Brønnøysundregistrene

ÅRSREGNSKAPET FOR REGNSKAPSÅRET 2020 - GENERELL INFORMASJON

Enheten

Organisasjonsnummer:	983 426 417
Organisasjonsform:	Aksjeselskap
Foretaksnavn:	NEPTUNE ENERGY NORGE AS
Forretningsadresse:	Vestre Svanholmen 6 4313 SANDNES

Regnskapsår

Årsregnskapets periode:	01.01.2020 - 31.12.2020

Konsern

Morselskap i konsern:	Ja
Konsernregnskap lagt ved:	Ja

Regnskapsregler

Regler for små foretak benyttet:	Nei
Benyttet ved utarbeidelsen av årsregnskapet til selskapet:	Regnskapslovens alminnelige regler
Benyttet ved utarbeidelsen av årsregnskapet til konsernet:	-

Årsregnskapet fastsatt av kompetent organ

Bekreftet av representant for selskapet:	Trygve Bøe
Dato for fastsettelse av årsregnskapet:	04.06.2021

Grunnlag for avgivelse

År 2020: Årsregnskapet er elektronisk innlevert
År 2019: Tall er hentet fra elektronisk innlevert årsregnskap fra 2020

Det er ikke krav til at årsregnskapet m.v. som sendes til Regnskapsregisteret er undertegnet. Kontrollen på at dette er utført ligger hos revisor/enhetens øverste organ. Sikkerheten ivaretas ved at innsender har rolle/rettighet for innsending av årsregnskapet via Altinn, og ved at det bekreftes at årsregnskapet er fastsatt av kompetent organ.

Brønnøysundregistrene, 30.06.2022

Resultatregnskap

Beløp i: NOK	Note	2020	2019
RESULTATREGNSKAP			
Inntekter			
Salgsinntekt olje og gass	3,5	5 801 830 361	8 701 742 186
Tariffinntekter		10 046 181	10 858 609
Andre inntekter	8	429 349 821	117 479 222
Sum inntekter		**6 241 226 363**	**8 830 080 017**
Kostnader			
Driftskostnader	10	1 717 066 993	1 501 003 476
Letekostnader		325 710 667	327 493 081
Lønnskostnader	6,7	158 867 008	67 164 678
Avskrivning på varige driftsmidler og immaterielle eiendeler	9	1 342 040 391	1 789 514 419
Annen driftskostnad	10	79 256 541	83 350 313
Sum kostnader		**3 622 941 600**	**3 768 525 967**
Driftsresultat		**2 618 284 763**	**5 061 554 050**
Finansinntekter og finanskostnader			
Renteinntekt fra foretak i samme konsern	8	5 236 042	25 163 415
Annen renteinntekt		33 047 992	23 370 757
Valutagevinst		940 749 437	721 494 765
Annen finansinntekt	3	55 697 530	
Sum finansinntekter		**1 034 731 001**	**770 028 937**
Nedskrivning aksjer datterselskap		123 400 000	
Rentekostnad til foretak i samme konsern	8	207 493 591	223 678 357
Annen rentekostnad		15 784 534	13 113 812
Valutatap		864 720 754	722 044 839
Annen finansinntekt	3	282 956	38 461 450
Sum finanskostnader		**1 211 681 835**	**997 298 458**
Netto finans		**-176 950 834**	**-227 269 521**
Ordinært resultat før skattekostnad		**2 441 333 929**	**4 834 284 529**
Skattekostnad på ordinært resultat	13	879 406 615	3 302 385 593
Ordinært resultat etter skattekostnad		**1 561 927 314**	**1 531 898 936**

Resultatregnskap

Beløp i: NOK	Note	2020	2019
Årsresultat		**1 561 927 314**	**1 531 898 936**
Overføringer og disponeringer			
Ordinært utbytte	14	1 556 500 000	
Overføringer til/fra annen egenkapital	14	5 427 314	1 531 898 936
Sum overføringer og disponeringer		**1 561 927 314**	**1 531 898 936**

Balanse

Beløp i: NOK	Note	2020	2019
BALANSE - EIENDELER			
Anleggsmidler			
Immaterielle eiendeler			
Goodwill		531 680 795	600 284 768
Sum immaterielle eiendeler		**531 680 795**	**600 284 768**
Varige driftsmidler			
Maskiner og anlegg	9	18 898 100 607	14 949 164 120
Sum varige driftsmidler		**18 898 100 607**	**14 949 164 120**
Finansielle anleggsmidler			
Investering i datterselskap	16	66 289 675	189 689 675
Investeringer i aksjer og andeler	16	188 000	188 000
Sum finansielle anleggsmidler		**66 477 675**	**189 877 675**
Sum anleggsmidler		**19 496 259 077**	**15 739 326 563**
Omløpsmidler			
Varer			
Boreutstyr, reservedeler	12	21 262 972	32 795 501
Sum varer		**21 262 972**	**32 795 501**
Fordringer			
Kundefordring fra operatør		302 384 116	649 197 601
Kundefordring	11	15 643 228	176 401 796
Andre fordringer	11	1 795 927 423	2 361 847 916
Betalbar skatt	13	1 051 073 702	
Sum fordringer		**3 165 028 469**	**3 187 447 313**
Investeringer			
Andre finansielle instrumenter	3	75 410 105	192 129 801
Sum investeringer		**75 410 105**	**192 129 801**
Bankinnskudd, kontanter og lignende			
Bankinnskudd, kontanter og lignende	4	4 351 305	16 529 236
Sum bankinnskudd, kontanter og lignende		**4 351 305**	**16 529 236**

Balanse

Beløp i: NOK	Note	2020	2019
Sum omløpsmidler		**3 266 052 851**	**3 428 901 851**
SUM EIENDELER		**22 762 311 928**	**19 168 228 414**
BALANSE - EGENKAPITAL OG GJELD			
Egenkapital			
Innskutt egenkapital			
Aksjekapital	14,15	141 500 000	141 500 000
Overkurs	14	1 273 500 000	1 273 500 000
Sum innskutt egenkapital		**1 415 000 000**	**1 415 000 000**
Opptjent egenkapital			
Annen egenkapital	3,14	1 444 976 248	1 663 406 362
Sum opptjent egenkapital		**1 444 976 248**	**1 663 406 362**
Sum egenkapital		**2 859 976 248**	**3 078 406 362**
Gjeld			
Langsiktig gjeld			
Pensjonsforpliktelser	7	227 293 630	210 460 595
Utsatt skatt	13	7 942 327 387	4 798 663 804
Andre avsetninger for forpliktelser	10	4 124 639 481	3 896 112 653
Sum avsetninger for forpliktelser		**12 294 260 498**	**8 905 237 052**
Annen langsiktig gjeld			
Langsiktig konserngjeld	11	3 373 000 000	3 373 000 000
Sum annen langsiktig gjeld		**3 373 000 000**	**3 373 000 000**
Sum langsiktig gjeld		**15 667 260 498**	**12 278 237 052**
Kortsiktig gjeld			
Leverandørgjeld	11	116 496 507	261 151 158
Betalbar skatt	13	137 091 424	1 118 459 298
Skyldige offentlige avgifter		77 448 947	12 917 080
Utbytte	14	1 556 500 000	
Gjeld til operatør		177 233 122	383 809 670

Balanse

Beløp i: NOK	Note	2020	2019
Finansielle instrumenter	3	176 486 910	
Annen kortsiktig gjeld		1 993 818 272	2 035 247 794
Sum kortsiktig gjeld		**4 235 075 182**	**3 811 585 000**
Sum gjeld		**19 902 335 680**	**16 089 822 052**
SUM EGENKAPITAL OG GJELD		**22 762 311 928**	**19 168 228 414**
POSTER UTENOM BALANSEN			
Garantistillelser	4	35 000 000	35 000 000

Skattedirektoratet

Saksbehandler	Deres dato	Vår dato
Geir Johannessen	22.01.2015	03.02.2015
Telefon	Deres referanse	Vår referanse
22 07 73 25/22 66 11 14	Trygve Bø	2015/59797

GDF SUEZ E&P NORGE AS
Postboks 242 Forus
4066 STAVANGER

Tillatelse til å utarbeide årsregnskap og årsberetning på engelsk språk for GDF SUEZ E&P Norge AS, org.nr. 983 426 417

Vi viser til deres brev av 22. januar 2015 der det søkes om dispensasjon fra kravet til å utarbeide årsregnskap og årsberetning på norsk språk for GDF SUEZ E&P Norge AS fra og med regnskapsåret 2014.

Skattedirektoratet gir på bakgrunn av en konkret helhetsvurdering GDF SUEZ E&P Norge AS dispensasjon fra kravet til å utarbeide årsregnskap og årsberetning på norsk språk fra og med regnskapsåret 2014, jf. regnskapsloven § 3-4 tredje ledd. Dispensasjonen forutsetter at opplysningene som vedtaket baserer seg på ikke endres vesentlig.

Kopi av dette brevet må sendes Regnskapsregisteret i Brønnøysund sammen med årsregnskapet. Det påligger den regnskapspliktige å dokumentere ved dette brev at tillatelsen er gitt.

Bakgrunn
GDF SUEZ E&P Norge AS driver virksomhet innen leting etter og utvinning av olje og gass. Konsernets arbeidsspråk er engelsk. Konsernet opererer i sektorer, der engelsk er det klart dominerende språket. Morselskapets aksjonærer er utenlandske selskaper og personer, og morselskapet henvender seg jevnlig til potensielle investorer som er basert i utlandet. All kommunikasjon med konsernets primære kunder og kreditorer foregår på engelsk. I lys av selskapets og konsernets situasjon, der enkelte av selskapets investorer kun behersker engelsk, all kommunikasjon med konsernets primære kunder og kreditorer skjer på engelsk, samt at engelsk er både arbeidsspråket til konsernet og bransjespråket der selskapet og konsernet opererer, fremstår kravet i regnskapsloven § 3-4 om utarbeidelse av årsregnskap og årsberetning på norsk som unødvendig. Ettersom konsernets arbeidsspråk er engelsk vil alle ansatte forstå regnskapet og årsberetningen selv om disse dokumentene i fremtiden blir utarbeidet i sin endelige form på engelsk. Det samme vil være tilfelle for kunder og kreditorer.

Skattedirektoratets vurdering
Etter regnskapsloven § 3-4 tredje ledd skal *"årsregnskapet og årsberetningen ... være på norsk. Departementet kan ved ... enkeltvedtak bestemme at årsregnskapet og/eller årsberetningen kan være på et annet språk."*

Postadresse
Postboks 9200 Grønland
0134 Oslo

Besøksadresse:
Se www.skatteetaten.no
Org.nr: 996250318
E-post: skatteetaten.no/sendepost

Sentralbord
800 80 000
Telefaks
22 17 08 60

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I Ot. prp. nr. 42 (1997-1998) Om lov om årsregnskap m.v., er det uttalt følgende om regnskapslovens formål, jf. pkt. 1.1:

> *"Regjeringen har som siktemål at regnskapsloven skal bidra til informative regnskaper for ulike grupper av regnskapsbrukere. Regnskapsbrukerne er dels investorer og kreditorer som tilfører kapital til foretakene, og dels andre grupper som har interesse av å vite hvordan foretaket drives, f.eks. de ansatte og lokalsamfunnet. Informasjonen til kapitalmarkedet skal gi grunnlag for riktig prising av finansielle objekter. Riktig prisdannelse på aksjer er en forutsetning for at ressursbruken i samfunnsøkonomien skal bli best mulig. Gode regnskaper vil også gjøre det vanskeligere for markedsdeltakere å ta ut spekulasjonsgevinster med basis i skjevt fordelt informasjon."*

Det fremgår således at et av hovedformålene med regnskapsloven er å bidra til *"informative regnskaper for ulike grupper av regnskapsbrukere"*. Regnskapsbrukere vil omfatte, jf. uttalelsen i proposisjonen, blant andre investorer, kreditorer, ansatte og lokalsamfunnet.

Det er etter Skattedirektoratets vurdering derfor avgjørende ved vurdering av om dispensasjon fra kravet til å utarbeide årsregnskap og/eller årsberetning på norsk kan gis, at det ikke foreligger mulige brukere av regnskapsinformasjon som blir vesentlig berørt negativt ved en eventuell dispensasjon.

Det er særlig hensynet til brukerne av regnskapsinformasjon som skal vurderes ved en dispensasjonssøknad. I denne vurderingen har Skattedirektoratet lagt særlig vekt på at selskapet inngår i et utenlandsk konsern og at arbeidsspråket er engelsk. Videre er det vektlagt at selskapet driver virksomhet i en internasjonal bransje der alle vesentlige aktører behersker og benytter engelsk språk.

Vennligst oppgi vår referanse ved henvendelser i saken.

Med hilsen

Rune Tystad
Seniorrådgiver
Rettsavdelingen, foretaksskatt
Skattedirektoratet

Geir Johannessen

Dokumentet er elektronisk godkjent og har derfor ikke håndskrevne signaturer

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Postboks 9200 Grønland	Se www.skatteetaten.no	800 80 000
0134 Oslo	Org.nr: 996250318	Telefaks
	E-post: skatteetaten.no/sendepost	22 17 08 60

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Geir Johannessen

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Income statement

	Note	2020	2019
Operating income			
Sales of oil and gas	3, 5	5 801 830 362	8 701 742 185
Tariff income		10 046 181	10 858 609
Other Income	8	429 349 821	117 479 222
Total operating income		6 241 226 363	8 830 080 017
Operating expenses			
Operating expenses	10	1 717 066 993	1 501 003 476
Exploration expenses		325 710 667	327 493 081
Payroll expenses	6, 7	158 867 008	67 164 678
Depreciation/Impairment	9	1 342 040 391	1 789 514 417
Other operating expenses	10	79 256 541	83 350 313
Total operating expenses		3 622 941 601	3 768 525 966
Operating profit		2 618 284 763	5 061 554 050
Financial income and expenses			
Interest income		33 047 992	23 370 757
Foreign currency exchange gain		940 749 437	721 494 765
Interest income from group companies	8	5 236 042	25 163 415
Other financial income	3	55 697 530	0
Impairment shares in subsidiaries		123 400 000	0
Interest expenses		15 784 534	13 113 812
Foreign currency exchange loss		864 720 754	722 044 839
Interest expenses to group companies	8	207 493 591	223 678 358
Other financial expenses	3	282 956	38 461 450
Net financial (-income)		176 950 834	227 269 521
Operating profit before tax		2 441 333 929	4 834 284 529
Tax expenses	13	879 406 615	3 302 385 593
Net income		1 561 927 314	1 531 898 936
Allocated as follows:			
Proposed dividend	14	1 556 500 000	0
Transfer (-from) other equity	14	5 427 314	1 531 898 936
Total allocations		1 561 927 314	1 531 898 936

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Balance sheet

NOK	Note	2020	2019
Non-current assets			
Intangible fixed assets			
Goodwill		531 680 795	600 284 768
Tangible fixed assets			
Property, plant & equipment	9	18 898 100 607	14 949 164 120
Shares in subsidiary	16	66 289 675	189 689 675
Other financial investments	16	188 000	188 000
Total tangible fixed assets		18 964 578 282	15 139 041 795
Total non-current assets		19 496 259 078	15 739 326 563
Current assets			
Drilling equipment and spare parts	12	21 262 972	32 795 501
Accounts receivable from operators		302 384 116	649 197 601
Trade accounts receivable	11	15 643 228	176 401 796
Current tax	13	1 051 073 702	
Financial instruments	3	75 410 104	192 129 800
Other receivables	11	1 795 927 423	2 361 847 916
Total receivables		3 240 438 573	3 379 577 113
Cash and cash equivalents	4	4 351 305	16 529 236
Total current assets		3 266 052 850	3 428 901 850
Total assets		22 762 311 928	19 168 228 414
Equity and liabilities			
Equity			
Paid-in capital			
Share capital	14,15	141 500 000	141 500 000
Share premium reserve	14	1 273 500 000	1 273 500 000
Total paid-in capital		1 415 000 000	1 415 000 000
Retained earnings			
Other equity	3,14	1 444 976 248	1 663 406 362
Total equity		2 859 976 248	3 078 406 362
Liabilities			
Pension liability	7	227 293 630	210 460 595
Deferred tax	13	7 942 327 388	4 798 663 804
Financial instruments	3		
Other provisions	10	4 124 639 481	3 896 112 653
Long term liability	11	3 373 000 000	3 373 000 000
Total provisions		15 667 260 498	12 278 237 052
Current liabilities			
Trade accounts payable	11	116 496 507	261 151 158
Public duties payable		77 448 947	12 917 080
Accounts payable to operator		177 233 122	383 809 670
Dividend	14	1 556 500 000	0
Tax payable	13	137 091 424	1 118 459 298
Financial instruments	3	176 486 910	0
Other short term liabilities		1 993 818 274	2 035 247 793
Total current liabilities		4 235 075 183	3 811 585 000
Total liabilities		19 902 335 681	16 089 822 052
Total equity and liabilities		22 762 311 928	19 168 228 414

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Cash flow statement

	2020	2019
Profit before tax	2 441 333 929	4 834 284 529
Net payment of tax	295 823 350	-3 216 047 885
Depreciation, impairments and accretion	1 698 849 841	1 912 592 517
Changes in accounts receivable and accounts receivable operators	507 572 054	771 385 601
Changes in accounts payable and accounts payable operators	-286 699 333	-1 169 182 189
Difference between pension cost and amounts paid into pension scheme	15 494 466	28 281 594
Changes in other balance sheet items	377 706 317	2 721 572 177
Net cash flow from operating activities	**5 050 080 624**	**5 882 886 344**
Acquired tangible fixed assets	-5 062 258 494	-4 514 326 686
Shares in subsidiary		
Net cash flow from investing activities	**-5 062 258 494**	**-4 514 326 686**
Dividend paid	0	-1 400 850 000
Net cash flow from financing activities	**0**	**-1 400 850 000**
Net change in cash and cash equivalents	-12 177 870	-32 290 342
Cash and cash equivalents at beginning of year	16 529 240	48 819 582
Cash and cash equivalents at end of year	**4 351 370**	**16 529 240**

Note 1 - Accounting policies
The annual accounts have been prepared in accordance with the Norwegian Accounting Act of 1998 and Norwegian generally accepted accounting principles.

Revenues
Revenue is recognised when the Company satisfies a performance obligation by transferring oil and gas to a costumer. For crude oil the point of delivery is at the offshore loading point or at shipment from the terminal. The point of delivery for gas is at the gas receiving terminal onshore.
Differences may arise in a joint operation between the Company'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 asset or liabilities, respectively, at net realisable value, with a corresponding adjustment through production cost. As a result, the reported operating result for each period reflect the Company's share of saleable production in that period.

Expenses
Expenses are expensed as incurred in accordance with the matching principle, either along with the revenues they have generated or identified as a periodical expense.

Estimates
In accordance with Norwegian generally accepted accounting principles, the management of the company is responsible for estimates and assumptions that affect the valuation of assets and liabilities in the balance sheet and depreciation in the income statement. The final realisable values may deviate from these estimates.

Classification and assessment of items in the balance sheet
Current assets and current liabilities include items due within one year and items related to ordinary working capital. All other items are classified as fixed assets or long-term liabilities.
Current assets are valued at the lower of cost and fair value. Short-term debt is valued at the historical nominal value.
Fixed assets are valued at cost, but written down to fair value if the decline in value is not expected to be temporary. Long-term loans are stated at the historical nominal value.

Foreign currency
Monetary balance sheet items in foreign currency are converted at the exchange rate on the closing balance date.
All foreign currency transactions are converted to NOK in accordance with the Company's monthly book-keeping currency exchange rates, which approximate market rates.

Exploration costs
Geological studies and analysis are expensed as incurred. Exploration drilling costs are temporarily capitalised until potential oil and gas reserves have been evaluated (the successful efforts method). When new reserves are discovered, fully developed and put into production, the exploration drilling costs will be depreciated based on the unit-of-production method. Drilling costs related to dry or non-commercial wells are expensed.

Property, plant and equipment
All costs related to the development of commercial oil or gas fields are capitalised as a part of the installation. Capital expenditures on fields in production are capitalised based on information from the operator.
Individual assets or groups of assets, classified as cash-generating units (CGUs), are tested for impairment when indicators of impairment are identified. When assessing whether an asset is impaired, the asset's carrying value is compared to the recoverable amount. The recoverable amount is the higher of the asset's fair value less cost to sell and the asset's value in use. An impairment loss is recognised when the recoverable amount is below the carrying amount and if the decline in recoverable amount is not considered temporary. If the assets are decided to be impaired, the carrying amount is written down to the recoverable amount and the reduction in asset value is recognised as an expense.

Depreciation of production assets
The depreciation of producing assets, including site rehabilitation costs, commences when the oil or gas field is brought into production. Depreciation is calculated according to the unit of production method. According to this method, the depletion rate is equal (since 1 January 2014) to the ratio of oil and gas production for the period to proved and probable reserves. Before this date, the ratio was based on proved developed reserves. The future capex linked to the 2P reserves are included in the calculation of the depreciation rate. This change of estimate has been decided in view of the evolution of the Group's portfolio of production assets. This change aims to improve the economic vision of the production asset's consumption of benefits over its useful life.

Property, plant and equipment is capitalised and depreciated linearly over its estimated useful life. Costs for maintenance are expensed as incurred, whereas costs for improving and upgrading property, plant and equipment are added to the acquisition cost and depreciated with the related asset.

Subsidiaries and investment in associates
Subsidiaries and investments in associates are valued at cost in the Company accounts. The investment is valued as the cost of the shares in the subsidiary, less any impairment losses. Consolidated financial statements are not prepared as the Company and its subsidiaries are included in the consolidated financial statements of the parent company.

Assets liabilities and expenses related to participating interests in exploration and production licences (joint ventures)

The Company's participating interests in exploration and production licences on the Norwegian Continental Shelf are accounted for in the income statement and balance sheet in accordance with the proportional consolidation method.

Transfer of interest in joint arrangements
Transfers of interests in petroleum licences on The Norwegian Continental Shelf require approval from the Norwegian Government. Under such transactions the sale price is generally considered to be on an "after tax" basis (after-tax transaction) as the consideration is not taxable for the seller and not deductable for the buyer through depreciation.

When acquiring licences that yield rights to exploration for and production of oil and gas, it will be assessed if the acquisition should be classified as a business combination or an asset acquisition. Acquisitions of individual licences which do not meet the definition of business combination will be classified as the acquisition of an individual asset.

Oil and gas producing licences
For oil and gas producing ownership interests, as well as licences in the development phase, the acquisition cost will be allocated between exploration costs, licence rights, production facilities, deferred taxes and goodwill.

In connection with agreements for acquisitions or trade of interests, the parties will establish a completion date for the acquisition of the net cash flow since the effective date often set on 1 January of the calendar year. In the period between the effective date and the completion date, the seller will include the acquired interest in the seller's accounts. In accordance with the acquisition agreement, there will be a settlement with the seller of net cash flow from the ownership interest during the period from the effective date to implementation date (Pro&Contra settlement). The Pro&Contra settlement will be adjusted against the income statement and against the acquisition cost, as the settlement (after reduction for taxes) is regarded as part of the payment for the transaction. Going forward from the implementation date, revenue and costs are included in the buyer's financial statements.

As regards taxes, the buyer will include for taxation net cash flow (Pro&Contra) and any other revenue and costs as of the effective date.

Allocations will not be made for deferred taxes and goodwill in connection with acquisition of licences that are defined as acquisition of assets.

