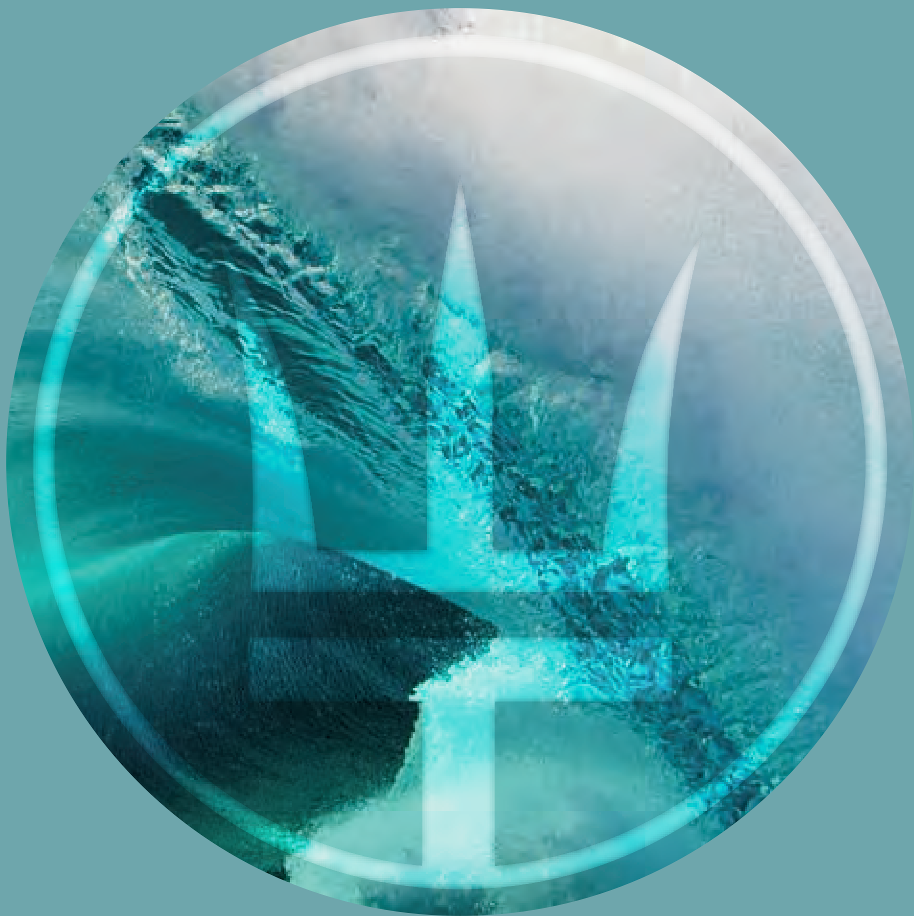


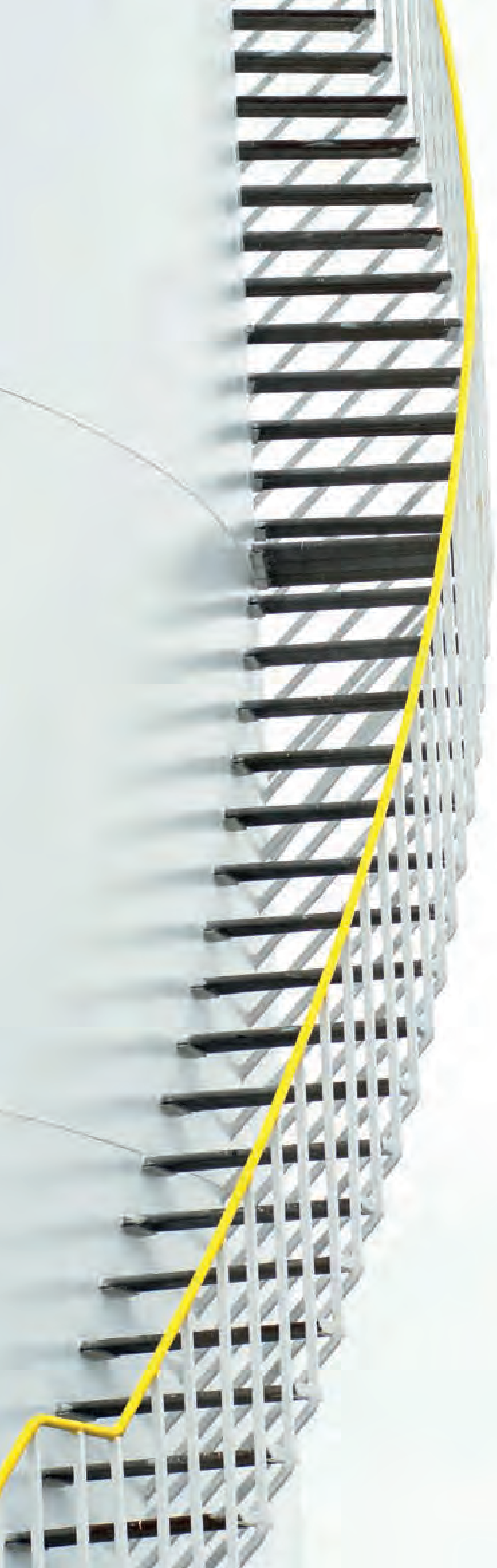
NEPTUNE ENERGY
ANNUAL REPORT AND ACCOUNTS 2019

Creating sustainable value

We want to make a positive contribution to meeting society's energy needs and the energy transition as the leading international gas-focused independent exploration and production company.

Our differentiated portfolio is long-life, low-cost and lower carbon and we're geographically diverse, with operations in Europe, North Africa and Asia Pacific.

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. EPI refers to the business of ENGIE E&P International S.A. (now renamed Neptune Energy International S.A.) and its direct or indirect subsidiaries.



Contents

Strategic report

At a glance	02
Our business model	04
Executive Chairman's message	06
Chief Executive Officer's message	08
Environment, social and governance	10
Operational review	20
Norway	24
Netherlands	26
UK	28
Germany	30
Algeria and Egypt	32
Indonesia and Australia	34
Financial review	36
Section 172(1) statement	41
Risk management	42

Governance

Corporate governance and Directors' report	46

Financial statements

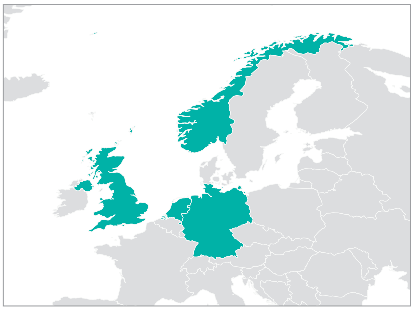
Independent auditor's report	54
Consolidated income statement	56
Consolidated statement of comprehensive income	56
Consolidated statement of financial position	57
Consolidated statement of changes in equity	59
Consolidated cash flow statement	60
Notes to the consolidated financial statements	62
Supplementary information gas and oil – unaudited	114
General information, forward looking statements, alternative performance measures, glossary of terms	115
Get in touch	116

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.

At a glance

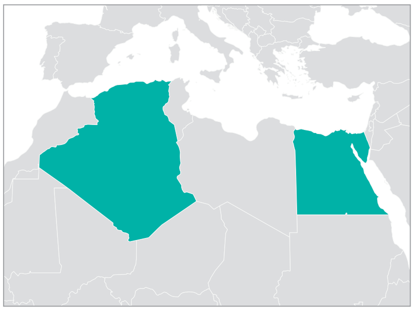
Neptune in numbers

Where we operate



Europe

Norway	Page 24
Netherlands	Page 26
UK	Page 28
Germany	Page 30



North Africa

Algeria and Egypt Page 32

Asia Pacific

Indonesia and Australia Page 34

Business profile

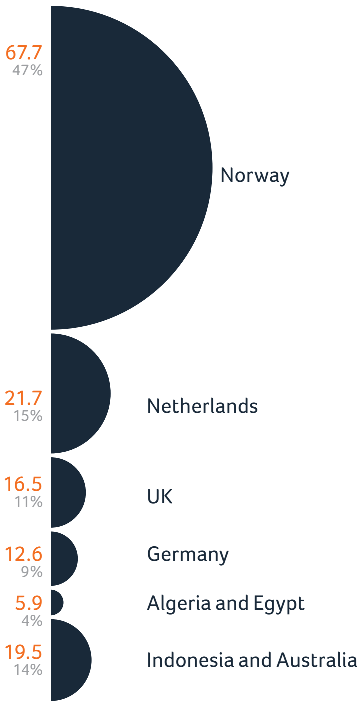
1,469
Total headcount

8
Countries we operate in

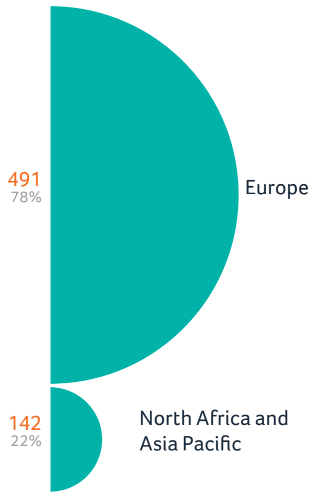
12
New licence awards in 2019

633 mmboe
2P reserves

Production
kboepd



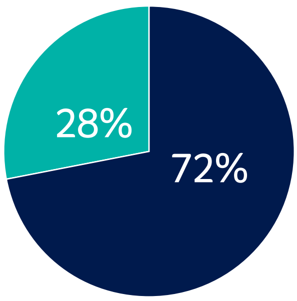
2P reserves
mmboe



Key performance indicators

Operating

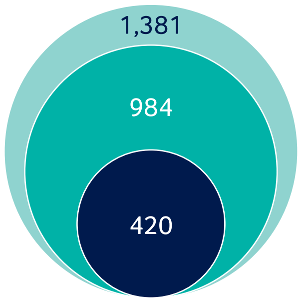
Production portfolio



Oil Gas

ESG

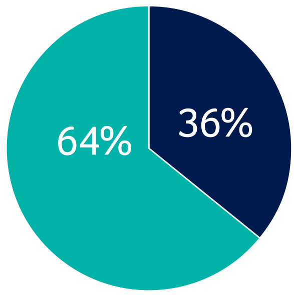
Economic impact: Europe



Direct: GDP generated by our operations Indirect: spend with supply chain Induced: wage spend in the wider economy

Financial

Revenue composition



Oil (including oil linked) Gas

143.9 kboepd
Total production

$2.8bn
Gross value added contribution

to the GDPs of Germany, the Netherlands, Norway and the UK

0.93x
Net debt/EBITDAX

85%
Production efficiency (including curtailments)

5.8kg
CO_2/boe

$1,321m
Cash flow

from operations after tax, before acquisition related expenses

90%
Reserves replacement ratio

2.1
Total recordable injury rate

number of total recordable injuries per one million hours worked

$10.3/boe
Opex

For our **glossary of terms**, see **page 115**.

For more information on our **operations**, see **page 20**.

For more information on our **ESG performance**, see **page 10**.

For more information on our **financial performance**, see **page 36**.

Our business model

The Neptune way

Our vision

Making a positive contribution to meeting society's energy needs and the energy transition as the leading international gas-focused independent E&P company

Investment proposition

A differentiated portfolio...

- Large-scale and diversified
- Long-life, low-cost and lower carbon
- Gas-weighted and well-positioned for the energy transition

...that delivers strong returns

- Significant cash flow generation and strong balance sheet
- Disciplined capital allocation
- Value-accretive growth and yield

Creating sustainable value for our stakeholders

Explore
A focused exploration programme balanced as to risk and reward and targeted around existing infrastructure

Develop
Developing fields, preferably as operator, with innovative low-cost solutions and short cycle times

Produce
Producing fields as efficiently as possible to maximise recovery, lower unit costs and reduce carbon intensity

Our values
- Excellence in HSE
- Accountability
- Integrity
- Teamwork

Neptune's DNA
- A powerful vision of the future
- Relentless commitment to doing what's right
- Seize opportunities for positive change
- Agile in our leadership and actions
- Take initiative and embrace accountability
- Celebrate success
- Embrace challenge
- Team of teams mindset
- Build great relationships

Our enduring priorities
- Focus on safe, economic **operations**
- Deliver superior field **development**
- Optimise the **portfolio** for the future
- Drive digital and technological **innovation**
- Realise the potential of our **organisation**
- Contribute positively to the **energy transition**
- Maintain our **social licence** to operate

Executive Chairman's message

Building on our strong beginnings to fuel the future

We are acutely aware of the dual challenges of building an E&P company that not only generates returns, but does so in a sustainable way.

We are building Neptune to be a resilient, low-cost, agile and innovative gas and oil producer at the forefront of the energy transition.

Two years on from the company's formation, we are a stronger business: one that is more geographically diverse, with a longer reserve life, a lower cost base and a lower carbon production profile that is heavily weighted towards gas. The result is a business that is delivering strong cash flows, has a robust balance sheet and is focused on both yield and value-accretive growth.

Since the formation of the business in 2018, investor and public scrutiny of energy companies has intensified. Being a young company coming into this environment does not give us an excuse to act more slowly. Quite the reverse, it focuses our minds on building a business to last, with responsibility at its core.

We are acutely aware of the dual challenges of building an E&P company that not only generates returns, but does so in a sustainable way. The work of the Board is to ensure the business is resilient and adaptable to change, while being well-positioned to take advantage of it.

The strength and depth of experience that my Board colleagues have provide valuable insight and challenge to balance short-term priorities with long-term objectives. I remain grateful to them all for their guidance.

Resilience in uncertain times

The coronavirus pandemic poses many challenges for society and global economies. Our primary responsibility is to our people, keeping them all safe and well. I am proud of the way we have reacted with speed, decisiveness and care to make sure that we have the right measures in place to ensure our people's health, while also maintaining our operational capability.

We have also seen a rapid deterioration in oil prices in 2020 that presents the energy sector with further challenges. While the pricing outlook is unclear, we are prepared for prices to be lower for longer.

We have built Neptune to be a resilient business, with a low cost base, relatively low leverage, a robust balance sheet, committed shareholders and a fully-funded development programme. While we have been quick to identify further cost savings across the business, we will not do so at the expense of long-term value. Furthermore, we see ourselves as an important player in helping the countries in which we operate navigate through the current situation by maintaining the supply of essential products and services.

Gas as a fuel for the future

If we look to the longer-term outlook for energy, we know that as the world's population grows, energy demand will follow.

With more than 850 million people around the world who still don't have access to reliable electricity, and ever larger numbers of people seeking travel and technology, energy is essential for social and economic development. At the same time, society is calling for a transformation to a low-carbon world.

While it is right that society demands a cleaner energy system, it is also right to say that the transition will not be instantaneous – nor will it come cheaply.

Under any scenario of the future global energy mix, including one that is aligned to the Paris Agreement goals, investment in oil and gas is needed today to meet demand in the decades ahead. Oil and gas resources that are low cost, accessible and efficient will be key in future scenarios, whether it be supplying increasing demand for heating and cooling, replacing retiring coal and nuclear fleets or backing-up intermittent renewable power generation.

Gas is flexible, easy to transport, a great store for energy and lower carbon than other fossil fuels. Importantly, relative to other forms of energy, its abundance means it's also relatively cheap. Replacing gas for heat, given its inherent high thermal efficiency, would require major infrastructure investment as well as a substantial increase in costs to the consumer.

Switching from coal to gas for power generation in the past decade alone has saved around half a billion tonnes of CO_2 emissions – equivalent to replacing some 200 million petrol and diesel vehicles with all electric vehicles running entirely on zero carbon electricity.

Important though gas is for both economic development and the energy transition, we need to minimise the carbon intensity of its production. This is why, even though we already have industry-leading performance in the carbon intensity of our existing operations, we are setting ambitious targets out to 2030.

To achieve these targets will require both investment and innovation. In the Netherlands, Neptune is already constructing the first offshore hydrogen project using renewable electricity.

Hydrogen has a role to play as it's plentiful, can be transported with little change to existing infrastructure and can be stored safely. In a net zero emissions scenario, scaling up these technologies is essential and requires extensive collaboration between policymakers and industry.

Our sector is uniquely placed to help, with the skills and experience to implement large-scale engineering projects, emissions reduction initiatives and innovative technologies. One such area is carbon capture and storage – and we are already partners in an operational project in Norway.

So, we are fully committed to being at the forefront of the energy transition, but also realise that under all current pathways gas remains an important part of the energy solution, in both its current and future forms. To eschew it is to expose society and energy consumers to potentially less secure, more costly and higher-carbon energy.

Trust and transparency

Although climate change may be the greatest challenge, sustainability is not just about greenhouse gas emissions. It is much broader in terms of how we act responsibly within the societies and communities where we operate as well as how we treat our own employees, partners, customers and suppliers.

Together with our current financial and operating disclosures, we are disclosing information on our environmental, social and governance (ESG) performance. The Board believes appropriate transparency, along with target setting and action plans, will build further understanding of where we are today and where we see ourselves tomorrow.

A 'mature start-up'

I often describe Neptune as a 'mature start-up'. 'Mature' in what we do and relentless about our safety, operational and environmental performance, but 'start-up' in the way we do it. It enables us to be quicker to adopt technology, quicker to turn ideas into reality and quicker to get to the right answers. Ultimately, it means we are quicker to generate value in all its forms.

Our people share common values, but, above all, a desire to be part of the success of a dynamic company at the start of its journey. The business we have built in just two years is testament to their determination and dedication.

The challenges we face may well be greater than those we've overcome, yet so are the opportunities. I am confident that the company is not only resilient enough to meet these challenges, but uniquely placed to make a positive contribution to meeting society's energy needs.

Sam Laidlaw

Executive Chairman
30 March 2020

Chief Executive Officer's message

Delivering on our strategy

Our financial headroom provides us ample firepower to pursue value-accretive growth opportunities should they arise, while our exploration and development portfolio ensures we have a pipeline of attractive organic opportunities.

Neptune delivered a solid performance during 2019, navigating a challenging operating environment amid weaker commodity prices.

While 2018 saw relatively buoyant commodity prices, 2019 saw oil prices fall on the back of increased supply and gas prices weaken, following milder winters in Asia and Europe.

As we have moved into 2020, commodity prices have softened materially, while the full impact of the coronavirus pandemic on demand is yet to be seen. Our objective has always been to structure Neptune to be resilient at whatever stage of the commodity price cycle. That means striking the right balance between our oil and gas exposure, while actively managing our commodity hedging.

As a result, while we are not immune from the impact of weaker prices, we are insulated from their full impact.

We firmly believe that a gas-weighted portfolio, that is both gas and oil-price linked, positions us well as global energy markets transition. It also provides investors with a differentiated offering.

Weaker prices mean our focus on underlying cost structures is even sharper. While we delivered cost-saving programmes across the Group in 2019, our focus remains on annual recurring cost savings. We made progress with this in 2019, but have identified more structural savings to pursue going forward. We recognise that some decisions can be particularly difficult for those affected, so we are committed to dealing with change collaboratively, respectfully and fairly.

As anticipated, production in 2019 was lower than in 2018, due to limited drilling activity coming into the year. Despite this, our production efficiency was robust, reflecting enhanced operations across the portfolio.

By increasing our use of technology we are better able to predict unplanned outages and to reduce the duration of planned maintenance. We are also working to improve our energy efficiency and to reduce our emissions.

Looking out for our people

Embedding a strong safety culture is the foundation of the business and our focus is relentless. The health and safety of our people is both paramount in importance and non-negotiable in approach.

While I am encouraged by the progress we made in 2019, we must remain vigilant to the risks we face. We have responded quickly and decisively to the challenges presented by the outbreak of coronavirus, with our priority being to secure the health and safety of our people.

Along with enacting our pandemic emergency plan, we are working closely with authorities and partners, as well as with our global health provider to put additional measures in place for those working both offshore and onshore.

We have also moved quickly to assure operational continuity by altering shift patterns, reducing non-critical activities and increasing our screening capability. And we have put in place mitigation plans for critical-path activities for all our project developments.

Our people are our biggest asset and their commitment, determination and tenacity continue to drive progress and change in what we do and how we accomplish our mission. In 2019, we undertook our first employee engagement survey and the results highlighted strong levels of engagement, as well as areas for improvement.

Overall employee engagement was 67%. Given the amount of change the business has undergone in the past two years, this was an encouraging result. However, we know we have more to do and will focus our efforts this year on training, development and wellbeing programmes.

Investing in growth

Fundamental to our success is a portfolio built for long-term growth. Our project pipeline and exploration programme extends our presence around key regions, while we executed value-accretive acquisitions that develop our footprint around key hubs, adding new avenues for growth.

These transactions, coupled with maturing contingent resources into reserves, resulted in another year of good reserve replacement. Of course, not all barrels are created the same, so it is particularly pleasing that our reserves additions are in our core areas and close to existing infrastructure, increasing the potential for lower-cost and shorter-cycle developments.

We continue to make good progress developing our projects and we remain on track to achieve production of 200 kboepd. The phasing of these developments meant that we expected 2020 to be a relatively capital-intensive year for the business, before we returned to more normal levels of expenditure in 2021. However, in response to lower commodity prices, we are moderating capital expenditure plans in the near term to offset anticipated lower revenues.

From the initial development phase through to operations, we are proud of the contribution we make to local and national economies, by stimulating growth and securing employment, both directly and indirectly through our supply chains.

We have built a strong exploration capability across the business. We have refreshed and upgraded our exploration acreage and have been awarded more than 20 new licences since the start of 2018, across Norway, Egypt and Indonesia.

The team's focus is on reducing exploration risk and bringing discoveries into production faster and at lower cost. Our work with world-leading technology firms to develop our digital subsurface programme is an exciting innovation and we look forward to developing its capability.

Neptune is now a more prospective, sustainable business, better balanced geographically, with a stronger pipeline of development opportunities.

Fit for the future

We have maintained a strong balance sheet, robust cash flow and healthy liquidity levels. Our aim is for our investment plans to be fully funded to keep us within our desired leverage ratios. We are committed to a low cost base and believe we can realise further savings in future, against a backdrop of softer commodity prices.

Our financial strength and low cost base give us resilience in a volatile marketplace. Our pipeline of development opportunities will further strengthen our cash flow through to 2021, enabling us to pursue growth opportunities as they arise.

James L House

Chief Executive Officer
30 March 2020

Environment, social and governance
Responsibly meeting the growing need for energy

Our ESG strategy sets out where we are today and where we would like to be in the years ahead. We've focused on the topics that matter most to our business and our stakeholders.

The world needs energy – and with our population set to grow to nine billion by 2040, it's going to need more. But societal expectations about how that energy is produced and used are changing. In the UK, for example, the government has set a net zero emissions target by 2050, and the European Commission has followed suit.

To meet the world's growing energy needs while reducing emissions, we need to rethink the way in which we find and produce energy and how we create sustainable value for our stakeholders. To help us do that, we developed our ESG strategy in 2019. This sets out our key areas for focus, along with performance measures. We've established carbon and methane intensity targets to 2030 as a first step, and are committed to reporting our performance in a transparent way.

We recognise that this is the start of the journey and we will detail our progress on an annual basis.

Our focus areas

To identify and assess our material topics, we engaged with a range of internal and external stakeholders, including investors, non-governmental organisations, partners and governmental representatives. We also examined ESG topics in their broader context by analysing existing and upcoming regulations, investor analysis and sustainability frameworks, such as the UN Sustainable Development Goals.

We then prioritised the topics according to the impact on our business and the level of stakeholder concern. These topics form the foundation of our ESG strategy, which was reviewed by our Corporate Responsibility Committee and approved by our Board in 2019.

The topics included in this report are those we assessed as having the highest impact on our business and of greatest stakeholder concern. We include performance data, and information on topics such as water, biodiversity and responsible supply chain management, on our website at neptuneenergy.com/esg.

For our key performance indicators, see **page 3** and our stakeholders, see **page 18**.

We support the UN Sustainable Development Goals, which aim to address global challenges such as poverty, inequality and climate change. Our core business contributes directly to the following goals and we provide examples of our contribution in this section.

We also contribute to the goals on health, education, reduced inequalities and the environment, through, for example, our community investment initiatives.
For more information, see page 14.

Our ESG strategy

Environment

Climate change and our role in a lower carbon world

- Maintain our gas-weighted portfolio
- Set ambitious carbon and methane intensity targets for our managed operations to 2030
- Use an internal carbon price for investment decisions
- Apply new technologies to reduce our carbon footprint

Environmental impacts
Implement our environmental policy, which sets out how we manage issues including biodiversity, water and waste

For more information see **page 12**.

Social

Health and safety
Aim for top quartile safety performance among peers in our operated regions

Economic impact
Measure our contribution to society via quantitative analysis of our direct and indirect impacts

Community investment
Focus our community investment on activities that are aligned with local needs and our business activities

Our people
Be the employer of choice by promoting a diverse and inclusive culture

For more information see **page 14**.

Governance

Corporate governance
Adopt the Wates Principles to enhance our corporate governance practices

Ethical conduct
Conduct our business with the highest degree of ethics and integrity

Human rights
Work with our suppliers and partners to manage potential human rights risks in our business and supply chain

For more information see **page 17**.

Climate change and environment

Environment

We want to reduce the impact that our operations have on the environment. To help us do that we developed a new environmental policy, working with employees, investors, industry bodies and non-governmental organisations to identify the biggest priorities. These include climate change, energy efficiency, greenhouse gas (GHG) and other air emissions, and spill prevention. The policy was approved by our chief executive officer in 2019.

Our environmental management system is certified to ISO 14001 in the UK and we plan to extend this to our other operations within the next three years. Our UK operations are also certified to the ISO 50001 energy management standard, along with our operations in Germany.

For performance data and information on water, waste and biodiversity see **neptuneenergy.com/environment**

Our role in a lower carbon world

We support the goals of the Paris Agreement and the net zero emissions by 2050 targets set by the UK government and the European Commission. Achieving these targets will require collective action from industry, government and consumers.

We believe we can be part of the solution, by maintaining our gas-weighted portfolio, improving the energy efficiency of our oil and gas production and using innovative technology such as carbon capture, use and storage and hydrogen production.

The board of directors of Neptune Energy Group Limited oversees our approach to managing climate-related risks, and in 2019 approved our carbon and methane emissions targets. These targets build on our experience of emissions reduction projects. In Norway, for example, we power our Gjøa field using hydroelectricity delivered via a submarine cable from the mainland. This saves around 200,000 tonnes of carbon dioxide (CO_2) every year.

We identify, assess and manage climate-related risks through our enterprise risk management system (see page 42). To prepare for future carbon regulation, we will incorporate an internal carbon price into our risk assessments and investment decisions from 2020.

Gas-weighted portfolio

We believe gas has a role to play both today and in the future, replacing coal as a lower carbon fuel for power generation, providing back-up to the variability of renewables and as a source of energy that is accessible, sustainable, transportable and affordable.

We have one of the highest gas weightings in our industry, with a production profile that is 72% gas and 28% oil. We intend to maintain a gas-weighted portfolio in the years ahead.

In the IEA's Sustainable Development Scenario, which is aligned with the Paris Agreement's objective of holding global temperature to well below 2°C, gas will gain market share over coal and oil by 2040 in sectors that are difficult to decarbonise, such as heavy-duty transport and industry.

Our commitments

For gas to play a full role in a lower carbon world, we recognise the need to take action to reduce methane emissions, advance carbon capture, use and storage technologies and develop low carbon gases, such as hydrogen.

That is why we are committed to:

- Targeting a carbon intensity of 6kg CO_2/boe by 2030 (see page 13).
- Maintaining the low methane intensity of our managed production and targeting net zero methane emissions by 2030.
- Building on our experience of capturing and storing CO_2:
  - At our K12b platform in the Netherlands, we participated in a 15-year programme to reinject CO_2 from a producing well into a producing gas field. This reduced CO_2 emissions during the lifetime of the project by around 100,000 tonnes.
  - Our partner-operated Snøhvit field in Norway captures and reinjects CO_2 back into the aquifer. Up to 700,000 tonnes of CO_2 is stored here each year.
- Participating in a pilot project to establish the world's first offshore green hydrogen production plant:
  - Our Q13-a platform in the Dutch North Sea will house a megawatt electrolyser that will produce green hydrogen from renewable energy. The hydrogen will then be transported via pipeline to a nearby platform, where it will be used to produce electricity. The plant is expected to be operational in 2021. The project was commissioned by Nexstep, the Dutch Association for Decommissioning and Re-Use, and TNO, the Netherlands Organisation for Applied Scientific Research.

Reducing operational emissions

The carbon intensity of our managed operations was 5.8kg CO_2/boe in 2019. We expect this to rise to 8.0kg CO_2/boe in 2020 due to additional compression at some of our existing fields.

Our carbon intensity is one of the lowest in the industry. Even by 2040, our projected level is still well below the industry average of 18kg CO_2/boe. But we see no grounds for complacency. Quite the reverse, we need to decarbonise further, which is why we have set a carbon intensity target of 6kg CO_2/boe by 2030. As a young company with a rapidly changing portfolio, carbon intensity is a more relevant long-term metric than absolute carbon emissions.

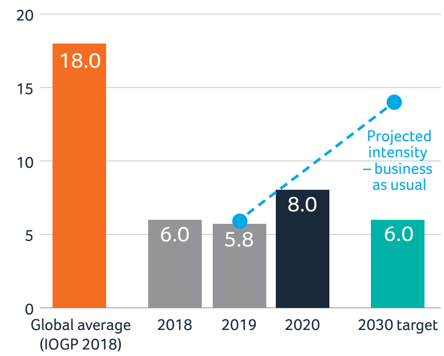
To meet this target, we will implement a range of actions such as reducing flaring and venting, replacing equipment, improving efficiency and using carbon capture technology.

Over the next few years we will continue to assess the potential of new technologies to further reduce our carbon emissions beyond 2030 and tackle the harder-to-abate facilities.

We'll review our target regularly so it remains stretching, taking account of portfolio changes, technological advances and other factors.

Carbon intensity

CO_2 kg/boe



We saw a decrease of almost 10% in our direct GHG emissions between 2018 and 2019. This was primarily due to improvements in our energy efficiency. For example, in Germany, we replaced gas-driven pumps with electric-powered models. In the UK, we replaced large diesel generators with smaller units that provide power during planned maintenance.

Our GHG data has been independently assured by EY. See **neptuneenergy.com/assurance**.

GHG emissions and energy performance[a]

	2019	2018
Direct GHG emissions (Scope 1) (tCO_2e)[b]	530,300	588,195
Indirect GHG emissions (Scope 2) (tCO_2e)[c]	31,586	27,854
Total scope 1 and 2 emissions (tCO_2e)	561,886	616,049
Carbon intensity (kg CO_2/boe)[d]	5.8	6.0
Methane intensity (%)	0.02	0.01
Energy consumption (MWh)	2,546,503	2,992,184
Reductions in energy use as a result of energy efficiency initiatives (MWh)	10,574	970
Flaring (GJ)	437,152	458,984

a) We report our GHG and energy consumption data from our managed operations. This includes Germany, the Netherlands, Norway and the UK.
b) Emissions from activities that we own or control, including the combustion of fuel and operation of facilities.
c) Emissions from the purchase of electricity, heat, steam and cooling for our own use.
d) Scope 1 and 2 emissions related to appraisal/development drilling and production/operations. We calculate intensity using wellhead production, in line with IPIECA sustainability reporting guidance.

Methane emissions

Methane is the primary component of natural gas and is a potent GHG. While it has a shorter lifespan than CO_2 – staying in the atmosphere for about a decade, compared with 200+ years for CO_2 – it has a much higher global warming impact. To meet the Paris Agreement goals, therefore, methane emissions need to be reduced from production and throughout the gas value chain.

Methane makes up 5% of our total GHG emissions. We inspect our operations for leaks and use technology, such as infrared cameras, at some of our assets as part of our leak detection and repair programme. We are currently assessing new technologies to detect methane, such as drones and satellites.

