	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		
Receivable from subsidiaries	**17.1**	16.5
Loan to parent company	**455.3**	455.3
Current assets	**472.4**	471.8
Amounts falling due after one year		
Inter-company loans receivable	**942.1**	938.7
Non-current assets	**942.1**	938.7
Total	**1,414.5**	1,410.5

The loan to parent company as at 31 December 2022 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 $449 of cash and cash equivalents at 31 December 2022 (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
Senior Notes	**6.625**	6.625	2025	**842.1**	838.7
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

Notes to the consolidated financial statements
continued

The movements in borrowings are described in the table below:

Group In millions of US$	31 December 2022
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**
Senior Notes	**838.7**	–	–	–	3.4	**842.1**
Uncommitted facilities	**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.

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	**415.6**	386.7
Lease liabilities	**64.2**	73.9
Wages and social security	**48.8**	47.0
Current trade payables and other liabilities	**828.1**	837.0
Other non-current liabilities	**34.7**	37.4
Lease liabilities	**58.4**	57.8
Non-current liabilities	**93.1**	95.2
Total	**921.2**	932.2

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
Loan from subsidiary	**455.3**	455.3
Amounts due to parent company	**7.2**	7.1
Interest payable to subsidiary	**7.3**	7.5
Current liabilities	**469.8**	469.9
Subordinated Neptune Energy Group Limited loan	**100.0**	100.0
Inter-company loan payable	**842.1**	838.7
Non-current liabilities	**942.1**	938.7
Total	**1,411.9**	1,408.6

The loan from subsidiary is payable to Neptune Energy Group Holdings Limited, a 100% owned subsidiary of Neptune Energy Group Midco Limited. The loan is repayable on demand and is interest free.

The non-current inter-company loan payable from subsidiary, Neptune Energy Bondco plc, bears interest and is due for repayment on 15 May 2025.

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.

Notes to the consolidated financial statements
continued

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.

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.

There were no provisions for the Company in both 2022 and 2021.

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.

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.

Notes to the consolidated financial statements
continued

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.

Group In millions of US$	31 December 2022 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	**1,284.9**	**–**	**–**	**1,284.9**
Other non-current assets[2]	**–**	**99.4**	**–**	**99.4**
Total	**1,405.7**	**99.4**	**13.0**	**1,518.1**

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.

Group In millions of US$	31 December 2021 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[1]	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.

Company In millions of US$	31 December 2022 Less than one year	Between two and five years	More than five years	Total
Financial assets at amortised cost				
Inter-company loan receivable	**–**	**942.1**	**–**	**942.1**
Receivable from parent company	**455.3**	**–**	**–**	**455.3**
Receivable from subsidiaries	**17.1**	**–**	**–**	**17.1**
Total	**472.4**	**942.1**	**–**	**1,414.5**

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				
Inter-company loan receivable	–	938.7	–	938.7
Receivable from parent company	455.3	–	–	455.3
Receivable from subsidiaries	16.5	–	–	16.5
Total	471.8	938.7	–	1,410.5

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.

	31 December 2022			
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]	**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**
Senior Notes	**–**	**842.1**	**–**	**842.1**
Subordinated Neptune Energy Group Limited loan	**–**	**100.0**	**–**	**100.0**
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	**412.8**	**33.8**	**–**	**446.6**
Total	**1,329.4**	**2,101.7**	**16.3**	**3,447.4**

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
Senior Notes	–	838.7	–	838.7
Subordinated Neptune Energy Group Limited loan	–	100.0	–	100.0
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	385.6	33.4	–	419.0
Total	1,926.3	2,514.0	20.3	4,460.6

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

Notes to the consolidated financial statements
continued

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.

Company In millions of US$	31 December 2022 Less than one year	 Between two and five years	 More than five years	 Total
Financial liabilities at amortised cost				
Inter-company loan payable	**–**	**842.1**	**–**	**842.1**
Payable to parent company	**7.2**	**100.0**	**–**	**107.2**
Loan from subsidiary	**455.3**	**–**	**–**	**455.3**
Payable to subsidiary	**7.3**	**–**	**–**	**7.3**
Total	**469.8**	**942.1**	**–**	**1,411.9**

Company In millions of US$	31 December 2021 Less than one year	 Between two and five years	 More than five years	 Total
Financial liabilities at amortised cost				
Inter-company loan payable	–	838.7	–	838.7
Payable to parent company	7.1	100.0	–	107.1
Loan from subsidiary	455.3	–	–	455.3
Payable to subsidiary	7.5	–	–	7.5
Total	469.9	938.7	–	1,408.6

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.

Notes to the consolidated financial statements
continued

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 on pages 76-84.

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.

Notes to the consolidated financial statements
continued

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 pages 28-31, 77 and 79-83 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.

Notes to the consolidated financial statements
continued

Group In millions of US$	Price movement	31 December 2022 Pre-tax loss/ (gain) on income	31 December 2022 Pre-tax loss/ (gain) on equity	31 December 2021 Pre-tax loss/ (gain) on income	31 December 2021 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.