Farm-in agreements
Farm-in agreements are usually made during the exploration and development phases, and are characterised by the seller deferring future financial advantages, in the form of reserves, to reduce future financing obligations. One example can be that a licence interest is acquired and covered by the seller's share of the drilling-related costs. During the exploration phase, the company will normally enter farm-in agreements based on historical costs, as actual value often is difficult to determine. However, during the development phase, farm-in agreements are entered as acquisitions at actual cost when the company is selling shares of oil and gas interests. Fair value is determined by the costs that the buyer has agreed to carry.

Swap/Unitisation
A swap of ownership interest is measured at the fair value of the interest to be swapped, unless the transaction lacks commercial substance or if the fair value of the swapped interest is not measurable. During the exploration phase where it is often difficult to determine fair value, the Company will normally account for swaps based on historical cost.

Spare parts and drilling equipment
Spare parts and drilling equipment are valued at the lower of cost or market value. Cost is estimated using the First In First Out (FIFO) method. Capital spare parts are capitalised and presented in the financial statements together with the investment.

Over/under lift and petroleum in stock
Obligations or receivables arising as a result of lifted quantities of crude oil and NGL that are larger or lower than the Company's participating interests in a licence are valued at net realisable value / market value.

Uncertain obligations
The Company will, through its activities, be involved in conflicts and disputes. The Company will accrue for obligations in connection with such unresolved issues based on the best estimate, when it is probable that an outflow of economic benefits will be required to settle the obligation.

Accounts receivables
Trade accounts receivables and other receivables are recorded at face value less a provision for any anticipated losses.

Asset retirement obligation
When the retirement obligation is incurred, the liability is recognised as a long term provision and the corresponding amount is capitalised as part of the producing asset. The asset is expensed through depreciation over the remaining useful life of the asset. Future changes in asset retirement obligation estimates are capitalised as part of the asset and charged to profit and loss prospectively over the remaining useful life of the asset.

Tax expense
Tax expense reflects both taxes on current taxable income and changes in deferred income taxes. Deferred tax is calculated based on net temporary differences between the book and tax values at year end. The calculation has taken into account future uplift on capitalised expenditures.
Uplift on capitalised expenditures reduces the special petroleum tax. Earned uplift from capitalised expenditures has been fully reflected in the deferred tax calculation.

Pensions
Accounting for the defined benefit pension plan is based on a linear vested principle and on expected salaries at the point of retirement. Changes in pension schemes are amortised over the remaining vesting period. Estimated deviations are continuously charged to equity. Social security tax is included in the pension cost and liability. The defined contribution pension plan is booked as current costs.

Accounting for licence cost
The Company's accounts reflects the net cost after charging partners their share of licence costs for permits the Company operates.

Cash flow statement
The cash flow statement is presented using the indirect method. Cash and cash equivalents include bank deposits.

Leasing
The Company has signed only operating lease agreements, and as such the related cost is charged to the income statement as incurred.

Financial Instruments
The Company enters into commodity based derivative contracts consisting of market swaps for oil and gas products.

Hedging
The Company applies the principals of NRS18 and uses the following criteria for classifying a derivative or another financial instrument as a hedging instrument: (1) the hedging instrument is expected to be highly effective in offsetting changes in the fair value of the cash flow of an identified object – the hedging effectiveness is expected to be between 80-125%, (2) the hedging effectiveness can be measured reliably, (3) satisfactory documentation is established before entering into the hedging instrument, showing among other things that the hedging relationship is effective, (4) for cash flow hedges, that the future transaction is considered to be highly probable, and (5) the hedging relationship is evaluated regularly with quantitative analysis and is considered to be effective.

Cash flow hedges
The efficient part of changes in the fair value of a hedging instrument is recognised in equity. The inefficient part of the hedging instrument is reported in the income statement. When a hedging instrument has matured, or is sold, exercised or terminated, or the parties discontinues the hedging relationship, even though the hedged transaction is still expected to occur, the accumulated gains and losses at this point will remain in comprehensive income, and will be recognised in the income statement when the transaction occurs. If the hedged transaction is no longer expected to occur, the accumulated unrealised gains or losses on the hedging instrument will be recognised in the income statement immediately.

Note 2 - Financial market risk
The Company's financial result is affected by fluctuations in crude oil and gas prices and foreign currency exchange rates (mainly USD, GBP and EUR).

Note 3 - Financial Instruments
The Company enters into commodity based derivative contracts consisting of swap and option derivative contracts for oil and gas products. Swap and option derivative contracts for oil are hedged towards Brent Blend; swap and option derivative contracts for gas are hedged towards National Balancing Point (NBP) and Title Transfer Facility (TTF) prices.

The realised value on swap and derivative contracts for the year 2020 is a gain of NOK 754 539 551,76. The realised hedging contracts which are not fulfilling the requirements of efficiency according to NRS 18 for hedge accounting are booked as part of financial result.

NOK	2020	2019
Total Gas hedging revenue (-loss)	358 074 067	118 342 164
Total Liquids hedging revenue (-loss)	396 465 485	-218 898
Total hedging revenues (-loss)	**754 539 552**	**118 123 266**
Financial income from hedging (-loss)	55 697 530	-38 217 118
Total hedging income (-loss)	**810 237 081**	**79 906 148**

NOK	Booked	31.12.2020	Due	2021	2022	2023
Cash flow hedge commodities asset	Asset	75 410 104		65 609 353	9 800 751	
Cash flow hedge commodities liabilities	Liability	-176 486 910		-170 912 583	-5 574 327	
Cash flow hedge commodities reserves equity	Equity	132 015 267		132 129 328	-114 061	
Market to Market	P&L Gain	-55 697 530				

Note 4 - Bank deposits
Restricted funds relating to withholding taxes
The Company has issued a bank guarantee towards the tax authorities of NOK 35 000 000, replacing the cash deposit for withholding taxes.

Note 5 - Operating revenues
Sales of the Company's production has derived the following revenues:

NOK	Norway	France	UK	Germany	Switzerland	Hungary	USA	Australia	TOTAL	2019 TOTAL
Crude oil	274 950 918		1 879 662 245		227 794 386				2 382 407 548	4 200 058 948
NGL	79 185 236	73 644 509	170 719 133		289 639 575	21 253 524			634 441 977	923 944 016
Gas	354 109 584		910 048 993	50 372 994	5 702 004	4 783 284			1 325 016 859	3 136 327 586
LNG			29 423 291		633 489 125				662 912 416	
Condensate			42 511 950						42 511 950	323 288 369
Hedging of oil and gas	64 748 658	173 559 572	154 750 521				299 652 286	61 828 514	754 539 552	118 123 266
Total	**772 994 396**	**247 204 081**	**3 187 116 133**	**50 372 994**	**1 156 625 090**	**26 036 808**	**299 652 286**	**61 828 514**	**5 801 830 302**	**8 701 742 185**

Note 6 - Salaries and fees

NOK	2020	2019
Salaries	528 766 938	470 131 655
Social security tax	77 875 218	79 271 814
Pension costs	92 037 292	90 550 703
Other employee benefits	37 596 296	(3 270 305)
Total salary	736 275 743	636 683 866
Salaries recharged to licences	577 408 735	569 519 188
Total net salary	**158 867 008**	**67 164 678**
Number of full-time equivalent employees in fiscal year	**329,0**	**336,0**

Remuneration for Managing Director
The Managing Director position is held by Odin Estensen. The total salary, bonus and other fringe benefits paid to the Managing Director for 2020 is NOK 5 290 893 of which NOK 5 159 850 is salary and NOK 131 073 is other benefits.

Remuneration of the Board
No remuneration to the Board were paid in 2020.

Audit fees
The fees paid to Ernst & Young during the year 2020, excluding VAT, are comprised of the following amounts:

NOK	2020
Audit decreed by law	3 944 917
Other attestation services	389 850
Technical VAT and tax services	115 195
Total	**4 449 962**

Note 7 - Pensions

The Company is required to have an occupational pension scheme in accordance with the Norwegian law on required occupational pension ("lov om obligatorisk tjenestepensjon"). The Company's pension scheme meets the requirements of that law.

The Company has a retirement benefit plan for all permanent staff. This benefit plan gives the employees the right to receive defined future pensions. The Company decided to change the pension scheme for the employees from a defined benefit plan to a defined contribution plan, as of 01.01.2016. The new pension scheme will be mandatory for all employees having more than 15 years remaining until retirement age, hence the employees having less than 15 years left until retirement will still be members of the old defined benefit pension plan. 284 employees are part of the defined contribution pension scheme and 46 employees are part of the defined benefit pension scheme. The Company's actuarial report is provided by Storebrand Pensjonstjenester AS. The value of these is mainly dependent on the number of years in service and the level of compensation at retirement. The obligation up to 12G is financed through an insurance company, the remainder is financed through normal operation.

NOK	2020	2019
Pension rights earned during the year, including a new retroactive pension scheme (2016-2018)	53 555 184	44 580 033
Defined contribution pension scheme	36 143 627	39 130 187
VNG pension cost	1 804 670	3 377 140
Interest expense on earned pension rights		3 358 161
Other pension cost (admin	533 811	105 181
Net pension cost	**92 037 292**	**90 550 703**

Assets/obligations	2020	2019
Pension benefit obligations	361 429 629	264 918 600
Plan assets	-131 907 526	-121 443 500
Yield assets	-2 228 474	-2 856 500
Defined contribution pension schemes	0	69 841 995
Net pension liability	**227 293 629**	**210 460 595**

Financial assumptions	2020	2019
Discount rate	1,70%	2,30%
Expected increase in salaries	2,00%	2,25%
Expected increase in pensions	0,00%	0,70%
Expected increase of social security base amount (G)	1,75%	2,00%
Expected return on plan assets	1,50%	1,80%

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Note 8 - Related Party Transactions

Related Party	Relationship to the Company	Value of Transactions 2020	Value of Transactions 2019	Nature of transactions	Other Comments
Neptune Energy Deutschland GmbH	Associated company	2 068 444	631 730	Operating and support income	Income statement
Neptune Energy Deutschland GmbH	Associated company	1 324 480	1 448 969	Operating and support expenses	Income statement
Neptune Energy Netherlands B.V.	Associated company	72 707 381	158 781 372	Operating and support income	Income statement
Neptune Energy Netherlands B.V.	Associated company	60 359 654	101 415 362	Operating and support expenses	Income statement
Neptune E&P UK Ltd	Associated company	16 818 144	47 804 584	Operating and support income	Income statement
Neptune E&P UK Ltd	Associated company	36 189 991	38 131 941	Operating and support expenses	Income statement
Neptune Energy International SA (Paris)	Associated company (Parent 2019)	14 057 795	186 794 297	Operating and support expenses	Income statement
Neptune Energy International SA (Paris)	Associated company (Parent 2019)	28 521 806	93 011 492	Operating and support income	Income statement
Neptune Energy Group Holdings Ltd. (UK)	Parent company	10 772 707	232 814 862	Operating and support expenses	Income statement
Neptune Energy Group Holdings Ltd. (UK)	Parent company	213 231 309	74 215 051	Operating and support income	Income statement
Neptune E&P UKCS Limited	Associated company	-	45 786	Operating and support income	Income statement
Neptune Energy Egypt B.V	Associated company	451 805	-640 220	Operating and support income	Income statement
Neptune Energy Touat B.V	Associated company	4 437 273	585 942	Operating and support income	Income statement
Neptune Energy Exploration B.V	Associated company	-	17 477 777	Operating and support income	Income statement
Noordgastransport B.V	Associated company	-	165 165	Operating and support expenses	Income statement
Noordgastransport B.V	Associated company	1 982	191 494	Operating and support income	Income statement
NOGAT B.V	Associated company	-	54 039	Operating and support expenses	Income statement
NOGAT B.V	Associated company	5 737	60 194	Operating and support income	Income statement
Neptune Energy Muara Bakau B.V.	Associated company	2 563 733	-	Operating and support income	Income statement
Neptune Energy Bonaparte PTY Ltd.	Associated company	110 376	-	Operating and support income	Income statement
Neptune Energy Participation Netherlands	Associated company	5 583	-	Operating and support income	Income statement
Neptune Energy Danmark ApS	Subsidiary	2 065 310	6 454 231	Operating and support income	Income statement
Neptune Energy International SA (Paris)	Parent company	-	17 489 013	Interest & financial revenue group account	Income statement
Neptune Energy Capital Ltd (UK)	Associated company	207 385 157	223 525 899	Accrued interest intercompany loan	Income statement
Neptune Energy Finance Ltd (UK)	Associated company	5 236 042	7 632 122	Interest & financial revenue group account	Income statement
Neptune Energy Finance Ltd (UK)	Associated company	108 433	194 739	Interest & financial cost group account	Income statement
Neptune Energy International SA (Paris)	Parent company	-	1 400 850 000	Dividend paid	Balance sheet

Some of the intercompany transactions are direct recharges and do not have a P&L effect.

Note 9 - Tangible fixed assets

NOK	Assets in Production	Assets under development	Equipment etc.	Capitalised exploration cost	TOTAL
Acquisition cost at 01.01.2020	36 461 208 074	3 599 568 110	648 890 643	219 689 271	40 929 356 098
Acquisitions during the year	3 048 347 429	1 826 674 706	18 325 260	443 623 476	5 336 970 871
Disposal	-24 864 952	0	0		-24 864 952
Impairment/Reversal impairment during the year		0	0	-39 727 319	-39 727 319
Reclassification	477 497	-477 497	0		0
Acquisition cost at 31.12.2020	39 485 168 047	5 425 765 319	667 215 903	623 585 428	46 201 734 697
Less accumulated depreciation at 31.12.2020	-26 515 715 046	-207 196 208	-580 722 837	0	-27 303 634 091
Book value as at 31.12.2020	**12 969 453 001**	**5 218 569 111**	**86 493 066**	**623 585 428**	**18 898 100 606**
Current year depreciation	-1 146 597 523	-146 233 253	-30 611 335		-1 323 442 112

Note 10 - Other provisions and obligation

NOK	2020	2019
Asset retirement obligation	3 874 287 286	3 480 855 750
Other long-term provisions	250 352 196	415 256 903
Other provisions	**4 124 639 481**	**3 896 112 653**

Other long-term provisions

Other long term provisions are mainly related to the Company's net liability related to the Gjøa liability to the Vega licences. This long term debt relates to capex pre-payments from the Vega licences to the Gjøa development project. The Gjøa liability is reduced according to units of production, based on the throughput of hydrocarbons from the Vega licences in the Gjøa processing facility.

Asset retirement obligation

In accordance with the concession terms of the Production licences which the Company holds, the Norwegian State can assume ownership of licence installations without charge when the production ends or when the licence expires. Alternatively the State can require the installations to be removed. In addition to provisions for future abandonment cost, provisions have been made for future costs of plugging and securing production wells. The accretion expense is classified as an operating expense.

	2020	2019
Asset retirement obligations at January 1	3 480 855 749	3 527 825 732
Liabilities incurred / revision in estimates	274 713 377	-147 630 075
Liabilities incurred VNG acquisition	0	0
Accretion expense	118 718 159	100 605 599
Disposal	0	54 493
Asset retirement obligations at December 31	**3 874 287 285**	**3 480 855 749**

Financial assumptions

Years until removal	**1-3 years**	**4-5 years**	**6-10 years**	**11-15 years**	**16-20 years**	**21-25 years**
Discount rate	1,70%	2,20%	2,80%	3,10%	3,30%	3,50%

Assets related to removal and abandonment are also included within tangible fixed assets described in note 9.

Drilling commitments

The Company, together with its licence partners, is committed to taking part in the drilling of wells in accordance with its licence agreements.

Contractual obligations

	2021	Thereafter	Total
Obligations committed NOK	1 932 585 074	388 713 638	2 321 298 712

The contractual obligations are related to the acquisition and construction of assets in licences where the Company has ownership interests.

Operating lease

	2020	2019
Operating lease NOK	27 760 666	34 182 726

Operating lease includes rental of offices and other facilities

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Note 11 - Inter-company balances

Receivables	**31.12.2020**	**31.12.2019**
Trade accounts receivable from inter-company	12 583 968	37 797 140
Short-term receivables from inter-company	501 272 173	1 455 355 289

Liability	**31.12.2020**	**31.12.2019**
Long term loan from inter-company	3 373 000 000	3 373 000 000
Margin Call		-
Trade accounts payables from inter-company	8 128 069	60 061 875

Note 12 - Drilling equipment

Spare parts and drilling equipment are valued at the lower of cost or market value. Cost is estimated using the First In First Out (FIFO) method. Capital spare parts are capitalised and presented in the financial statements together with the investment.

	2020	**2019**
Drilling and well equipment	21 262 972	32 795 501
Total Inventories	**21 262 972**	**32 795 501**

Note 13 - Taxes

Specification of the tax expense for the year:	**2020**	**2019**
Change in deferred tax before adjustment in tax rates	3 207 763 865	501 884 850
Current tax payable	-2 299 225 888	2 894 128 463
Adjustment for tax provision in prior years	-29 131 363	-93 627 721
Total tax expense	**879 406 615**	**3 302 385 592**
Specification of the tax basis for the year:		
Ordinary profit before tax	2 441 333 929	4 834 284 529
Permanent differences	29 028 493	74 139 454
Use of loss carried forward 22%	-202 424 861	-49 991 481
Change in temporary differences	-1 589 209 565	-890 876 553
Basis ordinary income tax	**678 727 997**	**3 967 555 949**
Net financial expenses/income (-) not subject to special petroleum tax	-5 644 453	5 167 017
Income/Loss (-) from onshore activities	-819 923 242	-55 158 498
Use of tax loss carry forward 22%	202 424 861	49 991 481
Extra depreciation temporary tax regime	-3 180 270 288	
Uplift on capitalised expenditures	-1 250 535 729	-362 691 008
Basis special petroleum tax	**-4 375 220 855**	**3 604 864 941**
Tax Payable:		
Basis ordinary income tax		
Loss carried forward - income tax		
Basis ordinary income tax after loss carried forward		
Tax payable - ordinary income tax 22%	149 320 159	872 862 309
Basis special petroleum tax		
Loss carried forward - special petroleum tax		
Uplift carried forward		
Basis special petroleum tax after loss and uplift carried forward		
Tax payable - special petroleum tax 56%	-2 450 123 679	2 018 724 367
Total tax payable	**-2 300 803 519**	**2 891 586 676**
Specification of basis for deferred tax:		
Net differences :		
Fixed assets	12 100 347 838	9 971 967 100
Pension liability	-227 293 630	-210 460 595
Crude oil inventory	0	0
Gain and loss account	14 897 076	20 396 345
Hedging Asset / Liability	-101 076 805	192 129 800
Restructuring cost	-18 898 723	-6 870 062
Over/underlift	287 936 760	392 727 911
Leasing commitment	0	0
Asset retirement obligations	-3 867 835 615	-3 474 404 079
Basis ordinary income tax	**8 188 076 901**	**6 885 486 419**
Limited capitalisation of interest on development projects	-47 757 120	-51 914 028
Gain and loss account	-12 394 556	-15 493 195
Hedging Asset / Liability	101 076 805	-192 129 800
Fixed assets tax values in 56% tax regime	3 180 270 288	
Unused uplift	-443 289 338	-761 919 411
Basis special petroleum tax	**10 965 982 980**	**5 864 029 985**
Deferred Tax Liability:		
Ordinary income tax (22%)	1 801 376 918	1 514 807 012
Special petroleum tax (56%)	6 140 950 469	3 283 856 792
Total deferred tax	**7 942 327 387**	**4 798 663 804**
Tax Payable/ Receivable:		
Ordinary income tax	-2 300 803 519	2 891 586 676
Tax effect of acquisition cost		
Tax effect of group contribution		
Tax paid abroad		
Prior year adjustments	14 891 010	-88 018 669
Appeals OTD		
Tax paid in advance	1 371 930 237	-1 685 108 709
Total tax payable in balance sheet	**137 091 429**	**1 118 459 298**
Total tax receivable in balance sheet	**-1 051 073 702**	
Reconciliation of tax expense and calculated tax expense:		
Ordinary profit before tax	2 441 333 929	4 834 284 529
Marginal tax at 78%	**1 904 240 465**	**3 770 741 933**
Uplift on capitalised expenditures	-521 867 168	-399 786 341
Hedging	-453 732 766	-44 415 994
Permanent differences depreciation §10	9 167 521	21 348 320
Permanent differences goodwill depreciation	53 511 099	53 511 099
Other permanent differences	-88 413 140	-15 349 250
Financial items not subject to special petroleum tax	5 631 966	18 463 198
Adjustments from prior years	-29 131 362	-102 127 373
Tax expense	**879 406 615**	**3 302 385 592**

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Note 14

	Share capital	Share premium reserve	Other equity	TOTAL
Equity at 31.12.2019	141 500 000	1 273 500 000	1 663 406 362	3 078 406 362
Current year net income			1 561 927 314	1 561 927 314
Hedging MTM			-223 562 942	-223 562 942
Pension actuarial valuation			-294 485	-294 485
Dividend 2020			-1 556 500 000	-1 556 500 000
Equity at 31.12.2020	**141 500 000**	**1 273 500 000**	**1 444 976 248**	**2 859 976 248**

Note 15 - Share capital and shareholder information

The share capital of the Company consists of 141 500 shares with a nominal value of NOK 1 000 per share.
All shares are held by the parent company, Neptune Energy Group Holdings Ltd.

The ultimate parent company (Neptune Energy Group Ltd) issues consolidated statements which include Neptune Energy Norge AS. This can be found on www.neptuneenergy.com.

Note 16 - Investment in subsidiaries and associates

The Company has ownership of 10,74% of the shares in Aksello AS, booked value of NOK 188 000
The Company holds a 100% share in Neptune Energy Denmark ApS (former VNG Denmark ApS). The subsidiary has its registered office in Denmark, but is operated by Neptune Energy Norge AS. The shares of Neptune Energy Denmark have a book value of MNOK 66,3.

Note 17 - Reserves (not audited)

According to the reserves information published by the Norwegian Oil Directorate, the Company`s share of remaining reserves at 31.12.2020 are:

	Licence duration	Oil (million Sm3)	Gas (billion Sm3)	NGL (million tonnes)	Condensate (million Sm3)
BAUGE	17.12.2029	1,00	0,22	0,11	0,00
BRAGE	06.04.2030	0,12	0,02	0,01	0,00
BYRDING	09.03.2024	0,04	0,07	0,01	0,00
DRAUGEN	09.03.2024	0,62	0,00	0,00	0,00
DUVA	22.02.2044	1,08	1,91	0,23	0,00
FENJA	04.02.2039	2,42	0,79	0,14	0,00
FRAM	09.03.2024	0,59	1,46	0,17	0,00
FRAM H-NORD	09.03.2024	0,01	0,00	0,00	0,00
GJØA	08.07.2028	0,30	2,12	0,48	0,00
GUDRUN	10.09.2032	2,09	1,84	0,21	0,00
HYME	17.12.2029	0,16	0,07	0,03	0,00
IVAR AASEN	31.12.2036	0,41	0,07	0,01	0,00
NJORD	10.04.2034	1,10	3,08	0,88	0,00
SNØHVIT	01.10.2035	0,00	17,48	0,61	1,75
VEGA	04.06.2035	0,09	0,35	0,10	0,00

Note 18 - Events after the balance sheet date

The Company has signed a Sales- and Purchase Agreement 3rd of June 2021, divesting 100% of the shares in Neptune Energy Denmark ApS to Danoil Exploration A/S. The expected Profit&Loss impact of the sale will not have any material effect on the Company's financial position.