Our methane intensity, which refers to methane emissions as a percentage of gas exported, was 0.02% in 2019. This is one of the lowest intensities in the sector and to maintain our focus, we have set a target of net zero methane emissions by 2030.

The majority of our methane emissions occur during venting processes at our operations in the Netherlands and we are looking for ways to reduce them. We are a member of NOGEPA, the Dutch industry association for oil and gas exploration and production, which signed an agreement with the government in 2019 to halve methane emissions from the Dutch offshore oil and gas industry by 2020 from 2017 levels.

We are also working with industry partners at a global level through our membership of the Climate and Clean Air Coalition's Oil and Gas Methane Partnership (OGMP). In 2019, we contributed to the development of the new OGMP standard for monitoring and reporting methane emissions, and submitted data on three of our oil and gas assets in the UK, Norway and the Netherlands. This represents more than 60% of our operated production.

Other air emissions

We are working to reduce air pollution from our activities. In the Netherlands, we implemented a programme to reduce nitrogen oxide (NOx) emissions to meet new targets set by the government. This included changing turbines on 18 platforms and has resulted in a reduction of NOx emissions of more than 50% since 2018. For performance data on our air emissions, see neptuneenergy.com/esg.

Spill prevention and containment

Our priority is to prevent all spills from occurring in the first place. However, we have contingency plans in place at our operations that focus on the protection of the local area in the event of a spill. We closely monitor our assets to minimise the risk of spills to the environment. We had no spills greater than one barrel in 2019. The largest volume spilled was 16 litres.

Social

Social

We are committed to making a positive contribution to society, safeguarding our people and providing a diverse and inclusive working environment.

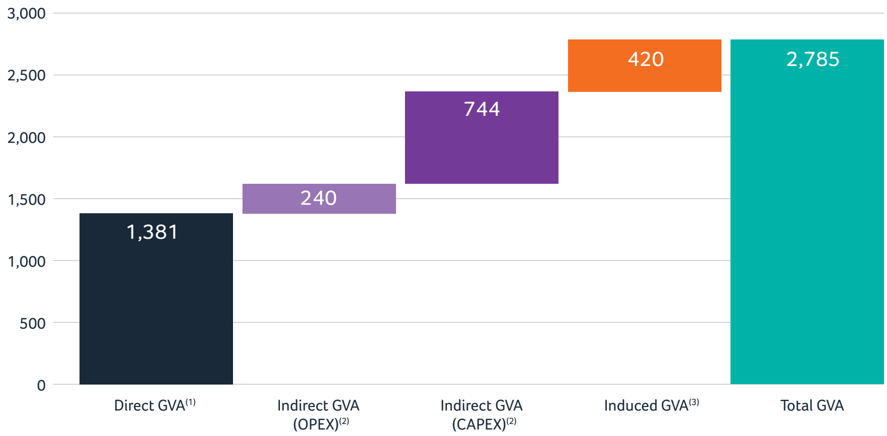
The relationships with the many local and regional communities in which we operate are an important part of our business. Through these partnerships, we can better understand the needs of each community and the impacts our activities are likely to have.

Working together with a wide range of local stakeholders, we are able to create appropriate sustainable development initiatives that reflect community priorities and focus on development.

For more information see **neptuneenergy.com/social**

Economic impact – gross value added (GVA) contribution in Europe

$m



1) We employ staff and our operations generate GDP.
2) We also spend money with our suppliers, who employ staff and generate GDP. They use other suppliers in turn.
3) Our own employees and those of suppliers spend their wages in the wider economy, generating more GDP and jobs.

Our contribution to the communities and countries in which we operate extends well beyond the provision of heat, light, mobility and power. We make a significant contribution by creating jobs, supporting local supply chains and paying taxes.

We supported an estimated $2.8 billion gross value added contribution to the gross domestic product of our European countries – Germany, the Netherlands, Norway and the UK – in 2019, and 11,500 jobs. This was $200 million higher than 2018 as we progressed our development projects and invested further through the supply chain.

Given our higher capital programme in 2020, we expect our economic impact to be greater still, underlining the important social and economic impact of the sector.

Community engagement

We consult with local communities throughout the different stages of our operations to help us understand their priorities and address their concerns.

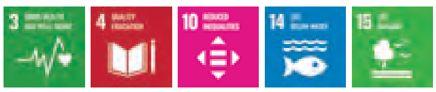
In Germany, we have a dedicated local stakeholder manager for each district where we operate. Stakeholders can also raise any concerns or questions via a telephone hotline or by email. The majority of concerns raised in 2019 related to noise, transport and timings for drilling activity.

At our Touat gas plant in Algeria, our community liaison manager engages with local authorities and community members to identify social investment opportunities. In 2019, we supported initiatives including a blood donation campaign, an exhibition of local artists and the provision of equipment for disabled women.

Social investment

We look for social investment opportunities where we can align local needs with our business activities. We are developing a group-wide social investment approach that will focus on local economic development, health, education and environment, and we will evaluate our decision to invest in a project against its alignment with the UN Sustainable Development Goals.

In addition to the goals our core business contributes to (affordable and clean energy, decent work and economic growth and climate action), our social investments align with the following goals:



We contributed $166,500 to social investment initiatives in 2019. This included support for a summer school programme on science run by social enterprise Forskerfabrikken in Norway and donations of school bags to children living close to our Touat gas plant in Algeria. We also supported environmental organisations, such as the Nature Foundation in Germany.

Safety

We want to make sure our people go home safely after every shift, no matter where in the world they work. Our continued pursuit of safety unites countries, departments and teams in a common purpose.

Our global operational integrity management standard and integrated management system provide a systematic way to drive continuous improvement. Together, they outline our requirements on issues including safety, health, emergency preparedness, environmental stewardship and risk management.

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 control of wells, and we put barriers in place to prevent them.

Employees and contractors must follow the IOGP's nine life-saving rules. The rules help protect our people against the most common causes of fatal incidents in our industry.

Having the right culture is key to good safety performance and we are reinforcing good practice through our group-led safety culture programme.

Safety performance is a factor in determining bonuses for our employees, as well as the executive team. Scorecards include targets for our total recordable injury rate (TRIR) and process safety event rate.

Our safety performance has continued to improve – with a 72% reduction in lost time injury frequency (LTIF) and a 60% reduction in TRIR since 2017.

Our process safety event rate, a key performance indicator that we introduced in 2019, was 2.19 per million hours worked. We had no tier 1 process safety events – losses of primary containment with the greatest consequence – in 2019. Our tier 2 process safety event (PSE) rate, which is the number of tier 2 PSEs per one million hours worked, was 0.07. This was well below our target of 0.39.

Contractor safety

We are committed to ensuring the safety of our workforce – this includes contractors as well as employees. Contractors carry out around 80% of the hours worked at Neptune and are, therefore, fundamental to the safety of our operations. Health and safety criteria are integrated into the pre-qualification and selection process for contractors and suppliers. Once on board, we work with them to build a strong safety culture through open, two-way communication. If there is a divergence between our own safety management system and those of our contractors, we put in place formal bridging systems.

We monitor contractor safety performance through the life of the contract, using third-party tools, and, where appropriate, through our own safety audits.

Learning from incidents

We record, investigate and analyse incidents and near misses. To help us learn from them we have adopted a 'restorative just' culture. 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 an incident helps us to learn and continuously improve.

Emergency preparedness

We test our emergency preparedness and response systems regularly. We have four tiers of emergency response, from site level to head office. The groups work together during an emergency, and each has specific tasks.

In 2020, we activated our pandemic emergency plan in response to the outbreak of coronavirus. We worked closely with our global health provider, along with authorities and partners, and put additional measures in place, such as implementing screening procedures and reducing non-critical activities.

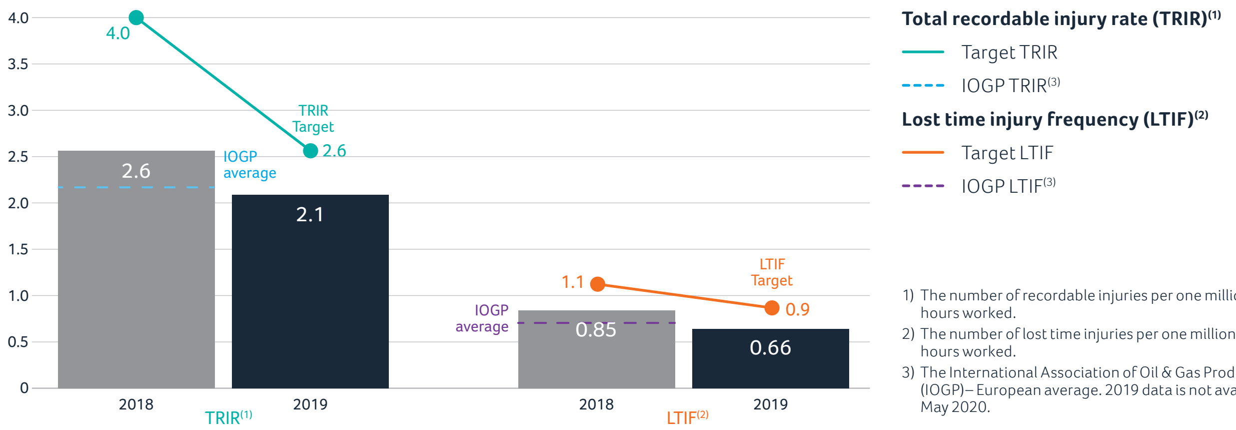
Health

Our duty of care for the people who work for us extends to their physical and mental health and we expect staff and contractors to be mindful of each other's wellbeing. To support this, we are implementing a global health directive, which sets out our approach to managing health risks and associated services within our operated activities.

Some of our work exposes our people to potentially harmful materials and we have implemented measures to reduce that risk. Recent studies have examined the long-term health effects of exposure to benzene, a volatile, carcinogenic compound found in petroleum. In response, we have set an internal benzene exposure level of 0.2 parts per million.

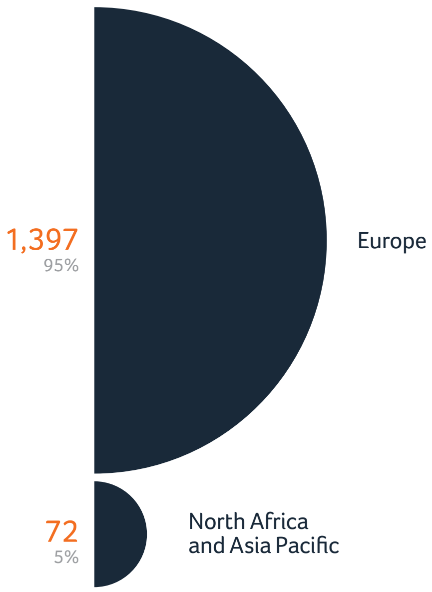
Results from our first employee engagement survey showed that employees would appreciate a greater focus on mental health and wellbeing. As a result, we've developed 'psychosocial' risk indicators for each of our countries and functions. The indicators cover issues that may affect people's psychological response to their work, such as high workload and a lack of control of tasks.

Our safety performance

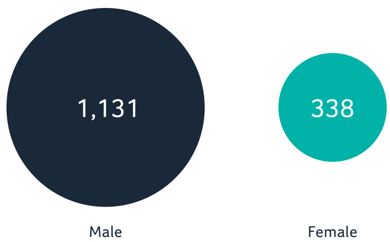


1) The number of recordable injuries per one million hours worked.
2) The number of lost time injuries per one million hours worked.
3) The International Association of Oil & Gas Producers (IOGP)– European average. 2019 data is not available until May 2020.

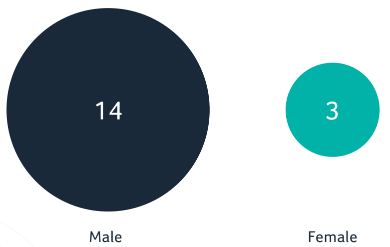
Employees by region



Employees by gender
(number)



Executive team by gender
(number)



Our people

We believe that a diverse workforce and an inclusive working environment create a more resilient and innovative business. We are committed to treating everyone with dignity and respect, and to providing a workplace that is free from discrimination, harassment and bullying. And we expect our partners and suppliers to do the same. We set out these commitments in our Equality, Diversity and Inclusion Policy.

From recruitment to career development to 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.

Our policy is that people with disabilities should be given fair consideration for all vacancies against the requirements for the role. Where possible, we make reasonable adjustments in job design and provide appropriate training for employees who become disabled.

1,469
Employees

46
Average age

Employee engagement

We conducted our first employee engagement survey in 2019, with a total of 72% of our employees participating. Our overall engagement score was 67%, and we will use this as a baseline from which to measure future performance. The results showed that people are motivated to contribute above expectations, but that we need to do more to ensure they feel valued. Mental health and wellbeing was an area highlighted for improvement. See page 15 for information on how we are addressing this.

Gender representation

Women represent 23% of our total workforce and 18% of our executive team. To address this gender imbalance and further develop our inclusive culture we are committed to:

- Ensuring diversity in job applicant shortlists.
- Establishing affinity groups to help employees with a common attribute, such as working parents, women, LGBTQ+, come together and help us understand how we can make Neptune a place where everyone can be themselves. Each affinity group will have an executive sponsor.
- Identifying high potential female talent at middle management levels so we can encourage progression to senior level roles.

In 2019, the Board consisted of three directors, all of whom were male. Board composition and diversity is being reviewed in 2020. For more information on our Board, and that of our parent company, see pages 46-49.

Employee forums

We work with employee forums at our larger operated facilities to encourage open, two-way dialogue.

We also operate a European Employee Engagement Forum, chaired by our group human resources director, which ensures that employee representatives can directly communicate with our executive team.

Around 52% of our employees are covered by a collective bargaining agreement. 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.

Following the difficult decision to close our Paris office, we worked with affected employees and their representatives to agree an appropriate settlement package. We also offered employees the opportunity to take up other roles within Neptune internationally, along with the necessary support to make these moves.

Governance and ethics

Governance

In order to ensure the highest standards of governance, ethics and integrity throughout our operations, we adopted the Wates Corporate Governance Principles in 2019. These set out six principles on purpose and leadership, board composition, director responsibilities, opportunity and risk, remuneration, and stakeholders.

For more information see **page 51.**

ESG governance

Our Corporate Responsibility Committee oversees our approach to ESG issues and performance. Reporting to our chief executive officer, members include senior leaders from health, safety and the environment, finance, legal, human resources, operations, corporate affairs and ethics and compliance. The committee met four times in 2019 to assess and prioritise our material issues, review our ESG strategy and our carbon intensity targets.

Tax and transparency

We are committed to acting with honesty and integrity in respect of tax laws and regulations, and to paying our fair share of 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.

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 the UK EITI report in 2019.

Ethical conduct

Our Code of Ethics and Business Integrity helps us to embed the highest ethical standards into our daily work, setting out five principles of action:

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

Every employee is responsible for complying with the Code. More than 90% of our employees completed our online ethics and whistleblowing training in 2019.

As part of our contractual agreements, we require our contractors and suppliers to adhere to our Business Ethics Principles for Contractors and Suppliers.

We investigate breaches of our Code and carry out disciplinary action where necessary.

Speaking up

We encourage our employees to speak up if they are concerned about any inappropriate, illegal or corrupt behaviour in relation to Neptune Energy's activities, as well as any actions that are, or could be, harmful to our business.

Our Whistleblowing Policy is designed to reassure anyone working for Neptune that they can raise concerns without fear of reprisals. Employees can speak to their managers, ethics and compliance officer, local legal counsel or Safecall, an independent confidential 24-hour reporting line.

We take a zero tolerance approach to corrupt business practices, including fraud and bribery. Our anti-bribery and corruption commitments are set out in our Code of Ethics and Business Integrity.

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 do not tolerate child, forced or bonded labour in any of our operations or by contractors working for us, as stated in our Code of Ethics and Business Integrity.

As part of our pre-contractual due diligence, we ask our suppliers to confirm that they comply with legislation relating to modern slavery. We published our second Slavery and Human Trafficking statement in 2019, which includes an evaluation of potential risks in our business and in our supply chain.

Working with governments and industry

We work with governments and regulators on issues that are relevant to our activities. For example, we demonstrated our hydrogen pilot project to government representatives in 2019, and discussed a range of issues such as gas specifications for the UK grid and industry targets to reduce emissions in the Netherlands and Norway.

We work with our industry via our membership of trade associations – these include Oil and Gas UK, Oil and Gas Methane Partnership, NOGEPA, Norwegian Oil and Gas, International Association of Oil & Gas Producers, IPIECA, BVEG and Nexstep. Through these memberships we share and learn from best practice on key issues such as emergency preparedness and emissions reductions.

Stakeholder engagement

Our stakeholders are those who are affected by, or who affect, our activities. We engage with our stakeholders regularly and the input we receive helps inform the decisions we make.

Stakeholder group	Form of engagement	How this engagement influenced our decision making
Our workforce	Employee engagement survey: online engagement survey carried out in October 2019 and completed by 72% of employees across the Group.	The results of the survey have been presented to the executive leadership team (ELT) and Boards. Members of the ELT and senior management have reviewed and discussed the results of the survey and have proposed initiatives to address some of the areas where lower scores were recorded. These initiatives will be implemented and monitored during 2020.
	Engagement with unions and works councils: management engage with union and works council representatives across the Group on a regular basis. These engagements are either part of a regular schedule of meetings or for specific purposes, such as to discuss an acquisition or the closure of an office.	The Group took the difficult decision to close its operations in Paris during 2019. Extensive meetings with the works council took place as part of the process of agreeing acceptable terms that would apply to colleagues who left the Group due to the office closure.
	Visits to offshore installations: in 2019, several members of the executive leadership team (including the CEO, the Group Human Resources Director and the Group HSEQ Director) and shareholder representatives visited some of our offshore installations.	Visits to our offshore installations enable the directors and members of senior management to understand working conditions offshore as well as the particular health, safety and environmental factors relevant to our business. This means they are well equipped to factor these considerations in to decision-making processes.
Our shareholders	We have regular meetings with representatives of our shareholders (including meetings of the Neptune Energy Group Limited (NEGL) Board, where representatives of the ultimate shareholders serve as directors of NEGL). In particular, during 2019, we organised a series of meetings with shareholder representatives to seek their views on our exploration activities, proposed M&A transactions, the 2020 budget and business plan, capital structure and our proposed ESG strategy.	The comments and views of the Group's shareholders were reflected in the broader strategic direction of the company, including the 2020 budget and business plan, and several M&A opportunities approved by the Board. In coming to their decision to approve the 2020 budget and business plan, the Board also had regard to the matters set out in Section 172(1) of the Companies Act 2006.
Our bondholders	We hold regular meetings with bondholders and present formal quarterly results presentations. During 2019, we conducted four formal quarterly updates and had more than 120 face-to-face meetings with bondholders and potential bondholders. The Company guarantees the bonds issued by its affiliate, Neptune Energy Bondco plc.	The feedback we receive from bondholders ensures that their interests are considered when making decisions that might affect the capability of the Group to meet its obligations towards bondholders and other creditors. We also take into consideration our bondholders' comments on ESG matters.
The communities in which we operate	At the Touat gas plant in Algeria, our community liaison manager engages with local authorities and community members to identify social investment opportunities. In 2019, we supported a blood donation campaign, an exhibition of local artists and the provision of equipment for disabled women. In addition, during the construction of our central processing facility, an Imam from the local community visited the site to talk to the workforce about the importance of safety.	Engaging with the local communities where we operate helps us to understand their concerns and reflect these concerns in the decision-making process. It also enables us to identify and address the effect of our operations in the local communities.

Stakeholder group	Form of engagement	How this engagement influenced our decision making
Our suppliers	We engaged with suppliers using a combination of conferences and one-on-one meetings. With all our major suppliers we have performance measures in place that are discussed regularly at weekly, monthly and quarterly performance review meetings, where suppliers are given the opportunity to suggest improvements in our relationships with them. We have high level relationship meetings with the top tier suppliers. We attend Sharefairs in the UK and other conferences to share our plans and what it takes to become a supplier for Neptune. In addition, we continued to encourage our suppliers to raise any concerns or issues they have with the Company, their contacts, members of our workforce or via Safecall, our confidential whistleblowing system. In 2019, we focused on safety with our suppliers, for example, holding workshops in the Netherlands and the UK to engage with them and get their views on how we can be safer.	Suppliers are appointed using a formal procurement process, usually requiring at least three quotations from different suppliers before an appointment is made. Suppliers are appointed on the basis of the most competitive quotations provided, considering the overall terms proposed by the supplier and their capability to provide the requested goods and/or services. We require our suppliers to adhere to our Business Ethics Principles for Contractors and Suppliers. Engaging with suppliers and understanding their capabilities is an important part of the appointment process, ensuring that they have the necessary competencies to provide their services to the Group in a safe and reliable manner.
Our joint venture partners	We work collaboratively with our joint venture partners and it is our ambition to be both the operator of choice and partner of choice in our operations and development activities. We engage with our partners via regular formal meetings (such as joint operating committees) and ongoing informal engagements. Alongside our partners, BP and JAPEX, we won the 'MER UK' category at the Oil & Gas UK award in 2019, recognising the parties' collaboration in aiming to achieve maximum economic recovery from the Seagull field.	Ongoing dialogue with our partners allows us to make better-informed decisions in the knowledge that the views of all interested parties have been considered. For example, collaboration on the Seagull development allowed the Group (and the other partners) to reach a final investment decision to proceed with the project in an accelerated timeframe.
Host governments and regulators	We engage with all host governments directly through meetings when senior members of staff are in country and indirectly through their embassies in London and through the British embassies in country. As part of the West Ganal signing process, the Group CEO met a range of officials representing SKK Migas (the Indonesian oil and gas regulator) and the Indonesian Government. This was supported with a series of briefings before and after with the Indonesian Embassy. As part of a European tour, SKK Migas requested follow-up meetings with Neptune leadership, which took place in 2019.	These meetings significantly strengthened the Group's contacts and links with SKK Migas and the Indonesian Energy Ministry, providing points of contact for issues to be raised directly when they arise and providing greater visibility of the concerns of the Indonesian government and SKK Migas in the decision-making process.
Government authorities and NGOs	As part of the pilot green hydrogen project in the Netherlands, we have worked with the government authority, Nexstep, and research body, TNO, to deliver an offshore electrolyser module on platform Q13-a. This diverse group covering academia, industry and government has given Neptune exposure to world-leading technology and thinking on decarbonising the gas industry.	Engagement with a broad range of non-governmental organisations (NGOs) helps the Group to assess energy priorities in our countries of operation. In addition, in North Africa the focus is on skills transfer and training.
	During the process of developing our environmental strategy, we talked to governmental bodies, regulators and environmental NGOs.	The discussions with these and other stakeholders have contributed to the Group's process for formulating an environmental strategy that reflects the concerns of these stakeholders by, for example, setting carbon targets (see page 13).
Our customers	Our customers tend to be large international corporations or state-owned enterprises. We engage with our customers strictly on arm's length terms and in accordance with all applicable laws and regulations.	Recommendations regarding significant customer contracts, such as a contract extension or price review, are scrutinised by the directors as to the fairness of the terms and compliance with underlying laws and regulations. Input from the directors is sought during the approval process.

Operational review
Building the business for long-term growth

Overview

Neptune Energy made important strategic progress in 2019, building the business for long-term growth through acquisitions, which added low-cost projects, material reserves and resources and incremental production in key geographies, including the UK, Norway, Indonesia and Germany.

In Indonesia, through our transaction with ENI and our new licence award, we have established a world-class acreage position in the Kutei Basin. This not only enhances value from our existing Jangkrik assets, but also improves alignment with our partners and provides material growth opportunities through the development of existing discoveries and longer-term exploration. The operator expects to bring the Merakes development onstream in mid-2021, adding 8 kboepd of net production at plateau and fully utilising spare capacity on the Jangkrik FPU, which is located 48km away from the field.

In October 2019, we announced the acquisition of the North Sea assets of Energean Oil & Gas for $250 million (which Energean is acquiring from Edison). The proposed transaction will add 3 kboepd of production and a 25% interest in the large Glengorm discovery in the UK and two new developments in Norway. This transaction is contingent on Energean Oil & Gas completing its transaction with Edison.

Subject to completion of the Energean Oil & Gas transaction, we are planning to participate in appraisal drilling at the Glengorm discovery in late 2020 or 2021. The field has significant resource potential and is likely to become part of the next phase of development projects at Neptune. Glengorm is located close to our Seagull project and our recent Isabella discovery, increasing the importance of the UK Central North Sea to Neptune.

In Norway, the first of these new developments, Dvalin, is due onstream in the fourth quarter of 2020, while the Nova field is being developed as a tie-back to our operated Gjøa field and is due onstream in 2021. Together these new developments are expected to add 12 kboepd of net production to Neptune at plateau.

While acquisitions enable us to bolt-on high quality and complementary assets, we are also focused on delivering organic growth through development projects and exploration, helping us to demonstrate a track record of delivery and become a partner of choice.

Health and safety is critical to our business and we continued to make improvements across the Group throughout the year, with material reductions in both injury frequency rates and lost time injuries. Targets for further health and safety improvements have been set for 2020. To achieve this, we have raised awareness, strengthened our safety culture and improved our processes and reporting.

Our operating reliability in 2019 was strong, with high production efficiency at our operated assets and operating costs at the lower end of guidance. However, Group production for the year was impacted by delays to the start-up and a slower than planned ramp-up at our Touat project in Algeria, and a number of curtailments, in Norway, the Netherlands and Indonesia, which were largely due to factors outside Neptune's control.

Softening commodity prices were also a challenge in 2019, with gas prices particularly weak due to milder winters in Europe and Asia. While we maintain a high hedge ratio, both oil and gas prices have moved lower in early 2020 and are likely to remain weak in the short term. This has been exacerbated by the impact of the coronavirus. The medium- and longer-term outlook is more positive and, as a gas-weighted business, we are well positioned to benefit from gas demand growth and the energy transition.

Despite lower production and softer commodity prices, our financial performance in 2019 was strong, with robust operating cash flows of $1,320.6 million during the period. We continue to invest in our growth projects and expect activity to increase in 2020 as we reach the final stages of our current development programme. Our growth plans are fully-funded from existing resources, however, our investment plan in 2020 is expected to result in an increase in our leverage ratio, which is currently low by industry standards. Capital discipline is important to us and we expect to significantly deleverage as our main project pipeline comes onstream.

Health and safety

In 2019, there were no serious personal injuries and our lost time incident frequency (LTIF) improved through the year from 0.85 to 0.66 per million hours worked. Our total recordable incident rate (TRIR) improved from 2.6 to 2.1 per million hours worked.

These figures include our joint venture operations. Our process safety event rate, a key performance indicator that we introduced in 2019, was 2.19 per million hours worked, which was below our target of 5.0.

During 2019 we continued to roll out our Safety Cultural Programme to ensure the right mind-set and common approach, regardless of where we work or what we do. That programme saw us focus on safety leadership, restorative just culture and the roll out of the revised International Association of Oil & Gas Producers Life Saving Rules.

In parallel, we further developed our company-wide health, safety, environment and quality incident management reporting system (Synergi), completed a company-wide risk assessment programme and implemented regular risk reviews. Importantly, we also ensured that ultimate responsibility for risk was firmly embedded in the line, as it is for all matters relating to health and safety.

In 2019 we rolled out our crisis management tool. This has helped improve cooperation and communication between the different tiers in our emergency response organisation. We are connected through four tiers from production site to head office. All tiers work in unison but have specific tasks in case of emergency or crisis. Crisis response exercises are carried out regularly.

Environment, social and governance (ESG)

We developed our ESG strategy in 2019 by engaging with our stakeholders (investors, non-governmental organisations, employees, partners and governmental representatives) and reviewing legislation, industry best practice and sustainability frameworks. This informed the identification and prioritisation of material topics for our ESG strategy.

We are committed to a gas-weighted portfolio as a key part of our investment proposition, positioning us well for the transition to a lower carbon energy world. We see gas as a fuel both for today and for the future, replacing coal as a lower carbon fuel for power generation, providing back-up to the variability of renewables and as a source of energy that is accessible, transportable and affordable.

For gas to play a full role in a lower carbon world, we recognise the need to take action to reduce methane emissions, advance carbon capture, use storage technologies and develop low carbon gases such as hydrogen. That is why we are committed to:

- Maintaining our industry-leading methane emissions performance. The methane intensity of our managed production was 0.02% in 2019. This is significantly below the industry average. We are targeting net zero methane emissions by 2030.
- Building on our experience of capturing and reinjecting CO_2 at our K12b platform in the Netherlands, and at our partner-operated Snøhvit field in Norway. Up to 700,000 tonnes of CO_2 is stored here each year.
- Participating in a pilot project to establish the world's first offshore green hydrogen production plant in the Netherlands.

To drive improvements in the energy efficiency of our operations, we are also targeting a carbon intensity of 6kg CO_2/boe for our managed production by 2030. This represents a 60% reduction compared with taking no action. We will review this target regularly, so it remains stretching, taking account of portfolio changes, technological advances and other factors.

We are continuously working to reduce our emissions and this approach is integrated in all our activities, ranging from offshore production facilities that are supplied with electric power from onshore (Gjøa in Norway and Q13 in the Netherlands), to large NOx reduction projects in the Netherlands and flaring and venting reduction initiatives in Germany. We continue to evaluate the opportunities for new technological solutions to further reduce our emissions and we will incorporate an internal carbon price into our risk assessments and investment decisions from 2020.

We make a significant economic contribution to the countries in which we operate. In 2019, we supported an estimated 11,500 jobs across our European activities and contributed $2.8 billion gross value added to the countries' economies. This was an increase on 2018 as we progressed our development projects, investing further through the supply chain.

Given our higher capital programme in 2020, we expect our economic impact to be greater still, underlining the important social and economic impact of the sector.

We support the UN Sustainable Development Goals (UN SDGs), which aim to address global challenges such as poverty, inequality and climate change. Our core business contributes directly to the goals on affordable and clean energy, decent work and economic growth and climate action.

> Our operating reliability in 2019 was strong, with high production efficiency at our operated assets and operating costs at the lower end of guidance.

We also contribute to goals on health, education and reduced inequalities through our social investments.

Project development

During 2019, we sanctioned two new projects (Seagull in the UK and Duva/P1 Gjøa in Norway) and announced the acquisition of a further three projects already in development. Including Touat, we now have nine sanctioned projects in development, up from two at the time of the Engie E&P acquisition in 2018. Together, these projects are expected to contribute around 110 kboepd of new production, enabling us to achieve a production milestone of 200 kboepd.

Beyond our existing project pipeline, we are actively identifying and maturing opportunities for the next phase of growth. While further technical and commercial work is required, new projects, which may include Touat Phase II, Glengorm, Isabella, Echino South, Maha, Merakes East and Petrel, will help maintain production at around the 200 kboepd level and support future growth beyond 2022.

Production

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

Total production (kboepd)	2019	2018[1]
Norway	67.7	77.8
UK	16.5	17.1
The Netherlands	21.7	28.3
Germany	12.6	13.0
North Africa	5.9	4.3
Asia Pacific	19.5	21.3
Total production (kboepd)	**143.9**	**161.8**

1) Daily average production over the period 15 February 2018 to 31 December 2018.

Although plant availability was generally good in 2019, production levels were impacted by the delayed start-up and a slower than expected ramp-up at our Touat project, along with a number of unplanned curtailments related to export systems.

These curtailments reduced output from our operations in Norway, the Netherlands, the UK and Indonesia and largely reflected third party issues outside Neptune's control. For the full year, we averaged 143.9 kboepd of production in 2019 (including 1.4 kboepd from equity accounted affiliates), but importantly we have started 2020 at significantly higher rates.