Group In millions of US$	31 December 2022 Pre-tax loss/ (gain) on income	31 December 2022 Pre-tax loss/ (gain) on equity	31 December 2021 Pre-tax loss/ (gain) on income	31 December 2021 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		
At 31 December 2021 and 31 December 2022	1,977,175,201	1,977.2

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.

27.2 Capital commitments

In millions of US$	Group 31 December 2022	Group 31 December 2021	Company 31 December 2022	Company 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 had no capital commitments in either 2022 or 2021.

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 Energy Group Holdings Limited	Management and technical services	UK	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$ Related party undertaking	Nature of transactions	2022 Purchases	2022 Accounts payable	2021 Purchases	2021 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$ Related party undertaking	Nature of transactions	2022 Sales	2022 Accounts receivable	2021 Sales	2021 Accounts receivable
ONE-Dyas B.V. (Carlyle investor)	Oil and Gas	**9.1**	**0.9**	8.4	0.6

Notes to the consolidated financial statements
continued

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 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	**6.6**	6.7
Long-term employee benefits – post-employment benefits	**0.3**	0.3
Total compensation to key management personnel	**6.9**	7.0

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 Midco 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.

Notes to the consolidated financial statements
continued

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.

Notes to the consolidated financial statements
continued

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% 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.

Notes to the consolidated financial statements
continued

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 Holdings Limited	UK	I	100%	100%	Holding 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

Notes to the consolidated financial statements
continued

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%.

Glossary of terms

2C resources are the best estimate of contingent resources
2P reserves are the best estimate of proved plus probable reserves
ARC the Group Audit and Risk Committee
bbl barrel of oil
boe barrel of oil equivalent
capex capital expenditure
carbon intensity the amount of carbon dioxide emissions per boe
CCS carbon capture and storage
CGU cash-generating unit
E&P exploration and production
ED&I equality, diversity and inclusion
EPI the business of ENGIE E&P International S.A. and its direct or indirect subsidiaries which we acquired on 15 February 2018
ESG environmental, social and governance
EUA carbon dioxide European Union Allowance
FEED front-end engineering design
FID final investment decision
FTE full-time equivalent
FVOCI fair value through other comprehensive income
G&A general and administration expenses
G&G geological and geophysical
GHG greenhouse gas
GVA gross value added
HSEQ health, safety, environment and quality
IEA International Energy Agency
IOGP International Association of Oil & Gas Producers
IPIECA the global oil and gas industry association for advancing environmental and social performance
kboepd thousand barrels of oil equivalent per day
kbpd thousand barrels per day
LNG liquefied natural gas
LTIF lost time injury frequency
M&A mergers and acquisitions
mcf thousand cubic feet of natural gas
methane intensity methane emissions from production operations as a percentage of the total gas exported
mmboe million barrels of oil equivalent
mmbtu million British thermal units
mscf a unit of measurement for gases, million standard cubic feet
mmcfpd million standard cubic feet per day
MWh megawatt hour, one million units of electrical power used for one hour
NEGL Neptune Energy Group Limited, the entity through which our investors own their interests in the Group
NOx nitrogen oxide, a source of air pollution
OCI other comprehensive income, an accounting term
OGMP Oil and Gas Methane Partnership 2.0
opex operating expenditure
PSE process safety event
PSER process safety event rate
RBL our Reserve Based Lending facility
SDGs UN Sustainable Development Goals
STEM science, technology, engineering and maths
TCFD Task Force on Climate-related Financial Disclosures
t CO_2e tonnes of carbon dioxide equivalent, a measure that allows you to compare the emissions of other GHGs relative to one unit of CO_2
Tier 1 PSE loss of primary containment with the highest consequence
Tier 2 PSE loss of primary containment with lesser consequence
Tier 3 PSE loss of primary containment that does not meet the tier 1 or 2 threshold
TRIR total recordable injury rate, a measure of safety performance

Non-GAAP measures

The Group uses certain non-GAAP and non-IFRS measures and ratios that are not required by, or presented in accordance with, any generally accepted accounting principles (GAAP) or IFRS. These non-IFRS and non-GAAP measures and ratios may not be comparable to other similarly titled measures of other companies and have limitations as analytical tools and should not be considered in isolation or as a substitute for analysis of our operating results as reported under IFRS or GAAP. Non-IFRS and non-GAAP measures and ratios are not measurements of our performance or liquidity under IFRS or GAAP and should not be considered as alternatives to operating profit or profit from continuing operations or any other performance measures derived in accordance with IFRS or GAAP or as alternatives to cash flow from operating, investing or financing activities. These non-GAAP measures are defined below:

- **EBITDAX:** EBITDAX 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. EBITDAX, as defined by the RBL, includes our share of net income from Touat in 2020 following the repayment of the Touat Vendor Loan. EBITDAX is the performance metric used to measure our ability to produce income from our operations in any given year. The Group uses EBITDAX as it is a principal key performance metric under the Group's RBL borrowing facility.
- **Underlying operating profit:** Underlying operating profit is the 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 impairments, restructuring costs and curtailment gains/losses that might otherwise distort comparability between periods.
- **Adjusted development cash capital expenditure:** Reflects the cash expenditure on property, plant and equipment, excluding acquisitions and exploration, but including capital expenditure of our equity-accounted entity – Touat. The Group uses adjusted development cash capital expenditure to monitor investing activities on a cash basis.
- **Free cash flow:** Free cash flow is calculated as net cash flow from operating activities less net capital investments during the period including repayments under leases. The Group uses free cash flow to evaluate cash available for financing activities, including dividend payments, after investments in maintaining and growing our business.
- **Operating cost per barrel:** Operating costs for the year divided by production of wholly owned affiliates. Operating costs for the purpose of per barrel expense excludes changes in the value of over/under-lifted entitlement to production, to net-off income from tariffs and services that serve to recover costs, to exclude pre-development costs and to exclude abandonment costs incurred on non-producing fields. This is a useful indicator of ongoing operating costs from the Group's producing assets.
- **DD&A per barrel:** Depreciation and amortisation of oil and gas properties and right-of-use assets for the year divided by production of wholly owned affiliates. This is a useful indicator of ongoing rates of depreciation and amortisation of the Group's producing assets.
- **Net debt:** The net of cash and cash equivalents and debt recognised on the balance sheet. Net debt excludes the Subordinated Neptune Energy Group Limited Loan, as defined by the RBL. This is an indicator of the Group's indebtedness and is a principal key performance metric under the Group's RBL borrowing facility.
- **Net debt/EBITDAX:** The ratio allows investors to see how significant net debt is relative to EBITDAX. It is a principal key performance metric under the Group's RBL borrowing facility.
- **Liquidity:** The sum of cash and cash equivalents on the balance sheet, and the undrawn amounts available to the Group on our principal facilities. This is a key measure of the Group's financial flexibility and ability to fund day-to-day operations.

General information

In this report, unless otherwise indicated, our production, reserves and resources figures are presented on a basis including our ownership share of volumes of companies that we account for under the equity accounting method, in particular, for the interest held in the Touat project in Algeria through a joint venture company. Production for interests held under production sharing contracts is reported on an appropriate unit of production basis.

Forward-looking statements

The discussion in this report includes forward-looking statements which, although based on assumptions that we consider reasonable, are subject to risks and uncertainties which could cause actual events or conditions to materially differ from those expressed or implied by the forward-looking statements. While these forward-looking statements are based on our internal expectations, estimates, projections, assumptions and beliefs as at the date of such statements or information, including, among other things, assumptions with respect to production, future capital expenditures and cash flow, we caution you that the assumptions used in the preparation of such information may prove to be incorrect and no assurance can be given that our expectations, or the assumptions underlying these expectations, will prove to be correct. Any forward-looking statements that we make in this report speak only as of the date of such statement or the date of this report.

Alternative performance measures

This report contains non-GAAP and non-IFRS measures and ratios that are not required by, or presented in accordance with, any generally accepted accounting principles (GAAP) or IFRS. These non-IFRS and non-GAAP measures and ratios may not be comparable to other similarly titled measures of other companies and have limitations as analytical tools and should not be considered in isolation or as a substitute for analysis of our operating results as reported under IFRS or GAAP. Non-IFRS and non-GAAP measures and ratios are not measurements of our performance or liquidity under IFRS or GAAP and should not be considered as alternatives to operating profit or profit from continuing operations or any other performance measures derived in accordance with IFRS or GAAP or as alternatives to cash flow from operating, investing or financing activities. Refer to ‘Glossary – non-GAAP measures’.

Get in touch

Neptune Energy Group Midco Limited is a private limited company registered in England and Wales (No. 10684661).

Registered office

Nova North, 11 Bressenden Place
London
SW1E 5BY
UK

+44 20 7832 3900

Contact details for other offices can be found on our website.

Website

See **neptuneenergy.com** for annual reports and results announcements, as well as information on our operations and our ESG performance.

Neptune Energy Neptune_Energy

Photo credits

We would like to give a special thanks to the following people and organisations for their images:
Pages 17 and 52 – Ulf Sjöqvist
Page 22 – Even Fløgstad/©Equinor
Page 23 – Martin Sobotta
Page 41 – Tereza Apostol
Page 42 – Henry Woodward
Page 44 – International Rescue Committee
Page 45 – Forskerfabrikken
Page 49 – Martin Kuchling
Page 56 – Stewart Green
Page 85 – Jan Arne Wold/©Equinor

FSC
www.fsc.org
MIX
Paper from responsible sources
FSC® C001785

Printed by a carbon neutral company to the EMAS standard and Environmental Management System certified to ISO 14001.
This document is printed on paper made of material from well-managed, FSC®-certified forests and other controlled sources.

This publication has been manufactured using 100% offshore wind electricity sourced from UK wind.

100% of the inks used are vegetable oil based, 95% of press chemicals are recycled for further use and, on average 99% of any waste associated with this production will be recycled and the remaining 1% used to generate energy.

Designed and produced by emperor
Visit us at emperor.works



neptuneenergy.com