31st of December 2020
4th of June 2021

DocuSigned by:
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James L. House
Chairman of the Board

DocuSigned by:
Harald [illegible]
Board member

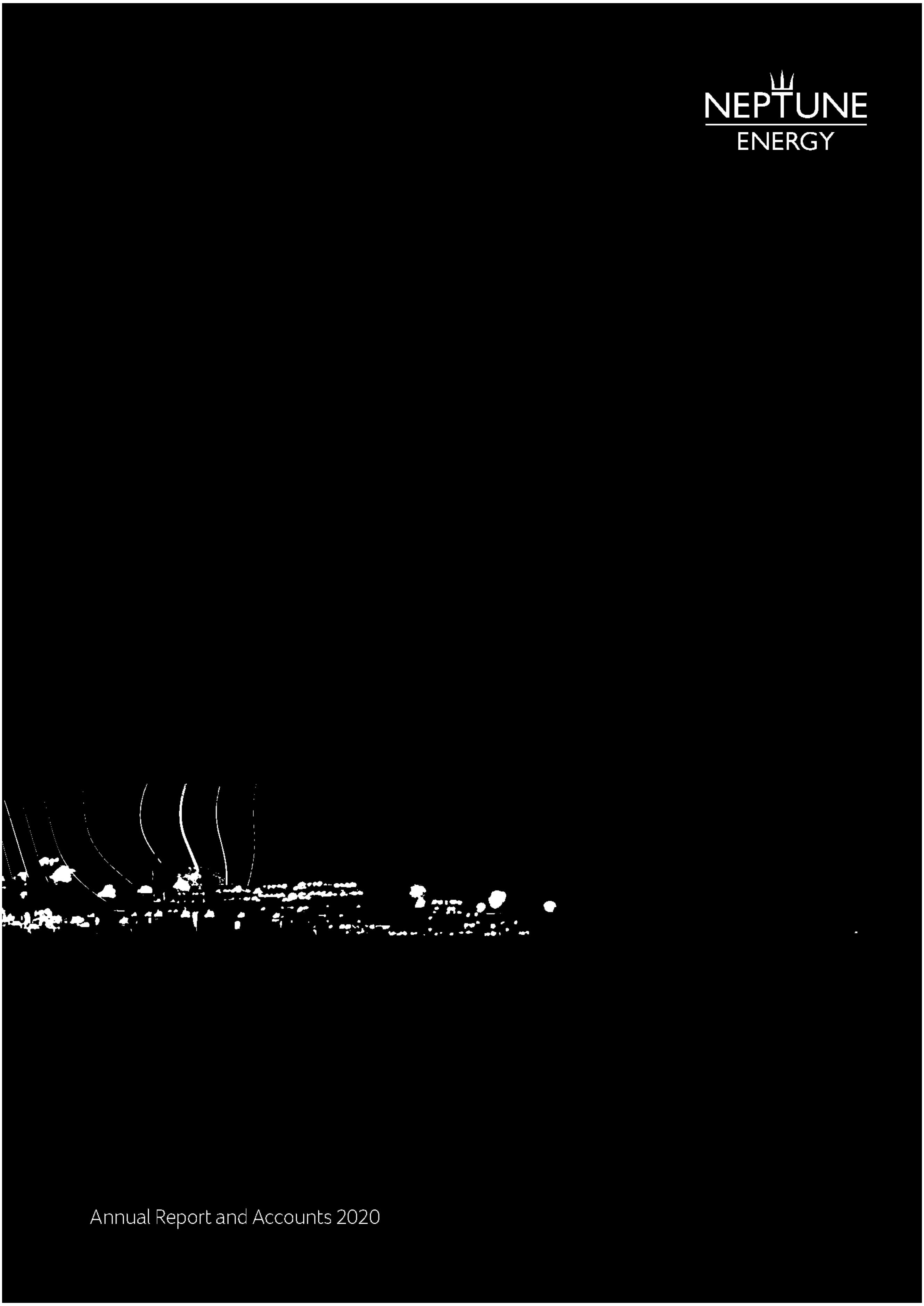
DocuSigned by:
Trond Myklebust
Board member

DocuSigned by:
976D6596CEFF4A4...
Hendrikus Thomas Sterkman
Board member

DocuSigned by:
Rune Haukebøe
Board member

DocuSigned by:
Odin Estensen
Managing Director

DocuSigned by:
Sidsel Margrethe Asheim
Board member



Annual Report and Accounts 2020

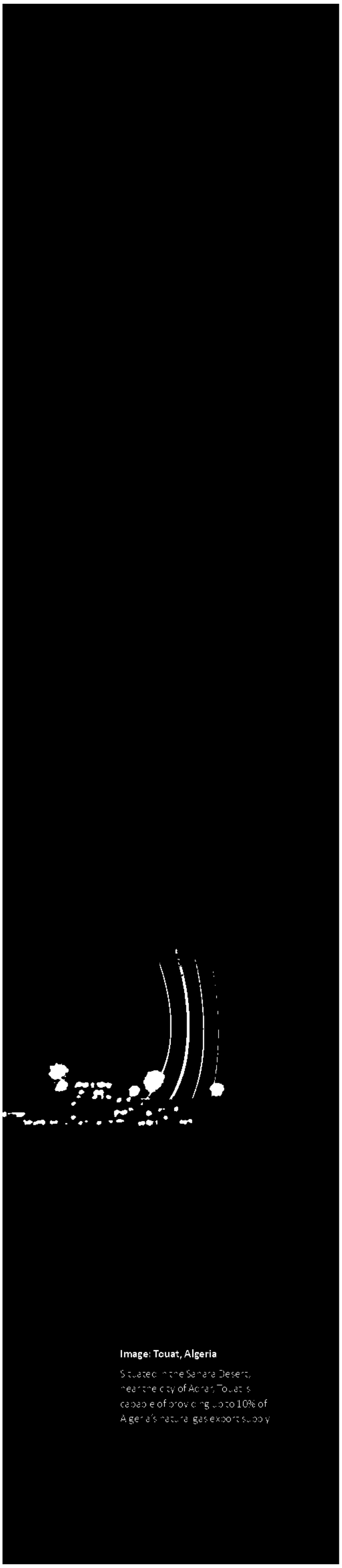


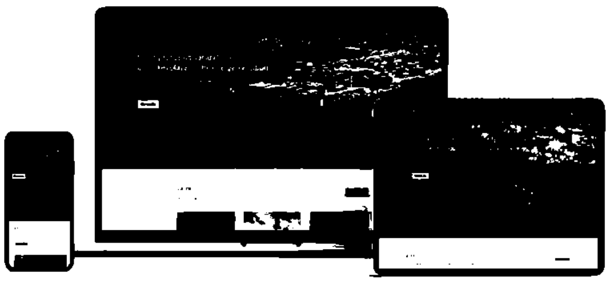
Image: Touat, Algeria

Situated in the Sahara Desert, near the city of Adrar, Touat is capable of providing up to 10% of Algeria's natural gas export supply

Neptune Energy is an independent exploration and production (E&P) company with operations across the North Sea, North Africa and Asia Pacific.

We want to be the leading independent E&P company by meeting society's changing energy needs and creating value for all our stakeholders.

Visit our website at *neptuneenergy.com*



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

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

Photo credits
Page 19 – Forth Estuary Towage and Valaris (rig)
Page 25 – TechnipFMC (Apache II)
Page 27 – Halo Trust

Contents

At a glance

An international gas-focused E&P company, set for growth

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.

We are uniquely positioned for the energy transition and are focused on growing our business safely, sustainably and responsibly.

We have one of the highest gas weightings and lowest carbon and methane intensities in our industry, with a production profile that is 75% gas and 25% oil. We intend to maintain a gas-weighted production portfolio in the years ahead.

We believe gas has a key 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.

Delivering material growth

Resilience and returns

- Continued focus on health and safety
- Low breakeven price, strong cash flows and deleveraging
- Headroom for value-accretive developments

Growth and yield

- Targeting production of around 200 kboepd in 2023
- Targeting 2P reserves of around 800 mmboe
- Contingent resources of 452 mmboe
- Good track record of value-accretive growth

Lower carbon

- Low carbon and methane intensity compared to industry peers
- Carbon capture and storage, green hydrogen and electrification
- Partnerships and investments in new energies

Where we operate

UK
We operate the Cygnus Alpha and Bravo facilities, producing gas from the Cygnus field. Cygnus is capable of supplying around 6% of UK gas production.

Projects
Seagull

Exploration
Isabella

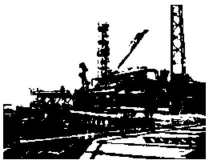
Important discoveries in 2020 provide longer-term, material growth opportunities

Dugong (Norway)

- Estimated recoverable resources between 40-120 mmboe.
- Appraisal drilling in the first quarter of 2021.
- Material upside potential in surrounding acreage, with a further exploration well to be drilled in 2021.
- Located close to existing infrastructure, with the potential to become a new core growth area.

Isabella (UK)

- Material high-pressure high-temperature discovery in the UK Central North Sea.
- Planning progressing for an appraisal well to be drilled in early 2022.
- Appraisal programme to reduce subsurface risks and progress project towards development.
- Potential development options being evaluated.



Norway
We have interests in seven producing fields and operate the Gjøa gas and oil field, which is powered using low carbon hydroelectricity from shore.

Projects
Duva, Fenja, Njord, Bauge

Exploration
Dugong, Echino South, Sigrun East

Netherlands
We are the largest gas producer in the Dutch North Sea. We operate 29 offshore facilities with four major treatment hubs.

New Energy projects
We are participating in PosHYdon, a pilot project to create the world's first offshore green hydrogen production plant and we're also pursuing a major CCS opportunity.

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

Projects
Adorf

Egypt
We have interests in an offshore oil field in the Gulf of Suez, an oil and gas field in the Egyptian desert and an operated exploration licence for the Gulf of Suez.

Indonesia
Working with Eni and other partners, we produce LNG for export to the region and gas for the domestic market to help meet the country's growing energy needs.

Projects
Merakes

Exploration
Maha

Algeria
As part of a joint venture with Sonatrach and ENGIE, we are producing gas from the Touat plant. Work on Phase 2, comprising 16 additional wells to be tied back to the current facility, is planned for 2021.

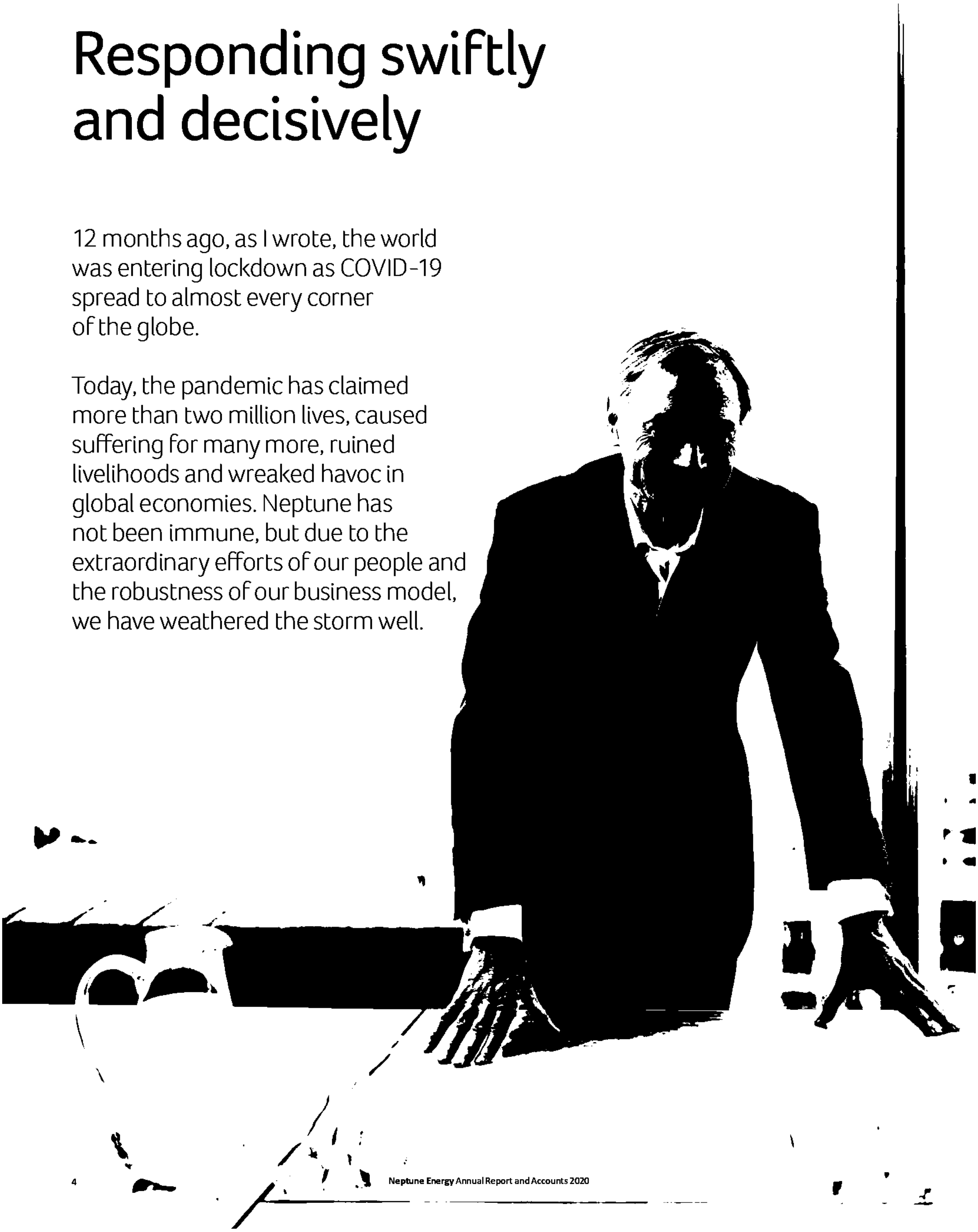
Australia
We are evaluating development concepts for Petrel, a large gas field located in the Timor Sea, which is one of the main gas-producing regions in Australia.

Executive Chairman's message

Responding swiftly and decisively

12 months ago, as I wrote, the world was entering lockdown as COVID-19 spread to almost every corner of the globe.

Today, the pandemic has claimed more than two million lives, caused suffering for many more, ruined livelihoods and wreaked havoc in global economies. Neptune has not been immune, but due to the extraordinary efforts of our people and the robustness of our business model, we have weathered the storm well.



While we enter 2021 with the promise of vaccines, the damage wrought by the pandemic is still being lived by millions and its impacts will be long-lasting.

The pandemic has shone a light not just on what companies do, but how they do it. People will remember those who acted responsibly.

I am proud of the way Neptune responded, swiftly and decisively, to protect our people, our contractors and suppliers, the communities in which we work, our assets and the environment.

But while we entered the period from a position of strength, we were not immune to the effects of the pandemic, which necessitated us taking some difficult decisions about the size and shape of the organisation to ensure that we thrive in a very different future. I am grateful to those who left the business for the role they played in building Neptune's strong foundations.

Resilience
The virus has changed the way we live, work and communicate. Lockdowns resulted in vast swathes of the world's cities being deserted, with remote and flexible working becoming commonplace for many.

While office workers swapped their takeaway coffees for home-made ones, it was frontline workers and small businesses that shouldered the greatest impact. Our employees and contractors continued to keep essential supplies of energy flowing safely in very challenging conditions around the world to meet the vital needs of our customers.

For the energy sector, the sharp decline in demand in the second quarter, caused by economic slowdown and travel restrictions, on top of an OPEC+ induced increase in supply in March, led to a sudden and severe fall in commodity prices.

Oil demand was hit particularly badly but started to recover in the fourth quarter, notably in Asia, due to the production cuts agreed by OPEC+ members and early signs of economic recovery. Oil prices ended 2020 above $50 per barrel and prices for natural gas ended the year at higher levels than the previous winter.

Our business model is to be a low-cost gas producer, well-positioned for the energy transition with long-life assets supporting strong free cash flow. When the pandemic struck, we were quick to respond, deferring capital expenditure where possible, reducing operating costs further, focusing on 'value over volume' and better targeting our exploration programme. We also pre-emptively strengthened our balance sheet further and improved our liquidity to some $1.3 billion at year end.

The Neptune that emerges is safer, faster and better. As we progress through 2021, we are a more resilient business, generating free cash flow at all points of the commodity cycle. Our strong portfolio of good exploration discoveries, together with a pipeline of near-term opportunities, provide strong earnings and cash flow growth potential for the future.

Our geographically diverse portfolio affords us both protection and optionality. It provides access to different markets and commodity prices, which helps de-risk our earnings exposure. At the same time, it provides competition for capital within the Group as we high grade investment opportunities in Europe, North Africa and Asia Pacific.

New Energy
The carbon intensity of our operated production is less than a third of the industry average. This positions us well for the energy transition, as we take further steps with the introduction of our New Energy team to scale partnerships and investments in lower carbon developments.

While the global financial crisis that began in 2007 threw the world off its low carbon path temporarily as affordability took precedence, the financial impact of the COVID-19 pandemic is likely to have a very different effect.

As governments seek ways to inject economies with fiscal stimulus, environmental and social considerations will be central for many. Fresh impetus is likely to be created by COP26 and with providers of both equity and debt capital placing a greater emphasis on sustainability.

I believe this is a strategic opportunity for Neptune. Our lower carbon portfolio and ambitious carbon and methane intensity reduction targets are the foundation from which to progress opportunities with carbon capture and storage, hydrogen and electrification.

Gas, produced efficiently, remains a key element of the energy transition – particularly in the switch away from coal-fired power. Our heavily gas-weighted portfolio, coupled with our exposure to LNG, positions us well.

However, if the world is to meet ever-more ambitious climate change targets, investors will need a great deal more certainty than they have now. That means energy policy and financial support mechanisms must work in lockstep. In some countries, while policy has been supportive, costs have remained prohibitive. In others, the reverse has been true.

Hydrogen and carbon capture and storage, both areas we are pursuing, are good examples of this. Both technologies can potentially make a very significant contribution to a low carbon energy world. As such, policy makers have brought forward ambitious targets and are considering enabling policy.

The challenge is that both technologies are prohibitively expensive without support mechanisms or other fiscal incentives. Such incentives have served their purpose in reducing the cost of renewable energy production. For carbon capture and storage to happen at scale and for the hydrogen dream to become a reality, governments need to show the same kind of bold thinking they did with renewables. Only then will costs come down and projects move forward.

Responsibility
The Board recognises Neptune's responsibility lies beyond just its provision of energy. We have a broader responsibility to our people, our partners, our host communities, our investors and the environment.

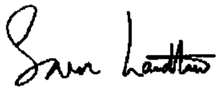
I am indebted to all our people and their families who supported them. The pandemic asked a lot of each and every one of them, both personally and professionally.

They showed dedication, passion and professionalism in dealing with it. Their resilience and Neptune's are inextricably linked.

It is a testament to our culture and the values of our people that we were able to support our communities when they most needed it – above and beyond our socio-economic impact. And I am confident our commitment to mental health and youth employment will make a positive difference as the full impacts of the pandemic emerge.

I closed last year's letter by writing that the challenges we faced may well be greater than those we had overcome. And so it proved. But Neptune emerged more resilient – and set for the next chapter of growth.

Sincerely,



Sam Laidlaw
Executive Chairman
10 March 2021

Chief Executive Officer's message

A resilient business set for growth

Typically in my letters to you, I speak about our strategy, performance and plans. While I will cover these key elements, I will do so this year through the lens of the unprecedented challenges we all faced over the past 12 months.

We entered 2020 with a resilient balance sheet and portfolio – and it was these factors that served us especially well, as we faced softer demand and weaker commodity prices.

Neptune's strength is truly a product of the resilience of our people. 2020 threw a lot at them, as well as society as a whole. While most office-based colleagues had to adapt to working from home and balancing work commitments while looking after their families, those who work at offshore or onshore locations had to contend with different work patterns, travel restrictions and new social distancing procedures.

Their dedication and ability to adapt to the changing environment are to their great credit, and I am immensely grateful to them all.

I am also proud of the lengths they went to in supporting the communities in which we work, giving freely and generously of their time and skills, while providing much-needed resources.

Neptune's people truly lived our values and demonstrated their alignment with our purpose, to be the leading independent E&P company by [illegible]eeting society's changing energy needs and [illegible]eating value for all our stakeholders.

De[illegible]ring the strategy, generating value
We [illegible] a unique combination of people,
po[illegible], partnerships and technologies
tha[illegible] apart and supports how we
[illegible] for our stakeholders.

[illegible] commodity prices and the
[illegible] COVID-19 have led to organisational
[illegible] business, our internal reviews
[illegible]idated our core strengths
[illegible]ness of our strategy.

[illegible] underpin our resilience,
[illegible]tion and growth potential.
[illegible]ne's differentiated portfolio
[illegible]rate value, even in a lower
[illegible] with an asset base that is:

- [illegible] geographically diverse.
- [illegible]st and lower carbon.
- [illegible]nd well-positioned to drive [illegible]rgy transition.

[illegible]ers strong returns through:

- [illegible] flow generation and strong [illegible]eet.
- [illegible]ed and focused capital allocation.
- [illegible] free cash flow.

Th[illegible] pillars are the foundation upon wh[illegible]eptune has been built. While the ind[illegible]try faced unexpected headwinds in 2020, ou[illegible]trategy proved to be resilient and will un[illegible]rpin the next chapter of our business.

Growth in reserves and production is central to this strategy, and our goal to build a business with potential for around 800 mmboe of 2P reserves and 200 kboepd of production remains on target.

These objectives are supported by a strong balance sheet, healthy project pipeline and development options across our portfolio.

M&A also remains an important element of our strategy, but with an emphasis on production and reserves rather than undeveloped resources.

In addition, we are taking further steps to support the transition to a lower carbon world through the creation of a New Energy team, which has already identified potential developments in hydrogen, carbon capture and storage, and electrification.

These will support our carbon intensity reduction targets and extend the life of valuable infrastructure, but they require the right governmental support and fiscal and regulatory frameworks to support larger-scale investments.

A better business, a fairer society
The foundation of our business is excellence in health and safety – it is non-negotiable. While I am encouraged by the progress we have made on our total recordable injury rate, particularly given the challenging conditions we faced, we know we must all guard against complacency and maintain a 'chronic sense of unease' with regard to health and safety.

We were quick to enact our pandemic emergency plan and also put in place measures to support those working both offshore and onshore, as infections started to propagate globally. This included launching a health and wellbeing portal and a dedicated Employee Assistance Programme.

With a large number of our people working from home, we had to adapt quickly. Underpinned by strong technology platforms, we increased communication at both a group and country level through townhalls, extended leadership team meetings, strategy sessions and an enhanced intranet portal.

In June, we made the difficult, but necessary, decision to reduce the size of the organisation by 400 roles, as we sought to drive greater efficiency. Acknowledging the impact on those affected, we put in place comprehensive outplacement support and engaged with all our colleagues to ensure a smooth and respectful transition.

2020 will not only be remembered for the COVID-19 pandemic, but also a year that forced society to confront social inequalities. Neptune has both a role to play and a responsibility to act to create a fairer society and work environment.

We encouraged our people to speak up to share their thoughts on how we can all help shape and support a more equal, diverse and inclusive (ED&I) working environment. As a result, we appointed Andrea Guerra, our VP of Subsurface, as our ED&I executive sponsor and developed an ED&I charter, which details the actions we will undertake in each of our countries.