At our Touat project, the plant was mechanically completed in the first half of 2019. However, a longer than expected commissioning and regulatory approval process delayed first gas until September 2019. The ramp-up to plateau was subsequently slowed by a number of technical and operational start-up issues with the plant facilities, which have now been resolved.

Excluding these third-party curtailments, reservoir performance across the Group's assets was strong and production efficiency high, averaging 88% (85% including third party curtailments). There are further operational improvements to make and we have restructured our global operations function to enhance focus and delivery of our key projects. We are also employing new technologies and digitalisation in more areas of the business to help improve our maintenance performance and lower operating costs.

From January 2020, Neptune changed its barrel of oil equivalent conversion factor to a standard 5.6 mscf/boe across the Group from its previous approach, which aggregated and converted volumes on a field by field basis. As our weighted-average conversion factor is 5.6 mscf/boe this change has a limited impact on our Group reserves but does impact our regional production numbers. The main change will be seen in Germany where the new factor results in approximately 5 kboepd of additional reported volumes, reflecting low calorific gas produced from the Altmark field. Modest increases in the Netherlands and the UK are largely offset by small declines in Norway and Egypt. There is no financial impact from the change in policy. The use of a single standard conversion factor for the entire Group is now consistent with other major oil and gas companies with a large number of assets.

Operational review

Reserves and resources

Reserves summary	Proved plus probable reserves (mmboe)
2P reserves at 31 December 2018	638
Production	(52)
Revisions, extension and discoveries	23
Acquisitions and divestments	25
2P reserves at 31 December 2019	**633**
Total reserves replacement ratio	90%
Total reserves production ratio	12 years

1) Numbers may not add up due to rounding differences.

The acquisition of an interest in the Merakes field, together with maturing contingent resources into reserves, contributed to a solid reserves performance in 2019. We ended the year with proved plus probable reserves (2P) of 633 mmboe and successfully replaced 90% of our production.

Reserves additions were evenly split between revisions, extensions and discoveries and acquisitions, with Indonesia, the Netherlands and the UK our strongest regions. Importantly, we now have a greater proportion of developed 2P reserves than before and expect further progress in the next two years as our project pipeline is brought onstream. Our 2P reserves to production ratio increased from 11 to 12 years.

Contingent resources provide Neptune with significant growth opportunities and in 2018 and 2019 we successfully matured 96 mmboe into reserves. 2C contingent resources at 31 December 2019 (under the development pending, on hold and unclarified categories) were estimated at 302 mmboe.

As the proposed acquisition of the North Sea assets from Energean Oil & Gas has not yet closed, reserves and contingent resources attributed to these assets are excluded and provide further material upside to be included in our future estimates. We currently estimate 2P reserves of 31 mmboe and 16 mmboe of contingent resources for these assets, with significant additional resource upside to be targeted in our drilling plans.

Our reserves estimates are reviewed annually by ERCe an independent third-party reserves auditor.

Exploration

We made good progress delivering our exploration strategy in 2019, drilling six wells and further developing our acreage position, particularly in Indonesia, Egypt, Norway and the UK. Two additional wells commenced in 2019 and were completed in Q1 2020. From our 2019 drilling programme we made an important discovery at Echino South, which was one of the largest made on the Norwegian Continental Shelf in 2019.

2019 drilling results

Country	Licence	Well	Working interest	Outcome
Norway	PL093	Skumnisse	7.56%	Dry
Norway	PL090	Echino South	15%	Oil and gas discovery
UK	P2133	Darach	30%	Oil and gas discovery
Germany	Schwegenheim	Schwegenheim	50%	Oil discovery

In the first quarter of 2020, we announced further discoveries at Sigrun East in Norway, Isabella in the UK and Schwegenheim in Germany. The Isabella discovery, which is located in the Central North Sea, is very encouraging with gas condensate and light oil encountered in several formations. The results of the well will be analysed to further evaluate the discovery, determine future appraisal activity and recoverable resource estimates.

The Sigrun East and Echino South discoveries are located close to existing infrastructure and offer potential for future development as subsea tie-backs. The Schwegenheim well has been suspended for future potential testing.

Due to lower commodity prices, the remainder of our 2020 exploration programme is under review.

2020 drilling results

Country	Licence	Well	Working interest	Outcome
Norway	PL025	Sigrun East	25%	Oil discovery
UK	P1820	Isabella	50%	Gas condensate discovery

We continue to look for longer-term exploration opportunities and in 2019 were awarded a total of 12 licences in Norway, the Netherlands, Egypt and Indonesia. Through acquisitions, we also secured important exploration licences in the UK and Indonesia offering both discoveries and material upside potential through drilling. Both areas will be a key focus for Neptune in the coming years. In January 2020, we were awarded a further 13 licences in Norway, including four as operator.

In early 2020, we announced plans to strengthen our digital subsurface capability, aimed at reducing risk and shortening the cycle between discovery and production. Harnessing cloud infrastructure, artificial intelligence and machine learning will enable us to interpret greater volumes of data, improve data access, reduce administration and enhance collaboration between our technical teams.

Financial highlights

Despite lower production and softer commodity prices, Neptune delivered a strong financial performance in 2019, benefitting from our hedging strategy, low operating costs, tax efficiencies and one-off tax credits. During the second half of the year, we issued a further $300 million of bonds as an additional issuance to our existing $550 million Senior Notes due 2025. This enhanced our available liquidity and provided greater financial flexibility prior to closing our acquisitions.

We continue to pursue a conservative financial strategy and maintain hedges in excess of the requirements of our RBL facility. As at 31 December 2019, our aggregate post-tax hedge ratio, as defined on page 38, for 2020 was 56%. Since the start of 2020, the commodity market outlook has become more uncertain, with oil prices falling sharply. We have responded by increasing our hedges in 2021 and 2022 to provide further protection for our medium-term cash flows.

At a Group level we achieved a strong operating cost performance, with opex of $10.3/boe in 2019. This reflected a good performance in Norway, where costs fell to $6.4/boe. We have also reduced G&A costs to $68.6 million, reflecting our cost efficiency programmes across the business, especially in Germany and the Netherlands. We completed the first stage of the closure of our Paris office at the end of 2019 and expect to complete the final phase by the end of the first half of 2020. While this has resulted in a one-off charge of $61.3 million in 2019, we expect it to deliver annual recurring cost savings once complete.

Despite reporting lower revenues, post-tax operating cash flows in 2019 remained strong at $1,320.6 million. We reinvested $825.5 million in development capex, mainly at the Njord and Fenja projects in Norway, and a further $61.9 million in exploration expenditure. In 2020, we plan to increase our investment in both development capex and exploration as we deliver on our growth strategy.

Neptune retains a strong balance sheet and available liquidity. Net debt (excluding the Subordinated Neptune Energy Group Limited Loan and Touat Project Loan) at the end of the period was $1,490.1 million, resulting in a net debt to EBITDAX (excluding our share of net income from Touat) ratio of 0.93 times. This remains well within the 3.5 times reserves base lending (RBL) covenant and in line with recent guidance.

In October 2019, the definition and calculation of the leverage ratio within the shareholders' agreement was aligned with the definition of the leverage ratio in the RBL facility documentation. While our capex programme and the planned completion of the EnergeanOil & Gas transaction will increase our leverage, we expect it to fall in 2021 to more normal levels as new projects come online.

Our financial position is strong and as at 31 December 2019 we had $1.2 billion of available undrawn facilities under the RBL, which, combined with our reported cash position of $85.4 million, provides headroom of $1.3 billion and fully funds our growth opportunities.

Outlook for 2020

Neptune is a resilient business and we have taken decisive steps to protect our people and operations during the COVID-19 pandemic. Our emergency pandemic plan has been implemented and working practices changed to ensure operational continuity. We have also put in place mitigation plans for our projects and will continue to evaluate supply chains for impacts.

Despite these challenges, Neptune expects to make important progress across its portfolio in 2020, with higher activity at our development projects, focused exploration programme and further cost and operating efficiencies. We aim to achieve this within a framework of continued improvements in our safety performance and environmental footprint. Neptune already has one of the lowest carbon intensities and methane emissions in the sector but has set ambitious targets to reduce this further over the next decade.

In 2020, we expect Group production to average 145-160 kboepd, dependent upon the timing of new developments coming on stream, the closing of the Energean Oil & Gas transaction as well as the impact of COVID-19. 2021 will see significant further growth as seven additional developments come onstream.

In response to lower commodity prices, we have identified cost reductions of $300–400 million across operating costs, general and administrative expenses (G&A) and capex. As a result, we have materially reduced our planned development expenditure by $250–350 million to $750–850 million in 2020. This investment programme will further develop our reserves base and underpin our growth strategy , although the timing of some activities may change as we implement our cost reduction plan. The remainder of our exploration programme in 2020 is under review.

Reflecting identified cost savings and our existing efficiency programmes, operating costs in 2020 are expected to remain low at around $10-11/boe. We are also targeting improvements in production efficiency at our operated assets.

While Neptune's investment plans are fully funded, we will continue to identify additional potential savings throughout our business, further safeguarding the profitability of our business and asset values.

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Operational review

Norway

Norway continues to be the largest contributor to Neptune's global production portfolio representing almost 47% of the Group's volume.

Production

Norway continued to deliver strong results for Neptune in 2019, with production in line with expectations, operating costs lower, and material progress achieved in our growth projects.

Production from Norway averaged 67.7 kboepd in 2019 and contributed 47% of Group volumes. Production for the full year reflected natural declines at some of our fields, along with shutdowns and third-party curtailments in the second half of the year. Underlying reservoir performance remained strong across our portfolio, reflected in our reserves estimates and a strong start to production in 2020.

Production optimisation and ongoing investment to mitigate natural declines is a key focus for the Group as we work to maintain low operating costs in Norway and to capture incremental growth opportunities in our core operating areas.

In 2019 we made important progress in this area, sanctioning the Gjøa P1 and Duva developments and acquiring an interest in the Nova development. All three of these projects are due to be tied back to our operated Gjøa platform and brought onstream in 2021. At Fram, our three new producing wells continue to perform ahead of expectations.

We expect production in Norway to be lower in 2020, as a result of ongoing natural declines and extended shutdowns planned at Gjøa, required for work associated with the Gjøa P1, Duva and Nova developments. Declines will be partially offset by additional volumes from Fram following the start-up of the Troll C Gas Module and new infill wells at Gudrun, Draugen and Vega. The Dvalin project is due to be brought onstream towards the end of 2020 and is expected to add 5 kboepd of gas production net to Neptune at plateau. The Askaladd field is also due to come onstream in the fourth quarter, increasing available production capacity at Snøhvit.

Operating costs in Norway declined to $6.4/boe in 2019, reflecting results from our business improvement plan, lower environmental costs, reduced tariffs and favourable currency movements. In 2020, lower production and higher maintenance costs are expected to increase operating costs.

Development

In 2019, we continued to make significant progress with our project development pipeline in Norway. Development capex increased significantly to $479.4 million, with Njord, Duva/Gjøa P1 and Fenja the main areas of investment. In 2020, we expect development capex to remain high as we progress towards first production on a number of our projects.

At our operated Fenja project, we successfully installed processing modules on Njord A and completed the first subsea umbilicals, risers and flowlines (SURF) campaign. Development drilling is due to begin in early 2020 and a second subsea installation campaign is planned in the summer months ahead of first production in the first quarter of 2021. This will add approximately 10 kboepd net to Neptune.

Production from Fenja is contingent on the delivery of the non-operated Njord Area redevelopment, which will contribute 25 kboepd of net production, including volumes from the Hyme and Bauge tie backs. The operator is still anticipating that Njord will be delivered on schedule, with sail-away of the Njord A platform and Njord B FSO anticipated in the third quarter of 2020.

The Duva, Gjøa P1 and Nova developments are all due to be tied-back to our operated Gjøa field. Good progress was made with each of these in 2019 and further important milestones are expected to be achieved in 2020.

At the Duva and Gjøa P1 projects a subsea campaign was undertaken in the second half of 2019 and we were able to complete more work than originally planned. A further subsea campaign is planned in 2020 and will consist of pipelay operations, subsea installations and umbilical pull-in, with operations expected to be completed by the fourth quarter. A development programme of six wells is underway and will continue throughout 2020.The subsea installations will be sequenced around the drilling campaigns to optimise delivery.

At the Nova project, we plan to install the processing module on to the Gjøa platform and commence a six well programme in the second quarter of 2020. The Duva, Gjøa P1 and Nova projects are expected to add 17 kboepd net to Neptune.

At Dvalin, the processing module was successfully lifted onto the Heidrun platform in 2019 and a four well development programme is now underway ahead of first gas expected in late 2020.

Exploration

Neptune participated in three exploration wells in 2019, leading to two discoveries. In the second half of the year, Equinor announced a discovery at our Echino South exploration well, which was one of the largest made on the Norwegian Continental Shelf in 2019. The discovery is located close to our Fram field.

The Sigrun East well was completed in early 2020 and an oil discovery was made. Sigrun East, together with the Sigrun discovery, announced in 2018, are likely to be commercialised as a tie-back to our non-operated Gudrun platform. Further exploration wells are planned at Grind, Dugong and Blasto.

Neptune was pleased to be awarded 13 new licences on the Norwegian continental shelf in the APA 2019 licencing round, early in 2020. The awards strengthen our footprint in and around our core areas and includes four operated licences. We continue to actively manage our exploration portfolio in Norway.

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Daily average production

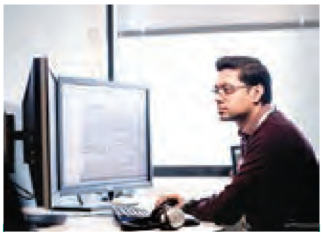
Gas production
kboepd

Gas production for sale as LNG
kboepd

Liquid production[2]
kbpd

Total production
kboepd

1) Daily average production over the period 15 February 2018 to 31 December 2018.
2) Liquid includes oil and condensate and other natural gas liquids.



Optimising production

The Duva and Gjøa P1 projects in the North Sea were approved by the Norwegian authorities in 2019, and we also acquired an interest in the Nova development.

All three of these projects are due to be tied back to our nearby Gjøa platform and brought onstream in 2021.

Production optimisation and ongoing investment to mitigate natural declines is a key focus as we work to maintain low operating costs in Norway and to capture incremental growth opportunities in our core operating areas.

Operational review

Netherlands

The Netherlands contributed on average 21.7 kboepd to Group production.

Production

Production from the Netherlands averaged 21.7 kboepd in 2019. Operations were impacted by unplanned shutdowns at the L5a-D, Q13a-A and F3-FB platforms and delayed development drilling in the second half of the year. While many of these curtailments reflected third party issues, they did highlight some challenges faced by mature production areas.

As a result, we embarked on a programme of significant work to deliver improved safety, asset integrity and production availability. To achieve this, we established a new inspection and maintenance plan to improve process safety at our operated facilities and increased our collaboration with third-party infrastructure owners. We also formed dedicated multi-disciplinary teams to implement solutions

In addition to improving production efficiency, we worked to enhance portfolio optimisation through incremental investments, faster permitting, lower costs and innovation. Our new technology and digitisation strategy will support these improvements.

With our new E17a-A6 development well onstream and shutdowns behind us, we ended 2019 strongly, with production significantly higher in the fourth quarter. In 2020, we expect volumes to increase modestly reflecting the start-up of the non-operated Sillimanite gas field (Neptune 7.5%), the L5a-D4 well (Neptune 60%) and additional development drilling.

Due to lower production, operating costs per barrel in the Netherlands increased to $13.6/boe in 2019 and operating costs are expected to remain broadly unchanged in 2020.

We achieved a reserves replacement ratio of 135% in 2019.

Development

In 2020, we plan a more active development programme with five new wells, including the delayed L5a-D4 well. Our investment programme includes two wells as part of the Sillimanite development and two operated infill wells (K9ab-A4 and L15-A109) in the western area of the Dutch North Sea. These will be drilled towards the end of 2020. The high pressure, high temperature L5a-D4 well, which was drilled in 2019 came onstream in February 2020 at a rate of 50 mmcfpd.

The first of the Sillimanite wells was successfully completed in January 2020 and has demonstrated strong reservoir productivity. The field was brought onstream in February at an initial rate of 35 mmcfpd. Drilling operations at the second development well is ongoing with completion expected in mid-2020. The Sillimanite South exploration well, due to be drilled in the third quarter of 2020, offers further production upside if successful and could be tied-in before the end of the year.

In 2019, we invested $75.2 million of development capex in the Netherlands. While investment in 2020 is expected to be lower, we continue to evaluate incremental production opportunities. The decision to end all Groningen onshore production by mid-2022, has increased the importance of the Dutch offshore gas industry to the economy and the carbon footprint of the domestic energy industry.

In 2020, we expect to progress our plans for the F17 and L15 developments. FEED for the F17 development was completed in 2019 and we plan to make a final investment decision in the second half of the year, with first oil possible in 2023. Permitting and design work for the L15 development is expected to continue throughout 2020, with first production anticipated in mid 2021.

Neptune has ownership stakes in the offshore pipeline operators NGT and NOGAT generating earnings of $4.8 million in 2019. Our interests in these assets provide opportunities for alignment and cooperation with other operators and may provide future synergies through integration with energy transition projects, such as PosHYdon.

In 2020, we expect to complete decommissioning activity at the L10 C, D and G platforms. The D18-A platform is due to cease production during the year and preparations for future decommissioning will commence.

In early 2020, we announced a four-year framework agreement for engineering, procurement, construction, installation and commissioning (EPCIC) and decommissioning services to Stork Worley Integrated Solutions. This expands our existing relationship and is intended to optimise our existing producing assets through brownfield modifications and keep them fit for the future.

Exploration

In 2020, Neptune has one firm exploration well that will drill the Sillimanite South prospect. The non-operated well will target a lower risk structure and is located close to the Sillimanite development.

In late 2019, Neptune was awarded a 28.33% working interest in the F5 permit, offering exploration opportunities close to our operated F3-B platform. We have also farmed into the F3b licence, with planning progressing for a possible well in early 2021. Neptune will have a 15% working interest in this licence.

To identify attractive drilling opportunities in the Netherlands, Neptune has initiated a joint exploration study with TNO. As part of this programme, we are continuing to reprocess a number of seismic datasets.

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Daily average production

2019	19.9
2018	26.1

Gas production
kboepd

2019	1.8
2018	2.2

Liquid production[2]
kbpd

2019	21.7
2018[1]	28.3

Total production
kboepd

1) Daily average production over the period 15 February 2018 to 31 December 2018.
2) Liquid includes oil and condensate and other natural gas liquids.

Green hydrogen

Neptune was selected to participate in a pioneering pilot project to create the first offshore green hydrogen production plant in the Dutch sector of the North Sea.

The PosHYdon project, which will be installed on our Q13a-A platform, will generate hydrogen using an electrolyser powered by wind energy. Hydrogen will be blended into the existing pipeline infrastructure and used to generate electricity.

First production is expected in 2021. The project is a collaboration between Neptune, Nexstep and TNO.

Operational review

UK

In the UK, production from the Group's assets averaged 16.5 kboepd in 2019.

Production

In the UK, we delivered important strategic progress and a strong underlying performance. Production for the year averaged 16.5 kboepd and while this was lower than planned due to export restrictions, short-term production records were achieved by Cygnus when capacity restrictions eased. This provides an encouraging indication for the longer term.

Across the entire period, production was impacted by higher than expected production at third-party fields and gas blending constraints. This was partly mitigated by a strong turnaround performance during the annual maintenance shutdown in August. We continue to focus on longer-term solutions to both of these production constraints. Strategically, the proposed acquisition of an interest in Tors, as part of the Energean Oil & Gas transaction, strengthens our interest in this core area and further aligns interests across the region.

In 2020, we expect production in the UK to increase reflecting stable production from Cygnus and incremental volumes from assets included in the proposed Energean Oil & Gas transaction.

Operating costs at our existing UK assets rose slightly to $7.5/boe in 2019, and are expected to remain at a similar level in 2020. Overall operating costs are expected to increase in 2020, reflecting the contribution of mature and higher-cost production assets included in the proposed Energean Oil & Gas transaction. We will work with the operators of these assets to identify opportunities to reduce costs going forward. Our overall operating cost per barrel is expected to remain below the industry average for the UK North Sea.

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Development

During 2019, Neptune invested $24.3 million in development activities in the UK. This reflected the sanctioning of our operated Seagull project and completion of the Cygnus A5 development well, brought onstream in June. In 2020, investment in our UK assets is expected to increase with spending focused mainly on the Seagull development.

At the Seagull project, construction of the topside is expected to begin in 2020. Production remains on schedule for start-up in the second half of 2021 , which is expected to contribute 15 kboepd net to Neptune.

At Cygnus, preparation work for a tenth infill well on the field is ongoing ahead of possible drilling in 2021.

Exploration

In 2019, Neptune participated in the drilling of the Darach and Isabella wells. A side-track of the Darach well was completed in August and confirmed the presence of both oil and gas. Further appraisal studies are planned to determine volume estimates and assess the commercial potential of the discovery. Spirit Energy has been appointed operator of the licence.

In early 2020, we completed drilling operations at the Isabella exploration well, confirming a material gas condensate and light oil discovery with hydrocarbons encountered in three formations. The results of the well will be analysed to further evaluate the discovery and determine future appraisal activity.

Planning is underway for an appraisal on Glengorm South. This is a lower-risk well targeting a significant resource potential. The Glengorm discovery, which is located close to our Seagull project, is a key asset to be acquired in the proposed Energean Oil & Gas transaction and material contingent resources are already attributed to the discovery.

We made five applications in the 32nd licensing round, including acreage around Seagull and Isabella. We expect awards to be announced in the first half of 2020.

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Daily average production

2019	16.1
2018	16.7

Gas production
kboepd

2019	0.4
2018	0.4

Liquid production[2]
kbpd

2019	16.5
2018[1]	17.1

Total production
kboepd

1) Daily average production over the period 15 February 2018 to 31 December 2018.
2) Liquid includes oil and condensate and other natural gas liquids.

Seagull project sanctioned

In 2019, Neptune and its joint venture partners, BP and Japex, agreed the final investment decision for the Seagull project in the UK North Sea.

Seagull is expected to contribute 15 kbpoepd net to Neptune. 2P gross reserves are estimated at 50 mmboe.

Seagull will be tied back to the BP-operated ETAP central processing facility, partially using existing subsea infrastructure. Neptune is the operator of Seagull and has a 35% equity interest.

Operational review

Germany

In 2019, production from Germany averaged 12.6 kboepd.

Production

Production in Germany declined by 3% in 2019, averaging 12.6 kboepd for the period. During the year, new wells were drilled on both the Römerberg and Rühlermoor fields, with the latter performing above expectations. A number of minor project delays and the underperformance of the Hamburg oil field, impacted our overall performance.

For 2020, reported production is expected to increase by around 5 kboepd, reflecting a change to Group-wide oil and gas conversion factors (see page 21 for details). This will impact the low calorific gas produced from the Altmark field in particular. Production for the year will also benefit from a full year contribution from the Emsland oil and gas fields acquired from Wintershall DEA in September 2019.

Operating costs, excluding royalties, declined to $21.4/boe in 2019. Operating costs in 2020 are expected to fall to around $17/boe, due to higher reported production.

We continue to review our cost structure in Germany and are targeting further savings in 2020. Through our restructuring in 2019, we reduced G&A costs by approximately 25%.

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Development

In 2019 we continued to invest across our German portfolio, spending $48.5 million in development capex. A similar level of activity is planned in 2020. A number of workover activities are scheduled in the first half of the year, targeting the Adorf, Kalle and Römerberg fields, while new wells are also planned at the Bramberge, Kietz, Georgsdorf, Ringe, Römerberg and Rühlermoor fields.

The infill wells at Bramberge are part of a refurbishment of the surface facilities. FEED was finalised in the fourth quarter of 2019 and the project sanctioned in early January 2020. Work is expected to continue throughout 2020 and 2021.

The Römerberg 7 well was successfully completed in the fourth quarter of 2019 and initial results are encouraging, supporting the technical and economic development of lateral wells in the Bunter Reservoir. The Römerberg 8 well was also completed in 2019. These results will be integrated into our future plans for further development of the field. We plan to drill the Römerberg 6 well in the second half of 2020.

Exploration

During 2019, we drilled the Schwegenheim-1 exploration well, resulting in a small oil discovery. The well has been suspended for potential long-term testing.

Daily average production

2019	6.9
2018	7.3

Gas production
kboepd

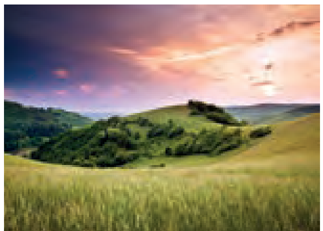
2019	5.7
2018	5.7

Liquid production[(2)]
kbpd

2019	12.6
2018[(1)]	13.0

Total production
kboepd

1) Daily average production over the period 15 February 2018 to 31 December 2018.
2) Liquid includes oil and condensate and other natural gas liquids.



Improving efficiency

In early 2020, we announced an investment of $19 million to upgrade one of our largest operated developments in Western Germany. Upgrades to the facilities at the Bramberge oil field will optimise technology and increase the productivity of the field.

The installation of two new separators will improve processing efficiency, while the upgraded facilities and technologies will reduce the overall footprint of the plant.

Work is scheduled to be complete by early 2023.

Operational review

Algeria and Egypt

Production from North Africa, averaged 5.9 kboepd in 2019 reflecting the start up of Touat.

Algeria

Production

We achieved an important milestone in 2019 with our material Touat project coming onstream in September 2019. While later than planned, Touat is a large and complex project in a remote desert location. The initial ramp-up phase encountered a number of technical and operational start-up issues with the plant facilities. As a result, production from Touat averaged 4.8 kboepd in the fourth quarter of 2019. These issues are now resolved and we are producing at close to plateau rates. Reservoir performance has so far been strong.

Due to stronger leadership, increased focus and greater co-operation with our partners, there has been a material improvement in health and safety at Touat. We will also continue our focus on delivering environmental improvements

Operating costs in Algeria are expected to average less than $9/boe in 2020.

Development

Capital expenditure associated with Touat (equity accounted investment) was $61.4 million in 2019, driving the final stages of the development. Investment is expected to decline materially in 2020 as our focus switches to delivering operational improvements.

In 2020, we have four planned workovers at Touat. We will also evaluate the potential to reduce emissions through a CO_2 reinjection feasibility project.

Egypt

Production

In Egypt, our assets have performed well, with both production and profitability in 2019 higher than expected. Production averaged 4.5 kboepd, supported by positive results from the Karam-10 development well, our infill programme at Alam El Shawish and workover campaign at Ashrafi. Production is expected to remain stable in 2020. Options to extend the Ashrafi concession, which expire in November 2020, are currently being evaluated with our partner.

Operating costs in the Egypt region were $9.4/boe in 2019 and are expected to remain around this level in 2020.

Development

We invested $16.7 million of development capex in 2019 with spending likely to remain broadly unchanged in 2020. We have 12 development wells planned across our assets, including at the Assil, Bahga, Magd and Karam fields. The Karam-11 well is due to be drilled in the second half of 2020 and expected onstream in early 2021.

Exploration

We formally signed the North West-El Amal concession, which is located in the central part of the Gulf of Suez, in February 2020. Planning is underway for the acquisition of 3D seismic.

Daily average production

2019	4.5
2018	3.1

Gas production
kboepd

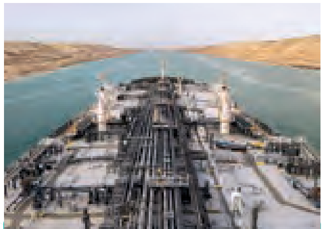
2019	1.4
2018	1.2

Liquid production[2]
kbpd

2019	5.9
2018[1]	4.3

Total production
kboepd

1) Daily average production over the period 15 February 2018 to 31 December 2018.
2) Liquid includes oil and condensate and other natural gas liquids.
3) Includes Egypt only for 2018.



First gas export

The Touat gas plant in Algeria is of strategic importance as we continue to grow our global gas production portfolio.

Together with our joint venture partner Sonatrach, we announced first gas export in September.

At plateau, Touat will represent around 6% of Algeria's total gas exports. The joint venture is led by Groupement TouatGaz, consisting of Neptune Energy Touat (65%) and Sonatrach (35%).

It is our first co-operated project in North Africa.

Operational review

Indonesia and Australia

In our Asia Pacific region, we achieved annual production of 19.5 kboepd in 2019.

Daily average production

2019	3.1
2018	n/a

Gas production
kboepd

2019	15.8
2018	20.5

Gas production for sale as LNG
kboepd

2019	0.6
2018	0.8

Liquid production [2]
kbpd

2019	19.5
2018 [1]	21.3

Total production
kboepd

1) Daily average production over the period 15 February 2018 to 31 December 2018.
2) Liquid includes oil and condensate and other natural gas liquids.
3) Includes Indonesia only for 2018.

Indonesia

Production

Net production in Indonesia averaged 19.5 kboepd in 2019, reflecting softer LNG markets in Asia. This constrained output during the second and third quarters, with curtailments from our buyers amounting to 2 kboepd. We expect to recognise cash for unlifted cargoes, under our take-or-pay provisions in 2020. Asian gas markets remain weak and further curtailments are possible in 2020.

In December 2019, the PT Saka Energia carry reimbursement was completed, providing additional entitlement production to Neptune from January 2020.

Operating costs of $13.3/boe increased in 2019 due to lower production and higher costs for C3/C4 purchases for blending. The second onshore pipeline tie-in project was completed in January 2020 and is expected to reduce C3/C4 requirements. As a result, we expect operating costs to be lower in 2020.

Development

In 2019, development capex in our Asia Pacific region increased significantly to $181.4 million. This reflected settlement of the Saka carry, infill drilling on Jangkrik and additional capex associated with the Merakes project from the completion date of the acquisition.

Our strategy in Indonesia is to develop other discoveries in the acreage surrounding Jangkrik to offset reductions and maintain output at close to the floating production unit (FPU) capacity. Our initial plan is to develop the Merakes field, with development of the Maha and Merakes East fields likely to commence as production capacity is required.

The Merakes project is a deepwater development of five subsea wells tied back to our Jangkrik FPU. The offshore pipeline was successfully installed in early 2020 and fabrication of the major FPU and SURF modules is now advanced. Due to the impact of the coronavirus, the operator of the Merakes development declared force majeure in March 2020. First gas from the project is now anticipated in mid-2021, adding 8 kboepd of net production.

Exploration

Through the award of the West Ganal licence in August and the acquisition of interests in the East Sepinggan and East Ganal licences announced in July, we have successfully built a world-class acreage footprint in the Kutei Basin, Indonesia.

While Neptune's initial focus is on the development of Merakes, significant exploration potential has already been identified in the surrounding area.

Australia

Exploration

We have acquired new 3D seismic covering the Petrel field and surrounding acreage. As part of our development strategy for the Petrel field, the new data will help further delineate the field and de-risk future upside opportunities. Data interpretation results are expected in the second half of 2020.

Meeting growing energy needs

We have been active in exploration and production in the Kutei basin in Indonesia since 2008.

In 2019, we established a world-class acreage position in the basin through our transaction with ENI and our new licence award. These transactions will enhance value from Jangkrik, which produces gas for LNG export as well as for the domestic market.

They will also provide material growth opportunities and contribute to meeting Indonesia's growing energy requirements.

Financial review
Robust financial results and resilient capital structure

633 mmboe
2P reserves

$1,600m
EBITDAX

$1,321m
Operating cash flow

$62.0/bbl
Average realised oil price

$10.3/boe
Average operating cost

0.93x
Net debt/EBITDAX

$826m
Development capex

$200m
Total cash dividend

Note
This report includes the group results for the twelve months ended 31 December 2019.