Mental health and youth unemployment are significant issues that affect the wider communities in which we operate, as well as our own employees and their families. COVID-19 has led to a surge in both – and this impact will have a lasting effect.

Companies can play an important role in addressing these two issues. Our work with Mental Health UK and Movement to Work is our first step and we are exploring opportunities for similar collaborations across Europe, North Africa and Asia Pacific.

Robust performance, positioned for growth
Despite the impacts of the pandemic and the softer commodity price environment, Neptune's operational and financial performance in 2020 was robust.

Our swift action to reduce costs, defer capital expenditure and optimise work plans protected our balance sheet and ensured operational continuity.

While our production volume in 2020 was affected by unplanned outages at non-operated assets in Norway and Algeria, our operated production performed well, with high levels of production efficiency.

New projects coming online in Norway and Indonesia during 2021, coupled with the resumption in production from Snøhvit and Touat, will result in significantly higher volumes at the end of the year. Further out, additional organic production from new projects in Norway and the UK will take us close to 200 kboepd in 2023, delivering material growth from our low-cost, lower carbon portfolio.

During 2020, we made significant discoveries at Dugong in Norway and Isabella in the UK, with other additional successes in Norway and north-western Germany. Together, these will enhance future cash flow and provide longer-term growth opportunities as we focus our exploration programme on the most value-enhancing prospects.

The diversity of our portfolio, balanced commodity price exposure and active hedging programme helped de-risk Neptune's revenue streams in 2020 against volatile prices, while, in concert, we took the opportunity to increase liquidity. This will provide additional headroom to support value-accretive acquisitions and growth opportunities as they arise.

As a result, Neptune heads into 2021 safer, faster and better – with growth opportunities that will deliver long-term value to all our stakeholders.

Sincerely,

James L House
Chief Executive Officer
10 March 2021

The global context

A diverse mix is key to meeting society's changing energy needs

2020 was a year unlike any other. Efforts to halt the spread of the COVID-19 virus – in the absence of a vaccine – left already volatile financial and commodity markets in an almost constant state of turmoil. The energy sector was hit particularly hard, but commodity prices began to improve by the end of the year, with gas prices ending at higher levels than the previous winter.

Lockdown measures and travel restrictions saw demand for oil and oil-based products – particularly jet fuel – tumble to its lowest level in 25 years.

At the same time, the collapse in talks between OPEC+ in March flooded an already weak market, putting pressure on global storage capacity and pushing Brent crude prices to their lowest level since 1991.

Production cuts agreed by OPEC+ members helped oil prices recover somewhat during 2020, with oil prices ending 2020 above $50 a barrel.

Natural gas prices remained more resilient than oil overall, due, in part, to its essential role in power generation and home heating.

Even before the pandemic, the market for liquefied natural gas (LNG) was set for oversupply in 2020, with many LNG projects coming online in the past five years and a record number of new liquefaction facilities given the go-ahead in 2019. Reduced demand brought on by the pandemic added to excess supply in 2020, and no new LNG projects were given the green light.

Promising news of COVID-19 vaccines buoyed markets towards the end of the year. 2021 will likely see a return to growth, with crude oil and gas prices already increasing steadily at the start of the year. In January 2021, Brent crude hit an 11-month high, fuelled partly by tighter supply figures and expectations of a drop in US inventories.

Gas prices, too, traded at their highest rate in more than a year in January 2021. Some of that could be attributed to a relatively low inventory of gas and a cold winter, with more people using heating in their homes, as well as very tight power generation markets. Asian gas prices, in particular, climbed to new highs, as a result of lower storage levels and strong demand for LNG, due to cold weather systems. The lack of new LNG projects sanctioned in recent months coupled with increasing demand for LNG is likely to result in a tightening of the LNG market in the next few years.

As for oil, the ongoing OPEC+ accord, primarily between Russia and Saudi Arabia, to maintain oil production curtailments has also helped shore up confidence of longer-term market recovery.

Energy demand
The COVID-19 pandemic has had a profound impact on the global energy system and the supply chains that support it. Only the World Wars and the Great Depression triggered a larger decline in energy demand in the past century.

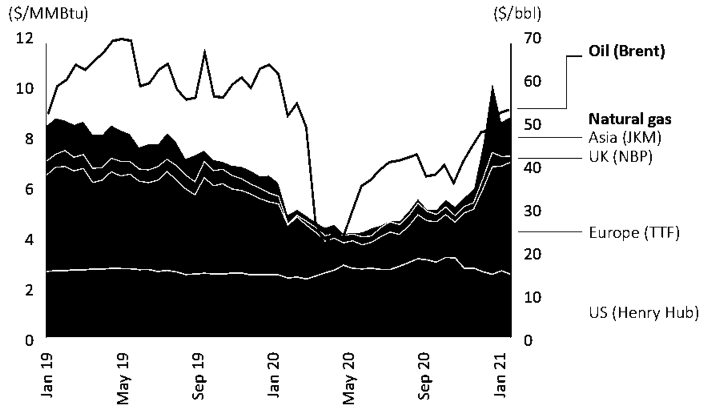
Oil consumption decreased around 9% in 2020, and natural gas demand almost 3%. Global LNG imports grew 3%, due in large part to Asia's recovery from the pandemic.

The change in energy demand resulted in greatly reduced activity levels for exploration and production (E&P), with global E&P investments decreasing around 30-40% compared with 2019.

Rystad analysis suggests that around 20% of planned investment in E&P in 2021 could be at risk of deferral or reduction. However, investments could recover to the pre-crisis level of $530 billion by 2023 if oil prices rise to around $65 per barrel.

As such, expectations across the global energy industry regarding future prices remain cautious. Oil and gas resources that are low-cost, lower carbon, accessible and efficient will be key to future success.

Oil and gas prices 2019-2021



Emissions and the energy transition
Energy-related carbon dioxide emissions fell 7% in 2020, taking annual CO_2 emissions back to a level not seen in a decade, according to the IEA. Methane emissions from oil and gas production dropped 10%, mainly due to lower production. The post-pandemic rebound of emissions is expected to be slower than after the financial crisis in 2010, with many governments developing sustainable recovery plans. However, the reductions achieved in 2020 are unlikely to break the overall upward trend post-pandemic.

Access to energy is key to recovery plans, with energy demand a critical driver in supporting economic growth. IEA analysis suggests that rising poverty levels pushed the number of people without access to electricity up for the first time since 2013. Alongside this, worldwide, countries making up almost half of global GDP, including China, now have commitments in place or policies aligned with achieving net zero emissions.

As countries progress towards meeting climate goals, it is expected that carbon prices will increase.

Research indicates that the European Commission's target to reduce net EU greenhouse gas emissions by at least 55% by 2030 (compared with 1990 levels) could push the average carbon price above €50/tonne.

Energy outlook
While the IEA projects that the era of growth in energy demand will come to an end within 10 years and then flatten out during the 2030s, even under its most ambitious climate scenario, oil and gas will provide 46% of global energy needs in 2040, with gas becoming increasingly important.

With oil and gas being part of a diverse energy mix in future demand scenarios, substantial investment will be required, partly due to declining production in existing fields.

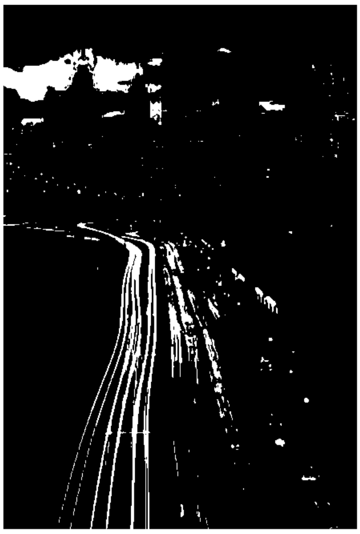
The IEA estimates that under the Sustainable Development Scenario (SDS), almost $68 trillion in total energy investment will be needed in the next 20 years. Indeed, Rystad analysis in January 2021 suggests that without an acceleration in exploration programmes and a $3 trillion capital injection, there is a risk that global oil supply may fail to match demand over the next 30 years, as some 139 billion new barrels would need to be discovered and developed by 2050.

Investment in lower carbon oil and gas production will be essential to meet both energy demand and climate targets, with the sector able to use its skills and experience to help decarbonise industries that are unable to meet climate change targets through electricity alone.

Getting to net zero will require a major transformation in how energy is produced and used. Electrification, hydrogen and carbon capture, use and storage (CCUS), will play a vital role in emissions reductions. In fact, the IEA states that reaching net zero will be impossible without CCUS, which can contribute both to reducing emissions in industry and to removing CO_2 to balance emissions that cannot be avoided. In the IEA's SDS, around 430 Mt CO_2 of energy-related and industrial process emissions are captured in the industry sector in 2030.

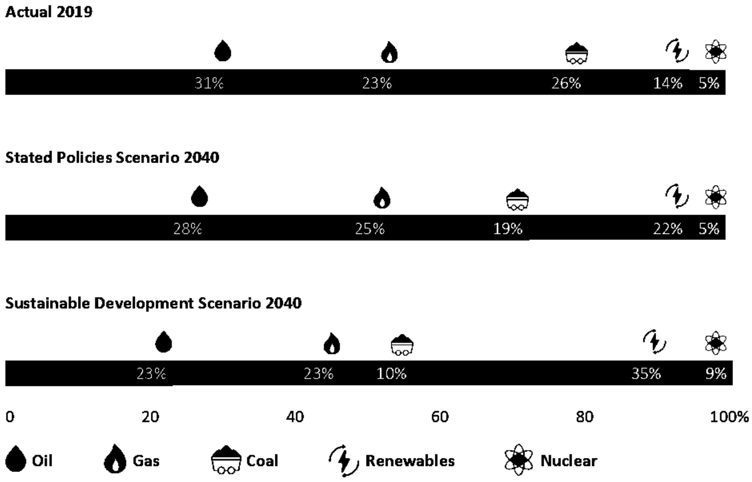
While electrification and CCUS are central to emissions reduction efforts, low carbon fuels such as hydrogen are also needed. The ability to produce hydrogen via wind-generated electricity and ease of transportation via existing infrastructure potentially make it a significant contributor to a lower carbon world.

Cost challenges will need to be overcome for both CCUS and hydrogen, and can only progress at the scale and speed needed with government support and a clear regulatory framework.



Energy consumption – 2040 scenarios

The IEA's *World Energy Outlook 2020* examines the effects of the pandemic and explores different pathways out of the crisis, including the Stated Policies and Sustainable Development Scenarios.



Stated Policies Scenario
The global economy returns to pre-pandemic levels in 2021 as the virus is brought under control.

Sustainable Development Scenario
Clean energy policy and development surges, placing the energy system on track to achieve sustainable energy objectives in full, including the Paris Agreement goals.

Our business model and strategy

Creating value for all our stakeholders

We work with our partners as an operator and a licensee to deliver energy where and when it is needed. We are focused on creating value by optimising operational efficiency, increasing productive capacity and growing our international presence.

Our goal is to build a business with potential for around 800 mmboe of 2P [illegible] and 200 kb[illegible]

Be the leading independent E&P company by meeting society's changing energy needs and creating value for all our stakeholders.

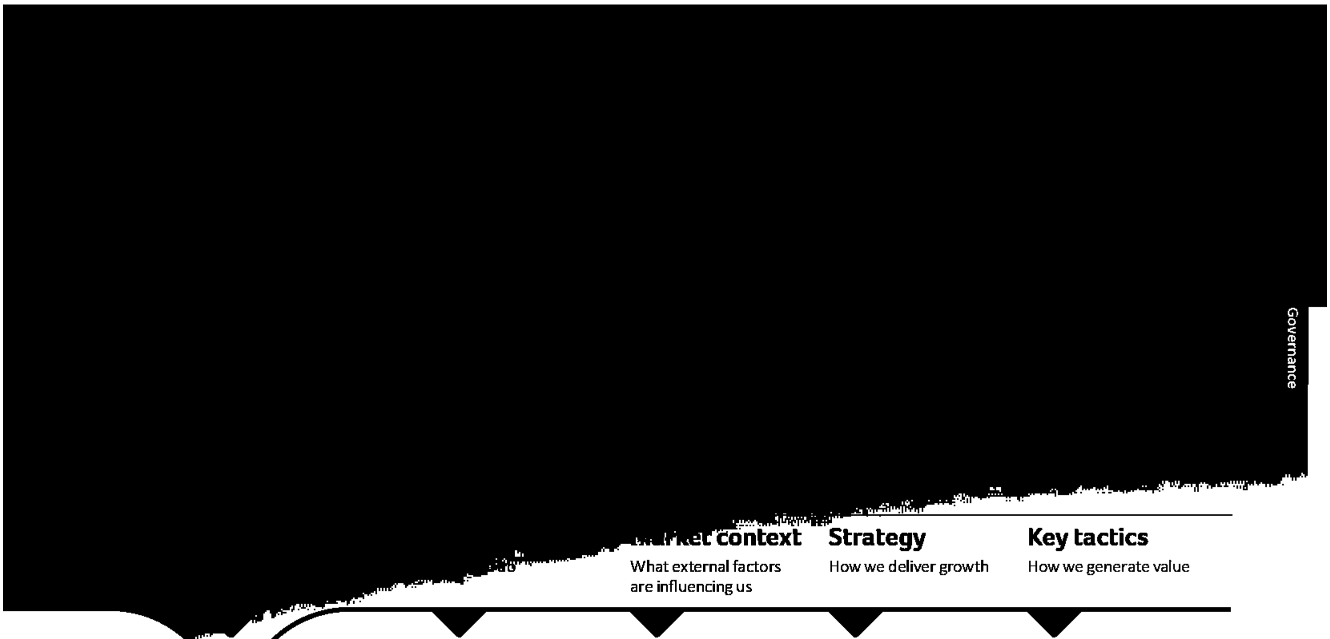
A differentiated portfolio...

- Large scale and geographically diverse
- Long life, low cost and lower carbon
- Gas-weighted and well-positioned to drive low carbon energy transition

...that delivers strong returns

- Significant cash flow generation and strong balance sheet
- Disciplined and focused capital allocation
- Growing free cash flow

The Neptune Way –



People
We have more than 1,400 people in Europe, North Africa and Asia Pacific and an entrepreneurial and innovative culture.

Portfolio
We have a geographically diverse portfolio which is long life, low cost and lower carbon.

Partnerships
We have strong relationships with our partners and host countries, which maximise value for local economies and societies.

Technology
We use technology to produce energy safely and efficiently.

	ket context What external factors are influencing us
Explore Focus exploration on shorter-term, material value-creating prospects, targeted around existing infrastructure	Economic recovery is unlikely to be smooth or predictable, which means greater volatility in commodity markets.
Develop Develop fields at pace, preferably as operator, with innovative low-cost solutions	Carbon will be priced in the global economy, advantaging gas over other fossil fuels and putting ever greater value on hydrogen and carbon capture and storage.
Produce Produce fields safely and efficiently to maximise recovery, lower unit costs and reduce carbon intensity	Shift in emphasis from stakeholders from what companies do, to how they do it, with ESG performance becoming a reason to choose, rather than refuse.

Strategy How we deliver growth	**Key tactics** How we generate value
Large scale and geographically diverse	• Focus on Europe, North Africa and Asia Pacific • Diversified revenue from gas, oil and LNG
Long life, low cost and lower carbon	• Maintain reserves to production ratio of >10 years • Target operating costs of ~$9/boe
Gas-weighted and well-positioned to drive low carbon energy transition	• Maintain ~70/30 gas/oil production mix • Target 6 kg CO_2/boe and net zero CH_4 by 2030 • Pursue New Energy opportunities
Significant cash flow generation and strong balance sheet	• Grow EBITDAX to >$2 billion by 2023 • Maintain net debt/EBITDAX <1.5x through the cycle
Disciplined and focused capital allocation	• Maintain excellent liquidity • Improve credit and ESG ratings
Growing free cash flow	• Demonstrate a track record of free cash flow generation • Deliver consistent yield and growth in shareholder value

Environmental, social and governance

Embedding ESG into our business

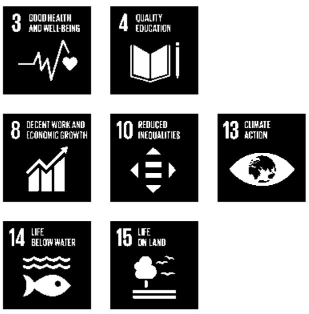
During 2020, we made good progress in delivering our ESG strategy, which is key to our ability to create value for all our stakeholders.

As a result of the COVID-19 pandemic, there was a marked global shift in emphasis from society on the importance of the role of companies in supporting their people, suppliers and local communities. The social inequalities highlighted by the pandemic, as well as the Black Lives Matter movement, have also led to a greater focus on equality, diversity and inclusion and organisational culture.

Our ESG Committee, which oversees our approach to ESG and ensures alignment with our business strategy, reviewed our ESG strategy and action plan in light of the changing global context and approved our three-year roadmap. See page 65 for more information.

See *neptuneenergy.com/esg* for our full performance data.

UN Sustainable Development Goals
We support the UN Sustainable Development Goals (SDGs), which aim to address global challenges such as poverty, inequality and climate change. We have incorporated the goals into our ESG strategy. The SDGs we have selected are those where we can make the most significant contribution, either through our core business or through our social investment initiatives.



ESG roadmap

We developed our three-year ESG roadmap in 2020, which sets out the actions we will take to deliver material growth in a safe, sustainable and responsible way. We'll review these actions regularly, taking account of portfolio changes, societal expectations, technological advances and other factors.

Our ESG strategy

Assessing our material issues

To identify and assess the ESG issues that have the greatest impact on our business and are of greatest concern for our stakeholders, we conduct a materiality assessment.

We engage with a range of internal and external stakeholders, including investors, NGOs, partners and governmental representatives to assess our key issues.

We also examine topics in their broader context by analysing existing and upcoming regulation, investor feedback and sustainability frameworks, such as the UN SDGs and the Task Force on Climate-related Financial Disclosures.

We then prioritise the issues according to the impact on our business and the level of stakeholder concern.

Issues that are included in our ESG strategy are those that we have assessed as being of high importance in terms of business impact and stakeholder concern.

Overall, our key issues in 2020 remained consistent with those in 2019. Social issues, however, gained greater prominence in 2020. As a result, we've further progressed the actions we are taking to support local communities and to advance an equal, diverse and inclusive working environment.

Our material issues	Alignment to SDGs
Environmental	
Climate change and our role in a lower carbon energy world	13
Environmental impacts	14, 15
Social	
Health and safety	3
Economic impact	8
Community investment	3, 4, 8, 10
Our people	3, 8, 10
Governance	
Corporate governance	
Ethical conduct	8
Human rights	3, 8, 10, 13, 14, 15

2019
Developing our ESG strategy
- Carbon and methane intensity targets
- UN Sustainable Development Goals
- Economic impact in operating countries

2020
Embedding ESG into our business
- Task Force on Climate-related Financial Disclosures (TCFD)
- Social purpose
- Equality, diversity and inclusion

2021
Integrating ESG into our supply chain
- Equity share emissions
- Human rights assessment
- Economic impact in non-operating countries

2022
Demonstrating track record
- All operated assets certified to ISO 14001, 50001 and 45001
- Top quartile ESG rating
- Supplier audits

What we said we would do	What we did	What we will do next
Maintain our gas-weighted production portfolio.	We maintained a gas-weighted production profile, at 75% gas and 25% oil. The percentage of gas in our 2P reserves is 72%.	We will continue our focus on being a low-cost gas producer, including when we consider M&A transactions, positioning us well for the energy transition.
Set ambitious carbon and methane intensity targets for our managed operations.	We set a carbon intensity target of 6 kg CO_2/boe and a net zero methane emissions target by 2030. In 2020, our carbon intensity remained modest at 6.3 kg CO_2/boe and our methane intensity decreased to 0.01%. See page 19.	We will develop emissions reductions plans in each of our operated countries in 2021 that will detail how we plan to meet our 2030 targets. We will work with our partners to calculate our equity share emissions and plan to report these in 2021.
Use an internal carbon price for investment decisions.	We incorporated an internal carbon price into our investment decisions. We began adopting the TCFD recommendations. See page 18.	We will evolve our TCFD reporting and conduct analysis to test the resilience of our portfolio under different scenarios.
Apply new technologies to reduce our carbon footprint.	We continued to progress our PosHYdon green hydrogen project. See page 18. We initiated a feasibility study into plans for a large-scale offshore carbon capture and storage (CCS) project in the Dutch North Sea. See page 18. We began a joint science project with the Environmental Defense Fund and The Carlyle Group to improve the accuracy of reporting methane emissions. See page 20.	We will scale-up our partnerships and investments in low carbon technologies, particularly hydrogen, CCS and electrification, via our recently established New Energy team.
Implement our environmental policy, which sets out how we manage issues including biodiversity, water and waste.	We developed environmental standards for our key environmental topics. See page 20.	We will develop biodiversity and water management plans and initiate ISO 14001 certification for our operated sites.
Aim for top quartile safety performance among peers in our operated regions.	We achieved our lowest total recordable injury rate in 2020 since Neptune's formation. We remain focused on embedding a strong safety culture. See page 16.	We will commence ISO 45001 occupational health and safety certification for our operated sites.
Measure our contribution to society via quantitative analysis of our direct and indirect impacts.	Our total gross value added contribution to the GDPs of our European operations was $2.1bn. See page 27.	We will initiate economic impact analysis in countries where we participate in non-operating joint ventures.
Focus our community investment on activities that are aligned with local needs and our business activities.	We integrated our social investment standard, which aligns our community investment with the SDGs, into our management system. We committed to support mental health and youth employment across our countries of operation. See page 26.	We will work with partners across our regions to drive support for our focus areas.
Be the employer of choice by promoting a diverse and inclusive culture.	We developed our equality, diversity and inclusion charter (ED&I). See page 23.	We will develop ED&I action plans for each of the countries where we work. We will also conduct gender and ethnic pay gap assessments.
Adopt the Wates Principles to enhance our corporate governance practices.	We continued our adherence to the Wates Principles. We also elected two new directors to the Board. See page 60.	We will continue to update our internal controls, including a review of our delegation of authority policy and terms of reference for our Investment Committee.
Conduct our business with the highest degree of ethics and integrity.	We introduced a new whistleblower channel through which our staff can report any concerns. See page 66.	We will complete an internal audit of the global ethics and compliance function.
Work with our suppliers and partners to manage potential human rights risks in our business and supply chain.	We developed a sustainable procurement action plan that integrates environmental and social considerations into supplier selection and assessments.	We will commission an external organisation to assess our business and supply chain using the UN Guiding Principles on Business and Human Rights.

Our key performance indicators

Measuring our progress

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

Operational

Production (kboepd) ⊘

Production is the volume of oil, gas and other natural gas liquids produced at Neptune's operations, including equity-accounted entities. Production is measured on an oil equivalent basis and shown as an average rate per day.

2020	142.4
2019	143.9
2018	161.8

☐ 143.8 kboepd including production-equivalent insurance receipts.

Total Group production reflected a reduction in planned activity due to COVID-19 restrictions, our cost reduction plan, weak gas demand in Asia and extended unplanned shutdowns at Snøhvit and Touat.

Production efficiency (%)

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

2020	81
2019	85
2018	88

Production efficiency at our operated assets was broadly in line with our performance in 2019. We are taking steps to improve production efficiency across our portfolio and targeting opportunities where we can best influence performance to deliver value over volume.