This report includes the Group results for the 12 months ended 31 December 2019. On 1 September 2019, we completed the asset acquisition in the Emsland region of Germany of certain oil and gas fields from Wintershall Dea. On 4 December 2019, we acquired a 20% interest in the East Sepinggan area, offshore East Kalimantan in Indonesia which is incremental to the earlier award of the West Ganal PSC in Indonesia in the same area. The comparative results include the acquisition of ENGIE E&P International S.A. (EPI) since 15 February 2018 as that is when Neptune acquired control over EPI and received the economic benefit of cash flows of this business. The acquisition of 100% of the share capital of VNG Norge, for cash consideration, was completed on 28 September 2018 and the results of VNG Norge were consolidated from the start of the fourth quarter 2018.

The consolidated statement of financial position for 31 December 2018 as previously disclosed has been revised as it was based on provisional assigned fair values of the acquisition of the VNG Norge business on 28 September 2018. On conclusion of the business combination accounting, the fair values was concluded in September 2019. The revisions to these financial statements did not constitute a restatement of the financial results as International Financial Reporting Standards (IFRS) allow a period of up to 12 months beyond the acquisition date of business combinations to finalise the associated judgements and assigned fair values.

Results of operations

$ millions	12 mths ended 31 December 2019	Period ended 31 December 2018 (note a)
Revenue	2,202.2	2,537.9
Operating profit (note c)	872.7	1,049.3
Profit before tax	676.8	906.1
Taxation	(237.8)	(644.6)
Net profit	439.0	261.5
EBITDAX (note b)	1,600.2	1,883.3
Net profit before business combination acquisition-related expenses (note d)	439.0	324.4
Cash flow from operations, after tax before acquisition-related expenses (note d)	1,320.6	1,219.3
Adjusted development cash capital expenditure (note e)	1,122.1	587.4
Net debt (book value) (RBL) (notes f and g)	1,490.1	1,283.8
Net debt/EBITDAX (RBL) (notes f and g)	0.93 x	0.62 x

a) Results for this period consolidate the acquired EPI business for the post-acquisition period only, from 15 February 2018 to 31 December 2018.

b) EBITDAX (as defined by the RBL and Shareholder agreements to exclude our share of net income from Touat). EBITDAX comprises net income for the period before income tax expense, financial expenses, financial income, other operating gains and losses, exploration expense and depreciation and amortisation.

c) 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.

d) Adjusted for acquisition-related expenses and taxes of $62.9 million in 2018 incurred in connection with the EPI and VNG Norge business combinations.

e) Includes capital expenditure of $61.4 million for the year to 31 December 2019 and $76.4 million for the period from 15 February to 31 December 2018 in respect of the Touat project, held by a joint venture company which Neptune accounts for under the equity method.

f) Net debt excludes Subordinated Neptune Energy Group Limited Loan and Touat project finance facility as defined by the RBL and Shareholder agreements.

g) EBITDAX is based on a 12-month actual for 2019. As Neptune only completed the acquisition of EPI on 15 February 2018, the 2018 12-month EBITDAX value of $2,054.8 is calculated on a pro-forma basis assuming Neptune had owned the business from 1 January 2018.

Total sales for the 12 months ended 31 December 2019 were $2,202.2 million (2018: $2,537.9 million), reflecting total production of 52.0 mmboe (2018: 50.9 mmboe) (for wholly owned affiliates) and realised prices, before and after hedging, as shown in the table below. The principal reason for the lower sales in 2019 was due to lower prices. The Brent crude price averaged $64.2 (2018: $71.7) per barrel for the 12 months ended 31 December 2019 and our average realised oil price (pre hedging) was $62.0 per barrel (2018: $69.6) for the same year. The LNG sales prices are linked to a combination of movements in oil and gas market prices, depending on the contract. The average realised gas price (pre hedging) was $4.7 per mcf for 2019 compared with $7.9 mcf for 2018. The European gas market faced significant pressure in 2019 as mild winter weather at the start of the year and a surge in LNG exports from the US combined to affect prices. A weak Asian gas market caused US LNG to target Europe rather than the Far East, resulting in European gas storage levels that were consistently elevated above their five-year seasonal averages.

Realised prices data:

	Q4 2019	12 months ended 31 December 2019	Pro-forma 12 months ended 31 December 2018	15 February to 31 December 2018 (note a)
Excluding impact of hedging:				
Average realised gas price ($/mcf)	4.2	4.7	8.1	7.9
Average realised LNG price ($/mcf)	8.0	8.3	7.5	8.2
Average realised oil price ($/bbl)	61.7	62.0	70.0	69.6
Average realised price, other liquids ($/bbl) (note b)	47.3	39.0	49.9	58.3
Including impact of hedging:				
Average realised gas price ($/mcf)	4.8	5.2	7.1	6.9
Average realised LNG price ($/mcf)	8.0	8.3	7.5	8.2
Average realised oil price ($/bbl)	62.0	61.5	67.5	67.5
Average realised price, other liquids ($/bbl) (note b)	47.3	39.0	49.9	58.3

a) Results for this period consolidate the acquired EPI business for the post-acquisition period, from 15 February 2018 to 31 December 2018

b) Other liquids includes condensate and other natural gas liquids

Operating costs were $533.5 million (2018: $520.6 million) for the 12 months to 31 December 2019 and our average operating cost per boe produced was $10.3/boe compared with $10.2/boe for 2018. Operating costs for the purpose of per boe expense are increased by $2.1 million (2018: $24.7 million reduction) for the 12 months ended 31 December 2019 to exclude changes in the value of under-lifted entitlement to production and to net-off income from tariffs and services which serve to recover costs.

Depreciation and amortisation expense was $624.2 million (2018: $656.1 million). The charge represents $12.0/boe produced compared with $12.9/boe produced for the period ended 31 December 2018. The 2019 effect of a full year of production and the inclusion of depreciation of right-of-use assets under IFRS 16 is offset by lower production levels including field production curtailments in Norway and unplanned production outages in Netherlands and an increase in reserves due to field revisions and extensions principally in Norway, the UK and the Netherlands.

Exploration expense for the year was $60.4 million (2018: $89.2 million) which includes costs incurred on G&G studies to review strategic growth opportunities. The lower 2019 charge compared with 2018 was due to lower seismic costs for data purchases predominantly in Norway and the UK partially offset by an increase in Australia.

General and administration expense of $68.6 million (2018: $131.6 million) for the year to 31 December 2019 consists primarily of costs that are not directly incurred for production or capital projects (including exploration), such as staff employment costs related to corporate functions and selling expenses, office costs and fees for services provided to us. In 2019, corporate gross general and administration costs have fallen compared with 2018, principally in the Paris office, and the Company has also allocated a higher proportion of salaries and other costs to projects than in 2018 as this is the first full year following the acquisition of EPI and VNG during 2018. In addition general and administration has also fallen due to our cost efficiency programmes across the business, especially in Germany and the Netherlands.

Share in net income of entities accounted for under the equity method was $2.1 million (2018: $4.0 million) for the year ended 31 December 2019. This represents the Touat joint venture, which commenced production in September 2019 of $1.0 million (2018: $0.7 million) and tariff income of one of our Dutch pipeline interests of $1.1 million (2018: $3.3 million).

Financial review

Other operating gains/(losses) were a loss of $43.7 million (2018 loss: $68.5 million) for the year to 31 December 2019. The 2019 loss includes a gain on mark-to-market on commodity contracts other than trading instruments $14.2 million (2018 loss: $45.2 million), a restructuring charge of $68.9 million (2018: gain $2.8 million), an impairment loss of $59.4 million (2018: $nil), a pension credit of $50.0 million (2018: $nil) and other gains of $20.4 million (2018 gains $15.8 million). The $68.9 million restructuring charge relates to group reorganisation costs in Germany and the decision to close the corporate office in France. The $59.4 million impairment loss includes impairments of a Netherlands cash generating unit (CGU) ($42.3 million) due to underlying reservoir performance and the reduction of the Group's assumption of future commodity prices, redetermination of licences across both Netherlands and UK and an appraisal well in Norway. The $50.0 million pension credit relates to a curtailment gain arising on the closure of a defined benefit pension plan in Netherlands and a settlement gain due to a reduction in future pension obligations in France. The prior period also included an acquisition related loss of $62.9 million, reflecting the requirement to expense business combination transaction expenses and related costs (such as tax levied in respect of share transfers and change of control) and a gain of $21.0 million from the release of a deferred consideration from the EPI acquisition.

The Group's operating profit for the year to 31 December 2019 was $872.7 million (2018: $1,049.3 million) before net finance costs. EBITDAX (as defined by the RBL and Shareholders Agreements) for the year was $1,600.2 million, compared with $1,883.3 million for the period ended 31 December 2018. The decrease in EBITDAX principally reflects lower realised commodity prices in the year offset in part by the effect of consolidating a full 12-months result from the EPI acquisition.

Net financing expenses were $195.9 million (2018: $143.2 million) for the year and include $122.5 million (2018: 106.7 million) of interest expense and unwinding of discount on abandonment provisions of $36.5 million (2018: $30.9 million). In 2019 there is also a net foreign exchange loss of $21.4 million (2018: $0.4 million gain) and $8.2 million interest expense in relation to right-of-use lease liabilities recognised following the adoption of IFRS 16 in the year. The net foreign exchange loss arises on the revaluation of loans and working capital balances across the Group and is principally impacted by the exchange rates for Euros, Norwegian Krona, Sterling and US Dollars.

The Group's total tax charge for 2019 is $237.8 million (2018: $644.6 million), comprising a current tax charge for the period of $330.4 million (2018: $567.1 million) and a deferred tax credit for the period of $92.6 million (2018: $77.5 million charge). The total tax charge for the period represents an effective tax rate of 35% (2018: 71%). The effective tax rate for the year is impacted by the following exceptional items.

Firstly, the impact of Seagull project sanction and a general improvement in the future profitability of the UK business has resulted in an increase in the UK's deferred tax asset balances ($234.8 million deferred tax credit). Additionally, post-EPI acquisition restructuring costs of approximately $68.9 million are presently assumed to result in limited effective tax relief for 2019. Finally, the tax charge is impacted by the successful resolution of tax enquiries in Norway and the Netherlands ($33.3 million current tax credit) and the recognition of additional deferred tax in Indonesia ($21.9 million deferred tax credit). Adjusting for these items, the effective tax rate for the period would be 71% of pre-tax income.

Net income for the year ended 31 December 2019 was $439.0 million (2018: $261.5 million) on a reported basis.

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 and options.

As at 31 December 2019, 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 $60/barrel for 2020, with upside capped at around $69/barrel in 2020.

For gas, hedging provided weighted average floor prices of $6.0/mmbtu for 2020, $5.9/mmbtu for 2021 and $5.9/mmbtu for 2022, with upside caps at $7.3/mmbtu , $7.3/mmbtu and $6.4/mmbtu respectively.

Aggregate post-tax hedge ratio:

	2020	2021	2022
Oil	27%	–	–
Gas	84%	60%	18%
Total weighted average	**56%**	**26%**	**7%**

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, but exclude the likely impact of the recent Edison acquisition announcement which is yet to complete.

The estimated net fair value (comprised of current and non-current assets and liabilities) on a mark-to-market basis of all our commodity derivative instruments at 31 December 2019, was an asset of $182.7 million (2018: $17.1 million liability), of which $134.6 million relates to contracts expiring in 2020.

Cash flow

Operating cash flow, after cash taxes, for the year to 31 December 2019 was $1,320.6 million (2018: $1,156.4 million). Cash taxes were $361.7 million (2018: $535.1 million) and largely relate to Norwegian taxes. The effective rate of cash tax as a percentage of pre-tax operating cash flow was 22% (2018: 32%).

Capital expenditure

Cash capital expenditure for the year to 31 December 2019, was $887.4 million (2018: $461.3 million before acquisitions), including $61.9 million (2018: $20.3 million) of capitalised exploration expenditure. This figure is significantly higher than last year as a result of expenditure on new development projects, primarily Njord, Duva/Gjøa P1 and Fenja. This excludes expenditure at the Touat project, where the joint venture is accounted for under the equity method of accounting as a joint venture. Our statement of cash flows reflects investment at Touat in terms of the cash injections made to fund the joint venture company, which were $69.0 million in the year.

$ millions	Year ended 31 December 2019	Period to 31 December 2018 (note a)
Investing cash flows:		
Development capex (note b)	825.5	441.0
Acquisitions – assets	235.2	70.0
Exploration capex	61.9	20.3
Acquisitions – exploration	25.2	–
Acquisitions - business combinations	–	3,546.5
Total cash capital expenditure	**1,147.8**	**4,077.8**

a) Results for this period consolidate the acquired EPI business for the post acquisition period, from 15 February 2018 to 31 December 2018.

b) Includes Saka carry reimbursement of $90.6 million.

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

Total exploration expenditure comprised the $61.9 million (2018: $20.3 million) cash capex and $60.4 million (2018: $89.2 million) expensed in respect of G&G costs.

Development cash capex was $825.5 million (2018: $441.0 million). The majority of expenditure was in Norway on the Njord, Duva/Gjøa P1 and Fenja project as well as progressing projects in the UK, Indonesia and the Netherlands.

We incurred $51.7 million (2018: $29.2 million) on decommissioning cash expenditure in the year to 31 December 2019, this was principally in the UK in relation to our equity share in our non-operated CMS assets and other legacy non-operated fields.

Acquisitions

On 26 July, the Group announced it had agreed to acquire interests in two production sharing contracts (PSC) in the Kutei basin, offshore Indonesia, a 20% working interest in the East Sepinggan PSC and a 30% working interest in the East Ganal PSC at a cost of $234.8 million including $0.7 million of exploration acquisition. The transaction completed in December 2019.

On 29 July, the Group announced an agreement to acquire interests in certain oil and gas fields in Germany from Wintershall Dea for $1.1 million. The Company is already a joint venture partner in the assets and operates the Bramberge oil field and the Grafschaft Bentheim gas fields, adding approximately 600 boepd to the Company's production in Germany. This deal completed in early September 2019.

On 26 August, the Group announced it and its partners Eni (operator) and Pertamina had been awarded the West Ganal PSC in Indonesia, also located in the Kutei basin. The consortium has committed to drilling four exploration wells during the first exploration period, in addition to acquiring seismic data.

On 14 October, the Group announced a conditional agreement with Energean Oil & Gas plc to acquire Edison E&P's UK and Norwegian producing, development and exploration assets for an initial cash consideration of $250 million, to be adjusted for working capital (effective date 1 January 2019). Contingent consideration of up to $30 million may be paid by the end of 2026 if certain conditions are met. At completion, we will acquire the entire issued share capital of Edison E&P UK Ltd, Euroil Exploration Limited and Edison Norge AS. The purchase is contingent on Energean completing its proposed acquisition of Edison E&P. The acquisition will provide the Group with growth in contingent resources, an estimated 31 mmboe of 2P reserves and near-term production in core areas of the North Sea close to our existing infrastructure.

In the year ended 31 December 2018, the expenditure on acquisitions totalled $3,546.5 million of which $3,205.2 million relates to the EPI acquisition, including adjustment payments and receipts under the sale and purchase agreement (SPA) which arose subsequent to closing, and associated acquisition costs of $60.4 million and a further $341.3 million related to the acquisition of VNG Norge AS.

Financing and liquidity

Management's financial strategy is to manage Neptune's capital structure with the aim that, across the business cycle, net debt (excluding vendor loans) to EBITDAX (excluding our share of net income from Touat), as defined by the RBL and shareholder agreement, remains modest. The ratio, at the end of the period, equals 0.93x.

We funded our business mainly with cash generated from operations and loan facilities. At 31 December 2019, we had the following debt outstanding:

- $690 million drawn under a $2 billion, committed RBL facility, which matures in 2024;
- $850 million of senior notes, paying a 6.625% coupon, maturing in 2025;
- $107.9 million Subordinated Neptune Energy Group Limited loan, maturing 2024;
- $256.2 million project finance facility for Touat, (which is repayable from net revenues of the project); and
- $100 million drawn under short-term borrowing facilities.

At 31 December 2019, our cash balance totalled $85.4 million (2018: $197.3 million) and our available and undrawn headroom under the RBL was $1.2 billion. We also had $96 million of letters of credit outstanding, of which $78 million were drawn down under an ancillary facility under the RBL. Our weighted average cost of borrowing for the Group was 5.431%.

Our corporate credit rating has not changed over the year and we continue to have a positive outlook from both Moody's and S&P, which rate us respectively at Ba3 and BB-. Fitch assigned Neptune an inaugural rating, in May 2019, of BB with a stable outlook. We will continue to seek to further strengthen these ratings over time.

All debt, with the exception of the RBL, carries a fixed interest rate. However, we swapped a sizeable amount of the RBL into fixed rate debt, taking advantage of historically low interest rates available in the market earlier in 2018. As a result, 85% of the debt portfolio at 31 December 2019 was fixed rate, which reduces Neptune exposure to increases in the USD Libor interest rate.

Financial review

On 25 October, the Group, via its wholly owned subsidiary Neptune Energy Bondco plc, issued an aggregate principal amount of $300 million of 6⅝% senior notes due 2025 which represent an additional issuance of the series of which an aggregate principal amount of $550 million were previously issued.

Financial condition

Operating cash flows of $1,320.6 million (2018: $1,156.4 million) more than covered investing cash flows of $1,194.8 million (2018: $4,082.0 million) and after financing costs and net debt repayment of $236.3 million (2018: $3,129.6 million inflow) during the year resulted in a net cash outflow of $110.5 million for the year to 31 December 2019 (2018: $204.0 million inflow). We ended the year with gross interest-bearing debt of $1,939.6 million (book value) and net debt (excluding Subordinated Neptune Energy Group Limited loan and Touat project finance facility) of $1,490.1 million. This represents a net debt to EBITDAX (excluding Touat cash flows) ratio of 0.93 times for the 12 months ending 31 December 2019 (2018: 0.62 times).

2020 outlook

While the short-term outlook is uncertain due to the COVID-19 pandemic and the subsequent fall in oil prices, we believe the longer-term outlook is positive for the gas sector and we are well positioned to benefit from the transition to a lower-carbon energy market. In response to lower commodity prices, we have identified cost reductions of $300–400 million across operating costs, G&A and capex. Our low-cost projects, long-life production and strong balance sheet provides resilience for the Group against softer commodity prices.

We expect production to average 145-160 kboepd in 2020, dependent upon the timing of new developments coming on stream, the closing of the Energean Oil & Gas transaction as well as the impact of COVID-19. Operating costs in 2020 are expected to remain low at $10-11/boe.

As a result of our cost savings initiatives, we have reduced our planned development capex by $250–350 million to $750–850 million in 2020. We continue to identify further potential savings throughout our business. The potential acquisition of the North Sea assets from Energean Oil & Gas remains contingent on Energean completing its transaction with Edison.

While lower commodity prices and our investment plans is expected to increase our leverage ratio, we have a strong balance sheet and significant available headroom. As our new low-cost projects come onstream in 2021, we expect production and cash flows to increase, which combined with a reduction in planned capex, is expected to reduce our leverage to more normal levels.

Risks and uncertainties

Investment in Neptune involves risks and uncertainties, these are summarised in detail on pages 42 and 43.

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 risks, including, but not limited to, fluctuations in oil and gas prices, currency exchange rates, interest rates and capital requirements. The Group is also exposed to uncertainties relating to 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 liquidity and capital resources arrangements in place, the consolidated accounts have been prepared on a going concern basis. The going concern basis is supported by future cash flow forecasts that support the Group on an ongoing basis.

While the short-term outlook is uncertain due to the coronavirus and the subsequent fall in oil prices, we believe the longer-term outlook is positive for the gas sector and we are well positioned to benefit from the transition to a lower-carbon energy market. Our low-cost projects, long-life production and strong balance sheet provides resilience for the Group against softer commodity prices. Our emergency pandemic plan has been implemented and working practices changed to ensure operational continuity. We have also put in place mitigation plans for our projects and will continue to evaluate supply chains for impacts.

In reaching the conclusion that the going concern basis is appropriate, we have stress tested future cash flow forecasts and covenant compliance for the Group to evaluate the impact of plausible downside scenarios. These include scenarios that reflect current market conditions, and updated short term commodity price forecasts. Additionally, we considered our planned cost reductions in response to lower commodity prices, which provide further resilience against softer commodity prices. We have also performed reverse stress testing to inform our judgement. Under all plausible scenarios, the Directors concluded that the Group retains sufficient liquidity and that the going concern basis remains appropriate.

Dividend

On 11 December 2019, Neptune Energy Midco Limited declared an internal Group interim dividend of $400.0 million to its immediate and ultimate parent, Neptune Energy Group limited (NEGL) (20.23 cents per fully paid ordinary share registered on the register of shareholders on that date, compared with 19.22 cents in 2018). This was enabled with a $200.0 million promissory note issued on 11 December 2019 and a cash payment of $200.0 million paid on 23 December 2019. The latter cash payment of $200.0 million was distributed by NEGL as a dividend and a capital redemption to its shareholders.

Armand Lumens
Chief Financial Officer
30 March 2020

Section 172(1) statement
Our stakeholders and board decision making

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

- likely consequences of any decisions in the long term;
- interests of the company's employees;
- need to foster the company's business relationships with suppliers, customers and others;
- impact of the company's operations on the community and environment;
- desirability of the company maintaining a reputation for high standards of business conduct; and
- need to act fairly as between members of the company.

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

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

As a result of this we have had an overview of engagement with stakeholders and other relevant factors which allows us to understand the nature of the stakeholders' concerns and to comply with our section 172 duty to promote the success of the company. Please see pages 18 and 19 for examples of how we engaged with our stakeholders in 2019.

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

- During 2019, the Board approved the 2020 business plan and budget for the Group, which includes an intensive capital programme to deliver key projects, enabling the Group to continue building a sustainable production profile. The Directors consulted with shareholder representatives during the budget approval process to ensure that the 2020 business plan fairly balances the interests of the shareholders while at all times maintaining sufficient liquidity to service the Group's debt obligations, which are guaranteed by the Company and other members of the Group.
- After recommendation by the executive leadership team and the Corporate Responsibility Committee, the Board has considered a new ESG strategy, to the Board including industry-leading carbon and methane intensity targets, use of an internal carbon price and support of the UN Sustainable Development Goals.

For further details on the Group's **ESG strategy and engagement with stakeholders** on ESG matters see page 10.

Risk management
A robust risk framework

Effective management of risk is fundamental to running our business and underpins Neptune's sustainable growth strategy. Risk is inherent to the nature and locations of our business as we explore, develop and produce hydrocarbons.

We are prepared to face these risks because we are confident in our abilities to mitigate them in a calculated and prudent way. In doing so, we are better able to identify and progress economically viable business opportunities that deliver sustainable value to society and satisfactory returns to our shareholders.

To avoid concentration of those risks around specific assets, products or geographies, we diversify them. We spread our investments geographically, balance assets and exploration prospects in our portfolio between mature, low-risk areas and higher-risk, high-return opportunities and share risks with joint venture partners. We also transfer the excess of certain risks to financial markets through insurance and hedging programmes to reduce the volatility of our free cash flow and reduce the financial impact of unforeseen and less likely events.

Risks are not static and their underlying levels are constantly influenced by emerging major external macro-economic trends. These include: pandemics (e.g. COVID-19); climate change; changes in legal and tax regulations across multiple jurisdictions; global political instability; cyber crime; and changes in sentiment to the oil and gas industry in society and in the capital markets.

Some external trends are positive, including increased digitalisation and modernisation of oil and gas technologies, carbon dioxide removal technologies, hydrogen generation, new and more effective use of data, as well as the focus on governance and business transparency. Neptune monitors and leverages those trends to improve our chances of success and reduce the overall risk profile of the Company.

How we manage risk

We are consistent in our approach to identifying and assessing key business and corporate risks using a robust risk framework. Risk is discussed and considered at every level of the business, and we actively encourage participation and sharing different perspectives. Open and transparent collaboration helps to gather diverse views to reduce biases in our assessment of risks. It also improves our understanding of the full potential impact of those risks and allows us to find the best actions we can take to reduce excessive risks. This can only happen if we maintain our organisational culture and we keep encouraging staff to challenge, raise issues and concerns, but also to identify ideas for improvement.

Risk process

We apply common risk reporting templates across all levels of the organisation from day-to-day risk management at the operational or project level, through to business leadership conversations, and up to quarterly meetings of the Group Audit and Risk Committee (ARC) and the Board.

Our business units regularly reassess their key risks and results of those assessments are consolidated into an enterprise risk register, which is monitored by the Group ARC and the Board.

Each risk has an owner assigned who is responsible for its assessment, effective control and mitigation strategies. Risk owners are accountable for implementation of effective risk reduction actions if such are required.

The risk reduction actions represent an opportunity for Neptune to improve its overall risk profile. The process is supported by a tool that captures risk information and we are going to leverage technology further to generate additional risk insights.

Risk dialogue

Risk management is embedded in Neptune's system of governance and is integrated in our business planning and performance management. We hold risk discussions as part of quarterly business performance reviews in order to understand risk context to business objectives, plans and forecasts. This allows us to understand where the uncertainties are in each business or functional area, assure ourselves that there is an appropriate risk response and that scenario and contingency planning is carried out when required.

The Group ARC was established to oversee and discuss key enterprise risks strategically and to monitor the effectiveness of the enterprise risk management process.

The Committee regularly reviews our enterprise risk portfolio and selectively challenges key enterprise risks. This enables the Committee to better understand the risk and its inter-dependencies so it can ensure alignment between the executives and risk owners. It also allows us to identify and prioritise resources accordingly.

Certain risks are delegated to other management committees, or cross-functional teams to manage:

- the Investment Committee: assesses the risks related to our new investment opportunities;
- the Corporate Responsibility Committee (CRC): oversees environment, social and governance risks; and
- the Operational Integrity Committee: oversees health, safety, environment and integrity risks in our operations.

All of these regular conversations are fundamental to keeping the organisation focused on the risks that matter both in the short term and over a longer-term planning horizon.

Principal risks and uncertainties

Types of risks inherent to our business

Risk	Our attitude and response to risk
Risks arising from our investments	
We invest capital in exploration, designed to discover and unlock hydrocarbons, thus creating sustainable value for all our stakeholders. However, our exploration efforts can be unsuccessful and could lead to write-offs. Also, in order to carry out exploration activity, we need access to promising acreage and licences, which we may be unable to obtain.	We have the expertise to evaluate and manage this risk. Our ability to generate value from exploration projects is further enhanced by the use of technology and tools. We have a strong track-record of securing access to new exploration acreage in competitive markets. We aim to share exploration costs and related commitments and our exposure to geological risk through participation in joint ventures. We also set annual exploration budgets to limit the amount of capital, which we expose to that risk.
Delivering on our strategy depends on our ability to replenish our reserves. If we are unable to progress our exploration, appraisal and development programme, our replacement of reserves may be affected. Also the actual level, quality and production volumes of our oil and gas reserves and resources could vary from the volumes we report if the assumptions, upon which the estimates of our oil and gas reserves and resources have been based, prove to be inaccurate.	Reserves replacement is at the core of our strategy to ensure we are a sustainable business. We are able to add reserves organically from existing assets, and we balance that with non-organic growth. We also diversify between operated and non-operated projects, and in different geographies, to improve our chances of success across the portfolio of exploration prospects. All our reserves are subject to independent external audit by ERC Equipoise Limited (ERCe). We also maintain internal checks and balances to ensure the evaluation of our book of reserves remains objective.
We invest in development projects that are capital intensive and, compared with other industries, can take longer to start production. We run a risk that such projects can overrun their budgeted costs and timelines reducing returns on invested capital.	We manage this risk through our project management capability, and through the diversification of risk with joint venture partners. We also partner with the most reliable subcontractors who can commit to our objectives and whose performance we manage continuously.
As part of the oil and gas lifecycle we are responsible for retiring oil and gas infrastructure at the end of its useful life. We run the risk that such decommissioning costs may be higher than planned.	We use third-party estimates to validate our cost assumptions and use quality contractors to deliver the decommissioning projects safely.
Risks arising from oil and gas activities and dealing in hydrocarbons	
Drilling operations as well as subsurface and topside installations are subject to wear and tear or accidental damage, which may cause loss of equipment integrity, leakages of oil or gas, fires, explosions and pollution. This can subsequently lead to injuries, loss of life, unexpected costs, loss of production, revenue and reputation.	We aim to avoid this risk at all reasonable cost and reduce it to levels that are as low as reasonably possible. We maintain a strong safety culture set by the Board, executive and business management. We also strictly adhere to laws, policies and internal procedures held in our integrated management system. We run regular maintenance and prevention activities and also develop barriers and protocols in case of an incident to ensure the impact is minimised. We investigate all incidents to understand their root causes and lessons learned are shared and communicated throughout the company to avoid similar incidents from happening in future. We maintain a comprehensive insurance programme, which gives us a level of protection from the adverse financial impact of such unforeseen events.
Changes in laws and regulations relating to climate change and the transition to a low-carbon economy, such as carbon taxation, could have a cost impact on our business.	We believe we can positively contribute to the energy transition through our gas-weighted portfolio and by improving operational emissions. To reduce our exposure to this risk, we have set carbon intensity targets to 2030. See page 13 for more information.

Risk management

Principal risks and uncertainties

Types of risks inherent to our business continued

Risk	Our attitude and response to risk
Risks relating to the external business environment	
Our main asset base is located around the North Sea in countries that have a long-established oil and gas industry, infrastructure and capability. While we continue to successfully invest in those countries, we also invest in emerging markets, where we can be exposed to increased political, social and regulatory challenges. In the worst case we can be subject to nationalisation, expropriation, unrest and loss of control over assets.	Our leadership team and country management are experienced in successfully managing businesses in challenging environments. We carefully assess the risks of entering into new countries and we maintain open and transparent business relationships with our host country stakeholders at national, local and community levels. We invest in countries that offer bilateral investment protection. We plan to continue to balance our investments between OECD and non-OECD countries.
The external business environment is a source of emerging risks and uncertainties for the industry. Intensifying focus on climate change, shifting sentiment towards the E&P industry, changes in geopolitical landscape, the COVID-19 pandemic, and uncertainty about post-Brexit trade relations between the UK and the EU are some of the examples of factors that add to the uncertainty of doing business.	We consider such risks and factor them into our plans. We cannot influence the outcome of such risks, so we prepare for them through our scenario and business continuity planning.
Host countries may change tax regimes and challenge stability arrangements, which we have in production sharing contracts, leading to changes to the economics of our projects and also to disputes and litigation.	We invest in countries that offer bilateral investment protection and respect the rule of law. In case of issues with respecting stability arrangements, we would defend our position.
As part of our business, we rely on the performance of our partners, suppliers and customers. Their performance may impact the performance of our investments leading to delays, additional costs or suspension or termination of the licences.	We assess risks associated with non-operated partnerships and we actively influence their direction to ensure the best outcome. We also screen our suppliers, particularly critical ones, across key factors that can impact their performance, including financial condition, competence and experience, and commitment to ethical standards. Similarly, we assess risks relating to our customers.
Risks relating to our organisation	
We depend on key members of management and independent experts and on our ability to retain and hire such persons to deliver our strategy and manage our growing business.	We run a rigorous leadership selection process and maintain a strong, open and transparent culture focused on performance. We develop succession plans for key roles to ensure we have a pipeline of talent, but we will be opportunistic and look outside for the most suitable candidates in case of loss of key personnel.
We continuously evaluate inorganic growth opportunities and should we acquire another business or asset there is a risk that we may be unsuccessful in integrating it and be unable to realise expected value from such acquisitions.	Our experienced leadership team has clearly demonstrated its capability to integrate new assets quickly and effectively.
Risks arising from failure of operational processes, systems and misconduct	
These types of risks arise when processes, systems or our staff do not operate as expected, leading to breaches of laws or regulations, breaches of our Code of Ethics and Business Integrity, process and system failures, and loss of integrity of our assets, systems, processes or data.	We do not have appetite for such risks as they destroy value and we attempt to reduce them to as low as reasonably possible by enforcing our internal standards and policies.
External risks related to financial markets	
Volatility of oil and gas prices is a key source of financial risk to Neptune. When the commodity prices are lower than expected we generate less cash, which can impact our financial condition and reduce capital available for our growth. Lower prices may also affect recoverability of our hydrocarbon reserves, which may impede our growth and result in asset impairments or write-offs.	We maintain a continuous hedging programme to ensure we lock in prices for major parts of our production while maintaining access to upside.
We may suffer from limited access to capital markets due to risk aversion towards industries exposed most to climate change risk. Lack of funding options may limit the growth of our business.	We actively engage with potential investors and have set out our ESG commitments. We also maintain loan facilities through the RBL to ensure our long-term liquidity supports the business.

Internal control

We maintain the Neptune integrated management system to ensure all our control requirements are managed consistently and kept live. The internal control system is linked to the enterprise risk management process and it is subject to assurance activities to confirm the key controls we defined are operating effectively. The foundation for Neptune's control system is its culture, which is defined by Neptune's vision, values and enduring priorities. For more information go to www.neptuneenergy.com. It is underpinned by a set of Group-wide principles around organisation design, delegated authority and competence frameworks, governance, communication and reporting as well as systems enabling them.

Internal audit and assurance

The compliance, legal and internal audit functions reduce compliance risks by monitoring and providing assurance about the effectiveness of our risk management, internal controls and compliance. In conjunction with the human resources (HR) function, the senior leadership team, and the Board, they also set the tone in the organisation by role-modelling behaviours and by recruiting staff with the right mindset to ensure a culture of integrity.

In 2019, the Board established an internal audit function, reporting to the Executive Chairman and the Chief Executive Officer. The Director of Internal Audit is defining the scope and risk-based plan for internal audit activity in 2020 and is responsible for coordination of enterprise risk management processes as well as internal assurance activities across the business.

We see an opportunity to strengthen the assurance activity further and, as part of our 2020 plans, we will explore technological solutions for making assurance activities more efficient.

2020 priorities

We continuously review the ways in which we run our business and have identified a number of opportunities to improve our system of risk, internal control and assurance in 2020. The key objective is to consolidate risk, control and assurance processes across the Group through the:

- implementation of Group-wide standards on risk management, audit and assurance;
- implementation of a common control framework and strengthening of functional risk and control oversight and functional assurance;
- consolidation of Group requirements in the integrated management system;
- definition of risk appetites for enterprise risks; and
- development of methodologies for assessing the physical impact of climate change risks and factoring them into our activity planning.

This strategic report, consisting of pages 2 to 45 was approved by the Board on 30 March 2020.

By order of the Board.

James L House

Chief Executive Officer

Governance
Corporate governance

During 2019, the Group built on its strong foundations and remained committed to the highest standards of governance, ethics and integrity throughout its operations.

To complement its existing management and compliance framework, the Group constituted its Audit and Risk Committee, adopted the Wates Corporate Governance Principles, and developed its ESG strategy.

Executive management

The Group is managed by the executive leadership team (ELT). This consists of senior management (see biographies on page 49), together with the heads of other functions and the managing directors of the countries in which we operate. With health, safety and the environment (HSE) always being the first agenda item, the ELT meets weekly to discuss operational matters such as production, exploration and projects, as well as overall performance of the Group.

Each month, the performance of the business is compared to the budget by means of a reforecasting and appraisal process. In addition, each of the businesses participated in performance reviews with the ELT and other members of the senior leadership team on three occasions during 2019.

Ethics and compliance

Our Code of Ethics and Business Integrity represents the cornerstone of a framework of ethics-related policies. It sets out five principles of action designed to equip everyone working for the Group with the tools to make the right decisions and act in accordance with the highest ethical values. Our Gifts and Invitations Policy and Conflict of Interest Policy also set out clear rules and guidelines for members of staff, including the circumstances in which such matters need to be approved or registered.

Our Whistleblowing Policy and Whistleblowing Reporting Procedure seek to ensure that everyone working for Neptune can raise any matters of genuine concern without fear of reprisals, safe in the knowledge that they will be taken seriously and that matters will be investigated appropriately and treated as confidential wherever possible. A report of a concern can be made through various internal reporting channels or using an external reporting line, Safecall.

During 2019, we also conducted awareness campaigns and online training sessions on our Code of Ethics and Business Integrity and Whistleblowing Policy. Every new member of staff is required to complete online ethics training when they join.

Additional information on these policies, as well as our statement on modern slavery, is available on our website.

Board of Directors

The Company's Board of Directors (the Board), comprises Sam Laidlaw (Executive Chairman), Jim House (Group Chief Executive Officer) and Armand Lumens (Group Chief Financial Officer). Biographies of the Directors are set out on page 49.

Among other things, during 2019 the Board:

- reviewed and commented on proposals for the Group's ESG strategy and approved the adoption of the Wates Corporate Governance Principles for Large Private Companies;
- approved the Group's 2019 budget and business plan, including the Group's capital expenditure programme and operating expenditure;
- approved the 2018 annual report and accounts as well as the quarterly earnings releases in 2019;
- considered and approved various M&A opportunities; and
- considered and approved a tap issue to the bond previously issued by Neptune Energy Bondco plc and guaranteed by the Company.

The Board works closely with the board of directors of our parent company, Neptune Energy Group Limited (NEGL) which is the entity through which our investors own their interests in the Group (for further detail on our investors, please refer to page 18). The directors of NEGL (the NEGL Directors) are nominated by our investors and are experienced business leaders with the skills necessary to support the business to deliver its strategy.

Details of the NEGL Directors are as follows:

Sam Laidlaw (Executive Chairman): see page 49 for Sam's biography.

Yuling Lu (China Investment Corporation nominee): Ms Lu serves as Director in China Investment Corporation (CIC). Her main mandate is investments in the global oil and gas and infrastructure sector since 2009. Before her career in CIC, Ms Lu worked at JPMorgan Hong Kong in the Asset Management Department, where she focused on investments in the real estate and infrastructure sectors.

She graduated from Tsinghua University with B.Eng. of Construction Management and MPhil. of Real Estate Financing from Cambridge University, UK.

Jianmin Bao (CIC nominee): Mr Bao oversees investment projects in infrastructure, energy, oil and gas, minerals and related investment funds at CIC Capital Corporation. Previously he managed North American fund investments and private credit market investments in the Private Equity department of CIC. Before his role in CIC, Mr Bao held a variety of senior roles in China Construction Bank, the Export-Import Bank of China and HSBC.

Mr Bao graduated from Shanghai Jiaotong University with a master's degree.

Ning Ge (CIC nominee): Ms Ge joined the NEGL board in November 2019. She serves as Senior Vice President in the Investment Department at CIC. She joined CIC in 2010 and has been an investment professional in various sectors including oil and gas, infrastructure, power and renewables.

Ms Ge received her PhD degree from the University of Illinois at Chicago in 2010 and her bachelor's degree from Beijing University in 2004.

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 the Chairman of AtlasInvest, a private holding company he founded in 2007 that is engaged in investments across the broad energy spectrum, and the 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, USA.

James 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 $2.5 billion fund focused on Europe and Africa. Mr Maguire has been active in the global energy markets for more than 30 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 (1977), an MA from Oxford University (1980) and a JD from the University of Virginia School of Law (1983).

James Brian Mahoney (CVC Capital Partners appointee): Mr Mahoney is a Partner at CVC Capital Partners (CVC), a world leader in private equity and credit with $80.5 billion of assets under management, $134.5 billion of funds committed and a global network of 24 local offices. He has responsibilities in both the Private Equity and Strategic Opportunities platforms, and currently represents CVC as a director on the boards of Neptune Energy, Ontic, Moto and Advantage Solutions. 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 (including energy) and geographies (principally Western Europe and North America). Prior to joining, Mr Mahoney was a Managing Director with Investcorp.

He has a bachelor's degree in Engineering from the University of Auckland (1994).

The NEGL board works to an agenda of standing items and exceptional matters appropriate to the Group's operating and reporting cycles.

Governance

Senior management

Our depth and breadth of experience

1 Sam Laidlaw
Executive Chairman
Company Director

A Chair I R Chair

2 Jim House
Chief Executive Officer
Company Director

A I Chair

3 Armand Lumens
Chief Financial Officer
Company Director

A I C

4 Mark Richardson
VP Projects

5 Gro Haatvedt
VP Exploration and Development

6 Andrea Guerra
VP Reservoir Engineering

7 David Hemmings
VP Business Development

I

8 Pete Jones
VP Operations Europe

I C

9 Philip Lafeber
VP Operations, North Africa and Asia Pacific

I

10 Julian Regan-Mears
Director of Corporate Affairs

C Chair

11 Amanda Chilcott
Group Human Resources Director

C R

12 Ben Walker
General Counsel

A C

13 Kick Sterkman
Group HSEQ Director

A C

14 Kaveh Pourteymour
Chief Information Officer

Committees as at 6 April 2020

- A Audit and Risk Committee
- C Corporate Responsibility Committee
- I Investment Committee
- R Remuneration and Nomination Committee

1 **Sam Laidlaw** 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 CEO of Centrica Plc, the integrated energy company engaged in sourcing, producing, trading and supplying energy and a range of related services.

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 (NCUB).

2 **Jim House** joined as CEO in January 2018. He has more than 30 years' experience across the International E&P industry in North America, Europe, North Africa and the North Sea.

Before taking up his role, he spent 26 years at Apache Corporation, most recently as the Senior Vice President responsible for Egypt, Mid-Continent US, Gulf Coast, Gulf of Mexico and International New Ventures.

Jim has served on the Upstream Committee of the American Petroleum Institute, the US Egypt Business Council within the US Chamber of Commerce, chaired the UK Oil Spill Prevention and Response Advisory Group (OSPRAG) plus the UK Production Efficiency Task Force while on the Council and Board of Oil and Gas UK.

Jim serves on the Texas A&M University Petroleum Engineering Department Industry Board and is a Lifetime Member of the Society of Petroleum Engineers.

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

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

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

4 **Mark Richardson** joined Neptune in March 2018 having previously worked for Apache and BP. He has more than 25 years' experience of the oil and gas sector and, before joining the industry, he was an officer with the Royal Engineers, serving with Commando Forces and specialising in military diving operations.

Mark has served on the Subsea UK Board and the UK Engineering Construction Industry Training Board.

5 **Gro Haatvedt** joined Neptune in October 2018 with more than 30 years' experience in the oil and gas sector.

Previously, she was Senior Vice President for Exploration in Aker BP and held a variety of senior international roles in Equinor.

Gro is a member of the Magseis Fairfield Board and Geo Trade Organisation, GTO in Norway.

6 **Andrea Guerra** joined Neptune in August 2018 and has more than 18 years' international oil and gas sector experience.

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

7 **David Hemmings** 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 acquisition and debt and equity financing.

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

8 **Pete Jones** joined Neptune in August 2018. He has more than 25 years' experience in the upstream oil and gas sector. He has a proven track record of leading asset and regional teams, and improving operating and safety-related performance , while optimising cost structures to deliver key business objectives. He was Managing Director of TAQA Europe and spent the majority of his career with Marathon Oil where he held a number of senior leadership positions including UK Managing Director and Regional Vice President.

9 **Philip Lafeber** 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 SE Asia. He has worked in Oman for Shell International and in West Africa for Schlumberger Wireline.

10 **Julian Regan-Mears** 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.

11 **Amanda Chilcott** joined Neptune in December 2018. With more than 20 years' experience in human resources, she has worked with the Ford Motor Company, BP and Aggreko in a variety of global roles in the UK, continental Europe, China and the US.

12 **Ben Walker** 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.

13 **Kick Sterkman** has 26 years of experience in upstream oil and gas, mostly in operational leadership roles, working for Expro, Clyde Petroleum, Wintershall and ENGIE. He joined Neptune as Head of HSEQ in February 2018 from ENGIE where he led Health, Safety, Environment, Quality and Security teams.

14 **Kaveh Pourteymour** joined Neptune in March 2019. Previously he was VP and CIO of Seadrill Management following senior leadership roles in BP's Global Refining and International Businesses and with BOC Edwards. Since 2008, he has held the position of Adjunct Professor at the business school of Imperial College London.

Directors' report

Group Audit and Risk Committee

During 2019, the NEGL Board established the Group's Audit and Risk Committee (ARC). The ARC assists the Board (and the NEGL Board) in discharging its duties in monitoring the integrity of financial statements, the adequacy of the system of risk management, and internal control. It also monitors the effectiveness, performance and objectivity of internal and external auditors.

Governance

During 2019, the terms of reference of the ARC were adopted to define its responsibilities, authorities and accountability. The ARC reports to the NEGL Board and consists of the Executive Chairman (who also acts as the ARC Chair), Chief Executive Officer, Chief Financial Officer, General Counsel, Director of Health Safety, Environment and Quality and Director of Internal Audit. The Group's external auditor and Director of External Reporting also attend meetings of the ARC. Other members of senior management can be invited by to discuss particular risk, control or assurance matters. As part of governance arrangements, the external auditor and Director of Internal Audit have unrestricted access to the Chair of the ARC. The Director of Internal Audit reports to the CEO.

During 2019, the ARC focused its work primarily on design and consolidation of Neptune's system of risk, control and assurance, oversight of the financial reporting process and monitoring of the relationship with EY, the Group's current external auditor.

Financial reporting process

The ARC held three meetings during 2019, which were aligned with the financial reporting calendar and external audit cycle. It received updates from Chief Financial Officer on the status of preparation of financial statements and discussed key financial results and matters of judgement. The ARC reviewed and approved a Group Accounting Policy Manual, which defines Neptune's accounting policies and guidelines across the Group, and also monitored changes in accounting standards, giving particular consideration in 2019 to implementation of IFRS 16 – Leases.

Risk management and internal control

The ARC focused on effective risk management and Neptune's well-defined and consistent internal control system in 2019. A key milestone of that work was an adoption of a common enterprise risk management framework which was rolled out to the business. Based on the adopted approach, the ARC led a Group-wide risk assessment aimed at identifying key enterprise risks, defining risk ownership for each risk and identifying risk reduction actions if required.

The results are held in an enterprise risk register, which the ARC reviews at each meeting. The register enables the ARC to identify and highlight key risk areas. These include cyber risk, health and safety, Brexit, commodity and currency risk, funding risk, key legal risk, as well as adequacy of the insurance programme for the Group. For more information on the work performed on risk management see page 42.

Other matters considered by the ARC

During 2019, the ARC also considered the following items (among others):

- the terms of appointment of the Group's external auditors, EY;
- EY's audit plan for the Group and materiality thresholds, as well as assessment of key audit risks, particularly regarding recoverability of goodwill and tangible oil and gas assets, recoverability of deferred tax assets as well as specific fraud risks around management override and revenue recognition;
- EY's report on the Group financial statements for the year ended 31 December 2018 and conclusions both on financial statements and on agreed audit focus areas;
- the terms on which non-audit services may be provided EY;
- the Group's disputes report;
- the Group's ethics and compliance programme; and
- the requirement for an Internal Audit function to be established and oversaw the appointment of the new Director of Internal Audit, who will further develop Internal Audit vision and plan in the context of the overall assurance framework of Neptune Energy, covering all enterprise risk categories.

Given the relatively recent formation of the Group, the ARC has simultaneously recognised a need to define and document key financial controls for the company. On the ARC's endorsement, a Group-wide project was initiated to document financial processes and related key financial controls. This is due for completion in 2020.

Group Remuneration Committee

The Group's Remuneration Committee (Remco) consists of the members of the NEGL Board as well as the Group Director of Human Resources, with the CEO attending by invitation. The Remco meets three times per year (and on an ad-hoc basis when required) to review and recommend matters relating to remuneration. During 2019, it considered the following matters (among others):

- salary planning across the Group;
- the output of the 2018 Group scorecard for the purposes of determining the Group performance element for bonus awards paid in respect of 2018;
- bonuses payable to members of the ELT in respect of 2018 performance;
- design of the 2019 scorecard;
- appointment of new members of the executive team and the terms of their appointment (including, where relevant, the incentive plan arrangements);
- the Group's long-term incentive plan for 2019;
- review of the Executive Leadership Team's performance;
- gender pay gap and pay ratios; and
- market data on reward in comparable companies.

Group Corporate Responsibility Committee

The Group Corporate Responsibility Committee (CRC) consists of the Director of Corporate Affairs, the Group HSEQ Director, the Chief Financial Officer, the Group Human Resources Director, the Environment, Social and Governance Manager, Director of Internal Audit, Head of Global Environmental Management, Global Head of Ethics and Compliance, Vice President of Operations, Europe and the General Counsel. During 2019, the CRC reviewed the ESG strategy and considered, among other things:

- the Group's approach to managing climate-related risks including the use of carbon and methane intensity targets;
- the Group's new environmental policy;
- the UN Sustainable Development Goals;
- revised framework for social investment;
- data and approach on inclusion and diversity;
- existing and upcoming ESG regulatory requirements; and
- ESG metrics and disclosure for the 2019 Annual Report.

Statement of corporate governance arrangements

Under the Companies (Miscellaneous Reporting) Regulations 2018, the Company is required to include a statement of corporate governance arrangements in its annual report for years beginning on or after 1 January 2019. The Company has adopted the Wates Corporate Governance Principles for Large Private Companies (published by the Financial Reporting Council in December 2018), which will apply to our reporting for 2019 and subsequent years. We set out below how the Principles were applied during 2019.

Principle 1 – Purpose and leadership

Our vision is to make a positive contribution to meeting society's energy needs and the energy transition as the leading international gas-focused independent exploration and production company. We aim to create sustainable value for our stakeholders through:

- A focused exploration programme that is balanced as to risk and reward and targeted around existing infrastructure.
- Developing fields, preferably as operator, with innovative low cost solutions and short cycle times.
- Producing fields as efficiently as possible to maximise recovery, lower unit costs and reduce carbon intensity.

Our differentiated portfolio is:

- Large-scale and diversified
- Long-life, low cost and lower carbon
- Gas-weighted and well-positioned for the energy transition.

We seek to deliver strong returns through significant cash flow generation and a strong balance sheet, disciplined capital allocation and value-accretive growth and yield.

Our culture is centred on our enduring priorities:

- Focus on safe, economic operations
- Deliver superior field development
- Optimise the portfolio for the future
- Drive digital and technological innovation
- Realise the potential of our organisation
- Contribute positively to the energy transition
- Maintain our social license to operate.

Our values of excellence in HSE, accountability, integrity and teamwork are a core component of our business and help to guide all our actions. These values form a key component of our drivers for success and provide a strong platform from which to ensure all of our activities are geared towards sustainable value.

Health, safety and the environment are at the heart of our business. Neptune's HSE policy applies to everybody working for, and on behalf of, the business. Our safety culture programme is a fundamental part of our HSE policy and is designed to ensure safe working is embedded in our thinking and in every action we take. 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 sustainable, low carbon future.

Principle 2 – Board composition

Details of the membership of the Board can be found on page 46. The Executive Chairman leads the Board and ensures that the views of all Directors are considered in the decision-making process.

Although there are no independent directors on the Board, the Directors are highly experienced business leaders and frequently consider the interests of a broad range of stakeholders (including employees, joint venture partners and bondholders) in their decision-making processes. Having led and held senior executive positions in other leading global organisations, the Directors bring many years of experience in the energy industry to the Group (for further details, see the biographies of the Directors on pages 48 and 49).

Since the Company is an intermediate holding company within the Group, the Directors believe that the Board is of an appropriate size given that it works closely with the board of directors of the Company's parent, NEGL. During 2020, the Directors intend to review the size and composition of the Board, taking into consideration the recommendations of the directors of NEGL as well as the opportunities for greater diversity.

Governance

Directors' report

Principle 3 – Director responsibilities

Decisions within the Group are carried out in accordance with strict principles set out in the shareholders' agreement for NEGL and constitutional documents for each member of the Group. In reaching their decisions, the directors also have regard to the Group's obligations to its bondholders and other stakeholders as detailed on pages 18 and 19. In accordance with the Company's articles of association and applicable law, the directors will not take part in any discussion or decision in which they have a conflict of interest.

The Directors receive detailed information relating to the operations and performance of the Group, both through the cycle of weekly and monthly ELT meetings and full Board meetings when required. The Board Committees also support the Board in its decision-making processes (see page 50 for further information).

During 2019, the Group continued to build its internal control framework as further described on page 45.

Principle 4 – Opportunity and risk

The Group's approach to strategic opportunities is set out in the Executive Chairman and Chief Executive Officer messages on pages 6 to 9. We seek to capitalise on opportunities (for example through mergers and acquisitions (M&A)) while mitigating risks where possible. The Group's functional and country leadership teams identify opportunities for the Group, which are regularly discussed at the meetings of the ELT. The Group's Investment Committee meets regularly (generally every two weeks) to discuss strategic opportunities including M&A, exploration and drilling activities while the Group's Audit and Risk Committee undertakes regular reviews of the key risks affecting the Group (including an assessment of whether risks are increasing or decreasing and the associated mitigations).

Please see page 42 for further information on the Group's approach to risk and risk management and page 50 for information relating to the Group Audit and Risk Committee.

Principle 5 – Remuneration

The Remco's primary purpose is to develop, maintain and implement remuneration policies. The overriding objective of such policies is to attract and retain high-calibre individuals with a competitive reward package based on the achievement of corporate performance targets. These are linked to individual performance and accountability, and supports the Group's commitment to exemplary safety standards and values while rewarding long-term value creation.

The Remco ensures that levels of compensation across the Group are sufficiently competitive to retain talent within the Group, as well as benchmarking the remuneration packages of the ELT. Additionally, the Remco reviews the Group's performance with regard to diversity and inclusion criteria, including benchmarking the Group against other industry players.

For further details of the **RemCo's activities in 2019**, see page 50.

Principle 6 – Stakeholders

We set out examples of how we engage with some of our key stakeholders, including our workforce, shareholders, bondholders, suppliers, local communities and customers, on pages 18 and 19. As well as informing business-level decisions, an overview of the output of this engagement and related developments is reported to the Board, Committees and/or ELT, to ensure due consideration is given to stakeholders and the output of this engagement when decisions are taken at those levels.

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 2019 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

Each of 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, and that they have taken all steps they ought to have taken 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 40
- 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 38 hedging and note 24 on page 100.
- Likely future developments in the business of the Company, see page 23.
- The research and development activities carried out by the Company, see page 12.
- Our engagement with suppliers, customers and others with whom we do business, see pages 18 and 19.

Conflicts of interest

Directors have a statutory duty to avoid situations in which they may have interests which conflict with those of the Company. 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 (2018: $nil) or incur any political expenditure (2018: $nil) during the year.

By order of the Board.

Sam Laidlaw

Executive Chairman
30 March 2020

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 International Financial Reporting Standards (IFRS), as published by the International Accounting Standards Board (IASB) and endorsed by the European Union, but makes amendments where necessary in order to comply with the Companies Act 2006. 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 IFRS has been followed, subject to any material departures disclosed and explained in the financial statements; and
- prepare the financial statements on the going concern basis unless it is inappropriate to presume that the Company will continue in business.

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

Independent Auditor's Report to the Members of Neptune Energy Group 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 2019 which comprise the Consolidated income statement, Consolidated statement of other comprehensive income, Consolidated and Parent statement of financial position, Consolidated and Parent statement of changes in equity, Consolidated and Parent cash flow statement and the related notes 1 to 30, including a summary of significant accounting policies. The financial reporting framework that has been applied in their preparation is applicable law and International Financial Reporting Standards (IFRSs) as adopted by the European Union and, as regards the parent company financial statements, as applied in accordance with the provisions 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 2019 and of the group's profit for the year then ended;
- the group financial statements have been properly prepared in accordance with IFRSs as adopted by the European Union;
- the parent company financial statements have been properly prepared in accordance with IFRSs as adopted by the European Union in accordance with the provisions 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 below. We are independent of the group and parent company 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.

Emphasis of matter – Effects of COVID-19

We draw attention to note 30 of the financial statements which describes the impact of the COVID-19 pandemic on oil and gas pricing, subsequent to year end, in addition to significant commodity market volatility relating to the global supply of oil. Our opinion is not modified in respect of this matter.

Conclusions relating to going concern

We have nothing to report in respect of the following matters in relation to which the ISAs (UK) require us to report to you where:

- the directors' use of the going concern basis of accounting in the preparation of the financial statements is not appropriate; or
- the directors have not disclosed in the financial statements any identified material uncertainties that may cast significant doubt about the group's or the parent company's ability to continue to adopt the going concern basis of accounting for a period of at least twelve months from the date when the financial statements are authorised for issue.

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.

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.

In connection with our audit of the financial statements, 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 audit or otherwise appears to be materially misstated. If we identify such material inconsistencies or apparent material misstatements, we are required to determine whether there is a material misstatement in the financial statements or a material misstatement of the other information. 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 53 , 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.

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

Use of our report

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

Ernst & Young LLP

Steven Dobson
(Senior statutory auditor)
for and on behalf of Ernst & Young LLP,
Statutory Auditor
London

30 March 2020

Notes:

1. The maintenance and integrity of the Neptune Energy Group Midco Limited web site is the responsibility of the directors; the work carried out by the auditors does not involve consideration of these matters and, accordingly, the auditors accept no responsibility for any changes that may have occurred to the financial statements since they were initially presented on the web site.
2. Legislation in the United Kingdom governing the preparation and dissemination of financial statements may differ from legislation in other jurisdictions.

Financial statements

Consolidated financial statements

For the year ended 31 December 2019

Consolidated income statement

Group In millions of $	Notes	Year ended 31 December 2019	Year ended 31 December 2018
Revenue	3	2,202.2	2,537.9
Cost of sales	6	(1,158.9)	(1,203.3)
Gross profit		1,043.3	1,334.6
Exploration expenses	6	(60.4)	(89.2)
General and administration expenses	6	(68.6)	(131.6)
Share of net income from investments using equity method	15	2.1	4.0
Operating profit after equity accounted investments	4	916.4	1,117.8
Other operating (losses)/ gains	8	(43.7)	(68.5)
Operating profit before financial items		872.7	1,049.3
Finance income	9	6.3	6.5
Finance costs	9	(202.2)	(149.7)
Profit before tax		676.8	906.1
Taxation	11	(237.8)	(644.6)
Net profit		439.0	261.5

All profits and losses arise as a result of continuing operations. The accounting policies on pages 62 to 73 together with the notes on pages 74 to 113 form part of these accounts.

Consolidated statement of other comprehensive income

Group In millions of $	Notes	Year ended 31 December 2019	Year ended 31 December 2018
Profit/(loss) for the year		439.0	261.5
Other comprehensive income:			
Items that may be reclassified to the income statement:			
Hedge adjustments net of tax (1)	23	143.9	(25.1)
Foreign currency translation		35.8	(142.8)
		179.7	(167.9)
Other items not reclassified to the income statement:			
Remeasurement of defined pension obligations, net of tax (2)		(20.1)	(0.1)
Other comprehensive income		159.6	(168.0)
Other comprehensive profit for the year, net of tax		598.6	93.5

1) Income tax related to hedge adjustments is $36.1 million charge (2018: $3.3 million credit) and is shown net of amounts reclassified to profit or loss or included in finance costs.

2) Income tax related to defined benefit obligations is $7.5 million credit (2018: $3 million credit).

Consolidated statement of financial position – Group

Group In millions of $	Notes	31 December 2019	31 December 2018
Non-current assets			
Goodwill [1]	12	640.8	648.2
Intangible assets [1]	13	150.9	111.1
Property, plant and equipment	14	4,430.8	3,922.2
Derivative instruments	23	74.9	40.1
Investments in entities accounted for using the equity method	15	604.7	540.9
Other non-current assets	23	110.6	8.8
Equity instruments	23	19.3	19.7
Deferred tax assets	11	691.0	438.6
Total non-current assets		6,723.0	5,729.6
Current assets			
Derivative instruments	23	147.4	33.2
Trade and other receivables	17	651.9	726.3
Inventories	16	60.4	64.3
Cash and cash equivalents	18	85.4	197.3
Income tax receivable	23	16.6	–
Total current assets		961.7	1,021.1
Total assets		7,684.7	6,750.7
Share capital	25	1,977.2	1,977.2
Hedging reserve	23	118.8	(25.1)
Foreign currency translation		(107.0)	(142.8)
Retained earnings/(deficit)		(103.5)	(122.4)
Total equity		1,885.5	1,686.9
Non-current liabilities			
Provisions	22	1,654.2	1,675.2
Long-term borrowings	19	1,815.6	1,788.2
Derivative instruments	23	28.6	31.1
Income tax payable	23	59.0	35.7
Other non-current liabilities	20	164.6	59.6
Deferred tax liabilities	11	750.1	582.2
Total non-current liabilities		4,472.1	4,172.0
Current liabilities			
Provisions	22	113.5	69.3
Short-term borrowings	19	124.0	–
Derivative instruments	23	18.6	73.6
Trade and other payables	20	222.7	94.5
Income tax payable	23	155.3	188.1
Other current liabilities	20	693.0	466.3
Total current liabilities		1,327.1	891.8
Total equity and liabilities		7,684.7	6,750.7

1) The balance sheet has been revised following the completion of the valuation of the assets and liabilities in the acquisition of VNG Norge AS (see note 5).

The accounts on pages 56 to 113 were approved by the Board and signed on its behalf by:

Armand Lumens, Chief Financial Officer

Consolidated financial statements

For the year ended 31 December 2019

Statement of financial position – Company

Company In millions of $	Notes	31 December 2019	31 December 2018
Non-current assets			
Investments	15	1,977.2	1,977.2
Inter-company loan receivable	17	939.7	654.0
Total non-current assets		2,916.9	2,631.2
Current assets			
Cash and cash equivalents	18	–	1.1
Trade and other receivables	17	216.8	0.2
Total current assets		216.8	1.3
Total assets		3,133.7	2,632.5
Share capital	25	1,977.2	1,977.2
Retained earnings		1.0	0.6
Total equity		1,978.2	1,977.8
Non-current liabilities			
Inter-company loan payable	20	939.7	654.7
Total non-current liabilities		939.7	654.7
Current liabilities			
Other current liabilities	20	215.8	–
Total current liabilities		215.8	–
Total equity and liabilities		3,133.7	2,632.5

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 $400.4 million (2018: $380.6 million).

Consolidated statement of changes in equity – Group

Group In millions of $	Share capital	Hedging reserve	Foreign currency translation	Retained earnings	Total
At 1 January 2018	–	–	–	(3.8)	**(3.8)**
Profit for the year	–	–	–	261.5	261.5
Other comprehensive income	–	(25.1)	(142.8)	(0.1)	(168.0)
Total comprehensive income	**–**	**(25.1)**	**(142.8)**	**261.4**	**93.5**
Transactions with owners of the Company:					
Issue of ordinary shares related to business combinations	1,977.2	–	–	–	1,977.2
Dividends paid (note 10)	–	–	–	(380.0)	(380.0)
At 31 December 2018	**1,977.2**	**(25.1)**	**(142.8)**	**(122.4)**	**1,686.9**
Profit for the year	–	–	–	439.0	439.0
Other comprehensive income	–	143.9	35.8	(20.1)	159.6
Total comprehensive income	**–**	**143.9**	**35.8**	**418.9**	**598.6**
Transactions with owners of the Company:					
Dividends paid (note 10)	–	–	–	(400.0)	(400.0)
Balance 31 December 2019	**1,977.2**	**118.8**	**(107.0)**	**(103.5)**	**1,885.5**

1) On Company incorporation 728 $1 shares were allotted, called up and fully paid.

2) The hedging reserve represents gains and losses on derivatives classified as effective cash flow hedges.