ESG

Total recordable injury rate ⊘

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

2020	1.4
2019	2.1
2018	2.6

In 2020, we achieved the lowest TRIR since Neptune's formation, which reflects our continuous efforts to improve safety. We remain focused on embedding a strong safety culture throughout our business.

Process safety event rate ⊘

We introduced PSER as a key performance indicator in 2019. This measures the number of process safety events (PSE) per one million hours worked.

2020	2.37
2019	2.19
2018	Not reported

In 2020, we had no tier 1 PSEs, which are losses of primary containment with the greatest consequence. We saw a slight deterioration in our PSER, with 27 out of 29 events in the tier 3 category. These are considered 'leading' indicators that help us prevent the more severe tier 1 and 2 events from occurring.

Financial

Opex ($/boe) ⊘

This is the average operating cost per barrel of oil equivalent produced.

2020	9.5
2019	10.3
2018	10.2

Operating costs in 2020 decreased slightly reflecting cost reduction measures, including some deferred maintenance activity.

Operating cash flow ($m) ⊘

This includes cash flow from operations, after tax and excluding acquisition costs incurred in connection with the EPI and VNG Norge transactions.

2020	915
2019	1,321
2018	1,219

Operating cash flow was resilient in 2020, as lower commodity prices were partially offset by hedging gains, lower operating costs and net cash tax refunds.

Key

⊘ Measures used in our performance scorecards for the Executive Team and all employees. We plan to incorporate an environmental metric into scorecards in 2021.

See **page 28** for more information on our operating performance.

2P reserves and 2C resources (mmboe)

Our 2P reserves is the best estimate of proved plus probable reserves. 2C resources is the best estimate of contingent resources and includes projects within the development pending, on hold and unclarified categories. See page 126 for an explanation of the inherent uncertainties surrounding 2C resources reporting.

	2P reserves	2C resources	Total
2020	**601**	**452**	**1,053**
2019	633	302	935
2018	638	244	882

■ 2P reserves.
□ 2C resources.

Over a three-year period, which reflects our current project cycles, our reserves replacement ratio was 128%. We also have significant contingent resources and continue to mature these opportunities for future development. 2P reserves includes 13 mmboe acquired as part of the Wintershall Dea transaction announced on 19 February 2021.

Reserves to production ratio (years)

This includes our 2P reserves to production ratio.

2020	**12**
2019	12
2018	11

We maintained a reserves to production life of 12 years in 2020.

See **page 12** for more information on our ESG performance.

Carbon intensity (kg CO_2/boe)

This includes Scope 1 and 2 emissions from our managed operations. This includes Germany, the Netherlands, Norway and the UK.

2020	**6.3**
2019	5.8
2018	6.0

● IOGP industry average was 17 kg CO_2/boe.

In 2020, our carbon intensity was slightly lower than expected due to the deferral of a compression project at one of our sites. We remain on track to meet our carbon intensity target of 6 kg CO_2/boe by 2030.

Methane intensity (%)

This refers to methane emissions as a percentage of gas exported from our managed operations. This includes Germany, the Netherlands, Norway and the UK.

2020	**0.01**
2019	0.02
2018	0.01

● OGCI industry average was 0.23%.

We continue to have one of the lowest intensities in the sector and to maintain our focus have set a target of net zero methane emissions by 2030. The decrease in 2020 was due primarily to methodology changes in Germany, which has improved the accuracy of our reporting.

Economic impact ($bn)

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

2020	2.1
2019	2.8
2018	2.6

Our total economic impact was slightly lower in 2020 than previous years, given the deferral of some capital programmes.

See **page 46** for more information on our financial performance.

Capex ($m)

This includes development capex, including equity-accounted entities.

2020	**741**
2019	887
2018	517

We reduced our investment in development capex in 2020 as we responded to the challenges of COVID-19 and revised our project schedules.

EBITDAX ($m)

This comprises net income for the period before income tax expense, financial expenses, financial income, impairment losses, other operating gains and losses, exploration expense and depreciation and amortisation. EBITDAX, as defined by the RBL, excludes our share of net income from Touat prior to 2020.

2020	**940**
2019	1,600
2018	1,883

Despite materially lower commodity prices, EBITDAX was resilient reflecting our diversified production, realised hedging gains and lower operating costs.

Net debt to EBITDAX (x)

This includes net debt (excluding Subordinated Neptune Energy Group Limited Loan) to EBITDAX, as defined by the reserve based lending (RBL) facility and shareholders agreement.

2020	**1.94**
2019	0.93
2018	0.62

Our leverage ratio increased reflecting repayment of the Touat Vendor Loan and lower EBITDAX. EBITDAX declined due to lower average commodity prices in 2020.

A strong safety culture is the foundation of our business

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.

Find out how we supported our people during the COVID-19 pandemic on **page 22.**

Discover more on how we manage our environmental impacts on **page 20.**

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. See page 52 for more information on risk management.

Employees and contractors must follow the International Association of Oil & Gas Producers' (IOGP) nine life-saving rules. These rules help protect our people against the most common causes of fatal incidents in our industry.

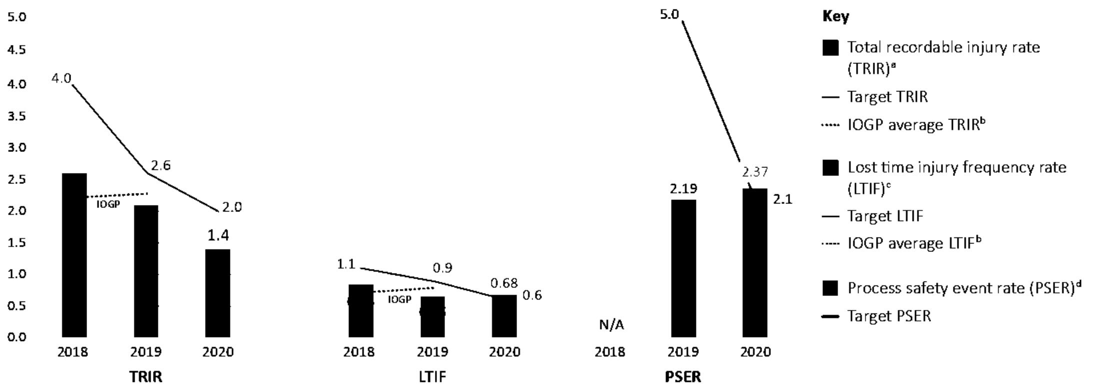
Having the right culture is key to good safety performance and we are reinforcing good practice through our group-led safety culture programme. Safety performance is a factor in determining bonuses for our employees, as well as the Executive Team. This includes targets for our total recordable injury rate (TRIR) and process safety event rate (PSER).

Safety performance

Despite the operational challenges posed by the COVID-19 pandemic, our TRIR improved to 1.4 per million hours worked in 2020, which is the lowest since Neptune's formation and reflects the efforts of the business to improve safety continuously. Our lost time injury frequency rate remained constant at 0.68 per million hours worked.

We had no tier 1 process safety events – losses of primary containment with the greatest consequence – in 2020. Our PSER, which includes tier 1, 2 and 3 process safety events, deteriorated slightly to 2.37 per million hours worked. Of the 29 events that occurred, 27 were in the tier 3 category and considered to be 'leading events'

Our safety performance



a The number of recordable injuries (fatalities, lost work day cases, restricted work day cases and medical treatment cases) per one million hours worked.
b IOGP – European average. 2020 data is not available until May 2021.
c The number of lost time injuries (fatalities and lost work day cases) per one million hours worked.
d The total number of tier 1, 2 and 3 process safety events per one million hours worked. This is a Neptune metric and is therefore not comparable to industry benchmark.

IOGP's life-saving rules

Bypassing safety controls
Obtain authorisation before overriding or disabling safety controls

Confined spaces
Obtain authorisation before entering a confined space

Hot work
Control flammables and ignition sources

Line of fire
Keep yourself and others out of the line of fire

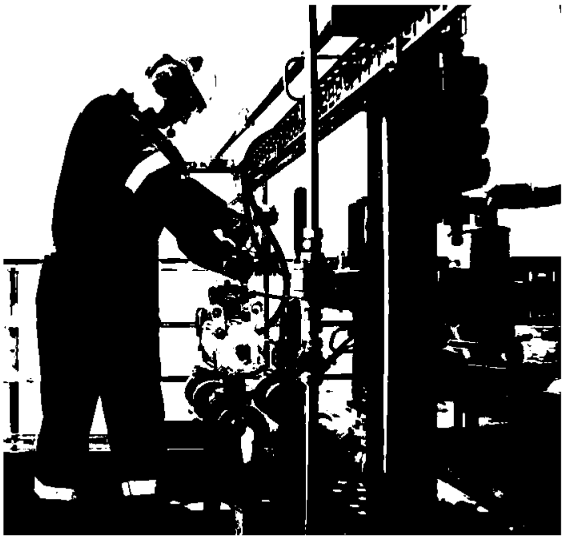
Safe mechanical lifting
Plan lifting operations and control areas

Driving
Follow safe driving rules

Energy isolation
Verify isolation and zero energy before starting work

Work authorisation
Work with a valid permit

Working at height
Protect yourself against a fall when working at height



that allow us to learn and help prevent the more severe tier 1 or 2 events from occurring.

Understanding the decisions and actions that led to an incident helps us learn and improve continuously. Improving process and technical safety is a key objective and in 2021 we will implement the IOGP's Process Safety Fundamentals and further improve safety leadership. We continue to develop our safety measurements tools, which strengthen employee and contractor awareness and enhance our ability to predict potential issues earlier.

Well integrity
Maintaining the integrity of oil and gas wells is crucial to avoiding harm to people or damage to the environment. Wells containing hydrocarbons at pressure are a major hazard that require systematic management.

Our global operating standards include requirements on well integrity that seek to ensure that our wells are managed safely and with care to the environment throughout their lifecycle.

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, our own safety audits.

Emergency preparedness and response
We operate a four-tier management model for emergency response that ensures the delivery of Neptune's duty of care in all scenarios from initial incident at site to board level.

In 2020, we activated our pandemic plan in response to the outbreak of COVID-19. We worked closely with our global health provider, International SOS, along with authorities and partners, putting additional measures in place across our operating assets and offices, such as implementing screening procedures and pausing non-critical activities.

We mobilised our full emergency response framework to support our operations in Algeria in down-manning non-critical roles and staff in vulnerable categories. This provided focused support to management in resolving developments that were outside business-as-usual activity and control mechanisms.

Working together on safety
We work with our peers to continue to improve our safety performance through industry associations such as the IOGP, the Energy Institute and IPIECA, the global oil and gas industry association for advancing environmental and social performance. At a country level, we participate in industry bodies, such as the UK's Emergency Preparedness Offshore Liaison Group.

Health
Our health strategy focuses on how we prevent adverse health impacts to our workforce, as well as how we enhance the health of our people and the communities in which we operate.

We developed a psychosocial risk indicator in 2020 in response to feedback from our employee engagement survey, which indicated that employees would appreciate a greater focus on mental health and wellbeing.

Psychosocial risk factors are associated with the way work is organised, designed and managed. Poorly managed, these risk factors can lead to stress, musculoskeletal disorders, heart disease and mental health disorders. The indicator will help strengthen our internal risk management processes so we can identify any issues at an early stage.

Globally, the pandemic has brought health issues to the forefront and we acted quickly to provide support to our people and their families.

We launched a health and wellbeing portal that gives our people direct access to a range of resources in four key areas – physical, mental, social and day-to-day wellbeing. The resources, developed with our global occupational health service, International SOS, include an Employee Assistance Programme. Our people, and their family members, are able to access practical information and counselling through the programme.

We worked with our industry and regulators to share lessons learned in relation to COVID-19. For example, at our Cygnus production facility in the UK we created a short video to explain how working on the facility had changed following new guidance and social distancing rules. The video was shared with industry association Oil and Gas UK and made available to other North Sea operators and service companies as an example of best practice for engaging with employees offshore.

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. We set an internal benzene exposure level of 0.2 parts per million and continue to monitor and mitigate the risk through our local management systems.

To help improve understanding of industry-related health issues, we participated in a number of initiatives in 2020, including studies on offshore worker exposure-related health.

We are also supporting a medical programme that aims to reduce the number of sudden cardiac arrests. The NEEDED programme will create a self-evaluation system for diagnosing and monitoring coronary artery disease, with a research centre expected to open in Sandnes, Norway, in 2021.

Climate change and environment

Our role in a lower carbon world

We are actively pursuing opportunities created by the energy transition, while working to reduce our operational emissions.

Advancing carbon capture and storage

CCS is an important technological option for reducing CO_2 emissions in the energy sector and will be essential to meeting Paris Agreement goals. We initiated a feasibility study into plans for a large-scale offshore CCS project in the Dutch North Sea in 2020, with the potential to safely store 120-150 million tonnes of CO_2 for third-party industrial customers. We will conduct the study in cooperation with our licence partners and industrial CO_2 emitters.

The study will assess the feasibility of injecting between 5-8 million tonnes of CO_2 annually into the depleted gas fields around our operated L10-A, L10-B and L10-E areas. If the project is developed, it will be one of the largest CCS facilities in the Dutch North Sea and could meet more than 50% of the CO_2 reduction being targeted by the Dutch industrial sector.

This project will build on the experience we gained on our K12-B platform in the Netherlands, where we participated in a 14-year programme to reinject CO_2 into the gas field. This reduced CO_2 emissions during the lifetime of the project by around 100,000 tonnes. The project was carried out in partnership with TNO, the Netherlands Organisation for applied scientific research. Our partner-operated Snøhvit field in Norway captures and reinjects CO_2 back into the aquifer. During normal operations, up to 700,000 tonnes of CO_2 a year is stored there.

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

We want to be part of the solution, by maintaining our gas-weighted portfolio, scaling-up partnerships and investments in lower carbon technologies and by reducing our operational emissions.

We are adopting the recommendations of the Task Force on Climate-related Financial Disclosures (TCFD). We recognise that implementing the TCFD recommendations fully will take a number of years and we will evolve our approach accordingly. We plan to use scenario planning to test the resilience of our business strategy in 2021. See *neptuneenergy.com/esg* for more information.

Governance
Our Board oversees our approach to managing climate-related risks and opportunities. In 2020, the Board reviewed climate matters, such as the establishment of our New Energy team, our carbon and methane intensity targets and the incorporation of an internal carbon price.

The Executive Team is responsible for assessing and managing climate-related matters, supported by business and functional expertise from our health, safety and environment, New Energy, corporate affairs and finance teams. See page 61 for more information on governance.

Strategy
One of our strategic priorities is to maintain our gas-weighted production profile and support low carbon development.

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, transportable and affordable.

We have one of the highest gas weightings in our industry, with a production profile that is 75% gas and 25% oil. We intend to maintain a gas-weighted portfolio in the years ahead, and the percentage of gas in our 2P reserves is 72%.

In the IEA's Sustainable Development Scenario, which is aligned with the Paris Agreement's objective of keeping the increase in average 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.

We have created a New Energy team to scale partnerships and investments in low carbon technologies, particularly hydrogen, carbon capture and storage, and electrification.

Hydrogen
There is a growing consensus internationally that hydrogen will be required at scale in order for countries to meet the ambitious targets set out by the Paris Agreement. We joined the European Clean Hydrogen Alliance in 2020, supporting the development of the EU's hydrogen strategy and its goal to become carbon neutral by 2050. The alliance brings together industry, public authorities and civil society.

The Netherlands is particularly well-positioned to lead the transition to a hydrogen economy, given its abundance of wind energy and existing infrastructure at sea and on land for the transport of gas and hydrogen.

We are progressing a pilot project, called PosHYdon, in the Dutch North Sea to establish the world's first offshore green hydrogen production plant. Our Q13-a platform will house a megawatt electrolyser that will produce green hydrogen from renewable energy. The green hydrogen will be blended with natural gas and transported onshore via existing pipelines.

The PosHYdon project was commissioned by Nexstep, the Dutch Association for Decommissioning and Re-Use, and TNO, the Netherlands Organisation for Applied Scientific Research, in close collaboration with the sector.

Electrification
We are exploring opportunities for electrification in our portfolio, building on our experience in Norway and the Netherlands. Our Gjøa gas and oil asset in Norway is powered using hydroelectricity delivered via a submarine cable from the mainland. As a result, Gjøa has one of the lowest carbon intensities in the Norwegian Continental Shelf, making it an attractive host platform for future subsea developments in the region.

Our Q13-a platform in the Netherlands is powered using electricity from shore, saving 16,500 tonnes of CO_2 a year.

In February 2021, plans for the electrification of our non-operated Gudrun platform, via the Sleipner field, in Norway were approved by the Norwegian Ministry for Oil and Energy. The project is expected to be implemented in 2022 and will reduce Gudrun emissions by around 60,000 tonnes of CO_2 a year.

Risk management
We identify, assess and manage climate-related risks through our enterprise risk management system. To prepare for future carbon regulation, we have incorporated an internal carbon price into our risk assessments and investment decisions.

We recognise that climate-related risks include risks related to the physical impacts of climate change, such as changes in the frequency and severity of extreme weather events and risks related to policy, legal, technology, market and reputational matters.

Metrics and targets
We are on track to meet our ambitious carbon and methane intensity targets of 6 kg CO_2/boe and net zero methane emissions by 2030.

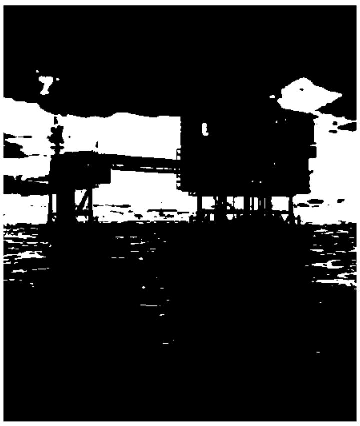
Carbon intensity from our managed production was broadly flat in 2020 at 6.3 kg CO_2/boe. This was slightly lower than expected due to deferred compression requirements at Cygnus, one of our operated assets. Our carbon intensity is significantly below the industry average of 17 kg CO_2/boe.

While we expect our carbon intensity to rise to around 9 kg CO_2/boe during 2021 due to the start of the compression project at Cygnus, we aim to achieve our target in the medium to longer term through a range of measures including replacing equipment, improving energy efficiency and electrification where feasible and economic.

Our operations in the UK and Germany are currently certified to the ISO 50001 energy management standard, and we plan to extend this to all our operated assets in 2021. As part of this, we are reviewing energy savings opportunities across our operations.

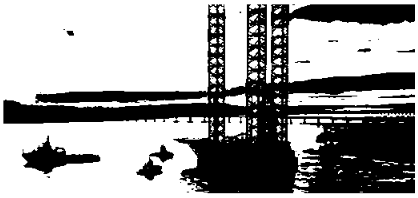
We saw a decrease in our direct GHG emissions in 2020. This was primarily due to lower production volumes. In 2021, we will work with our partners to calculate our equity share emissions.

Energy efficiency
In 2020, improvements in energy efficiency led to a reduction in energy use of 1,581 MWh. This includes energy saved by reducing the number of pumps that provided power during planned maintenance in Norway. In Germany, we replaced pumps with control valves at some of our sites. In the Netherlands, we were able to eliminate the need for a secondary diesel generator on our K12-K platform, reducing power consumption and eliminating the need for offshore fuel transport.



Enhancing our lower carbon position

We are taking steps to decarbonise our portfolio and create value from New Energy opportunities.



Creating value from low carbon investments

L10 CCS project
Feasibility study and FEED
Further developments
Identify further potential projects

- CCS project pipeline
- Longer-term operated opportunities – build on Neptune's CCS experience in the Netherlands and Norway

PosHYdon green hydrogen pilot
Funding, regulatory support and FEED

- Hydrogen project pipeline
- Integrated development plan for the Netherlands

Reducing intensity, hitting targets

Electrification
- Gjøa already electrified, Gudrun electrification project approved
- Study underway at Snøhvit

- Reductions in flaring and venting
- Methane emissions study

- Electrification and re-purposing
- Non-operated emissions reduction projects

2021 → **2030 (6 kg CO_2/boe, net zero CH_4)**

Greenhouse gas emissions and energy performance[a]

	2020	2019	2018
Direct GHG emissions (Scope 1) (tCO_2e)[b]	512,113	530,300	588,195
Indirect GHG emissions (Scope 2) (tCO_2e)[c]	43,701	31,586	27,854
Total Scope 1 and 2 emissions (tCO_2e)[d]	555,814	561,886	616,049
Carbon intensity (kg CO_2/boe)[e]	6.3	5.8	6.0
Carbon intensity (tCO_2e per kt hydrocarbon production)[f]	54.2	–	–
Methane intensity (%)	0.01	0.02	0.01
Energy consumption (MWh)[d]	2,538,760	2,546,503	2,992,184
Reductions in energy use as a result of energy efficiency initiatives (MWh)	1,581	10,574	970
Flaring (GJ)	393,682	437,152	458,984
Emissions from business travel (Scope 3) (tCO_2e)[g]	843	–	–

a We report our GHG emissions and energy consumption data from our managed operations. This includes Germany, the Netherlands, Norway and the UK. Our methodology for performance data is in our Basis of Reporting at *neptuneenergy.com/esg*.
b This includes emissions from combustion for energy, flare, direct hydrocarbon emissions, company cars, fleet vehicles and exclusive contract logistics from operations we own or control. From 2020, we have redefined our Scope 1 reporting boundary to exclude emissions from third-party drilling activities, which we consider as Scope 3 emissions.
c This includes emissions from the purchase of electricity. Less than 1% of our Scope 2 emissions is for the purchase of heat, steam and cooling for our own use.
d In compliance with the Streamlined Energy and Carbon Reporting (SECR) requirements, our total UK Scope 1 and 2 emissions were 32,874 tonnes CO_2e, which is 6% of the total from our managed operations. Our total UK energy consumption was 104,331 MWh which is 4% of the total. All of our emissions in the UK were emitted by entities in our Group incorporated in the UK.
e This includes Scope 1 and 2 emissions related to production/operations. We calculate intensity using wellhead production, in line with IPIECA sustainability reporting guidance. Our UK carbon intensity was 1.3 kg CO_2/boe. We expect this to increase in 2021 due to the start of the compression project at Cygnus.
f As per SECR requirements, we are reporting tCO_2e per 1,000 tonnes hydrocarbon production. This includes emissions from production only. Our UK carbon intensity was 10.9 tCO_2e/kt hydrocarbon production.
g This includes car and air travel. Emissions from business travel cars only was 262 tCO_2e. Emissions from business travel for the UK was 225 tCO_2e. We do not currently report emissions from the use of our sold product as the majority of our production is gas, which is sold primarily to utilities and major energy companies, who report this as part of their Scope 1 emissions and have a better understanding of end use.

EY has provided limited independent assurance over all metrics in the table above, with the exception of reductions in energy use as a result of efficiency initiatives. See *neptuneenergy.com/assurance* for EY's assurance statement.

Environmental management
We want to reduce the impact that our operations have on the environment. Our environmental policy identifies priority areas, such as energy efficiency, greenhouse gas and other air emissions, water, waste, biodiversity and spill prevention.

We are committed to monitoring the impact of our activities and mitigating their effect on the environment. We implement best available techniques within our activities to minimise any potential environmental impacts.

Our policy is supported by our environmental standards, which detail our requirements, ensuring a common understanding throughout Neptune.

Our environmental management system is certified to ISO 14001 in the UK, and we plan to extend this to our other operations in 2021.