3) The foreign currency translation reserve represents exchange gains and losses arising on translation of foreign currency subsidiaries.

Statement of changes in equity – Company

Company In millions of $	Share capital	Retained surplus/ (deficit)	Total
At 1 January 2018	–	–	–
Profit for the year	–	380.6	380.6
Total comprehensive income for the period	**–**	**380.6**	**380.6**
Transactions with owners of the Company:			
Issue of ordinary shares related to business combinations	1,977.2	–	1,977.2
Dividends paid (note 10)	–	(380.0)	(380.0)
At 1 January 2019	**1,977.2**	**0.6**	**1,977.8**
Profit for the year	–	400.4	400.4
Other comprehensive income for the period	–	–	–
Total comprehensive income for the period	**–**	**400.4**	**400.4**
Transactions with owners of the Company:			
Dividends paid (note 10)	–	(400.0)	(400.0)
Balance 31 December 2019	1,977.2	1.0	1,978.2

1) On 15 February 2018, 1,977,174,473 $1 shares were allocated, called up and fully paid.

Consolidated financial statements

For the year ended 31 December 2019

Consolidated cash flow statement – Group

Group In millions of $	Year ended 31 December 2019	Year ended 31 December 2018
Cash flows from operating activities		
Profit before taxation	676.8	906.1
Adjustments to reconcile profit before tax to net cash flows:		
Depreciation and amortisation	624.2	656.1
Unsuccessful exploration costs written off	0.2	7.6
Impairment losses	59.4	–
Finance costs	202.2	149.7
Finance income	(6.3)	(6.5)
Share of net income from equity investments	(2.1)	(4.0)
Fair value change in contingent consideration	–	(21.0)
Other non-cash income and expenses	(1.4)	(0.4)
Fair value movement on commodity-based derivative instruments	(14.2)	46.4
Movement in provisions including decommissioning expenditure	(89.2)	(53.6)
Working capital adjustments	232.7	11.1
Income tax paid (net)	(361.7)	(535.1)
Net cash flows used in operating activities	1,320.6	1,156.4
Cash flows from investing activities		
Expenditure on exploration and evaluation assets	(87.1)	(20.3)
Expenditure on property, plant and equipment	(1,060.7)	(511.0)
Expenditure on business combination and acquisitions, net of cash acquired	–	(3,546.5)
Proceeds from sale of equity investments	–	4.3
Proceeds from sale of assets	11.6	–
Finance income received	4.2	6.1
Net investment made in equity accounted investments	(62.8)	(14.6)
Net cash flows used in investing activities	(1,194.8)	(4,082.0)
Cash flows from financing activities		
Proceeds from issue of shares	–	1,977.2
Proceeds from loans and borrowings	1,566.0	3,192.3
Repayment of borrowings	(1,439.5)	(1,510.3)
Repayment of obligations under leases	(32.3)	–
Finance costs paid	(130.5)	(149.6)
Dividends paid	(200.0)	(380.0)
Net cash flows from financing activities	(236.3)	3,129.6
Net increase/(decrease) in cash and cash equivalents	(110.5)	204.0
Cash and cash equivalents at 1 January	197.3	0.4
Net foreign exchange differences	(1.4)	(7.1)
Cash and cash equivalents at 31 December	85.4	197.3

Cash flow statement – Company

Company In millions of $	Notes	Year ended 31 December 2019	Year ended 31 December 2018
Cash flows from operating activities			
Profit before taxation		400.4	380.6
Adjustments to reconcile profit before tax to net cash flows:			
Finance costs		52.0	31.8
Finance income	9	(450.4)	(411.1)
Working capital adjustments		0.2	(0.2)
Net cash flows from operating activities		2.2	1.1
Cash flows from investing activities			
Loans made to subsidiaries		(309.6)	(650.9)
Investment made in subsidiaries		–	(1,977.2)
Finance income received		47.3	31.1
Dividend received		200.0	380.0
Net cash flows used in investing activities		(62.3)	(2,217.0)
Cash flows from financing activities			
Proceeds from issue of shares		–	1,977.2
Proceeds from loans and borrowings		307.8	651.6
Dividend paid		(200.0)	(380.0)
Finance costs paid		(48.8)	(31.8)
Net cash flows from financing activities		59.0	2,217.0
Net increase in cash and cash equivalents		(1.1)	1.1
Cash and cash equivalents at 1 January		1.1	–
Cash and cash equivalents at 31 December		–	1.1

The notes on page 74 to 113 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 2019 were authorised for issue in accordance with a resolution of the Board on 30 March 2020.

The Group is principally engaged in oil and gas exploration and production.

1. Basis of preparation

The consolidated financial statements for the year ended 31 December 2019 have been prepared in accordance with International Financial Reporting Standards (IFRS) as adopted by the European Union (EU).

The preparation of financial statements in conformity with IFRS 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 accounting policies adopted in the preparation of these consolidated financial statements are consistent with those followed in the preparation of the Group's annual consolidated financial statements for the period ending 31 December 2018 except where, due to the adoption of new standards effective as of 1 January 2019 (see note 1.1). The Group has not early-adopted any other standard, interpretation or amendment that has been issued but is not yet effective.

The consolidated statement of financial position for 31 December 2018 as previously disclosed has been revised as it was based on provisional assigned fair values of the acquisition of the VNG Norge business on 28 September 2018. On conclusion of the business combination accounting the fair values were concluded in September 2019. The revisions to these financial statements did not constitute a restatement of the financial results as IFRSs allow a period of up to 12 months beyond the acquisition date of business combinations to finalise the associated judgements and assigned fair values. See note 5 for further information.

1.1 New standards, interpretations and amendments adopted by the group

IFRS 16 Leases was issued in 2016 to replace IAS 17 Leases and is required to be adopted by 2019. Under the new standard all lease contracts, with limited exceptions, are recognised in financial statements by way of right-of-use assets and corresponding lease liabilities. The Group has applied the modified retrospective approach, which means that the cumulative effect of initially applying the standard is recognised at the date of initial application and there is no restatement of comparative information. The Group elected to use the transition practical expedient to not reassess whether a contract is, or contains, a lease at 1 January 2019. Instead the Group applied the standard only to contracts that were previously identified as leases applying IAS 17 and IFRIC 4 at the date of initial application. The Group also applied the practical expedient to exclude the initial direct costs from the measurement of the right of use asset at the date of initial application.

In March 2019, the IFRS Interpretations Committee (IFRIC) finalised its decision regarding 'liabilities in relation to a joint operator's interest in a joint operation (IFRS 11 Joint Arrangements)', concluding that a joint operator should recognise the liabilities for which it has primary responsibility, which may be different from its share in the joint operation. As a consequence of this ruling the Group has recognised the full value of joint venture lease liabilities for which it has primary responsibility, recognising its joint venture share as a right-of-use asset and the partners share as a joint venture receivable.

The application of the standard has impacted both the measurement and disclosures of leases over a low-value threshold, with terms longer than one year and on the classification of expenditures and consequently the classification of cash flow from operating activities, cash flow from investing activities and cash flow from financing activities. It has also impacted the timing of expenses recognised in the statement of income. The adoption of the new standard at 1 January 2019, on a gross basis has had a negligible impact on equity following the recognition of lease liabilities of $145 million and additional right-of-use assets of $110 million and JV partner receivables of $35 million. These liabilities have been measured at the present value of the remaining lease payments, discounted using the Group's marginal cost of finance as of 1 January 2019, which is the Company's rate on its corporate Reserve Based Lending (RBL) facility currently 5.7%. A 1% change in the cost of borrowing would have impacted the value of lease liabilities on transition by $5.4 million.

The following categories of leases have been identified: land, buildings (offices, warehouses and supply bases), transportation assets (helicopter, supply and standby vessels), property, plant and equipment.

Where the asset is dedicated to an operated joint venture and Neptune has transferred substantially all the risks and rewards incidental to ownership on a pro-rata basis to joint venture (JV) partner(s) Neptune recognises the gross lease liability but derecognises the proportion of the right-of-use asset that is sub-leased, which is recognised as a JV receivable. Where there are options to extend a contract and it is reasonably certain that the contract will be extended, the lease period extension is included in the assessment. The right-of-use asset is recognised within property, plant and equipment at the present value of the liability at the commencement date of the lease, adding any directly attributable costs. The right-of-use asset is depreciated on a straight-line basis over the lease term.

The Group has elected to use the exemptions proposed by the standard on lease contracts for which the lease terms ends within 12 months as of the date of initial application, and lease contracts for which the underlying asset is of low value. These leases will continue to be accounted as operating leases and are not material in the context of the Group financial results. Furthermore, the use of a single discount rate is applied to a portfolio of leases with reasonably similar characteristics.

The impact of adopting IFRS 16 on 1 January 2019 has been the immediate recognition of right-of-use assets of $110 million, a JV partner receivable of $35 million and lease liabilities of $145 million, with a reclassification of costs from 1 January 2019 that would previously have been reported under operating lease expenses to depreciation of leased assets and unwinding of the discount on leased assets.

Initial recognition of lease	Current	Non-current	Value on transition $m
Land	2	13	15
Buildings	10	36	46
Transportation	22	61	83
Property, plant and equipment	-	1	1
Total	34	111	145

The difference between the closing 2018 value of operating lease commitments of $189 million and the opening value to be recognised as the lease liability of $145 million is $44 million. This arises primarily as a result of the deduction of $86 million of items outside the scope of IFRS 16 reporting, being pipeline capacity commitments, offset by the addition of $96 million of items within the scope of IFRS 16 while previously being outside the scope of IAS 17. These are extension options reasonably certain to be exercised, the inclusion of gross attribution of contracted assets within operated joint operations. Additionally, there are $14 million of jointly controlled assets that are not recognised under IFRS 16 and $40 million as a result of applying a discount rate of 5.7% being the Group's incremental borrowing rate.

In millions of $	1 January 2019
Reconciliation of operating lease commitments to IFRS 16 liability	
Operating lease commitments at 31 December 2018	
As disclosed in the Group's consolidated financial statements	189
Recognition exemption - jointly controlled assets [(1)]	(14)
Scope exemption - pipeline booking capacity commitments	(86)
Extension options reasonably certain to be exercised	53
Leases within joint operations	43
Discounted using incremental borrowing rate as at 1 January 2019 of 5.7%	(40)
Lease liabilities recognised at 1 January 2019	**145**

1) Includes the recognition exemption for low-value assets and short-term leases of $0.1 million.

IFRIC 23 Uncertainty over Income Tax Treatments (effective 1 January 2019)

IFRIC 23, Uncertainty over Income Tax Treatments, was issued by IASB on 7 June 2017. The Interpretation provides guidance on the accounting for current and deferred tax assets and liabilities in circumstances in which there is uncertainty over income tax treatments. IFRIC 23 requires the entity to contemplate whether uncertain tax treatments should be considered separately or as a group based on the predictability of the resolution. In addition, the entity should assess if the tax authority will accept uncertain tax treatments, and in the case where it is not probable, the interpretation requires the entity to reflect the uncertainty with disclosure of the most likely amount and the expected value of the income tax payable or recoverable. The interpretation became effective for annual periods beginning on 1 January 2019. The adoption of this interpretation did not have a material impact on the consolidated financial statements as the Group's uncertain tax provisions comply with IFRIC 23 and no additional disclosure was required.

Interest Rate Benchmark Reform (effective 1 January 2020)

Interest rate benchmark reform amendments to IFRS 9, IAS39 and IFRS 7, was issued by the IASB in September 2019. Interbank offered rates (IBORs) are interest reference rates, such as LIBOR, EURIBOR and TIBOR, that represent the cost of obtaining unsecured funding, in a particular combination of currency and maturity and in a particular interbank term lending market. Reforms are underway which aim to achieve a shift away from individual trader quotes to observed transaction rates and to increase the population on which those rates are based.

The International Accounting Standards Board (IASB) has published 'Interest Rate Benchmark Reform (Amendments to IFRS 9, IAS 39 and IFRS 7)' as a first reaction to the potential effects the IBOR reform could have on financial reporting. The amendments are effective for annual periods beginning on or after 1 January 2020, with earlier application permitted.

The guidance published considers reliefs to hedge accounting in the period before the reform. These amendments provide temporary relief from applying specific hedge accounting requirements to hedging relationships directly affected by IBOR reform. The reliefs have the effect that IBOR reform should not generally cause hedge accounting to terminate. However, any hedge ineffectiveness should continue to be recorded in the income statement under both IAS 39 and IFRS 9. Furthermore, the amendments set out triggers for when the reliefs will end.

Neptune has chosen not to adopt the amendments early as the majority of its hedging instruments are commodity-based and are therefore not impacted by the proposed amendments. Those few hedging instruments that the Group holds which might have otherwise been affected by the proposed amendment are all expected to mature before any reform to the interest rate benchmark has been finalised and so the new amendment is expected to have no impact on the current financial statements of the Group.

Notes to the consolidated financial statements

Plan Amendment, Curtailment or Settlement - amendments to IAS 19 (effective 1 January 2019)

Effective for annual periods beginning on or after 1 January 2019, an amendment has been made to IAS 19 Employee Benefits to address the accounting when a plan amendment, curtailment or settlement occurs during a reporting period.

When accounting for defined benefit plans under IAS 19, the standard generally requires entities to measure the current service cost using actuarial assumptions determined at the start of the annual reporting period. Similarly, the net interest is generally calculated by multiplying the net defined benefit liability (asset) by the discount rate, both as determined at the start of the annual reporting period. The amendments specify that when a plan amendment, curtailment or settlement occurs during the annual reporting period, an entity is required to:

- Determine current service cost for the remainder of the period after the plan amendment, curtailment or settlement, using the actuarial assumptions used to remeasure the net defined benefit liability (asset) reflecting the benefits offered under the plan and the plan assets after that event.
- Determine net interest for the remainder of the period after the plan amendment, curtailment or settlement using: the net defined benefit liability (asset) reflecting the benefits offered under the plan and the plan assets after that event; and the discount rate used to remeasure that net defined benefit liability (asset).

This clarification provides that entities might have to recognise a past service cost, or a gain or loss on settlement, that reduces a surplus that was not recognised before.

While there have been curtailment and settlement events affecting the Groups defined benefit pension schemes in both the Netherlands and France, the circumstances that gave rise to these events were only triggered at the end of the reporting period. Therefore, given the proximity of these to the balance sheet date, the amendments to IAS 19 have had no effect on the presentation of the current financial statements

Several other financial reporting amendments and interpretations apply for the first time in 2019, but do not have a significant impact on the consolidated financial statements of the Group.

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

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
- assessment of fair value of assets and liabilities acquired as part of a business combination.

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; and
- unforeseen operational issues.

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 of these provisions.

See note 22 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 28 for further information.

Measurement of recognised tax loss carry-forwards
Deferred tax assets are recognised on tax loss carry-forwards when it is probable that taxable profit will be available against which the tax loss carry-forwards can be utilised. The estimates of the taxable profit that will be available against which the unused tax losses can be utilised, are based on taxable temporary differences relating to the same taxation authority and the same taxable entity and estimated future taxable profits. These estimates are based on life of field projections and generally only include sanctioned fields and projects. Unsanctioned wells and fields may be included if future profits are considered to be probable in the relevant circumstances. The estimates use underlying assumptions on prices, capital and operating expenditure and reserves which are consistent with those used for asset impairment review. For example, oil and gas prices are based on an internal view of management expectations based on market consensus prices for the first three years and then thereafter at $65/bbl inflated at 2% per annum from 2023. See note 11 for further information.

Business combination
In accounting for the acquisition, as disclosed in note 5, the identifiable assets and liabilities acquired were recognised at their fair value in accordance with IFRS 3 Business Combinations. The determination of their fair values is based, to a considerable extent, on estimates and judgements. The significant estimates used to determine these fair values are consistent with those discussed above and the significant judgement in determining commercial reserves is discussed below in note 1.3.2.

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.

Notes to the consolidated financial statements

Significant accounting policies

1.4 Basis of consolidation

Subsidiaries and business combinations

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

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

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

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

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

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

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

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

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

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

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

Investments in joint operations and joint ventures

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

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

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

Interests in associates

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

1.5 Foreign currency translation

Presentation and functional currency

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

Transactions and balances

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

Group companies

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

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

1.6 Intangible assets

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

1.7 Assets relating to the exploration and production of mineral resources

i) Acquisition costs of unproved properties: exploration licences and concessions correspond to licences or rights acquired in areas in which the existence of oil and gas reserves has not yet been demonstrated. The costs of acquiring such exploration licences are capitalised within intangible assets.

ii) Exploration and evaluation costs: the Group adopts the successful efforts method of accounting for exploration and evaluation costs. Costs incurred prior to the award of a licence are expensed in the period in which they are incurred. The costs of geological and geophysical surveys and studies are expensed in the period incurred. Exploration and appraisal drilling costs are capitalised in cost centres by well, field or exploration area, as appropriate, pending the results of the exploration activities. Internal costs are expensed unless directly attributed to drilling operations. Costs are then written off as exploration expense in the income statement unless commercial reserves have been established or if the determination process has not been completed and there are no indications of impairment. When the exploratory phase has resulted in the recognition of commercial reserves, the related costs are first assessed for impairment and (if required) any impairment recognised, then the remaining balance is transferred to property, plant and equipment.

iii) Property, plant and equipment: expenditure on the acquisition of proved properties and on the construction, installation or completion of facilities such as platforms, pipelines and the drilling of development wells, including any development or delineation wells, is capitalised within oil and gas properties – PP&E.

In accordance with IAS 16, the initial cost of assets relating to the exploration and production includes an initial estimate of the costs of decommissioning and restoring the site on which the facilities are located when production operations cease, when the entity has a present legal or constructive obligation for decommissioning or to restore the site. A corresponding provision for this decommissioning obligation is recorded for the amount of the asset component.

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

v) Depreciation of production assets: the depreciation of production assets, including decommissioning costs, starts when the oil or gas field is brought into production, and is based on the unit of production method. According to this method, the depletion rate is equal to the ratio of oil and gas production for the period to proved and probable reserves, as applied to the capitalised cost plus future estimated costs to develop those reserves.

Pipeline assets are depreciated on a straight-line basis over a period not exceeding the projected useful economic life of the asset.

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

Notes to the consolidated financial statements

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

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 CGUs and the carrying amount of each unit is compared with its recoverable amount.

For operating entities which 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 CGUs expected to benefit from the business combination. Country groups of CGUs to which goodwill has been allocated are tested for impairment annually, or more frequently when there is an indication the unit may be impaired. If the recoverable amount of the group of CGUs is less than the carrying amount of the unit, the impairment loss is allocated first to reduce the carrying amount of any goodwill allocated to the unit and then to the other assets of the unit pro-rata on the basis of the carrying amount of each asset in the unit. An impairment loss recognised for goodwill is not reversed in a subsequent period.

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

1.11 Leases

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

Group as a lessee

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

1.11.1a Right-of-use assets

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

Right-of-use assets depreciation periods (years)

Land	up to 23 years
Buildings	2 to 10 years
Transportation	2 to 5 years
Property, plant and equipment	5 years

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

1.11.1b Right-of-use assets - assets within joint arrangements

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

1.11.2a Lease liabilities

At the commencement date of the lease, the Group recognises lease liabilities measured at the present value of lease payments to be made over the lease term. The lease payments include fixed payments (including in substance fixed payments) less any lease incentives receivable, variable lease payments that depend on an index or a rate, and amounts expected to be paid under residual value guarantees. The lease payments also include the exercise price of a purchase option reasonably certain to be exercised by the Group and payments of penalties for terminating the lease, if the lease term reflects the Group exercising the option to terminate. Variable lease payments that do not depend on an index or a rate are recognised as expenses in the period in which the event or condition that triggers the payment occurs. In calculating the present value of lease payments, the Group uses its incremental borrowing rate at the lease commencement date because the interest rate implicit in the lease is not readily determinable. After the commencement date, the amount of lease liabilities is increased to reflect the accretion of interest and reduced for the lease payments made. In addition, the carrying amount of lease liabilities is remeasured if there is a modification, a change in the lease term, a change in the lease payments (e.g. changes to future payments resulting from a change in an index or rate used to determine such lease payments) or a change in the assessment of an option to purchase the underlying asset. The Group's lease liabilities are included in Trade payables and accruals (see note 20).

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 Groups 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.

Notes to the consolidated financial statements

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 expense on a straight-line basis over the lease term.

During 2018 the Group held assets for its various activities under lease contracts as set out in IAS 17. Payments made under operating leases were recognised as an expense on a straight-line basis over the lease term in 2018.

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 1.19 '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, hedging derivatives, 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. 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.

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, 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 in net income. 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 net income.

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, under 'Mark-to-market on commodity contracts other than hedging instruments', below the current operating income, for derivative instruments with non-financial assets as the underlying, and in financial income or expenses for currency, interest rate and equity derivatives.

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 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.

Notes to the consolidated financial statements

Equity investments held at fair value through OCI
Where the Group holds an equity investment primarily for strategic purposes, the Company 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 Company 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 Provisions

1.18.1 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.

1.18.2 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; 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. However, actuarial gains and losses on other long-term benefits such as long-service awards, are recognised immediately in income.

Net interest on the net defined benefit liability (asset) is presented in net financial expense (income).

1.18.3 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 in financial expenses for the period.

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

1.19 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 makeup 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.

Further information regarding segmental analysis is contained in note 4.

1.20 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.

1.21 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.

1.22 Cash dividend

The Group and Company recognises 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.

Notes to the consolidated financial statements

2. Financial risk management

Group financial risk factors

The Group's activities expose it to a variety of financial risks: market risk (e.g. currency 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 Euros (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.

Please refer to our risk disclosure on pages 43 and 44.

3. Revenue from contracts with customers

Set out below is the reconciliation of the revenue from contracts with customers with the amounts disclosed in note 4.

	2019		
Group In millions of $	Production revenue	Other	Total
External customers	2,114.7	87.5	2,202.2
Total Group revenue	2,114.7	87.5	2,202.2

	2018		
Group In millions of $	Production revenue	Other	Total
External customers	2,511.7	26.2	2,537.9
Total Group revenue	2,511.7	26.2	2,537.9

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 external customers are revenues of $441.0 million, $377.3 million and $255.4 million (2018: $529.0 million and $465.0 million) relating to the Group's customers who each contribute more than 10% of total revenue. 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.

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. Segmental information

4.1 Segmental analysis

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 two geographical regions comprising seven areas: UK, Norway, Netherlands, Germany, North Africa, Asia Pacific and Corporate.

	Year ended 31 December 2019							
In millions of $	UK	Norway	Nether-lands	Germany	North Africa	Asia Pacific	Corporate	2019 Total
Production revenue by origin	193.3	988.3	256.5	190.4	46.8	439.4	-	2,114.7
Other revenue	5.9	14.4	57.7	9.5	-	-	-	87.5
Revenue	199.2	1,002.7	314.2	199.9	46.8	439.4	-	2,202.2
Current operating Income	60.7	612.5	95.5	(23.5)	12.0	156.0	1.1	914.3
Share of net income from investments using equity method	-	-	1.1	-	1.0	-	-	2.1
Net operating profit after equity-accounted investments	60.7	612.5	96.6	(23.5)	13.0	156.0	1.1	916.4
Mark-to-market on commodity contracts other than trading instruments								14.2
Group reorganisation costs								(68.9)
Impairment loss								(59.4)
Other gains								70.4
Profit before financial items								872.7
Financial income								6.3
Finance costs								(202.2)
Profit before tax								676.8

	Year ended 31 December 2018							
In millions of $	UK	Norway	Nether-lands	Germany	North Africa	Asia Pacific	Corporate	2018 Total
Production revenue by origin	219.2	1,172.0	358.2	192.5	40.0	529.8	-	2,511.7
Other revenue	5.2	0.6	13.2	7.2	-	-	-	26.2
Revenue	224.4	1,172.6	371.4	199.7	40.0	529.8	-	2,537.9
Current operating income	96.8	801.5	132.2	8.7	3.4	223.2	(152.0)	1,113.8
Share of net income from investments using equity method	-	-	3.3	-	0.7	-	-	4.0
Net operating profit after equity-accounted investments	96.8	801.5	135.5	8.7	4.1	223.2	(152.0)	1,117.8
Mark-to-market on commodity contracts other than trading instruments								(46.4)
Restructuring release								2.8
Acquisition transaction costs								(62.9)
Release of EPI deferred consideration								21.0
Other gains								17.0
Profit before financial items								1,049.3
Financial income								6.5
Finance costs								(149.7)
Profit before tax								906.1

Notes to the consolidated financial statements

In millions of $	UK	Norway	Netherlands	Germany	North Africa	Asia Pacific	Corporate	Total
	Year ended 31 December 2019							
EBITDAX (including equity accounted affiliates)	146.1	828.9	193.5	56.0	27.7	343.1	5.9	1,601.2

In millions of $	UK	Norway	Netherlands	Germany	North Africa	Asia Pacific	Corporate	Total
	Year ended 31 December 2018							
EBITDAX (including equity accounted affiliates)	184.6	1,088.7	287.9	76.7	15.2	431.8	(200.9)	1,884.0

In millions of $	UK	Norway	Netherlands	Germany	North Africa	Asia Pacific	Corporate	Total
	Year ended 31 December 2019							
Balance sheet								
Assets	1,484.3	2,608.4	726.6	575.2	701.9	1,502.0	86.3	7,684.7
Liabilities	(302.9)	(1,593.1)	(900.5)	(636.7)	(21.6)	(310.3)	(2,034.1)	(5,799.2)
Net assets	1,181.4	1,015.3	(173.9)	(61.5)	680.3	1,191.7	(1,947.8)	1,885.5

In millions of $	UK	Norway	Netherlands	Germany	North Africa	Asia Pacific	Corporate	Total
	Year ended 31 December 2018							
Balance sheet								
Assets	1,020.3	2,398.6	698.3	553.7	619.6	1,324.9	135.3	6,750.7
Liabilities	(249.1)	(1,353.6)	(845.1)	(601.5)	(29.3)	(230.9)	(1,754.3)	(5,063.8)
Net assets	771.2	1,045.0	(146.8)	(47.8)	590.3	1,094.0	(1,619.0)	1,686.9

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.

Capital investment

In millions of $	UK	Norway	Netherlands	Germany	North Africa	Asia Pacific	Corporate	Total
	Year ended 31 December 2019							
Investments accounted under equity method	-	-	(6.2)	-	70.0	-	-	63.8
Capital expenditure	96.0	516.7	76.6	100.2	27.7	324.8	1.3	1,143.3
	96.0	516.7	70.4	100.2	97.7	324.8	1.3	1,207.1

In millions of $	UK	Norway	Netherlands	Germany	North Africa	Asia Pacific	Corporate	Total
	Year ended 31 December 2018							
Investments accounted under equity method	-	-	29.3	-	511.5	-	-	540.8
Capital expenditure	116.1	184.3	32.5	79.6	11.3	31.7	1.8	457.3
	116.1	184.3	61.8	79.6	522.8	31.7	1.8	998.1

5. Business combinations

5.1 Acquisition of Engie E&P International SA

During 2018, the Group finalised the fair values of the assets and liabilities of Engie E&P International SA which completed on 15 February 2018. All contingent consideration relating to the transaction was settled prior to the commencement of 2019.

5.2 Acquisition of VNG Norge AS

On 28 September 2018, the Group acquired 100% of the voting shares of VNG Norge AS (an unlisted company based in Norway) from its parent VNG AG (a German natural gas and energy service provider).

VNG Norge AS has a portfolio of 42 licences, five producing fields and three development projects including: in Norway, the Fenja oil development (30% and operator), Bauge (2.5%); and in Denmark, Solsort (13.8%). The VNG Norge asset base is highly complementary to Neptune's existing Norwegian portfolio. The fair values of the identifiable assets and liabilities of VNG Norge AS as at the date of acquisition were:

In millions of $	Fair value recognised on acquisition
Non-current assets	
Intangible assets	10.5
Property, plant and equipment	293.1
Deferred tax asset	117.1
Total non-current assets	420.7
Current assets	
Trade and other receivables	56.4
Inventories	-
Cash and cash equivalents	71.2
Total current assets	127.6
Total assets	548.3
Non-current liabilities	
Provisions	(112.4)
Total non-current liabilities	(112.4)
Current liabilities	
Trade and other payables	(1.2)
Other current liabilities	(80.0)
Total current liabilities	(81.2)
Total identifiable net assets at fair value	354.7
Goodwill arising on acquisition (provisional)	82.1
Purchase consideration	436.8
Analysis of cash flows on consideration	
Net cash acquired with the subsidiary (including cash flows from investing activities)	71.2
Purchase consideration	(436.8)
Contingent consideration outstanding	24.3
Net cash flow on acquisition	(341.3)

Purchase consideration comprised cash of $412.5 million and contingent consideration of $24.3 million.

The goodwill recognised arises principally as a result of recognition of deferred tax liabilities for the temporary difference between assigned fair values of oil and gas properties, which are based on post-tax values, and their tax base. The goodwill is not deductible for income tax purposes.

Notes to the consolidated financial statements

Contingent consideration

Included in the purchase consideration at acquisition was $24.3 million which would be payable based upon satisfaction of certain tests linked to project success factors and milestones. No contingent consideration is payable if the tests are not achieved. The fair value of this contingent consideration was $23.2 million as at 31 December 2019 with all the difference being due to currency translation adjustments between the two reporting dates. The possible outcome for contingent consideration ranges from $nil to $50 million.

The fair values recognised on acquisition were provisional at year ended 31 December 2018. In September 2019, the valuation was completed and the acquisition date fair value of the intangible assets was $10.5 million, being $1.4 million lower than the provisional fair value of $11.9 million. As a result, there was a corresponding increase in goodwill of $1.4 million leading to a revision of 2018 values.

6. Operating profit/(loss) before taxation

Included within the Group's operating profit/(loss) before taxation were the following items:

Group In millions of $	Year ended 31 December 2019	Year ended 31 December 2018
Cost of sales		
Movements in over/under lift balances	(17.3)	0.4
Production, insurance and transportation costs	517.6	503.4
Depreciation of property, plant and equipment	614.6	649.0
Amortisation of intangible assets	9.6	7.0
Other operating costs	34.4	43.5
Exploration expenses		
Exploration and evaluation expenditure	60.2	81.5
Unsuccessful exploration expenditure written off	0.2	7.7
General and administration expense include		
Employee costs	58.4	89.0
Auditors remuneration:		
Fees payable to the Company's auditor for the audit of the Company's annual accounts	1.6	2.0
Audit of the accounts of subsidiary companies	0.5	0.4
Non-audit fees	1.3	1.1

Ernst & Young LLP has served as Neptune Energy's independent external auditor for the three-year period ended 31 December 2019. The external auditor is subject to reappointment at the year-end Board meeting and has been reappointed for the 2020 period end.

7. Staff costs

Group In millions of $	Year ended 31 December 2019	Year ended 31 December 2018
Wages and salaries	190.4	152.5
Social security costs	29.3	13.5
Pension costs	29.9	23.1
Total	249.6	189.1

The average number of persons employed during the year (including Directors) was 1,458 (2018: 1,383).

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 $5.2 million (2018: $3.6 million).

7.1 Total Directors' remuneration

The total Directors' remuneration is:

Group In millions of $	Year ended 31 December 2019	Year ended 31 December 2018
Short-term employee benefits	6.2	6.7
Other long-term benefits – post-employment benefits	0.1	-
Total	6.3	6.7

Highest paid Directors' remuneration

Group In millions of $	Year ended 31 December 2019	Year ended 31 December 2018
Short-term employee benefits	3.0	3.2
Total	3.0	3.2

8. Other operating losses/(gains)

Group In millions of $	Year ended 31 December 2019	Year ended 31 December 2018
Mark-to-market on commodity contracts other than trading instruments:		
Loss/(gain) on commodity derivative instruments at fair value through profit and loss	(19.5)	31.2
Loss/(gain) on foreign exchange forward at fair value through profit and loss	(1.7)	12.0
Loss/(gain) on foreign exchange swaps at fair value through profit and loss	(6.6)	-
Loss/(gain) on ineffectiveness on commodity contracts designated as hedges	0.5	2.4
Loss/(gain) on excluded components on commodity contracts designated as hedges	13.1	1.2
Loss/(gain) on excluded components on interest rate swaps designated as hedges	-	(0.4)
Loss/(gain) on equity investments at fair value through profit and loss	-	(1.2)
Restructuring provision cost/(release) (see note 22)	68.9	(2.8)
Business combination transaction costs	-	62.9
EPI deferred consideration release	-	(21.0)
Impairment loss (see notes 13 and 14)	59.4	-
Pension schemes settlement/(curtailment credit) (see note 28.4)	(50.0)	-
Other gains	(20.4)	(15.8)
Total	43.7	68.5

Other gains includes $17.3 million relating to the reduction of the credit loss provision (see note 17).

Notes to the consolidated financial statements

9. Finance income and costs

9.1 Finance income

Group In millions of $	Year ended 31 December 2019	Year ended 31 December 2018
Bank interest income	4.2	6.1
Interest income from joint arrangements for right-of-use assets	2.1	-
Net foreign exchange gains	-	0.4
Total finance income	6.3	6.5

In the Company, finance income of $450.4 million (2018: $411.1 million) includes dividend income of $400.0 million (2018: $380.0 million).

9.2 Finance cost

Group In millions of $	Year ended 31 December 2019	Year ended 31 December 2018
Interest expense	122.5	106.7
Commitment fees	13.6	12.1
Unwinding of discount on decommissioning and other provisions	36.5	30.9
Interest expense lease liabilities	8.2	-
Net foreign exchange losses	21.4	-
Total finance costs	202.2	149.7

10. Dividend

Group In millions of $	Year ended 31 December 2019	Year ended 31 December 2018
Aggregate amount of dividends paid in the year	200.0	380.0
Aggregate amount of dividends liable to pay at the balance sheet date	200.0	-

Company In millions of $	Year ended 31 December 2019	Year ended 31 December 2018
Aggregate amount of dividends paid in the year	200.0	380.0
Aggregate amount of dividends liable to pay at the balance sheet date	200.0	-

On 11 December 2019, Neptune Energy Midco Limited declared an internal Group interim dividend of $400.0 million to its immediate and ultimate parent, Neptune Energy Group limited (NEGL) (20.23 cents per fully paid ordinary share registered on the registered shareholders on that date, compared with 19.22 cents in 2018). This was enabled with a $200.0 million promissory note issued on 11 December 2019 and a cash payment of $200.0 million paid on 23 December 2019. The latter cash payment of $200.0 million was distributed by NEGL as a dividend and a capital redemption to its shareholders.

No final dividend is proposed (2018: $nil).

11. Taxation

The major components of income tax expense in the consolidated income statement are:

Group In millions of $	Year ended 31 December 2019	Year ended 31 December 2018
Current taxation		
Charge for the year	364.9	567.1
Adjustment in respect of prior years	(34.5)	-
	330.4	567.1
Deferred taxation		
Origination and reversal of temporary differences in current year	(93.7)	77.5
Adjustment in respect of prior years	1.1	-
	(92.6)	77.5
Total income tax expense recognised in income statement	237.8	644.6

The effective tax rate for the Group for 2019 was 35% (2018: 71%). The change in the effective tax rate is principally due to the recognition of deferred tax assets in the year.

11.1 Reconciliation between theoretical income tax expense and actual tax expense

Group In millions of $	31 December 2019	31 December 2018
Profit/(loss) before taxation	676.8	906.1
Expected weighted average statutory tax rate	77%	71%
Expected tax charge/(credit) at weighted average statutory rate	523.2	646.2
Effects on tax charge of:		
Income subject to tax at different statutory rates	(33.9)	0.7
Non tax-deductible expenditure	23.2	0.3
Income not subject to taxation	(4.3)	(3.7)
Utilisation of previously unrecognised deferred tax assets	(12.6)	(5.3)
Adjustments in respect of prior years	(33.4)	9.6
Recognition of deferred tax assets	(292.4)	(43.6)
Non-recognition of deferred tax assets	48.9	39.6
Other items	19.1	0.8
Total income tax charge/(credit)	237.8	644.6

Included in the table for 2019 are a number of exceptional items largely in relation to deferred tax. These include the impact of Seagull project sanction and a general improvement in the future profitability of the UK business, which resulted in an increase in the UK's deferred tax asset balances ($234.8 million deferred tax credit), the successful resolution of tax enquiries in Norway and the Netherlands ($33.3 million current tax credit) and the recognition of additional deferred tax in Indonesia ($21.9 million deferred tax credit).

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

Group In millions of $	31 December 2019	31 December 2018
Difference type		
Actuarial gains/(losses)	7.5	2.5
Cash flow hedges	(36.1)	3.3
Net deferred tax (expense)/income	(28.6)	5.8

Notes to the consolidated financial statements

11.3 Changes in deferred taxes

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

Group In millions of $	PP&E	Retirement obligations	Pensions	Tax losses	Other	Total
At 1 January 2019	(861.8)	349.9	43.4	370.0	(45.1)	(143.6)
Reclassification	(180.3)	(9.2)	-	193.0	(3.5)	-
Credit/(charge) for the year	(277.8)	22.8	(5.0)	376.2	(23.6)	92.6
Charge to equity and other comprehensive income	-	-	7.5	-	(36.1)	(28.6)
Currency translation adjustments	4.1	(2.4)	(2.0)	18.4	2.4	20.5
At 31 December 2019	(1,315.8)	361.1	43.9	957.6	(105.9)	(59.1)
Deferred tax assets						691.0
Deferred tax liabilities						(750.1)
Deferred tax liabilities, net						(59.1)

Group In millions of $	PP&E	Retirement obligations	Pensions	Tax losses	Other	Total
At 1 January 2018	-	-	-	-	-	-
Business combination – ENGIE E&P International S.A.	(744.2)	176.7	44.3	377.2	(61.0)	(207.0)
Business combination – VNG Norge AS	(121.5)	87.0	-	81.6	69.9	117.0
Credit/(charge) for the year	79.2	64.9	(4.8)	(120.3)	(96.5)	(77.5)
Charge to equity and other comprehensive income	-	-	-	-	5.8	5.8
Currency translation adjustments	(75.3)	21.3	3.9	31.5	36.7	18.1
At 31 December 2018	(861.8)	349.9	43.4	370.0	(45.1)	(143.6)
Deferred tax assets						438.6
Deferred tax liabilities						(582.2)
Deferred tax liabilities, net						(143.6)

There were no net deferred tax assets and liabilities recognised in the Company for 2019 or 2018.

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

Group In millions of $	31 December 2019	31 December 2018
Unused tax losses	1,631.9	2,908.0
Other deductible temporary differences	506.3	-
Total temporary difference for which no deferred tax asset is recognised	2,138.2	2,908.0

Of the above unrecognised deductible temporary differences, $2,119.3 million (2018: $2,886.2 million) are not subject to time limits for utilisation. Other deductible temporary differences not recognised relate predominantly to the UK where deferred tax on Investment allowances and the ARO liability is not fully recognised.

12. Goodwill

Group In millions of $	31 December 2019	31 December 2018
Cost at 1 January	648.2	-
Business combination - ENGIE E&P International S.A.	-	627.0
Business combination – VNG Norge AS	-	82.1
Currency translation adjustments	(7.4)	(60.9)
Cost and net book value at 31 December	640.8	648.2

The goodwill arose on the acquisition on 15 February 2018 of ENGIE E&P International S.A. (EPI) (now renamed Neptune Energy International S.A.), an unlisted company based in France which was the holding company of a group involved internationally in oil and gas exploration and production. Further goodwill arose on the acquisition on 28 September 2018 of VNG Norge AS (an unlisted company based in Norway) from its parent VNG AG (a German natural gas and energy service provider).

The goodwill from these 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 $550.1 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 remaining goodwill is assigned to the Netherlands, Germany and Egypt group of CGUs. The carrying amount of the goodwill allocated to these CGUs is not significant in comparison with the Group's total goodwill. The Group uses the fair value less cost of disposal method to calculate the recoverable amount of the CGU consistent with a level 3 fair value measurement as defined in note 23. In determining the fair value, the Group have used a post-tax discount rate of 8-12% based on a country-based weighted average cost of capital. Oil and gas prices are based on an internal view of management expectations based on market consensus prices for the first three years and then thereafter at $65/bbl inflated at 2% per annum from 2023.

The Group's recoverable value of assets is sensitive, inter alia, to oil and gas prices. The Group has run sensitivity analyses on the prices outlined above. The recoverable amount of one of the country's group of CGUs to which goodwill is allocated exceeds the aggregate amount of the carrying values by $35 million. If the prices were to decrease by approximately 4%, the recoverable amount of this country's group of CGUs would equal the aggregate of the carrying values. The above sensitivity has flexed revenues and tax cash flows but operating costs and capital expenditures have been kept constant.

In September 2019, the valuation of assets acquired from VNG Norge AS was finalised. The value of intangible assets in the business combination was decreased by $1.4 million leading to a corresponding increase in goodwill that is shown as a revision to the 2018 values (see note 5).

Notes to the consolidated financial statements

13. Intangible assets

Group In millions of $	Exploration and evaluation	Other	Total
Cost at 1 January 2018	–	–	–
Business combinations	77.4	37.9	115.3
Additions	16.7	3.0	19.7
Unsuccessful exploration expenditure	(7.7)	–	(7.7)
Transfers to property, plant and equipment	(3.9)	–	(3.9)
Currency translation adjustments	(2.3)	(3.3)	(5.6)
Cost at 31 December 2018	80.2	37.6	117.8
Additions	77.4	8.6	86.0
Disposals	(6.6)	–	(6.6)
Unsuccessful exploration expenditure	(0.2)	–	(0.2)
Impairment loss	(8.9)	–	(8.9)
Transfers to property, plant and equipment	(4.7)	(17.0)	(21.7)
Currency translation adjustments	1.4	(0.6)	0.8
Cost at 31 December 2019	138.6	28.6	167.2
Amortisation at 1 January 2018	–	–	–
Charge for the year	–	(7.0)	(7.0)
Currency translation adjustments	–	0.3	0.3
Amortisation at 31 December 2018	–	(6.7)	(6.7)
Charge for the year	–	(9.6)	(9.6)
Currency translation adjustments	–	–	–
Amortisation at 31 December 2019	–	(16.3)	(16.3)
Net book value at 31 December 2019	138.6	12.3	150.9
Net book value at 31 December 2018	80.2	30.9	111.1

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

In September 2019, the valuation of assets acquired from VNG Norge AS was finalised. The value of intangible assets in the business combination was decreased by $1.4 million leading to a revision of 2018 values (see note 5).

14. Property, plant and equipment

Group In millions of $	Oil and gas properties	Other fixed assets	Total
Cost at 1 January 2018	-	-	-
Business combinations	4,339.0	33.9	4,372.9
Additions	435.8	1.9	437.7
Transfers from intangible assets	3.9		3.9
Currency translation adjustments	(258.5)	(2.4)	(260.9)
Cost at 31 December 2018	4,520.2	33.4	4,553.6
IFRS 16 opening balance restatements	58.9	51.2	110.1
Additions	1,054.9	2.4	1,057.3
Disposals	(17.6)	(0.6)	(18.2)
Transfers from intangible assets	21.7	-	21.7
Currency translation adjustments	(10.8)	(0.6)	(11.4)
Cost at 31 December 2019	5,627.3	85.8	5,713.1
Accumulated depreciation at 1 January 2018	-	-	-
Charge for year	(646.5)	(2.5)	(649.0)
Currency translation adjustments	17.6	-	17.6
Accumulated depreciation at 31 December 2018	(628.9)	(2.5)	(631.4)
Charge for year (1),(2)	(605.5)	(11.7)	(617.2)
Impairment loss	(50.5)	-	(50.5)
Disposal	16.8	0.6	17.4
Currency translation adjustments	(0.3)	(0.3)	(0.6)
Amortisation at 31 December 2019	**(1,268.4)**	**(13.9)**	**(1,282.3)**
Net book value at 31 December 2019	4,358.9	71.9	4,430.8
Net book value at 31 December 2018	3,891.3	30.9	3,922.2

1) Includes capitalised depreciation of $2.6 million related to right-of-use assets in Norway

2) Refer to note 21 for depreciation charge related to right-of-use assets

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 23. In determining the fair value, the Group has used a post-tax discount rate of 8-12% based on a country-based weighted average cost of capital. Oil and gas prices are based on an internal view of management expectations based on market consensus prices for the first three years and then thereafter at $65/bbl inflated at 2% per annum from 2023.

During 2019 there were impairments of $50.5 million to property, plant and equipment. This included $8.2 million of redeterminations and a pre-tax impairment of $42.3 million (post-tax $22.0 million) relating to a single CGU (a gas field) in the Netherlands. This was driven primarily by underlying reservoir performance and the reduction in the Group's assumptions of future commodity prices. The recoverable amount of the CGU is $152.3 million post tax. Sensitivity analyses for this CGU indicate that if oil and gas prices were to fall by 10% an impairment of $37.6 million post tax would arise. A 10% rise in oil and gas prices would lead to an impairment of $7.8 million post-tax. Considering the discount rates a 1% decrease in the rate would lead to a further post-tax impairment of $5.1 million whereas a 1% increase in the rate would lead to a reduction in the post-tax impairment of $4.9 million. The impairment was calculated as detailed above.

Notes to the consolidated financial statements

15. Investments

Group In millions of $	Equity	Total
Cost at 1 January 2018	–	–
Joint ventures	540.9	540.9
Cost at 31 December 2018	540.9	540.9
Additions	63.8	63.8
Cost at 31 December 2019	604.7	604.7

Interest in joint ventures

The Group has an 18.57% interest in Noordgastransport BV and a 54% interest in Neptune Energy Touat BV (formerly named GDF SUEZ E&P Touat BV).

Group In millions of $	31 December 2019	31 December 2018
At 1 January	540.9	–
Business combinations	–	523.1
Share of results in the year	2.1	4.0
Dividends paid	(6.2)	–
Equity injection contribution	69.0	14.6
Currency translation adjustments	(1.1)	(0.8)
At 31 December	604.7	540.9

Neptune Energy Touat BV 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:

Group In millions of $	31 December 2019	31 December 2018
Non-current assets	1,128.5	1,045.6
Current assets	90.6	82.4
Current liabilities	(92.0)	(129.8)
Non-current liabilities	(50.2)	(51.0)
Equity	1,076.9	947.2
Group's share of equity – 54%	581.5	511.5
Group's carrying amount of the investment	581.5	511.5

Group In millions of $	2019	2018
Revenue	25.6	–
Other income	6.6	–
Cost of sales	(20.0)	–
Gross profit	12.2	–
General and administration expenses	(11.6)	(2.3)
Finance income	0.5	2.4
Profit before tax	1.1	0.1
Income tax credit	0.7	2.0
Profit for the year	1.8	2.1

Included within current assets are cash and cash equivalents of $1.4 million (2018: $2.7 million).

Included within cost of sales is depreciation of oil and gas assets of $12.1 million (2018: $nil).

The Touat development had capital commitments of $39.2 million (2018: $48.0 million) for which the Group has a corresponding commitment, as disclosed in Note 26. A 2018 contingent liability associated with the Touat development project is also disclosed in note 26.

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 $	Equity	Total
Cost at 1 January 2018	-	-
Investment in subsidiaries	1,977.2	1,977.2
Cost at 31 December 2018	1,977.2	1,977.2
Additions	-	-
Cost at 31 December 2019	1,977.2	1,977.2

16. Inventories

Group In millions of $$	31 December 2019	31 December 2018
Hydrocarbons – stock of gas	7.0	5.1
Raw materials and consumables	53.4	59.2
Total	60.4	64.3

The Company held no inventories in 2019 or 2018.

Included within raw materials and consumables is $18.9 million (2018: $2.8 million) in respect of provisions for deterioration and obsolescence.

17. Trade and other receivables

Group In millions of $	31 December 2019	31 December 2018
Amounts falling due within one year		
Trade receivables	290.7	358.3
Under-lift position	89.4	70.6
Other taxes receivable	12.1	83.7
Other receivables	252.6	210.7
Prepayments and accrued income	7.1	3.0
Total	651.9	726.3

Trade receivables are stated net of credit loss provisions of $5.1 million (2018: $22.4 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).

Notes to the consolidated financial statements

Other receivables includes amounts related to joint venture partner funding and right-of-use joint venture receivables.

Company In millions of $	31 December 2019	31 December 2018
Amounts falling due within one year		
Receivable from subsidiaries	215.4	-
Receivable from parent company	1.1	-
Other current assets	0.3	0.2
Current assets	216.8	0.2
Amounts falling due after one year		
Inter-company loan receivable	939.7	654.0
Non-current assets	939.7	654.0
Total	1,156.5	654.2

Included within amounts receivable from subsidiaries is $200.0 million (2018: $nil) in respect of a promissory note issued on 11 December 2019 from Neptune Energy Group Holdings Limited in respect of an interim dividend declared.

The inter-company loans are receivable from Neptune Energy Group Holdings Limited a 100% owned subsidiary of Neptune Energy Group Midco Limited.

18. Cash and cash equivalents

Group In millions of $	31 December 2019	31 December 2018
Cash at bank and in hand	75.1	191.1
Restricted cash	10.3	6.2
Total cash and cash equivalents	85.4	197.3

Cash and cash equivalents comprise cash in hand, deposits with maturity of three months or less and other short-term money market deposit accounts that are readily convertible into known amounts of cash. Restricted cash includes monies held for decommissioning obligations.

The Company held $nil cash and cash equivalents at 31 December 2019 (31 December 2018: $1.1 million).

19. Borrowings

Group In millions of $	Interest rate 2019 %	Interest rate 2018 %	Maturity	31 December 2019	31 December 2018
Non-current interest-bearing loans and borrowings- more than five years					
Reserve Base Lending facility	4.213	5.730	2024	643.7	943.4
Touat project finance facility	6.000	6.000	2024	232.2	200.2
Subordinated Neptune Energy Group Limited loan	7.750	7.750	2024	107.9	106.9
Senior Notes	6.625	6.625	2025	831.8	537.7
Total non-current				1,815.6	1,788.2
Current interest-bearing loans and borrowings					
Touat project finance facility	6.000		2020	24.0	-
DNB uncommitted facility	3.286		2020	50.0	-
Citi Bank uncommitted facility	2.336		2020	50.0	-
Total current				124.0	-
Total				1,939.6	1,788.2

The movements in borrowings are described in the table below:

Group In millions of $	31 December 2019
At 1 January 2019	1,788.2
Associated cash flows	
Repayment of borrowings	(1,439.5)
Drawdown of borrowings	1,566.0
Debt arrangement fees	(8.0)
Non-cash movements	
Capitalised interest	20.9
Movement in accrued interest	(0.4)
Amortisation of debt arrangement fees	12.4
At 31 December 2019	1,939.6

On 11 May 2017, certain subsidiaries within the Group entered into a revolving reserves-based lending facility (RBL) with total aggregate commitments of $2,000 million. The outstanding debt is repayable in line with the amortisation of bank commitments over the period from 1 April 2021 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. 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 reviewed annually 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 borrowing base was $1,981 million at 31 December 2018 and was increased following the March 2019 redetermination to $1,996 million. The facility is a multi-currency facility and incurs interest on outstanding debt at US dollar and Sterling LIBOR, EURIBOR or NIBOR plus an applicable margin. The facility is secured over the shares of certain companies within the RBL group, and certain of their oil and gas assets. As at 31 December 2019, total drawings under the facility were $690 million.

Neptune Energy has been working with its RBL bank syndicate and has implemented several changes to the facility. These include the addition of Merakes, Indonesia and Touat, Algeria to the borrowing base. As a result, the new borrowing base has been increased from $2.0 billion to $2.5 billion (including the impact of the Energean Oil & Gas transaction) for the next 12 months with a delay in the first scheduled repayment from 2021 to 2022, while keeping the final maturity date unchanged as May 2024. We have also exercised the accordion option to upsize the RBL.

On 25 October 2019, the Group via its wholly-owned subsidiary Neptune Energy Bondco plc issued an aggregate principal amount of $300 million of 6⅝% senior notes due 2025 which represent an additional issuance of notes of the series of which an aggregate principal amount of $550 million were previously issued. As a result of the $300 million bond issue in October, which was used to partially repay drawn commitments under our RBL.

On 27 December 2017, Neptune Energy Touat Holding BV (an indirect 100% subsidiary of the Company) entered into a term loan from ENGIE CC SCRL. The lender has agreed to provide loan financing to fund costs in respect of the Group's interest in the Touat field in Algeria. As at 31 December 2019, $250 million had been drawn under the facility. The loan incurs interest at 6%; following three months of successful production this will increase to 8%.

In February 2018, the Company entered into a $100 million shareholder loan from Neptune Energy Group Limited, for the purposes of part-funding the costs of acquiring the shares in EPI. The loan is for a period of six years and incurs interest at 7.75%.

Notes to the consolidated financial statements

20. Trade payables and other liabilities

Group In millions of $	31 December 2019	31 December 2018
Trade and other payables	222.7	94.5
Other current liabilities	567.5	414.5
Lease liabilities	72.3	-
Wages and social security	53.2	51.8
Current trade payables and accruals	915.7	560.8
Other non-current liabilities	64.9	59.6
Lease liabilities	99.7	-
Non-current trade payables and accruals	164.6	59.6
Total	1,080.3	620.4

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

Included within other current liabilities is $200.0 million (2018: $nil) in respect of a promissory note issued on 11 December 2019 to the immediate and ultimate parent undertaking in respect of the interim dividend declared (see note 10) and Indonesian deferred income of $67.5 million (2018: $nil). The remainder of the balance is principally related to joint venture funding.

Company In millions of $	31 December 2019	31 December 2018
Trade and other payables	1.2	-
Payable to parent company	207.4	-
Interest payable to subsidiary	7.2	-
Current trade payables and accruals	215.8	-
Interest payable to parent company	-	6.9
Interest payable to subsidiary	-	4.7
Subordinated Neptune Energy Group Limited loan	107.9	106.9
Inter-company loan payable > 1 year	831.8	536.2
Non-current trade payables and accruals	939.7	654.7
Total	1,155.5	654.7

Included within amounts payable to parent company is $200.0 million (2018: $nil) in respect of a promissory note issued on 11 December 2019 to the immediate and ultimate parent undertaking in respect of the interim dividend declared.

The Inter-company loans are payable to Neptune Energy Bondco PLC a 100% owned subsidiary of Neptune Energy Group Midco Limited.

21. 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 two and 23 years while transportation assets generally have leases between two and five 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.

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 $	Oil and gas properties	Other fixed assets	Total
At 1 January 2019	58.9	51.2	110.1
Additions	24.7	0.2	24.9
Deletions	(0.7)	-	(0.7)
Depreciation expense	(16.1)	(8.6)	(24.7)
Currency translation adjustments	-	(0.2)	(0.2)
Total	66.8	42.6	109.4

The Group recognised a JV partner receivable of $35 million at 1 January 2019 in respect of right-of-use assets dedicated to operated joint ventures.

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

Group In millions of $	31 December 2019
At 1 January 2019	(145.3)
Additions	(57.6)
Disposals	0.6
Interest	(8.2)
Payments[1]	40.5
Other	(0.5)
Currency translation adjustments	(1.5)
At 31 December 2019	(172.0)

1) The payments include $8.2 million relating to interest and $32.3 million relating to principal repayments

Group In millions of $	31 December 2019
Within one year	72.3
Current trade payables and other liabilities (see note 20)	72.3
Between two and five years	90.5
More than five years	9.2
Non-current trade payables and other liabilities (see note 20)	99.7

Notes to the consolidated financial statements

The following are the amounts recognised in profit or loss:

Group In millions of $	31 December 2019
Depreciation expense of right-of-use assets	(24.7)
Interest income from joint arrangements for right-of-use assets	2.1
Interest expense right-of-use assets	(8.2)
Expense relating to leases of low-value assets	(0.4)
Income from subleasing right-of-use assets	6.1
Total amount recognised in profit and loss	(25.1)

The Group has total cash outflows for leases of $40.5 million. The future cash outflows relating to leases that have not yet commenced are disclosed in note 26.

22. Provisions

Group In millions of $	Decom- missioning	Restructuring	Post- employment benefits	Other	Total
At 1 January 2019	1,504.8	5.7	232.5	1.5	1,744.5
Charge for the year	1.4	73.8	14.0	5.3	94.5
Unwinding of discount	32.9	-	3.6	-	36.5
Additions	29.4	-	-	-	29.4
Change in discount rate	-	-	27.6	-	27.6
Reclassifications	-	4.1	(3.7)	(1.0)	(0.6)
Utilisation/paid	(51.7)	(12.8)	(24.7)	-	(89.2)
Unused provisions released to income statement	(1.0)	(4.9)	(50.9)	(0.5)	(57.3)
Currency translation	(15.0)	0.7	(3.4)	-	(17.7)
At 31 December 2019	1,500.8	66.6	195.0	5.3	1,767.7

The restructuring provision relates to the transformation activity of the business. There were no provisions for the Company in both 2019 and 2018.

Group In millions of $	31 December 2019	31 December 2018
Current		
Restructuring	41.8	5.7
Post-employment benefit and other long-term benefits	11.4	-
Decommissioning	55.0	62.1
Other	5.3	1.5
Current total	113.5	69.3
Non-current		
Restructuring	24.8	-
Post-employment benefit and other long-term benefits	183.6	232.5
Decommissioning	1,445.8	1,442.7
Non-current total	1,654.2	1,675.2
Total	1,767.7	1,744.5

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 the 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 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% to 3.5% in 2019. The discount rate range used in 2018 was not significantly different. 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 provision is matched with an entry to property, plant and equipment. The depreciation charge on this asset is included within current operating income and the cost of unwinding of discount is booked in financial expenses.

23. Financial assets and liabilities

Financial risk management objectives

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

Fair values of financial assets and liabilities

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

Fair values of derivative instruments

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

Set out below is an overview of financial assets, other than cash and short-term deposits, held by the Group as at 31 December 2019 including their maturity. For items held at amortised cost there is no significant difference between their fair value and amortised cost value.

	31 December 2019			
Group In millions of $	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	1.5	-	-	1.5
Commodity derivatives in qualifying hedging relationships[(1)]	145.8	74.9	-	220.7
Foreign forward exchange contracts at fair value through profit and loss	0.1	-	-	0.1
Equity instruments designated at fair value through OCI				
10.58% interest in Erdgas-Verkaufs-Gesellschaft mbH, Münster	-	-	19.3	19.3
Financial assets at amortised cost				
Trade and other receivables	651.9	-	-	651.9
Income tax receivable	16.6	-	-	16.6
Other non-current assets	-	110.6	-	110.6
Total	815.9	185.5	19.3	1,020.7

1) Of the $145.8 million due under one year, $90.3 million is due within six months.

Notes to the consolidated financial statements

Group In millions of $	31 December 2018 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	2.0	1.4	-	3.4
Commodity derivatives in qualifying hedging relationships[1]	31.2	38.7	-	69.9
Equity instruments designated at fair value through OCI				
10.58% interest in Erdgas-Verkaufs-Gesellschaft mbH, Münster	-	-	19.7	19.7
Financial assets at amortised cost				
Trade and other receivables	726.3	-	-	726.3
Other non-current assets	-	-	8.8	8.8
Total	759.5	40.1	28.5	828.1

1) Of the $31.2 million due under one year, $17.1 million is due within six months.

Group In millions of $	31 December 2019 Less than one year	Between two and five years	More than five years	Total
Financial assets at amortised cost				
Inter-company loan receivable	-	107.9	831.8	939.7
Receivable from subsidiaries	215.4	-	-	215.4
Receivable from parent company	1.1	-	-	1.1
Other current assets	0.3	-	-	0.3
Total	216.8	107.9	831.8	1,156.5

Group In millions of $	31 December 2018 Less than one year	Between two and five years	More than five years	Total
Financial assets at amortised cost				
Inter-company loan receivable	-	-	642.3	642.3
Receivable from subsidiaries	-	-	11.7	11.7
Other current assets	0.2	-	-	0.2
Total	0.2	-	654.0	654.2

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, other than cash and short-term deposits, held by the Group as at 31 December 2019 including their maturity. The Senior Notes held by the Group have a fair value of $850.4 million, compared with the carrying amount of $831.8 million (2018: a fair value of $514.3 million, compared with the carrying amount of $537.7 million). This financial liability would be classed as Level 1. For all other items held at amortised cost there is no significant difference between their fair value and amortised cost value.

Group In millions of $	31 December 2019 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]	12.7	26.8	-	39.5
Interest rate derivatives in qualifying hedging relationships	3.8	1.8	-	5.6
Foreign forward exchange contracts at fair value through profit and loss	2.1	-	-	2.1
Contingent consideration of the VNG Norge AS acquisition	-	23.2	-	23.2
Financial liabilities at amortised cost				
Short-term borrowings				
DNB uncommitted facility	50.0	-	-	50.0
Citi Bank uncommitted facility	50.0	-	-	50.0
Long-term borrowings				-
Reserve Base Lending facility	-	643.7	-	643.7
Senior Notes	-	-	831.8	831.8
Touat project finance facility	24.0	188.9	43.3	256.2
Subordinated Neptune Energy Group Limited loan	-	107.9	-	107.9
Trade and other payables	222.7	-	-	222.7
Wages and social security	53.2	-	-	53.2
Lease liabilities	72.3	90.5	9.2	172.0
Corporate taxes payable	155.3	59.0	-	214.3
Other liabilities	567.5	41.7	-	609.2
Total	1,213.6	1,183.5	884.3	3,281.4

1) Of the $12.7 million, $7.7 million is due within six months.

Notes to the consolidated financial statements

Group In millions of $	31 December 2018 Less than one year	Between two and five years	More than five years	Total
Financial liabilities at fair value				
Commodity derivatives at fair value through profit and loss	9.9	4.2	-	14.1
Commodity derivatives in qualifying hedging relationships[1]	51.1	25.2	-	76.3
Interest rate derivatives in qualifying hedging relationships	0.4	1.7	-	2.1
Foreign forward exchange contracts at fair value through profit and loss	12.2	-	-	12.2
Contingent consideration of the VNG Norge AS acquisition	24.3	-	-	24.3
Financial liabilities at amortised cost				
Long-term borrowings				
Reserve Base Lending facility	-	-	943.4	943.4
Senior Notes	-	-	537.7	537.7
Touat project finance facility	-	-	200.2	200.2
Subordinated Neptune Energy Group Limited loan	-	-	106.9	106.9
Trade and other payables	94.5	-	-	94.5
Wages and social security	51.8	-	-	51.8
Corporate taxes payable	188.1	35.7	-	223.8
Other liabilities	390.2	-	59.6	449.8
Total	822.5	66.8	1,847.8	2,737.1

1) Of the $51.1 million, $28.0 million was due within six months.

Group In millions of $	31 December 2019 Less than one year	Between two and five years	More than five years	Total
Financial liabilities at amortised cost				
Inter-company loan	-	107.9	831.8	939.7
Payable to parent company	207.4	-	-	207.4
Payable to subsidiary	7.2	-	-	7.2
Other current liabilities	1.2	-	-	1.2
Total	215.8	107.9	831.8	1,155.5

Group In millions of $	31 December 2018 Less than one year	Between two and five years	More than five years	Total
Financial liabilities at amortised cost				
Inter-company loan	-	-	643.1	643.1
Payable to parent company	-	-	6.9	6.9
Payable to subsidiary	-	-	4.7	4.7
Total	-	-	654.7	654.7

23.1 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 2019 and 2018.