We carry out environmental impact assessments during the planning phase of our projects. At an operational level, we comply with, or exceed, all relevant international and regional environmental regulations. We conduct environmental audits to ensure compliance.

Other air emissions
We are working to reduce air emissions from our activities. In the Netherlands, we continued to work towards meeting nitrogen oxide (NOx) emission reduction targets, as prescribed by national legislation. In 2020, we brought an additional nine engines in line with regulatory requirements, due to improved environmental and operational management.

Oil 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 monitor our assets closely to minimise the risk of spills to the environment.

We had no oil spills greater than one barrel in 2020. We conducted an internal audit of our oil spill preparedness in 2020, which confirmed that we have well-documented, appropriate emergency response planning in place in the countries where we work.

Water
We use freshwater in our drilling and production processes. We also use non-fresh water, such as seawater. Our environmental policy commits us to manage the impact of our water use in areas of scarcity and to monitor and reduce hazardous contaminants in the water we return to the environment.

None of our operated assets were located in water scarce areas in 2020.

Methane emissions

Methane is the primary component of natural gas and is a potent greenhouse gas (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 on a CO_2e basis. 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.

Our methane intensity, which refers to methane emissions from our managed operations as a percentage of gas exported, was 0.01% in 2020. This is one of the lowest intensities in the sector. We remain on track to achieve our target of net zero methane emissions by 2030. The decrease in our methane intensity in 2020 was primarily due to methodology changes in Germany, which have enabled us to improve the accuracy of our reporting.

Improving the reliability of methane data
We are a member of the Oil and Gas Methane Partnership (OGMP) and submitted data on three of our assets in the UK, Norway and the Netherlands. This represents more than 60% of our operated production.

We are a signatory to OGMP's new framework, which will improve the reporting accuracy and transparency of methane emissions in the sector. OGMP 2.0 aims to deliver a 45% reduction in the industry's methane emissions by 2025 and a 60-70% reduction by 2030.

The framework includes the companies' own operations as well as the joint ventures responsible for a substantial share of their production.

The OGMP is a Climate and Clean Air Coalition initiative led by the UN Environment Programme, the European Commission and the Environmental Defense Fund (EDF).

We are working with EDF and The Carlyle Group on a joint science project to test a first-of-its-kind approach for measuring methane emissions from offshore oil and gas facilities.

EDF will co-ordinate a team of international researchers that includes Scientific Aviation, a provider of airborne emissions sensing, and Texo DSI, a UK-based drone platform provider, to evaluate advanced methods for quantifying facility-level offshore methane emissions, identify key sources and prioritise mitigation actions.

State-of-the-art drone, aircraft and methane sensing technologies will be deployed on the Neptune-operated Cygnus platform to provide a close-up view of operations typical of a North Sea offshore facility, such as gas separation, drying and compression technology, and flaring and venting.

The study will help us identify where we need to take further action and how we can apply new measurement techniques across our global operated portfolio. The research is planned to start in mid-2021, with outcomes due to be published in a scientific peer-reviewed paper in 2022.

Waste
Waste is created at all stages of exploration and production. Therefore, we require all our projects and operations to establish a waste management plan to prevent waste as the first priority, followed by options for recycling and reuse.

Decommissioning
We consider environmental factors during the decommissioning and closure of a site.

When decommissioning wells onshore, for example, we fill in the wells and dismantle the extraction and processing equipment. Well sites are cleared and refilled with topsoil to return the land to its original condition.

During 2020, we spent $41 million on decommissioning depleted fields and site restoration.

We are working with mining authorities and state government to recover disused mud pit sites in Germany. We completed the abandonment and remediation of the Rühlermoor mud pit in 2020, which included the disposal of around 50,000 cubic metres of waste from former oil production. We expect to hand over the cleaned-up area in mid-2021.

Plans to decommission the Brüchau landfill site are also underway. We presented decommissioning options for the site, which was used to store industrial waste from the 1970s, to mining and state authorities in May 2020.

Biodiversity
It is our aim to minimise adverse impacts from our operations on biodiversity. In total, 22 of our operated assets are within or near a protected area. This includes the Cygnus field in the UK, 12 locations in Germany, our Gjøa field in Norway and four sites in the Netherlands.

In the UK, Cygnus is within an area that has been designated as protected due to the significant presence of harbour porpoise. Underwater noise from oil and gas activities, such as large-scale piling, has the potential to disrupt the species. We aim to minimise this and use passive acoustic monitoring when carrying out these kinds of activities.

We plan to develop biodiversity and water management plans for our operated assets in 2021.

See *neptuneenergy.com/esg* for our full performance data, including other air emissions, water and waste.

Building strong relationships to create value for local economies.

Contents

Our stakeholders continued

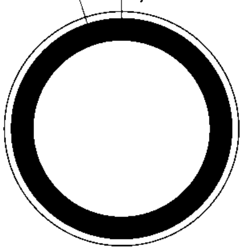
Our people

1,409[1]
employees

46
average age of employees

40
nationalities

Employees by region



- Europe
- North Africa and Asia Pacific

1 Employee numbers are based on full-time equivalent as at 31 December 2020.

Our people drive our success. Having a skilled and diverse workforce and an inclusive working environment creates a more resilient and innovative business. We have around 1,400 employees in Europe, North Africa and Asia Pacific working together to deliver our strategic ambitions.

We want our workforce to be representative of the communities in which we work. As such, each of our country operations is led by a managing director who is a national of the country.

Since we were established three years ago, we have built a dynamic and unique culture where new and different ways of thinking are part of our DNA. Embracing diversity of thought helps avoid 'group think' and fosters an innovative, entrepreneurial mindset, with the opportunity for all to contribute.

Supporting our people during COVID-19
Protecting the health and safety of our people was our first priority throughout the COVID-19 pandemic.

The risk of mental health issues, stress and isolation was a key concern and all employees were given access to our new health and wellbeing portal and Employee Assistance Programme. See pages 16-17 for more information on health and safety. We provided additional technology and equipment to our office staff to help them work from home more flexibly and comfortably. In addition to the safety measures we implemented for our offshore workers, we also put extra precautions in place to keep offshore gyms and leisure facilities open.

We increased the frequency of townhalls and other online sessions to support employees and update them on the changing situation.

The combined impact of the pandemic and the sharp fall in commodity prices meant that we needed to reshape our organisation. This meant the loss of around 400 roles. Following this difficult decision, we worked with affected employees and their representatives to agree an appropriate settlement package and we provided outplacement support to those affected.

Skills development
The energy sector relies on new generations of talent to enable the energy transition. We participate in initiatives to showcase the opportunities that the energy sector provides. For example, in the Netherlands we participated in the Young Energy Officers programme, an initiative launched in association with the Netherlands Oil and Gas Exploration and Production Association (NOGEPA). The initiative aims to engage young professionals in discussions about the energy transition and 2050 net zero goals.

In the UK, we participated in an online event to encourage young people into the energy industry, organised by the East of England Energy Group. The forum, which brought together students, education providers and industry, showcased the diverse range of roles the sector has to offer and highlighted potential career paths to the next generation of employees.

We also participate in mentoring programmes, such as one run by the Engineering Construction Industry Training Board, to share our experience and help mentees find and develop their skills and talents.

We provide a range of development opportunities from on-the-job learning to online training. As one example, we have a First Line Manager training programme that is targeted at people who are new to leadership roles and an online development programme for more experienced leaders. These programmes include a mix of learning via virtual classrooms, face-to-face learning, LinkedIn Learning modules, 360-degree feedback and practical application designed to fit with the managers' other priorities. In 2020, around 100 people completed these programmes.

Employee engagement
We conducted our second employee engagement survey towards the end of 2020, with participation from 72% of our employees. Our overall engagement score was 70%, compared with 67% in 2019.

The results demonstrated that people are motivated to contribute above expectations and they take personal responsibility for maintaining high standards of safety. Manageability of individual workloads, as well as training and career development opportunities, were highlighted as areas for improvement, and we will work with our employees to address these in 2021.

All employees take part in at least two formal reviews a year, discussing priorities, performance and career development with their manager.

We work with employee forums at our larger operated facilities to encourage open, two-way dialogue. As a result of what we heard from employees in our 2019 engagement survey, we increased communication at both a group and country level through townhalls, weekly CEO blogs, extended leadership meetings, strategy sessions and an enhanced intranet site.

We also operate an employee engagement forum to ensure that employee representatives can communicate directly with our Executive Team. The forum is chaired by our Group Human Resources Director, who was appointed to the Board in 2020.

Around 47% 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.

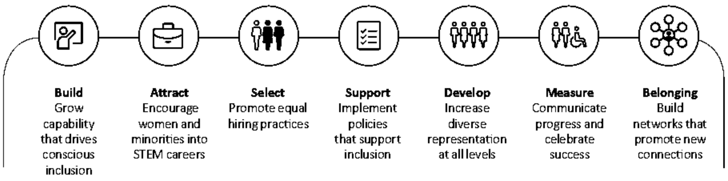
Our voluntary turnover rate was 2.7% in 2020.

Our ED&I charter

Andrea Guerra
VP Subsurface, Neptune Energy

"As a young woman growing up in central Colombia with an interest in maths and problem-solving, I was fortunate to have certain mentors who recognised my abilities at key stages in my development.

Today, as head of Neptune's worldwide subsurface team, I make it a priority to foster a fair, equitable and inclusive culture at Neptune. In our industry we need to solve complex problems on a daily basis and to do this we need to hear from everyone. If we don't, the best ideas may never see the light of day. Everyone's voice should be heard and appreciated – this is critical today, more than ever."



Excellence in HSE | Accountability | Integrity | Teamwork

Equality, diversity and inclusion
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 are, or become, disabled.

We are committed to treating everyone with dignity and respect, and to providing a workplace that is free from discrimination, harassment and bullying. We expect our partners and suppliers to do the same. We set out these commitments in our Equality, Diversity and Inclusion (ED&I) Policy.

We want to create an environment where everyone is accepted and valued. A strong commitment to ED&I is not just the right thing to do, it is essential. Diverse and inclusive companies perform better because they are able to understand different perspectives and make better, more informed decisions that accurately reflect the societies in which we live.

To drive our ED&I ambitions forward, we set up a central working group and appointed our VP of subsurface, Andrea Guerra, as our ED&I executive sponsor.

To understand the issues that matter most to our employees, we conducted an online poll and followed up with employee-led sessions in each of the countries where we work for more in-depth feedback.

The feedback we received highlighted that there was an opportunity to communicate more on where we are today, where we want to be in the future and how we are going to get there.

Throughout the year, we delivered focused communications to raise awareness of ED&I within Neptune, including CEO blogs, townhalls and yammer discussions. We also reviewed industry best practice, as well as existing and upcoming legislation.

What we learned from these activities helped inform our new ED&I charter. The charter, which is underpinned by our values, outlines our key commitments and the actions we will take to help create a truly inclusive organisation. This includes actions we will take at a group level, as well as those that are country-specific.

Gender representation

With females making up just 22% of our workforce in 2020, we are working to address our gender imbalance. We appointed two women to our Board in 2020, which was previously all male. For more information on our Board, and that of our parent company, see pages 61-64.

Gender diversity is a key component of our ED&I charter, which includes ensuring diversity in job application shortlists and encouraging women into science, technology, engineering and maths careers.

We are also identifying high-potential female talent at middle management levels to encourage progression to senior roles.

	Female	Male	Female %
Board	2	3	40%
Senior leaders	22	144	13%
Executive Team	4	16	18%
All employees	316	1,093	22%

Our stakeholders continued

Our partners and suppliers

4,500+
suppliers of goods and services

80%
of hours worked at Neptune are by contractors

We work with an international network of trusted, high-quality organisations to deliver the services and complex infrastructure needed to provide the energy that the world needs.

We are committed to building mutually beneficial relationships that help drive technical excellence and innovation.

A collaborative approach is key in helping to deliver our strategy and supports new ways of working in exploration and production. For example, we established a subsea alliance agreement with TechnipFMC two years ago based on shared goals and values, supported by a commercial model in which collective positive performance is rewarded.

Both Neptune and TechnipFMC recognised that it was vital to maintain flexibility, respond quickly to changing circumstances and to adhere to high health, safety, environmental and ethical standards.

The partnership has led to outstanding operational performance. Despite COVID-19 restrictions, all project delivery goals have been met with a safety record that is best-in-class.

Engagement
We engage with our joint venture partners via regular formal meetings, such as joint operating and technical committees, and ongoing informal engagements.

We aim to work to the highest safety and ethical standards and expect our suppliers to do the same. Our Business Ethics Principles for Contractor and Supplier Companies sets out our expectations on acting in accordance with all laws and regulations, establishing a culture of integrity and having procedures in place to combat bribery.

Prior to engaging with a supplier, we carry out a risk assessment and due diligence. We use a screening platform that identifies matters such as sanctions, criminal convictions and any adverse media reports in respect of suppliers and evaluate the results as part of the decision on whether to engage with a supplier.

Throughout the contract lifecycle, we aim to maintain open and transparent dialogue with suppliers. We engaged with suppliers primarily through virtual platforms in 2020 due to COVID-19 restrictions. The frequency of these interactions increased over the year to ensure we remained connected and maintained safe operations across our business.

The engagements varied from one-to-one discussions to multi-supplier conferences on topics such as safety and health, with a focus on managing the impacts of COVID-19. These proactive interactions helped mitigate the impact COVID-19 had on our operations.

We have performance measures in place with all our major suppliers that are discussed regularly at weekly and monthly calls. Formal quarterly performance reviews and six-monthly relationship-level meetings were maintained, and in some cases stepped up, providing suppliers with an opportunity to give feedback.

We work with our suppliers to help them understand and apply our health and safety, as well as other, standards. This helps set expectations, identify mutual opportunities to learn from one another and indicate areas for improvement.

During our Petrelex 3D survey in Australia, we conducted project and site safety kick-off meetings with our main supplier. This created a highly collaborative working environment in which Neptune proactively shared technical input to weekly quality control meetings.

We also engage with our suppliers to reduce our environmental footprint. In the UK, we worked with one of our suppliers to reuse surplus steel casing from drilling activities. The materials were repurposed for the construction industry to be used as pilings for new buildings. This helped save

368 tonnes of CO_2e in 2020. For our Seagull project, we are partnering with an organisation to recycle and reuse the plastic and metal in the waste conductors and tubular protectors for the project.

In the UK, we are a signatory to Oil and Gas UK's Supply Chain Code of Practice. This sets out best practice guidelines and works with suppliers to reach the highest attainable standards of business ethics, health, safety and environmental operations.

Suppliers can report any concerns of potential or actual breaches of our ethical standards to Safecall, an independent, confidential reporting line.

We developed a multi-year sustainable procurement action plan in 2020, which includes incorporating environmental considerations into our supplier principles and conducting a human rights assessment of our supply chain.

Assessing modern slavery risk
We are committed to maintaining effective controls to ensure modern slavery is not taking place anywhere in our own business or our supply chains. Our commitments are outlined in our Anti-Slavery and Human Trafficking Policy, which we launched in 2020.

We are opposed to all forms of modern slavery and 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 make every effort to prevent our activities having a negative impact on human rights and take steps to remedy situations where this arises.

We carry out periodic ethics-related risk assessments throughout our business, and these include an assessment of the risk of the existence of slavery and human trafficking in our business.

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

Collaborating on the digital revolution

To support our growth plans, we have implemented a digitalisation strategy that creates differentiation through the application of advanced technologies across the business. This includes working with partners and suppliers to maximise efficiencies.

We are adopting cloud-based applications developed by Halliburton to lower the cost and improve the efficiency of our drilling and wells activities. These applications will allow us to create 'digital twins' to model a specific well's performance, predict problems before they occur and make better business decisions.

In the UK southern North Sea, we awarded a subsea inspection contract to geo-data specialist Fugro. The firm used state-of-the-art remote monitoring and digital compression and communications tools to inspect subsea structures at our Cygnus gas field. A remote team used the tools to interpret and process data and report back to Neptune in real time.

We also partnered with 3D technology specialist Eserv to create a digital map of our Cygnus platform. This map helps us detect integrity issues early on and plan essential maintenance work. Much of the traditional work can now be carried out onshore, which helps reduce the cost and environmental impact of offshore travel.

We are working with Microsoft and others to shift much of our physical IT infrastructure to a hybrid cloud model. This will lower costs and give us greater flexibility. Non-cloud data will be stored at a location in Norway that is 100% powered by renewable energy, while the cold climate allows the facilities to be kept cool naturally. Using this facility will lower the carbon dioxide emissions associated with our traditional data centres by 98%. We expect all our data to have migrated to this hybrid model by 2022.

Our digitalisation strategy: creating differentiation through advanced technologies

Faster exploration to production

Safer, more secure

Enhanced asset integrity

Lower costs, higher efficiency

Digital subsurface	Digital assets	Digital supply chain and back office, workplace
Higher resolution, lower risk, accelerate development	Improve safety, reduce cost, optimise production	Automation, communication, collaboration and knowledge management
Advanced tech and AI, faster geological analysis and reservoir modelling, efficient drilling and wells lifecycle	Digital twins, AI, remote production monitoring, inspections and technical support	Optimise inventory, lower cost and automated back office, from 'data to intelligence'
Reduce cycle time from exploration to production	Improved safety and operational excellence, higher asset integrity, emission reduction	Maximise efficiencies, more engaged people, the best access to information and knowledge
End-to-end GeoCloud applications installed	Digital twins on Gjøa, Cygnus, L5, K9A platforms Halliburton iEnergy Cloud	Digital supply chain Power BI

Our stakeholders
continued

Our communities

$2.1 billion
Gross value added contribution to the GDPs of Germany, the Netherlands, Norway and the UK

11,400 jobs
supported via our direct, indirect and induced economic impact

6
UN Sustainable Development Goals supported

Brian Dow
Chief Executive, Mental Health UK

“Millions of people across the UK have had to deal with the isolating effects of lockdown during the pandemic. For people who are older and in rural communities this can be a double disadvantage, so we are thrilled to be working with Neptune Energy to help digitally equip, skill up and give access to online support so that they can stay connected with friends and loved ones.”

The relationships with the many local 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 opportunities our activities are likely to generate.

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.

We participate in social investment work where local need aligns with our business priorities. We assess all opportunities – at both a group and country level – against four core community investment themes – local economic development, education, health and environment, which are aligned with the UN Sustainable Development Goals (SDGs).

We launched our social investment standard in 2020. That standard is embedded in our management system and formalises our decision-making process. It includes an assessment of the SDGs, alongside our ethics and compliance requirements.

We contributed $231,339 to social investment initiatives in 2020 (2019: $166,500). The majority of this spend was in the UK, Norway, Netherlands and Germany, where we have operated assets.

Addressing social inequalities
We took swift action to support local communities in response to the COVID-19 pandemic. In Indonesia, for example, we partnered with NGO, Yayasan Mata Air Foundation, to donate essential items to medical staff in hospitals in Jakarta. And in Egypt, we supported the 'One Hand' initiative, which provided medical supplies and equipment to help the country fight the pandemic.

As the pandemic escalated, the physical, psychological and economic implications sharpened the world's focus on social inequalities. It raised new questions about the purpose of corporates and the part they can play in addressing social inequalities.

We looked at areas where we could make the most difference, which align with our social investment themes and relevant UN SDGs. As a result, we are forming partnerships around the world to support two key issues: mental health and youth employment.

Mental health
We are partnering with Mental Health UK to fund a three-year project that provides individuals in rural communities with the skills, access and support to find the help they need to manage their mental health. We will also support the charity's Clic website which provides people across the UK with access to community support, 24 hours a day. Our employees will have the opportunity to be trained as volunteers to join a community of moderators that assist visitors to the site.

Youth employment
We joined Movement to Work, a coalition committed to helping young people not in education, employment or training connect with the world of work. The movement is helping us identify opportunities, such as work placements, to help break the 'no experience, no job' cycle that many young people face.

We are applying this approach across the countries where we operate. For example, in Germany we are supporting a programme that helps disadvantaged young people participate in mentoring programmes and find jobs.

In Norway, we continued to support a summer school programme, run by social enterprise Forskerfabrikken, that aims to get more young people interested in natural science. We supported 10 courses, with around 250 schoolchildren participating in 2020.

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. For example, in the process of decommissioning a gas extraction site in Bentheim county, local community members requested that the site be developed into a conservation area. We partnered with the Nature Conservation Foundation to enhance the habitat of local species, including endangered amphibians.

In Geeste, where our Bramberge oil field is situated, we organised a site visit for the local mayor, who was interested in the ongoing construction at the asset. The visit was hosted by our country managing director and the mayor was able to see first-hand the work that is underway to modernise the plant and optimise the field's production life.

The majority of concerns raised in 2020 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 2020, we supported initiatives including donations of office furniture to cultural associations and local community organisations, and an electrical generator to a maternity unit in a hospital in Adrar.

Partnering with The HALO Trust on safety

We are working with worldwide humanitarian landmine clearance organisation, The HALO Trust, to further improve safety performance within both organisations.

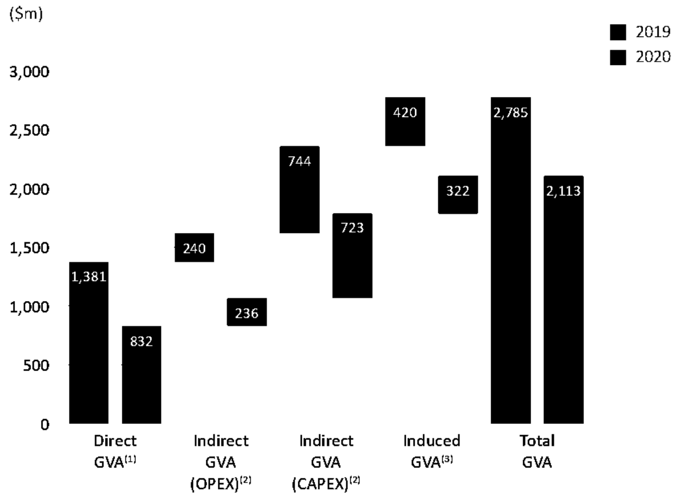
Neptune teams will share their approach to incident management, root cause databases and learning review techniques, gained from decades of experience in the oil and gas industry, with HALO.

In turn, HALO will share how their use of training and supervision supports positive behaviours and practices among teams clearing landmines and other unexploded ordnance from areas affected by war.

“This is a really progressive and innovative approach to improving how we work. There are strong connections in what we do, we both operate in challenging, often dangerous, environments on a daily basis, and we both have a strict safety culture that runs through everything we do. So there is a great deal we can learn by talking to each other.”

James Cowan
CEO, The Halo Trust

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



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

We supported an estimated $2.1 billion gross value added contribution to the gross domestic product of our European countries – Germany, the Netherlands, Norway and the UK – in 2020, and some 11,400 jobs. Our total economic impact was lower than 2019 given the deferral of some capital programmes.

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

We have commissioned an external organisation to conduct an independent human rights assessment of our performance against the UN Guiding Principles on Business and Human Rights to identify good performance and areas for development. We will report on the outcomes of this in 2021.

See **pages 24-25** for information on our approach to working with our suppliers.

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 worked with the Norwegian oil and gas trade association and major operators in the Norwegian Continental Shelf in 2020 to bring forward a temporary tax regime that ensured continued activity during the pandemic, while maintaining investment levels for the medium term.

We support the Extractive Industries Transparency Initiative (EITI), which is designed to improve accountability for the revenues paid and received for a country's oil, gas and mineral resources. We submitted data for publicly available EITI reports in the UK, Netherlands and Indonesia in 2020.

Operational review

Neptune delivered a resilient operational and financial performance in 2020, generating an underlying operating profit.

Contents

Large scale and diversified

- Continued improvement in health and safety, with our total recordable injury rate down to 1.4 per million hours worked in 2020.
- Full year production of 142.4 kboepd, within revised guidance range (143.8 kboepd including production-equivalent insurance receipts).
- 2021 production guidance of 130-145 kboepd, reflecting outages at non-operated assets in Norway and Algeria (140-155 kboepd including production-equivalent insurance receipts). Expect to exit 2021 at materially higher production rates with new projects online in Norway and Indonesia and production restarts.
- Entering a period of growth, targeting production of close to 200 kboepd in 2023, with all existing sanctioned projects onstream.

Long life, low cost and lower carbon

- 2P reserves of 601 mmboe and 1P reserves of 392 mmboe. Three-year reserves replacement ratio of 128%. Significant ~50% increase in 2C resources to 452 mmboe, providing material future growth potential. Targeting medium-term 2P reserves of ~800 mmboe, supported by organic and inorganic growth.
- Delivered cost savings and deferrals on target of $350 million and reduced opex to $9.5/boe. Breakeven price of $29.8/boe.
- Carbon intensity from managed production stable at 6.3 kg CO_2/boe, on-track to hit 2030 target of 6 kg CO_2/boe. Methane intensity from managed production of 0.01%, with 2030 net zero methane emissions target also on track.
- Project pipeline to deliver a medium-term reduction in opex to <$9/boe and carbon intensity.

Gas weighted and well-positioned for the energy transition

- 75% of 2020 production volume was gas, 72% of reserves. Revenue exposure of 47% gas, 18% LNG and 35% oil diversifies risk.
- Commenced feasibility study into CCS plan for the Netherlands, progressing with PosHYdon green hydrogen pilot project and Gudrun electrification project approved. Evaluating further electrification opportunities in Norway and the UK.
- Developed ESG roadmap, aligned with UN Sustainable Development Goals and the Financial Stability Board Task Force on Climate-related Financial Disclosures, to drive improvements in the business.
- European activities supported some 11,400 jobs and contributed an estimated $2.1 billion gross value added in 2020.

Significant cash flow generation and strong balance sheet

- Operating cash flow of $915 million despite lower commodity prices, supported by hedging gains and Norwegian tax refunds. EBITDAX of $940 million and an underlying operating profit of $287 million.
- Total available liquidity of $1.3 billion at the end of the period. Development projects fully funded from operating cash flow.
- Net debt to EBITDAX of 1.94x at 31 December 2020. Expect leverage to slightly increase in H1 2021 due to capex phasing, before declining in H2 2021. Aim to maintain ratio of <1.5x through the cycle.

Disciplined and focused capital allocation

- Development capex of ~$700 million to support project pipeline, with new projects in 2021 to add 27 kboepd at plateau.
- Exploration spend of ~$150 million in 2021 targeting appraisal of high-value prospects, including Dugong (Norway). Targeting FID for Dugong in 2022 to submit PDO to benefit from enhanced tax regime in Norway.
- Fully-funded investment programme within operating cash flow in 2021 to support sanctioned projects and high-value exploration prospects.

Growing free cash flow

- Positive free cash flow generation in 2020, despite weaker prices and lower production. $775 million FCF since EPI acquisition.
- Expect to generate materially higher free cash flow in 2021, with increasing production supporting future revenues.
- Higher commodity prices to lead to an increase in EBITDAX compared to 2020.
- Given the improving commodity and economic outlook for the financial year 2021, the Board of Directors of Neptune Energy Group Limited declared a $200 million interim dividend on 24 February 2021.

Financial summary

Neptune Energy	2020 12 months to 31 December 2020	2019 12 months to 31 December 2019
Total daily production (kboepd) (note a)	**142.4**	143.9
Total daily production (kboepd) including production-equivalent insurance payments (note b)	**143.8**	143.9
Operating costs ($/boe)	**9.5**	10.3
EBITDAX ($m) (RBL basis) (note c)	**939.8**	1,600.2
Underlying operating profit (note d)	**287.3**	951.0
Cash flow from operations, after tax ($m)	**915.4**	1,320.6
Adjusted development cash capital expenditure ($m) (note e)	**741.4**	1,122.1
Free cash flow ($m) (note f)	**70.8**	89.3
Net debt ($m) (book value) (RBL basis) (note g)	**1,821.4**	1,490.1
Net debt/EBITDAX (RBL basis) (note g)	**1.94x**	0.93x

a) Production and realised price figures are for wholly owned affiliates and equity accounted affiliates.
b) Including business interruption insurance payments, converted to a net entitled production equivalent.
c) EBITDAX comprises net income for the period before income tax expense, financial expenses, financial income, impairment losses, other operating gains and losses, exploration expense and depreciation and amortisation. EBITDAX as defined by the RBL and shareholder agreement includes our share of net income from Touat in 2020 following the repayment of the Touat Vendor Loan. EBITDAX for 2019 excludes our share of net income from Touat.
d) Underlying operating profit is calculated as operating (loss)/profit before the impact of impairment losses, restructuring costs and pension settlements or curtailments. A full calculation is shown below.
e) Includes capital expenditure of $24.1 million for the year (2019: $61.4 million) in respect of the Touat project, held by a joint venture company which Neptune accounts for under the equity method.
f) Free cash flow is calculated as net cash flow from operating activities less net capital investments during the period including repayments under leases.
g) Net debt excludes Subordinated Neptune Energy Group Limited Loan and Touat project finance facility as defined by the RBL and Shareholder agreements. The Touat project finance facility was repaid at the end of September 2020.

Underlying operating profit is calculated before the impact of impairment losses, restructuring costs and pension curtailment credits as follows:

$ millions	Year ended 31 December 2020	Year ended 31 December 2019
Operating (loss)/profit before financial items	(95.4)	872.7
Add back:		
Share of net loss from investments using equity method – Touat impairment	32.7	–
Impairment loss	325.7	59.4
Net restructuring cost	25.3	68.9
Deduct:		
Pension scheme settlement/(curtailment credit)	(1.0)	(50.0)
Underlying operating profit	**287.3**	**951.0**

Operational review

Building the business for long-term growth

The COVID-19 pandemic led to unprecedented disruption to societies and economies around the world as governments initiated national lockdowns, restricting the movement of people and curtailing economic activity. Not only did this impact our people, operations and projects, but it also led to a sharp fall in oil prices as demand declined dramatically within just a few months. The combination of these factors provided unique challenges for our industry in 2020.

Neptune reacted quickly and decisively to protect our people, operations and balance sheet. By doing so, we reduced costs significantly, enhanced liquidity and preserved long-term asset values. While this necessitated difficult decisions, it has shown that Neptune is resilient and agile. It has also demonstrated the value in our conservative hedging policy and diverse production portfolio. Not only does this protect us from commodity price risks, but also specific asset risks, enabling us to maintain significant earnings and cash flow generation throughout the period.

The strategic review that we carried out in the second quarter of 2020 validated our approach, while identifying necessary changes to our organisation as we position ourselves to deliver growth in a more uncertain outlook. Following implementation of these changes, we are leaner, more integrated and more focused on delivering value over volume, with greater competition for capital allocation between our business units.

Throughout the year, we faced a number of operational challenges. Our emergency pandemic plan, which we initiated during the early stages, changed the way we work and ensured that we had few operational disruptions from COVID-19. We did, however, defer some non-safety critical maintenance activity and, as part of our resilience plan, slowed our project schedules where we had the flexibility to do so.

In the second half of 2020, technical issues at the onshore facilities of two of our key assets, the joint venture-operated Touat gas plant (Algeria) and the non-operated Hammerfest LNG facility servicing the Snøhvit field area (Norway), impacted operations significantly and resulted in lower production in 2020. Losses of revenues are covered by business interruption insurance and this is expected to mitigate lower expected production in 2021 as we work with our partners to bring these assets back online.

Despite these issues, our health and safety performance continued to improve in 2020, with a reduction in our total recordable injury rate (TRIR). We continue to focus on further improvements in 2021, including to our lost time injury frequency (LTIF) and process safety event rate (PSER). Carbon intensity from our operated portfolio remained modest at 6.3 kg CO_2/boe, around 63% lower than the industry average.

Our financial performance in 2020 was robust, with EBITDAX of $940 million and operating cash flows of $915 million. We preserved liquidity through upsizing our RBL facility and reducing investment materially, limiting the increase in leverage, which remains well within covenants. Leverage is expected to rise modestly during the first half of 2021, but decline later in the year as capex reduces further and cash flows increase, due to new production coming online.

While these outages will curtail average production in 2021, cash flow is largely protected by insurance receipts, and output from new projects starting up will result in significantly higher exit rates as we enter a period of growth. With further new projects coming online in 2022, we expect to be producing close to 200 kboepd in 2023, with further medium-term development opportunities in Norway, Indonesia, Algeria and Australia.

Organisation
In June, we announced proposed changes to the shape, structure and size of Neptune's organisation to drive greater efficiencies and effectiveness. These changes were announced in response to the unprecedented challenges presented by the COVID-19 pandemic, lower commodity prices and the uncertain outlook.

Our review of the business validated our overall strategy, corporate structure and core operating countries. The changes we made to the organisation enable us to operate with greater flexibility and responsiveness, while our 'team of teams' structure delivers greater organisational efficiency, without reducing our overall capability.

As part of these plans we reduced the number of employees and contractors across our business and closed our office in Oslo (Norway), while maintaining a key in-country presence in Stavanger (Norway). We expect to finalise the closure of our office in Lingen (Germany) in the first half of 2021 and are currently negotiating the sale of this property. We will open our new German headquarters in Hannover in the second quarter of 2021. Throughout the reorganisation we engaged with the works councils and provided comprehensive outplacement support to all those affected.

To support our growth plans, we have implemented a new digitalisation strategy that creates differentiation through the application of advanced technologies across the business:

- Digital subsurface: aims to reduce cycle time from exploration to production.
- Digital assets: targeting improved safety and operational performance, higher asset integrity and emission reduction plans.
- Digital supply chain and back office: focused on maximising efficiencies and reducing waste along the whole value chain.
- Digital workplace: concentrated on more engaged people, more productivity including enhanced access to essential information and knowledge.

Our digitalisation strategy has improved cyber security, while enabling improved cycle times from faster hydrocarbon discovery to development, and optimising existing producing assets and cost structures.

Production

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

Total production (kboepd)	2020	2019
Norway	54.7	67.7
UK	18.3	16.5
The Netherlands	21.1	21.7
Germany	17.0	12.6
North Africa	12.5	5.9
Asia Pacific	18.8	19.5
Total production (kboepd)	**142.4**	**143.9**

Total Group production for 2020 averaged 142.4 kboepd, within our revised guidance range of 140-145 kboepd. This reflected a reduction in planned activity due to COVID-19 restrictions, our cost reduction plan, weak gas demand in Asia and extended unplanned shutdowns at both Snøhvit and Touat.

Losses of revenue from the shutdown at Snøhvit are largely being recovered through business interruption insurance, but did not make a material contribution to 2020 revenues. Including these production-equivalent insurance payments, economic production averaged 143.8 kboepd, which was flat on 2019. We expect Touat to restart production by the end of the first quarter of 2021 and Snøhvit to come back online early in the fourth quarter of 2021. We remain in discussions with our insurers regarding business interruption payments.

While overall output in Norway was impacted by the issues at Snøhvit, production at our operated Gjøa field was strong, partially mitigating the decline in production. In the UK, production was strong due to high production efficiency and export availability, which we took advantage of during the latter part of 2020 with higher gas prices. Output in the Netherlands was marginally lower as we continue to focus on improving safety and facility integrity. In Germany, reported production increased due to the change to Group-wide gas conversion factors. Production in Egypt was broadly stable.

In Indonesia, production started the year strongly as we front-loaded output ahead of a planned shutdown at Jangkrik in July. However, due to COVID-19 and weak gas demand in Asia, high inventories at the Bontang LNG facility during the mid-part of the year ultimately curtailed production during the second and third quarters. Volumes increased towards the end of 2020 as economies recovered and colder weather increased demand. Exports are expected to increase further in 2021 as the new Merakes development comes onstream.

Production efficiency at our operated assets was 81% in 2020 and was broadly in line with our performance in 2019, taking into consideration planned shutdowns, including activities for our new projects. At our non-operated and joint venture assets, production efficiency was materially lower, particularly in the fourth quarter, due to the disruptions at Snøhvit and Touat. We are taking steps to improve production efficiency across the portfolio and target opportunities where we can best influence performance to deliver value over volume. This includes maintenance and shutdown optimisation, enhanced production surveillance and sharing integrity management best practice across the operated portfolio.

Production in 2021 is expected to be weighted towards the second half of the year as new projects in Norway and Indonesia come online and production is restarted at Snøhvit and Touat.

Projects

Due to the impact of COVID-19 and lower commodity prices, we revised schedules for several projects in 2020 where we had the contractual flexibility to do so. By deferring activity, we mitigated risks from supply chain disruptions and third-party infrastructure constraints and smoothed our investment profile across 2020-22. While this pushed out first production at some projects, the overall impact on production is limited, with growth delayed rather than reduced.

Despite these challenges, we made significant progress in 2020 and brought the 8 kboepd Gjøa P1 project onstream successfully in February 2021. We expect the Merakes project to come onstream in the second quarter of 2021 and the Duva project later in the third quarter, adding a further 11 kboepd and 8 kboepd respectively.

In 2021, we plan a significant step up in activity at our operated Fenja and Seagull developments, although we continue to optimise project schedules around third-party constraints. The Fenja project is due onstream in the second quarter of 2022, but is contingent on the timing of the Equinor-operated Njord Future project. Fenja and Njord are expected to add a further 37 kboepd at plateau rates.

At our Seagull project, the pipeline was laid in the fourth quarter of 2020 and topside modifications on the BP-operated ETAP platform began. In early 2021, a four-well drilling campaign commenced, which is expected to last 18 months. First oil from Seagull is due in early 2023, adding 15 kboepd of new production.

With new lower cost production coming onstream, we expect Group opex to decline to less than $9/boe in 2023. Our low-cost production reflects the gas weighting in our portfolio, which is expected to remain around our current 70/30 gas to oil weighting in the medium term. With capex commitments for sanctioned projects declining, we expect our pre-tax and financing breakeven price to fall materially below $30/boe moving forward.

Within our New Energy team, we have initiated a feasibility study into plans for a large-scale offshore CCS project in the Dutch North Sea, with the potential to safely store 120-150 million tonnes of CO_2 for third-party industrial customers. The study will assess the feasibility of injecting between five and eight million tonnes of CO_2 annually into the depleted gas fields around the Neptune-operated L10-A, L10-B and L10-E areas. This builds on the experience we have of injecting CO_2 in the K12 fields.

We have moved forward with plans for our offshore green hydrogen pilot at the PosHYdon project in the Netherlands, which is due to enter the design phase in 2021.

Electrification provides further opportunities to decarbonise existing production in Norway and the UK. A plan for the electrification of the Gudrun platform was approved in early 2021 and is expected to start-up in late 2022. We continue to assess the technical feasibility and financial viability of potential developments.

Operational review continued

Reserves

Reserves summary	Proved plus probable reserves (mmboe)
2P reserves at 31 December 2019	**633**
Production	(52)
Revisions, extension and discoveries	6
Acquisitions and divestments	14
2P reserves at 31 December 2020	**601**
Total reserves replacement ratio	39%
Total reserves production ratio	12 years

We ended 2020 with proved plus probable reserves (2P) of 601 mmboe and replaced 39% of our production. This follows reserve replacement ratios of 90% in 2019 and 244% in 2018 as our projects were brought into the portfolio and sanctioned. Over a three-year period, which more closely reflects our current project cycles, our reserves replacement ratio was 128%. Our 2P reserves to production ratio was unchanged at 12 years.

Within 2P reserves, extensions and discoveries contributed a 34 mmboe net increase in reserves, largely due to the success at Adorf and also the movement from contingent resources at Cygnus, Duva and Römerberg. This was offset partially by negative price effects and modest engineering downgrades at Duva, Fenja and Jangkrik. We recognised a reserves upgrade at Touat as a result of production performance, while there were also engineering upgrades at both Seagull and Merakes.

Contingent resources

Contingent resource summary	**2C resources (mmboe)**
2C resources at 31 December 2019	**302**
Revisions, extension and discoveries	147
Acquisitions and divestments	3
2C resources at 31 December 2020	**452**

In 2020, we delivered significant growth in contingent resources and matured 29 mmboe into reserves. Over a three-year period, which reflects our development timeline more closely, we have transferred 125 mmboe of contingent resources to reserves, demonstrating a strong track record of growth. Contingent resources (under the development pending, on hold and unclarified categories) in 2020 increased by 150 mmboe to 452 mmboe as at 31 December 2020. The increase in contingent resources largely reflects our exploration success, which added around 90 mmboe and significant value to our portfolio.

The increase in contingent resources is encouraging and provides a positive outlook as we target growth in reserves to around 800 mmboe, supported by organic and inorganic growth. Within our portfolio of undeveloped discoveries, Dugong (Norway), Isabella (the UK), Maha (Indonesia) and Petrel (Australia) offer material growth potential and are key areas for appraisal and development activity in the near term.

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

Exploration

During 2020, we refocused our exploration strategy on shorter-term, material value-creating prospects around existing infrastructure. These changes reflect prevailing market conditions and a commensurate reduction of planned activity in the medium term. As a result, we have relinquished acreage in non-core areas and deferred higher-risk activity. While we are reducing our overall exploration footprint in Europe, we have been awarded new acreage in Norway as we strengthen our position in core areas and focus on high-value assets, such as Dugong and Isabella.

In Asia Pacific, our exploration strategy has been to add growth opportunities around our key assets at Jangkrik and Petrel, where we have large-scale and long-life assets.

We achieved positive results from our drilling programme in 2020, announcing discoveries in Norway, the Netherlands, the UK and Germany. During the period we confirmed seven discoveries from eight wells drilled, including material new fields at Dugong and Isabella, where follow-up activity is planned in the next year. Discoveries at Sillimanite South (Netherlands), Adorf-Z15 and Ringe-6 (both Germany) were brought onstream in 2020.

2020 drilling results

Country	Licence	Well	Working interest	Outcome
Norway	PL025/187	Sigrun East	25%	Oil and gas discovery
Norway	PL889	Grind	50%	Dry
Norway	PL882	Dugong	45%	Oil discovery
Norway	PL586	Bue/Frisbee	30%	Oil discovery
The Netherlands	D12a	Sillimanite South	11%	Gas discovery
UK	P1820	Isabella	50%	Oil and gas discovery
Germany	Adorf	Adorf-Z15	67%	Gas discovery
Germany	Ringe	Ringe-6	45%	Oil discovery

Notes: Includes exploration and appraisal drilling.

In addition to our drilling activity in 2020, we acquired new seismic data on the North West El Amal concession in Egypt and on the large Petrel discovery in Australia. Seismic processing has been completed and interpretation is underway in both countries. In Egypt, planning for the first exploration well is expected to commence later in 2021, while we are evaluating development options in Australia.

In 2021, we plan to drill up to 11 new wells, including important appraisal wells on the Dugong and Maha discoveries and an exploration well targeting the Dugong Tail (Norway) prospect. We will also undertake planning activities for an appraisal well on the Isabella discovery to be drilled early in 2022.

In the Netherlands, we plan to drill two prospects in 2021, including a shallow gas target located within tie-back distance to the Neptune-operated F3-B facilities. The Assil C105 and Bahga C101 Deep prospects are to be drilled in Egypt towards the end of 2021 and have near-term production potential.

2021 drilling programme

Country	Licence	Well	Working interest	Type
Norway	PL882	Dugong	45%	Appraisal
Norway	PL882	Dugong Tail	45%	Exploration
Norway	PL090	Blasto	15%	Exploration
Norway	PL090	Apodida	15%	Exploration
Norway	PL970	Ommadawn	30%	Exploration
Norway	PL1041	Lullaby	30%	Exploration
The Netherlands	F5-A	Shallow gas	28.33%	Exploration
The Netherlands	N4	Turkoois	16%	Exploration
Egypt	Alam El Shawish West	Assil C105	25%	Exploration
Egypt	Alam El Shawish West	Bahga C101 Deep	25%	Exploration
Indonesia	West Ganal	Maha-2	30%	Appraisal

Notes: Drilling schedule subject to change.

Financial performance
For a detailed overview of financial performance and underlying profit see pages 29 and 91.

Despite materially lower commodity prices, Neptune delivered a resilient financial performance in 2020 with EBITDAX of $940 million and post-tax operating cash flows of $915 million. Our cost reduction plan reduced our capital investment programme significantly, resulting in positive free cash flow of $71 million, compared with a potential material cash outflow as commodity prices trended lower earlier in the year. We also agreed to terminate the agreement to acquire Edison E&P's UK and Norwegian subsidiaries from Energean Oil & Gas, significantly enhancing near-term liquidity.

Our financial performance was driven by our diversified production, hedging strategy, lower operating costs and Norwegian tax refunds, which will continue to support the business in 2021. While commodity prices have strengthened in recent months, our post-tax hedge ratio of 53% in 2021 provides protection to downside risks and we retain good exposure to further improvements in the macro environment.

Operating costs in 2020 decreased to $9.5/boe reflecting cost reduction measures, including some deferred maintenance activity, which will increase operating costs temporarily in 2021. While G&A costs were stable in 2020, our restructuring activity resulted in a $33 million provision.

In 2020, we received $70 million of net cash tax refunds, which related mainly to temporary changes to the upstream fiscal regime in Norway. We expect to receive a further $110 million of net cash tax refunds in 2021. We also received $9 million in relation to business interruption insurance proceeds in Norway in 2020 and expect to receive further payments in 2021.

During the year, we identified impairments related to lower long-term commodity price assumptions and underlying reservoir performance at certain assets. For the full year, net pre-tax impairments were $326 million, with the $201 million increase from our Q3 2020 results, attributable mainly to our operations in Indonesia and the Netherlands. We also identified a $33 million post-tax impairment of our equity-accounted Touat joint venture due to market conditions. Excluding these exceptional items, we delivered an underlying operating profit of $287 million in 2020.

Notwithstanding our cost reduction measures, we continued to make significant investment across our portfolio in 2020, with adjusted development capex of $741 million, mainly at Njord, Merakes, Gjøa P1 and Fenja. This represented a $250 million reduction on our original investment plans. In addition, we invested a further $145 million in exploration spend and incurred $41 million in decommissioning expenditure. We expect investment in development to decline in 2021, reflecting completion of key projects at Gjøa P1, Duva and Merakes.

In the first half of 2020, we successfully redetermined our RBL facility, upsizing the facility to $2.6 billion and increasing the borrowing base to $2.3 billion. At year end, net debt increased to $1.8 billion, reflecting the repayment of the Touat project financing facility, which was previously excluded from this calculation and will reduce net interest costs going forward. The increase in net debt, together with lower 12-month rolling EBITDAX, resulted in a net debt to EBITDAX leverage ratio of 1.94x at year end, which remains within the RBL covenant of 3.5x. Leverage is expected to decline in the second half of 2021 as capex falls and cash flows increase. Headroom under the RBL of $1.2 billion, together with cash of $0.1 billion, provides available liquidity of $1.3 billion at year end.

This positive outlook and strong liquidity are reflected in our corporate credit ratings, which have remained unchanged in 2020.