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

	31 December 2019			
Group In millions of $	Date of valuation	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-19	220.7	220.7	-
Commodity derivatives at fair value through profit and loss	31-Dec-19	1.5	1.5	-
Foreign forward exchange contracts at fair value through profit and loss	31-Dec-19	0.1	0.1	-
Non-listed equity Instruments				
10.58% interest in Erdgas Münster GMBH	31-Dec-19	19.3	-	19.3
Total		241.6	222.3	19.3

	31 December 2018			
Group In millions of $	Date of valuation	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-18	69.9	69.9	-
Commodity derivatives at fair value through profit and loss	31-Dec-18	3.4	3.4	-
Non-listed equity Instruments				
10.58% interest in Erdgas Münster GMBH	31-Dec-18	19.7	-	19.7
Total		93.0	73.3	19.7

The valuation of Neptune's interest in Erdgas Münster has been calculated based on an enterprise value/EBITDA multiple taking into account recent transactions involving suitable comparative infrastructure companies and was acquired as a consequence of the EPI acquisition.

Notes to the consolidated financial statements

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

Group In millions of $	Date of valuation	31 December 2019 Total	Significant observable inputs (Level 2)	Significant unobservable inputs (Level 3)
Liabilities measured at fair value				
Derivative financial liabilities				
Commodity derivatives in qualifying hedging relationships	31-Dec-19	39.5	39.5	-
Interest rate derivatives in qualifying hedging relationships	31-Dec-19	5.6	5.6	-
Forward foreign exchange contracts at fair value through profit and loss	31-Dec-19	2.1	2.1	-
Contingent consideration of the VNG Norge AS acquisition	31-Dec-19	23.2	-	23.2
Total		70.4	47.2	23.2

Group In millions of $	Date of valuation	31 December 2018 Total	Significant observable inputs (Level 2)	Significant unobservable inputs (Level 3)
Liabilities measured at fair value				
Derivative financial liabilities				
Commodity derivatives in qualifying hedging relationships	31-Dec-18	76.3	76.3	-
Commodity derivatives at fair value through profit and loss	31-Dec-18	14.1	14.1	-
Interest rate derivatives in qualifying hedging relationships	31-Dec-18	2.1	2.1	-
Forward foreign exchange contracts at fair value through profit and loss	31-Dec-18	12.2	12.2	-
Contingent consideration of the VNG Norge AS acquisition	31-Dec-18	24.3	-	24.3
Total		129.0	104.7	24.3

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

23.2 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 OCI in accordance with Level 3 are shown below:

	Group		Company	
In millions of $	31 December 2019	31 December 2018	31 December 2019	31 December 2018
Fair value at 1 January	19.7	–	-	–
Acquisitions	-	21.2	-	–
Currency translation adjustments	(0.4)	(1.5)	-	–
Fair value at 31 December	19.3	19.7	-	–

A 5% change in the EBITDA multiple to the Level 3 instrument above as applied would result in a $1 million change in valuation (2018: $1 million change).

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

	Group		Company	
In millions of $	31 December 2019	31 December 2018	31 December 2019	31 December 2018
Fair value at 1 January	-	-	-	-
Acquisitions	-	3.1	-	-
Total gains or losses recognised in the income statement	-	1.2	-	-
Disposals	-	(4.3)	-	-
Currency translation adjustments	-	-	-	-
Fair value at 31 December	-	-	-	-

On 18 December 2018, the Group sold its equity investment in General Energy Recovery Inc, a Canadian company engaged in R&D for a net profit of $1.2 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 $	31 December 2019	31 December 2018	31 December 2019	31 December 2018
Fair value at 1 January	(24.3)	-	-	-
Acquisitions	-	(24.3)	-	-
Total gains or losses recognised in the income statement	-	-	-	-
Currency translation adjustments	1.1	-	-	-
Fair value at 31 December	(23.2)	(24.3)	-	-

The contingent consideration is based on management's expectation on achieving certain project milestones. The possible range for the contingent consideration is $nil to $50 million.

Notes to the consolidated financial statements

23.3 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 $	Cash flow commodity hedge reserve	Cost of commodity hedging reserve	Cash flow interest rate hedge reserve	Cost of interest rate hedging reserve	Total hedge reserve
At 1 January 2019	17.0	6.9	1.2	-	25.1
Add: costs of hedging deferred and recognised in OCI	(212.9)	(26.8)	5.7	-	(234.0)
Less: reclassified from OCI to profit or loss or included in finance costs	68.4	(13.1)	(1.3)	-	54.0
Less: deferred tax	3.8	32.3	-	-	36.1
At 31 December 2019	(123.7)	(0.7)	5.6	-	(118.8)

Group In millions of $	Cash flow commodity hedge reserve	Cost of commodity hedging reserve	Cash flow interest rate hedge reserve	Cost of interest rate hedging reserve	Total hedge reserve
At 1 January 2018	-	-	-	-	-
Add: costs of hedging deferred and recognised in OCI	179.9	9.7	2.2	(0.4)	191.4
Less: reclassified from OCI to profit or loss or included in finance costs	(161.2)	(1.2)	(1.0)	0.4	(163.0)
Less: deferred tax	(1.7)	(1.6)	-	-	(3.3)
At 31 December 2018	17.0	6.9	1.2	-	25.1

Excluded from the table above is a profit of $0.5 million (2018: profit of $2.4 million) of hedge ineffectiveness that was taken directly into the profit and loss. The value of any CVA adjustment is not material.

There were no financial derivatives held by the Company in 2019 and 2018.

24. Financial risk factors

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 in the following sections relate to the position as at 31 December 2019 with comparatives as at 31 December 2018.

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.

24.1 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 an active portfolio management. The Board of Directors, who have ultimate responsibility for liquidity risk management, believe that the Group has sufficient cash, undrawn committed funds under its borrowing base facility and expected sources of liquidity to meet the business's forecast requirements for the short, medium and long term.

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

24.2 Credit rate risk

Credit risk is managed on a Group basis. 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. The Group does not have any significant credit risk exposure to any single counterparty or any group of counterparties.

The Group's maximum exposure to credit risk for the components of the statement of financial position at 31 December 2019 and 2018 is the carrying amounts as illustrated in note 23.

24.3 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 smoothing the impact of gas and oil price volatility on earnings by reducing exposure to market prices. It thereby improves 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.

This hedging programme applies 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 as at the respective balance sheet date:

	31 December 2019			31 December 2018		
Group	Volumes	Average price	Period of hedge	Volumes	Average price	Period of hedge
OIL HEDGES VS BRENT	mmbbl	$/bbl		mmbbl	$/bbl	
Commodity cap	2.5	76.0	up to 1 year	6.0	75.2	up to 3 years
Commodity floor	2.5	60.5	up to 1 year	5.5	58.7	up to 3 years
Commodity swap	1.9	60.4	up to 1 year	0.7	51.3	up to 3 years
GAS HEDGES VS NBP	000's mmbtu	$/mmbtu		000's mmbtu	$/mmbtu	
Commodity cap	57,848	8.33	up to 2.5 years	37,141	7.84	up to 3 years
Commodity floor	57,848	6.31	up to 2.5 years	37,141	5.93	up to 3 years
Commodity swap	29,520	5.64	up to 3 years	17,746	5.26	up to 3 years
GAS HEDGES VS TTF	000's mmbtu	$/mmbtu		000's mmbtu	$/mmbtu	
Commodity cap	47,460	7.49	up to 2.5 years	35,926	7.87	up to 3 years
Commodity floor	47,460	5.81	up to 2.5 years	35,926	5.82	up to 3 years
Commodity swap	21,396	5.63	up to 3 years	8,674	5.25	up to 3 years

There were no financial derivatives held by the Company in 2019 and 2018.

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.

Neptune'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.

Notes to the consolidated financial statements

At 31 December 2019 the aggregate post-tax hedge ratio for the Group was:

	2020	2021	2022
Oil	27%	0%	0%
Gas	84%	60%	18%

At 31 December 2018 the aggregate post-tax hedge ratio for the Group was:

	2020	2021	2022
Oil	47%	21%	0%
Gas	56%	40%	13%

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

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

		31 December 2019		31 December 2018	
	Price movement	Pre-tax loss/(gain) on income	Pre-tax loss/(gain) on equity	Pre-tax loss/(gain) on income	Pre-tax loss/(gain) on equity
SENSITIVITY ANALYSIS					
NBP gas price	+10% pence/ therm increase	-	41.2	(6.5)	45.6
NBP gas price	-10% pence/ therm decrease	-	(41.9)	5.9	(44.9)
Brent oil price	+10%/bbl increase	(0.1)	46.6	(0.1)	23.9
Brent oil price	-10%/bbl decrease	(0.3)	(48.3)	(0.6)	(25.2)

24.4 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 effecting 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 no cross currency derivative contracts at the end of 2019. Cross currency derivative contracts held at 31 December 2018:

Group	Currency	Terms
$/EURO FORWARD	$200 million	1-month USD Libor vs 1-month Euribor within 3 months

The Group held US$22 million of US$ NOK forwards as at 31 December 2019 (2018: US$228 million) all expiring within a year.

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

	31 December 2019		31 December 2018	
	Pre-tax loss/(gain) on income	Pre-tax loss/(gain) on equity	Pre-tax loss/(gain) on income	Pre-tax loss (gain) on equity
SENSITIVITY ANALYSIS				
+10% Euro	-	-	(22.8)	-
-10% Euro	-	-	21.3	-
+10% NOK	(33.9)	-	(19.8)	-
-10% NOK	33.9	-	24.1	-

24.5 Interest rate risk

The Group is exposed to the impact of interest rate fluctuations on its consolidated statements. The Group monitors its exposure to fluctuations in interest rates and may use interest rate derivatives to manage the fixed and floating composition of its borrowings.

The Group is holding the following interest rate derivative contracts:

	31 December 2019			31 December 2018		
Group	Currency	Terms	Period of hedge	Currency	Terms	Period of hedge
INTEREST RATE SWAPS	$400 million	Average 2.59%	Between 1-3 years	$400 million	Average 2.59%	Between 1-3 years

The Group has entered into interest rate derivatives to manage its exposure to fluctuations in the $ interest rate. The impact on reported income and on equity of a 100 basis-point movement in the $ year-end interest rate would be as follows:

	31 December 2019		31 December 2018	
	Pre-tax loss/(gain) on income	Pre-tax loss/(gain) on equity	Pre-tax loss/(gain) on income	Pre-tax loss/(gain) on equity
+100 basis points	-	(5.2)	(0.1)	(8.7)
-100 basis points	-	5.4	-	8.9

25. Called up share capital

Group and Company	Number	$million
Allotted, called up and fully paid		
At 1 January 2018	728	-
Issued in the year	1,977,174,473	1,977.2
At 31 December 2018	1,977,175,201	1,977.2
Issued in the year	-	-
At 31 December 2019	1,977,175,201	1,977.2

On 15 February 2018, 1,977,174,473 $1 shares were allotted, called up and fully paid.

Notes to the consolidated financial statements

26. Commitment and contingencies

26.1 Lease commitments

The Group has lease contracts that have not yet commenced as at 31 December 2019. The future lease payments for these non-cancellable lease contracts are $14.0 million within one year and $15.7 million within two to five years.

The Group has financial commitments in respect of capacity bookings as at 31 December 2019. These were disclosed as operating lease commitments in 2018 but do not meet the definition of leases under IFRS 16. The future payments for these contracts are $15.5 million within one year, $54.7 million within two to five years and $12.7 million in more than five years.

26.2 Capital commitments

	Group		Company	
In millions of $	31 December 2019	31 December 2018	31 December 2019	31 December 2018
Amounts due:				
Within one year	393.4	352.6	-	-
After one year but within two years	29.8	93.4	-	-
Total	423.2	446.0	-	-

As at 31 December 2019, the Group had commitments for future capital expenditure amounting to $423.2 million (2018: $446.0 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.

26.3 Contingencies

As at 31 December 2019, the Group has no contingent liabilities (2018: $15 million) as described below. The Company had no contingencies in either 2019 or 2018.

26.4 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 2019 the Group has not identified any material contingent liabilities as all are deemed remote in nature. In 2018 the following disputes were identified:

Development project

CCC (Consolidated Contractors Group) and DAH (Dar El Handasah) have issued a claim to Groupement Touat Gaz (GTG) under the EPC contract for the construction of the living quarters. The claim consists of an extension of time and additional costs. The claim lacks substantiation and legal justification and GTG has rejected the claim. Parties are in discussions to agree on a path forward. The joint venture between ENGIE and Neptune (Neptune Energy Touat BV) holds 65% in GTG. Neptune Energy holds a 54% share in the joint venture with ENGIE.

There are no pending legal proceedings for the Company as at 31 December 2019 (2018: none).

27. 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 29.

Group

Related party undertaking	Principal activities	Country of incorporation	% Equity interest
Neptune Energy Group Holdings Limited	Management and technical services	United Kingdom	100

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

During 2019, the Group did not enter into any material transactions or transactions of an unusual nature with related parties.

Transactions with Group investors:

Related party undertaking $ millions	Nature of transactions	2019 Purchases	2019 Accounts payable	2018 Purchases	2018 Accounts payable
CIEP Neptune S.A.R.L (Carlyle investor)	Advisory services	-	-	10.2	-
Oceanus Jersey Limited (CVC investor)	Advisory services	-	-	1.0	-
Beijing Rheingau Investment Corporation (CIC investor)	Advisory services	-	-	12.5	-
ONE-Dyas B.V. (Carlyle investor)	Oil and Gas	9.8	-	-	-

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 periods ended 31 December 2019 and 31 December 2018, 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.

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	2019	2018
Short-term employee benefits	6.2	17.6
Long-term employee benefits – post-employment benefits	0.1	-
Total compensation to key management personnel	6.3	17.6

There are no other related party transactions.

Company

There are no related party transactions other than inter-company interest and loans.

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 period ended 31 December 2019 and 31 December 2018, 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.

Notes to the consolidated financial statements

28. Pension and post-retirement benefits

28.1 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 defined contribution.

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.

Netherlands

Until 31 December 2019 Neptune Energy Nederland BV and its Dutch subsidiaries had a defined benefit pension plan covering substantially all of its employees. The pension plan was administered by ASR. At the end of 2019, the Group closed the plan to future accrual giving rise to a curtailment gain of $31 million. Benefits accruing after 1 January 2020 will be provided via a defined contribution plan. The defined benefit plan assets are qualifying insurance policies matching the liabilities. No future contributions are therefore expected to be required.

Germany

Neptune Energy Deutschland has seven defined benefit plans, corresponding to different groups of employees successively incorporated in the Company. The defined benefit plans are financed by book reserves. Five of the plans are closed to new entrants but still incur service costs.

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. 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.

The decision to close the corporate office in France was made during 2019. As a result of which, except for the ANE (Avantage en Nature Energie) plan, the majority of defined benefit plan liabilities have been removed for employees who have been made redundant as commitments for Neptune only cover employees while on the IEG payroll. For the ANE plan, Neptune engagement has been reduced to those Energy employees who contributed for more than 15 years. As Neptune no longer has any obligation or reduced obligation towards these liabilities, this removal has been treated as a settlement gain. Two of the defined benefit plans are funded. Any assets expected to be transferred as a result of the closure have been treated as a settlement loss. A net settlement gain of $19 million has been recognised as a result of the decision to close the corporate office in France.

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 Storebrand AS. There are two other unfunded plans which are also administered by Storebrand.

28.2 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.

Plans are externally funded except within those countries where it is common practice to use book reserves, for example, in Germany.

28.3 Defined benefits plans

28.3.1 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 statement of financial position:

Group In millions of $	Pension benefit obligations [1]	Other post-employment benefit obligations [2]	Long-term benefit obligations [3]	Total benefit obligations
A – Change in projected benefit obligations				
Projected benefit obligations at 1 January 2019	(416.5)	(24.0)	(4.8)	(445.3)
Business combination	0.2	-	-	0.2
Service cost	(12.0)	(0.4)	(1.6)	(14.0)
Settlements/curtailments	42.9	13.2	(0.3)	55.8
Interest cost on benefit obligations	(7.0)	(0.4)	(0.2)	(7.6)
Financial actuarial gains and losses	(64.9)	(4.4)	(0.7)	(70.0)
Demographic actuarial gains and losses	0.5	3.2	0.9	4.6
Benefits paid	15.2	0.5	4.4	20.1
Other including translation adjustments	10.8	4.9	(5.3)	10.4
Projected benefit obligation at 31 December 2019 A	(430.8)	(7.4)	(7.6)	(445.8)

Group In millions of $	Pension benefit obligations [1]	Other post-employment benefit obligations [2]	Long-term benefit obligations [3]	Total benefit obligations
B – Change in fair value of plan assets				
Fair value of plan assets at 1 January 2019	212.8	-	-	212.8
Business combination	(0.2)	-	-	(0.2)
Interest income on plan assets	4.0	-	-	4.0
Settlement/curtailments	(5.8)	-	-	(5.8)
Financial actuarial gain and losses	37.7	-	-	37.7
Contributions received	19.8	0.5	4.4	24.7
Benefits paid	(15.2)	(0.5)	(4.4)	(20.1)
Other including translation adjustments	(2.3)	-	-	(2.3)
Fair value of plan assets at 31 December 2019 B	250.8	-	-	250.8

Group In millions of $				
C – Funded Status A+B				
Net benefit obligation	(180.0)	(7.4)	(7.6)	(195.0)

At 31 December 2019 the pre-paid benefit cost was $nil (2018: $nil).

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

Group In millions of $	Pension benefit obligations [1]	Other post-employment benefit obligations [2]	Long-term benefit obligations [3]	Total benefit obligations
A – Change in projected benefit obligations				
Projected benefit obligations at 1 January 2018				
Business combination	(406.6)	(40.4)	(7.2)	(454.2)
Service cost	(10.5)	(2.9)	(0.5)	(13.9)
Interest cost on benefit obligations	(6.9)	(0.5)	(0.1)	(7.5)
Financial actuarial gains and losses	(11.7)	0.1	0.1	(11.5)
Demographic actuarial gains and losses	11.5	14.5	2.6	28.6
Benefits paid	12.6	5.2	0.3	18.1
Other (translation adjustments)	(4.9)	-	-	(4.9)
Projected benefit obligation at 31 December 2018 A	(416.5)	(24.0)	(4.8)	(445.3)

The business combination projected benefit obligation relates to the acquisition of the ENGIE business, on the acquisition of VNG, Neptune did not acquire any defined benefit obligations.

Group In millions of $	Pension benefit obligations [1]	Other post-employment benefit obligations [2]	Long-term benefit obligations [3]	Total benefit obligations
B – Change in fair value of plan assets				
Fair value of plan assets at 1 January 2018				
Business combination	199.3	-	-	199.3
Interest income on plan assets	4.1	-	-	4.1
Financial actuarial gain and losses	6.1	-	-	6.1
Contributions received	14.8	4.7	-	19.5
Benefits paid	(11.5)	(4.7)	-	(16.2)
Other (translation adjustments)	-	-	-	-
Fair value of plan assets at 31 December 2018 B	212.8	-	-	212.8

Group In millions of $				
C – Funded status A+B				
Net benefit obligation	(203.7)	(24.0)	(4.8)	(232.5)

At 31 December 2018 the pre-paid benefit cost was $nil.

1) Pensions and retirement bonuses

2) Gratuities and other post-employment benefits

3) Length of service awards and other long-term benefits

28.4 Components of net pension cost

Group In millions of $	31 December 2019	31 December 2018
Current service cost	14.0	13.8
Net interest expense	3.6	3.3
Actuarial gains and losses on long-term benefit obligations	0.1	(2.6)
Non-recurring items[1]	(54.7)	1.5
Total	(37.0)	16.0

(1) Non-recurring items includes settlement and curtailment gains of $50.0 million.

28.5 Reconciliation of balance sheet surplus/(deficit) over the period

Group In millions of $	31 December 2019	31 December 2018
Surplus/(deficit) at start of year	(232.5)	(254.9)
Expense (charge)/credit	37.0	(16.0)
Employer contributions	24.7	19.5
Actuarial gain/(loss) recognised in OCI	(27.6)	18.9
Currency translation gain/(loss)	3.4	-
Surplus/(deficit) at end of year	(195.0)	(232.5)

28.6 Funding

The funding of these obligations at 31 December 2019 can be analysed as follows:

Group In millions of $	Projected benefit obligation	Fair value of plan assets	Total net obligation
Underfunded plans	(249.8)	249.2	(0.6)
Unfunded plans	(195.9)	-	(195.9)
Plans in surplus	(0.1)	1.6	1.5
At 31 December 2019	(445.8)	250.8	(195.0)

Group In millions of $	Projected benefit obligation	Fair value of plan assets	Total net obligation
Underfunded plans	(229.7)	212.8	(16.9)
Unfunded plans	(215.6)		(215.6)
At 31 December 2018	(445.3)	212.8	(232.5)

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

% of total	31 December 2019	31 December 2018
Equity investments	1	11
Insurance contracts	98	89
Other	1	-
Total	100	100

All of the plan assets are located in Europe.

Notes to the consolidated financial statements

28.7 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.

2019 assumptions:

Eurozone

Group	Pension benefit obligations[1]	Other post-employment benefit obligations[2]	Long-term benefit obligations[3]
Discount rate	0% to 1.00%	0% to 1.00%	0% to 0.40%
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	2.30%	-	-
Inflation rate	1.50%	-	-

2018 assumptions:

Group	Pension benefit obligations[1]	Other post-employment benefit obligations[2]	Long-term benefit obligations[3]
Discount rate	1.85%	1.85%	1.85%
Inflation rate	1.80%	1.80%	1.80%

1) Pensions and retirement bonuses

2) Gratuities and other post-employment benefits

3) Length of service awards and other long-term benefits

Discount 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 2019. The inflation assumption is based on the long-term target of the European Central Bank for inflation. Plans have been grouped by duration into four categories, very short (on average three years duration), short (on average eight years' duration), medium (on average 14 years' duration) and long (on average 20 years' duration).

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 2019.

Risk analysis

The closure of the Dutch defined benefit plan and the closure of the French office has removed a substantial amount of defined benefit risk. Of the remaining liabilities, the main risks that the Neptune Group faces are:

Around half 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 his/her spouse, so increases in life expectancy result in an increase in the plans' liabilities.

Sensitivity to key assumptions

According to the Group's estimates, a 100 basis points increase in the discount rate assumption would result in a decrease of approximately 17% in the projected benefit obligation (2018: increase 16%). A 100 basis points decrease in the discount rate assumption would result in an increase of approximately 19% in the projected benefit obligation (2018: decrease 16%).

The inflation rate was determined for each area. A 100 basis points increase or decrease in the inflation rate, with no change on the discount rate, would result in a change of approximately 6% in the projected benefit obligation (2018: 16%).

A change in one year in the average life expectancy would result in a change of approximately 5% in the projected benefit obligation.

Future benefit payments

The aggregate duration of the Group's defined benefit obligations is 18 years at 31 December 2019. The expected future benefit outgo is as follows:

Future benefit payments $m	31 December 2019
Next year: paid from scheme assets	4.5
Next year: paid directly by employer	12.1
Expected in year 2021	15.8
Expected in year 2022	15.4
Expected in year 2023	15.3
Expected in year 2024	15.7
Expected in year 2025 to 2029 (total)	78.1

The amount expected to be paid by the Group in 2020 is $12.1 million. These payments are to meet benefits expected from unfunded plans.

Notes to the consolidated financial statements

29. Principal subsidiary undertakings, joint ventures, associates

At 31 December 2019, 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 Denmark Aps	Denmark	C	100%	100%	Oil and gas
Neptune Energy France SAS	France	D	100%	100%	Oil and gas
Neptune Energy International S.A.	France	D	100%	100%	Holding Company
BHKW Manschnow GmbH	Germany	E	50%	50%	Oil and gas
Gewerkschaft Küchenberg Erdgas und Erdöl 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
Westdeutsche Erdölleitung GmbH	Germany	F	50%	50%	Oil and gas
ENGIE E&P Malaysia BV	Netherlands	H	100%	100%	Oil and gas
Gaz de France Exploration Libya BV	Netherlands	H	100%	100%	Oil and gas
GDF SUEZ E&P Eastern Indonesia BV	Netherlands	H	100%	100%	Oil and gas
GDF SUEZ Exploration Mauritania BV	Netherlands	H	100%	100%	Oil and gas
Neptune Energy Alam El Shawish BV	Netherlands	H	100%	100%	Oil and gas
Neptune Energy Arguni I BV	Netherlands	H	100%	100%	Oil and gas
Neptune Energy Ashrafi BV	Netherlands	H	100%	100%	Oil and gas
Neptune Energy E&P Holdings Netherlands BV	Netherlands	H	100%	100%	Holding Company
Neptune Energy East Ganal BV	Netherlands	H	100%	100%	Oil and gas
Neptune Energy East Sepinggan BV	Netherlands	H	100%	100%	Oil and gas
Neptune Energy Egypt BV	Netherlands	H	100%	100%	Oil and gas
Neptune Energy Exploration BV	Netherlands	H	100%	100%	Oil and gas
Neptune Energy Facilities Netherlands BV	Netherlands	H	100%	100%	Oil and gas
Neptune Energy Germany BV	Netherlands	H	100%	100%	Oil and gas
Neptune Energy Holding Netherlands BV	Netherlands	H	100%	100%	Holding Company
Neptune Energy Jakarta BV	Netherlands	H	100%	100%	Oil and gas
Neptune Energy Muara Bakau BV	Netherlands	H	100%	100%	Oil and gas
Neptune Energy Netherlands Administration BV	Netherlands	H	100%	100%	Oil and gas
Neptune Energy Netherlands BV	Netherlands	H	100%	100%	Oil and gas
Neptune Energy North Ganal BV	Netherlands	H	100%	100%	Oil and gas
Neptune Energy North West El Amal BV	Netherlands	H	100%	100%	Oil and gas
Neptune Energy Participation Netherlands BV	Netherlands	H	100%	100%	Oil and gas
Neptune Energy South West Alamein BV	Netherlands	H	100%	100%	Oil and gas
Neptune Energy Touat BV	Netherlands	H	54%	54%	Oil and gas

Company name	Country of incorporation	Registered Office	Holding	Proportion of voting rights and shares held	Main activity
Neptune Energy Touat Holding BV	Netherlands	H	100%	100%	Oil and gas
Neptune Energy West Ganal BV	Netherlands	H	100%	100%	Oil and gas
ENGIE Sud Est Illizi BV	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 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
Production North Sea Netherlands Ltd	USA	H	100%	100%	Oil and gas

Registered Office addresses

A	Level 2, 5 Mill Street, Perth WA 6000, Australia
B	Avenida Presidente Vargas, No. 309, 21 floor (part), Centro, City and State of Rio de Janeiro, Zip Code 20040-010, Brazil
C	Vestre Svanholmen 6, 4313 Sandnes, Norway
D	9-11, Allée de l'Arche, Tour Egée, 92400 Courbevoie
E	Langewahler Straße 60, 15517 Fürstenwalde/Spree
F	Riethorst 12, 30659 Hannover
G	Waldstraße 39, 49808 Lingen (Ems), Germany
H	Einsteinlaan 10, 2719 EP Zoetermeer, the Netherlands
I	Nova North, 11 Bressenden Place, London, SW1E 5BY, UK

30. Events after the reporting period

Post the balance sheet date, macro-economic uncertainty has arisen due to the COVID-19 pandemic, which has impacted oil and gas pricing in addition to significant commodity market volatility relating to the global supply of oil. This volatility may have an impact on our earnings and cash flow but we are a resilient business, with an effective hedging and overall risk management programme in place. We have established mitigation plans for our projects and will continue to evaluate supply chains for ongoing impacts.

In addition, the significant estimates and judgements that will be made in preparing future financial statements may also be impacted if the current macro-economic uncertainty continues and estimates of long-term commodity prices decrease.

In particular, we expect the following would be impacted:

- the estimated recoverable amounts of intangible assets, property, plant and equipment and goodwill would be lower and the headroom of recoverable amounts over respective carrying values would reduce. We do not believe, based on current forecasts, that significant impairments would arise. However, this could result in additional impairment being required on property, plant and equipment where the recoverable amount of one CGU in the Netherlands has already been impaired and so is sensitive to changes in commodity prices (as described in note 14). Similarly on goodwill, one of the country's groups of CGUs has headroom of $35 million and is sensitive to changes in prices (see note 12); and
- deferred tax assets recognised on unutilised tax losses in the UK (note 11) would decrease, if our estimates of taxable profits against which the tax losses can be utilised are reduced.

Neptune Energy has been working with its RBL bank syndicate and has implemented several changes to the facility. These include the addition of Merakes, Indonesia and Touat, Algeria to the borrowing base. As a result, the new borrowing base has been increased from $2.0 billion to $2.5 billion (including the impact of the Energean Oil & Gas transaction) for the next 12 months with a delay in the first scheduled repayment from 2021 to 2022, while keeping the final maturity date unchanged as May 2024. We have also exercised the accordion option to upsize the RBL.

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 2018	500	138	638
Acquisitions	2	22	25
Revisions, extensions and discoveries	32	(9)	23
Production[2]	(43)	(9)	(52)
2P reserves at 31 December 2019	491	142	633

	Contingent resources (mmboe)		
	Europe	North Africa and Asia Pacific	Total Neptune Energy
2C resources at 31 December 2018	105	139	244
Acquisitions	3	30	33
Revisions, extensions and discoveries	21	4	25
2C resources at 31 December 2019	130	173	302

1) The above are management estimates, which are independently audited by ERCe.

2) As per PRMS (SPE/SPEE/WPC/AAPG/SEG) guidance, production is equal to the liftings.

3) Numbers may not add up due to rounding differences.

4) 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.

5) 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.

General information

This report includes the results of the acquired EPI business consolidated since 15 February 2018, which is the acquisition date as that is when Neptune acquired control over EPI. Comparative data for Neptune for the corresponding reporting period ended 31 December 2018 therefore includes only ten and a half months results contribution from the EPI business.

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.

Glossary of terms

2C reserves 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

CRC the Group Corporate Responsibility Committee

E&P exploration and production

EBITDAX an indicator of financial performance used when reporting earnings for oil and mineral exploration companies' earnings before interest, taxes, depreciation (or depletion), amortisation, and exploration expense

ELT our executive leadership team

EPI the business of ENGIE E&P International S.A. and its direct or indirect subsidiaries which was acquired on 15 February 2018

ESG environmental, social and governance factors used to measure a company's performance

FEED front end engineering and design

G&A general and administrative expenses

G&G geological and geophysical

HSE health, safety and environment

HSEQ health, safety, environment and quality management

kboepd thousand barrels of oil equivalent per day

kbpd thousand barrels per day

LNG liquefied natural gas

LTIF lost time injury frequency, a measure of safety performance

M&A mergers and acquisitions

mcf thousand cubic feet of natural gas

mmboe one million barrels of oil equivalent

mmbtu one million British thermal units. A BTU is the amount of heat required to raise the temperature of one pound of water by one degree fahrenheit

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 though which our investors own their interests in the Group

NGO non-governmental organisation

NOx nitrogen oxide, a source of air pollution

OCI other comprehensive income, an accounting term

RBL our Reserves Based Lending facility

SURF subsea umbilicals, risers and flowlines used in deepwater exploration

tCO_2e tonnes of carbon dioxide equivalent, a measure that allows you to compare the emissions of other greenhouse gases relative to one unit of CO_2

TRIR total recordable injury rate, a measure of safety performance

General information

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Neptune Energy Group Midco Limited is a private limited company registered in England and Wales (No. 10684661).

Corporate website

The Neptune Energy corporate website – **www.neptuneenergy.com** – provides useful information including annual reports and results announcements, as well as information on our operations and our ESG performance.

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