The outlook for 2021
While COVID-19 vaccines provide optimism for societies and markets, it is expected to take some time to immunise a sufficient number of people to resume a more normal way of life. As a result, the rate of economic recovery is expected to vary by region, with resulting oil and gas demand likely to moderate in the short term. Commodity prices at the beginning of 2021 have been higher than through much of 2020 but, due to an uncertain global economic outlook, we remain prudent in managing our short- and longer-term fiscal requirements.

We took swift and decisive action in early 2020 to protect our business and strengthen our resilience, which leaves us well-positioned for the coming year. New projects coming online during 2021, coupled with our existing gas-weighted production, provide exposure to the recent recovery in gas prices, which will contribute to materially higher cash flow generation as the year progresses. We retain a high hedge ratio in 2021, providing ongoing protection against downside commodity price risk, while we continue to benefit from tax refunds from temporary changes to the upstream fiscal regime in Norway.

We aim to achieve continued improvements in our safety performance in 2021 and will also take further steps to lower our environmental footprint by implementing initiatives to reduce operational emissions, while addressing longer-term opportunities through our New Energy team. We already have among the lowest carbon and methane intensities in the sector and have set ambitious targets to reduce these further. However, we expect our carbon intensity to rise moderately in 2021, reflecting our production outlook and implementation of gas compression in the UK.

The temporary loss of production from Touat and Snøhvit in late 2020 impacts our production outlook for 2021 materially. Depending upon when these assets return to full production and new developments come on stream, we expect Group production to average 130-145 kboepd. Production-equivalent insurance proceeds for 2021 is expected to average around 10 kboepd, increasing our guidance range to 140-155 kboepd. With new projects online and a return to full production at Touat and Snøhvit, we expect to exit the year at materially higher production rates, with further growth anticipated in 2022 and 2023 as we bring additional new developments online.

Following our restructuring in 2020 and reflecting our development schedule, we are targeting a further reduction in expenditure in 2021. Development capex, including investment at Touat, is expected to be around $700 million and will be weighted towards the first half of the year, leading to higher expected free cash flow in the second half of 2021 as production also increases. Development capex at our sanctioned projects will decline further in 2022 and 2023 as projects are completed and brought onstream. This excludes uncommitted sustaining capex for new projects, which are progressing towards sanction.

Exploration spend is expected to be around $150 million in 2021, with around half to be invested in drilling activity. We expect decommissioning spending to remain low at around $55 million in 2021, largely focused on the UK, the Netherlands and Germany.

Our development and exploration expenditure continues to be weighted towards our operations in Norway, but we also expect higher year-on-year investment in the UK, Germany and the Netherlands as activity in these countries increase.

Operating costs are expected to increase modestly in 2021 reflecting higher tariffs, unfavourable foreign exchange assumptions and cost increases at non-operated assets. As a result, while opex remains low, it is expected to average $11-12/boe for the full year. Opex per barrel is expected to fall sharply from 2022 as new lower-cost production is brought onstream.

Due to the actions taken in 2020, Neptune remains fully funded from projected operating cash flows, supported by significant available liquidity. While leverage will increase in the first quarter of 2021, we expect it to decline to around 1.5x in the second half of the year as EBITDAX increases and net debt falls. We retain a disciplined and focused approach to capital allocation and will invest selectively in new opportunities, including through M&A, where it makes strategic sense and delivers strong returns.

Operational review
continued

Norway

Daily average production

Gas production
(kboepd)

2020	**21.3**
2019	24.1

Gas production for sale as LNG
(kboepd)

2020	**8.0**
2019	13.3

Liquid production[1]
(kbpd)

2020	**25.4**
2019	30.3

Total production
(kboepd)

2020	**54.7**
2019	67.7

1 Liquid includes oil and condensate and other natural gas liquids

Odin Estensen
Managing Director, Norway

> **"Beyond contributing a significant part of Neptune's production today, Norway is central to Neptune's growth tomorrow. Over the next two years, we will bring on three new operated projects and four non-operated projects. In addition, we will progress longer-term development opportunities through our exploration programme."**

Production

After a strong start to the year, production in Norway was impacted temporarily by planned shutdowns and a fire at the non-operated Hammerfest LNG facility, which shut-in production from the Snøhvit fields from October. The operator, Equinor, expects operations at Hammerfest to restart in October 2021. Neptune's losses of revenue from the Snøhvit Unit are recoverable through business interruption insurance (less a deductible), and for 2020 Neptune received payments totalling $9 million. Excluding insurance payments, Neptune's production in Norway averaged 54.7 kboepd in 2020, which contributed 38% of Group volumes.

In 2020, our operated Gjøa field delivered a strong performance, with high production efficiency and several wells producing longer than expected. During the year, we executed two shutdowns successfully, reducing planned outages from 60 to 32 days. Two further shutdowns, totalling 45 days, are planned in 2021 as part of our maintenance and development programmes.

At our non-operated fields, production efficiency was lower than expected. At Gudrun, production was impacted by slow drilling progress and the geo-mechanical failure of one of two producers, which was successfully redrilled. A shutdown was completed as planned in September. At Fram, output was impacted by temporary export restrictions at Troll C and two unplanned shutdowns in the third quarter for repairs. Annual shutdowns in 2021 are planned at Fram in April and Gudrun in September.

Due to the loss of LNG output from the Hammerfest facility, production from Norway in 2021 is expected to be lower than in 2020. Production losses will be offset partially by new volumes coming onstream from the Gjøa P1 development, which started up in February, and the Duva development, which is expected online in the third quarter. At Gudrun, three new wells are due to start-up, which will complete the current infill campaign. Together with the restart of production at Snøhvit, these new projects will result in significantly higher volumes at the end of the year.

Economic production in 2021, including insurance proceeds, is expected to be materially higher than in 2020. Production will continue to increase in 2022 and 2023 as we bring our new projects onstream.

Operating costs in Norway remained low in 2020, at $7.0/boe, but rose slightly as cost reductions were offset by lower production. In 2021, operating costs per barrel are expected to rise reflecting deferred maintenance expenditures from 2020, higher processing and logistics costs and reduced production. Lifting costs are expected to decline again in 2022 as production increases.

As part of our organisational changes in 2020, we closed our ancillary office in Oslo and reduced employee and contractor numbers to reflect our new structure and longer-term planned level of activity. As part of this process, we relinquished some acreage and deferred activity as we renew focus on core areas, including Dugong, Gjøa, Njord and Gudrun.

Development

Due to the challenges of COVID-19 and implementation of our cost reduction plan, the development schedules for our operated Duva and Fenja projects were revised in 2020. While this deferred some production growth in 2021 and 2022, it significantly lowered our capex commitments in 2020. Despite this, we continued to make significant investment in our assets in Norway, with development capex of $445 million in 2020. With our projects starting to come onstream, we expect development capex in Norway to decrease around 25% in 2021.

In 2020, we made important progress on our operated Gjøa P1 and Duva projects, with both tracking under budget. During the year, we successfully completed the main subsea campaigns and commenced drilling activities. At Duva, we expect topside scope and well completions to be completed in the third quarter of 2021. First production from the Gjøa P1 project commenced on schedule in February 2021. Together, the Gjøa P1 and Duva projects are expected to contribute 16 kboepd at plateau.

First oil from our operated Fenja project is expected in the second quarter of 2022, following delays to the non-operated Njord Future project announced by Equinor in late 2020. In 2020, we commenced the first drilling campaign, installed the majority of the subsea infrastructure and a 9 km section of the production pipeline. The subsea pipeline is expected to be completed in the second half of 2021, with the second drilling campaign starting in the fourth quarter of 2021. The Fenja project remains on budget and is expected to contribute 11 kboepd at plateau.

At the Njord Future project, Equinor, the operator, has advised that sail-away of the Njord A Floating Production Unit is now expected in the second half of 2021, together with offshore hook-up and commissioning. Onshore construction and commissioning of the Njord B Floating Storage Unit are scheduled to be completed in the third quarter ahead of sail-away.

In mid-2020, temporary changes to the petroleum tax regime were approved by parliament in Norway, providing accelerated recoveries for investments and tax refunds for expenditures in 2020 and 2021. The legislation also applies to new projects submitted for approval before the end of 2022, considerably improving economics for a range of projects.

Among our recent discoveries, we are evaluating the potential to accelerate development of Dugong, Echino South, Sigrun and Sigrun East to benefit from this temporary change in legislation. Together with currently undeveloped 2P reserves, we have the potential to produce more than 100 kboepd in Norway, demonstrating its significant growth potential within our portfolio.

In February 2021, plans for the electrification of our non-operated Gudrun platform were approved by the Norwegian Ministry for Oil and Energy. The project is expected to start-up in late 2022.

Exploration

Neptune participated in four exploration wells in 2020, resulting in three new discoveries at Bue, Dugong and Sigrun East. The most significant of these was the Neptune-operated Dugong discovery, which was announced in June, and is now being fast-tracked for potential development. We expect to submit a development plan for Dugong in 2022. We have identified significant resource potential in Dugong and the surrounding acreage and further assessment of this potential will be a key focus for Neptune in 2021.

In 2021, we plan to drill up to six exploration and appraisal wells. We have started drilling an appraisal well on the Dugong discovery and will return in the third quarter for an exploration well targeting the Dugong Tail prospect. We are also drilling a well on the Blasto prospect, located close to our recent Echino South discovery near the Fram field. A further well, targeting the Apodida prospect, will be drilled in the same area later in the year, as we prioritise resource potential in our core areas.

The Netherlands

Daily average production

Gas production
(kboepd)

2020	**19.5**
2019	19.9

Liquid production[1]
(kbpd)

2020	**1.6**
2019	1.8

1 Liquid includes oil and condensate and other natural gas liquids

Total production
(kboepd)

2020	**21.1**
2019	21.7

Lex de Groot
Managing Director, The Netherlands

"Neptune is the largest offshore gas producer in the Netherlands – and ideally placed to support the energy transition. With CCS and green hydrogen projects underway, we will connect energy systems and add value to the energy transition by extending the life of critical infrastructure."

Production
Production from the Netherlands averaged 21.1 kboepd in 2020. Operations were impacted by lower production efficiency as we focused on improving safety and facility integrity, which will benefit production output in the longer term. This activity led to a sharp reduction in PSER in 2020 and we are targeting continued improvement in 2021.

During periods of high availability, production was strong, supported by new volumes from the Sillimanite development, which came onstream in March. Production in the fourth quarter averaged 22.6 kboepd and has begun 2021 strongly.

In 2021, production is expected to be slightly lower reflecting our continued focus on facility integrity and maintenance programmes, which will include some activity deferred from 2020 due to COVID-19 restrictions. Planned shutdowns will therefore result in seasonally lower production in the second and third quarters.

Production optimisation in the Netherlands remains a key opportunity as we focus on delivering growth at strategic hubs through disciplined and targeted investment. In 2021, we plan to drill a new well at K9ab-A4 and workover wells at G14-A and K9ab-B. Additional infill opportunities provide further growth opportunities.

Despite lower production, we reduced operating costs in the Netherlands in 2020 to $13.8/boe. While our cost reduction programme will deliver further operating cost savings in 2021, lower production will increase unit opex.

Development
In 2020, our development activity was partially curtailed by COVID-19 restrictions and our cost reduction initiative, which led to the deferral of the K9ab-A4 and L15-A109 wells. The L5a-D4 well was brought onstream in early 2020 and was followed by the successful development of the Sillimanite field. In mid-2020, a new discovery was made at the Sillimanite South prospect, which was tied in and commenced gas production in early December 2020. A further potential development well in the area is being evaluated.

We invested $24 million of development capex in the Netherlands in 2020 and, while investment will increase in 2021, spending will remain relatively modest. The majority of our planned investment is on the K9ab-A4 development well.

Reducing our environmental footprint through the establishment of a New Energy team is an important strategic objective for Neptune, and, in December 2020, we announced a feasibility study into plans for a CCS project to inject CO_2 in the depleted gas fields around the Neptune-operated L10-A, B and E areas.

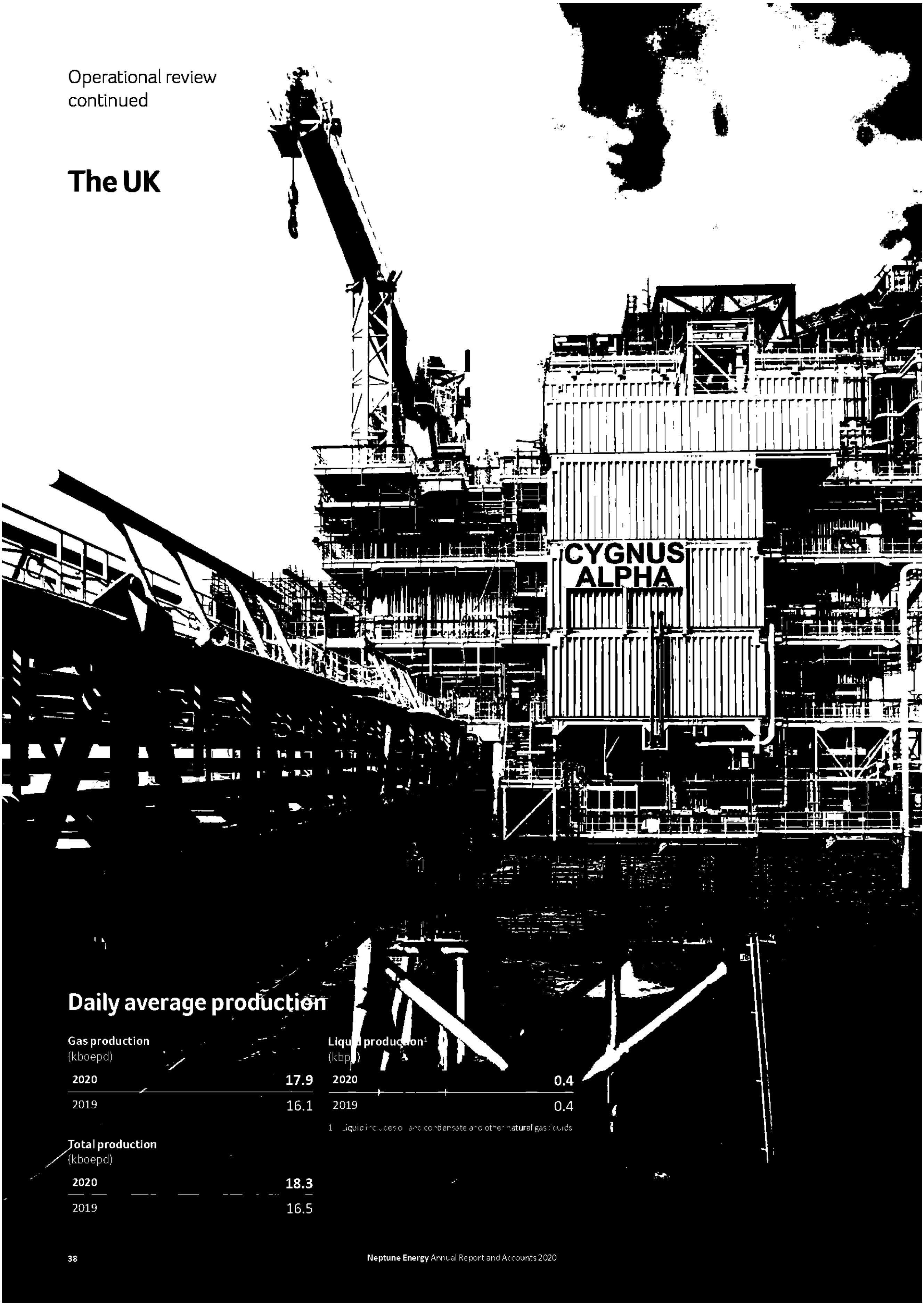
At our green hydrogen project, PosHYdon, which will be hosted on our Q13a platform, the subsidy application was submitted in January 2021 and the project is expected to enter the design phase later in the year. PosHYdon is a key part of Neptune's vision for offshore large-scale green hydrogen production in the Dutch North Sea. It will be the first example of smart offshore energy system integration – utilising offshore wind, offshore gas and green hydrogen, together with the use of existing offshore infrastructure. Co-use and re-use of existing offshore infrastructure will speed up crucial steps towards a low carbon future, reducing opex and extending the life of offshore infrastructure and gas production.

In 2020, we completed the decommissioning of the L10 C, D and G platforms and ceased production from the G14-B and D18-A fields. In 2021, our decommissioning programme in the Netherlands includes the plugging and abandonment of several wells and the warm stacking of several assets ahead of abandonment. We are collaborating with other operators and Nexstep to optimise our decommissioning strategy.

Exploration
Following on from the successful Sillimanite development, a gas discovery was announced at the Sillimanite South prospect in the second quarter of 2020. As planned, the discovery was tied into the Wintershall-operated D12-B platform.

In 2021, we plan to drill two further exploration wells. One targeting a shallow gas target in the F5a block, operated by Neptune. A discovery in this licence would unlock further potential for shallow gas in the area and could be tied back to the Neptune-operated F3-FB facilities. The second exploration well planned targets a high-potential prospect in the N04 and German H&L licenses, operated by ONE-Dyas, and close to the planned N05 development.

As part of Neptune's strategy to extend the life of critical infrastructure, we have identified further low-risk prospects that will be matured further for potential drilling in the coming years.



Operational review
continued

The UK

Daily average production

Gas production
(kboepd)

2020	**17.9**
2019	16.1

Liquid production[1]
(kbpd)

2020	**0.4**
2019	0.4

1 Liquid includes oil and condensate and other natural gas liquids

Total production
(kboepd)

2020	**18.3**
2019	16.5

Alexandra Thomas
Managing Director, UK

"Cygnus is one of the lowest carbon gas fields in the North Sea – and strategically important for the UK. With our Seagull project and development opportunities at Isabella, we will continue to play a crucial role in the UK's energy future."

Production

In the UK, we achieved a strong performance in 2020, with production averaging 18.3 kboepd. Production remained at a high level for the first half of the year, but was impacted in the second half by a planned shutdown at Cygnus, export restrictions at Bacton and short duration blend gas outages. At the end of the year, production from Cygnus increased regularly to around 320 mmcfpd as we took advantage of higher available export capacity and stronger gas prices.

Our health and safety performance in the UK remains excellent and in November 2020 we achieved 24 months LTI free and 12 months TRIR free. Our annual planned shutdown at Cygnus was completed safely, on schedule and under budget. An extended shutdown is planned in May 2021, aligned with the wider UK Forties Pipeline system outage, and will include deferred maintenance from 2020 due to COVID-19 restrictions.

Operating costs in the UK declined to $7.3/boe in 2020 as we delivered cost reductions and benefitted from higher production. Unit opex will increase in 2021 due to lower planned production, but is expected to remain low. Production in 2021 will be impacted by the planned shutdown, compression start-up and lower anticipated blend availability.

Neptune continues to support the consultation to revise the UK gas quality standard to maximise economic recovery and enable Cygnus gas export without the need for blending. A joint impact study by the Health and Safety Executive and Department for Business, Energy & Industrial Strategy is underway and is expected to report towards the end of the year. A full public consultation is due to start in the second quarter of 2021.

At <2 kg CO_2/boe, Cygnus' carbon intensity is currently among the lowest in the UK North Sea and we are focused on reducing our environmental impact further, particularly given the impact of future gas compression at the field. We have commissioned a study to review possible low carbon options, which include electrification.

Development

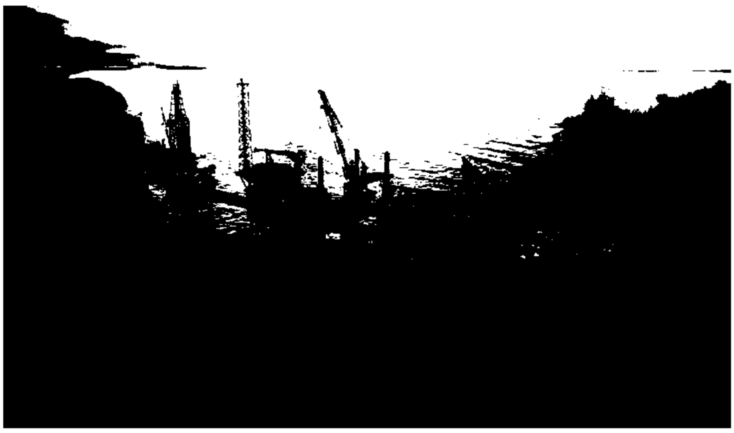
During 2020, we invested $55 million in development activities in the UK. The majority of the investment was at our operated Seagull project, where production and other utility pipelines were installed in the third quarter, while topside construction commenced at the BP-operated ETAP facility in November.

Development capex is expected to more than double in 2021 as activity at the Seagull project ramps up. In early 2021, development drilling at Seagull commenced, with four wells to be completed back-to-back by mid-2022. Further subsea campaigns are also planned during 2021, including installation of subsea manifold structures and the control umbilical by the third quarter. Production remains on schedule for start-up early in 2023 and is expected to contribute 15 kboepd net to Neptune.

At Cygnus, the gas compression project is due to start-up in the second quarter of 2021, which will help maintain production ahead of the future drilling campaign. The infill campaign is likely to see two further wells drilled in 2022. Neptune is also considering further asset investment opportunities as part of its longer-term strategy in the Greater Cygnus Area.

Exploration

In early 2020, we announced a material new gas condensate and light oil discovery at the Isabella prospect, located in the Central North Sea. Analysis of the discovery is encouraging and planning for an appraisal well is progressing, which will help de-risk key uncertainties. The well is now scheduled for early 2022.



Daily average production

Gas production
(kboepd)

2020	**11.1**
2019	6.9

Liquid production[1]
(kbpd)

2020	**5.9**
2019	5.7

1 Liquid includes oil and condensate and other natural gas liquids

Total production
(kboepd)

2020	**17.0**
2019	12.6

Andreas Scheck
Managing Director, Germany

"We have grown the business in Germany through organic development and selective acquisitions. Our portfolio contains material future development opportunities at Römerberg and Adorf, while we will continue to focus on maximising efficiency and exploring new energy opportunities."

Production
Production in Germany averaged 17.0 kboepd in 2020, with the increase from 2019 reflecting largely a change to Group-wide gas conversion factors. Production was stable for most of 2020 before increasing towards the end of the period after the Adorf discovery was brought onstream in late October. Further production growth is expected in the second half of 2021 through additional development drilling.

In early 2021, we announced the acquisition of production assets in the Emsland and the Grafschaft Bentheim region from Wintershall DEA. The transaction increases production by approximately 1.8 kboepd and enables us to leverage synergies across our operations.

The low calorific Altmark gas field will possibly cease production at the end of 2021, reducing average annual production volumes in Germany by around 5 kboepd from 2022.

Operating costs, excluding royalties, declined to $13.3/boe in 2020 reflecting higher reported production. Opex per barrel is expected to decline further in 2021 as lower cost production comes onstream. In February 2021, reductions in state royalties on oil and gas production in the Lower-Saxony region came into effect. As a result, no state royalties are now payable in 2020. The state royalty rate will increase to 5% in 2021 and to 10% for the period 2022 until 2030.

Development
In 2020, development capex in Germany declined around 15% to $42 million, reflecting the impact of COVID-19 and lower commodity prices. Following the success of the Adorf-Z15 well, we expect to increase investment in 2021 substantially, with increased drilling and maintenance activity. This includes some maintenance programmes deferred from 2020. During the year we expect to drill three new wells at the Adorf, Römerberg and Rühlermoor fields.

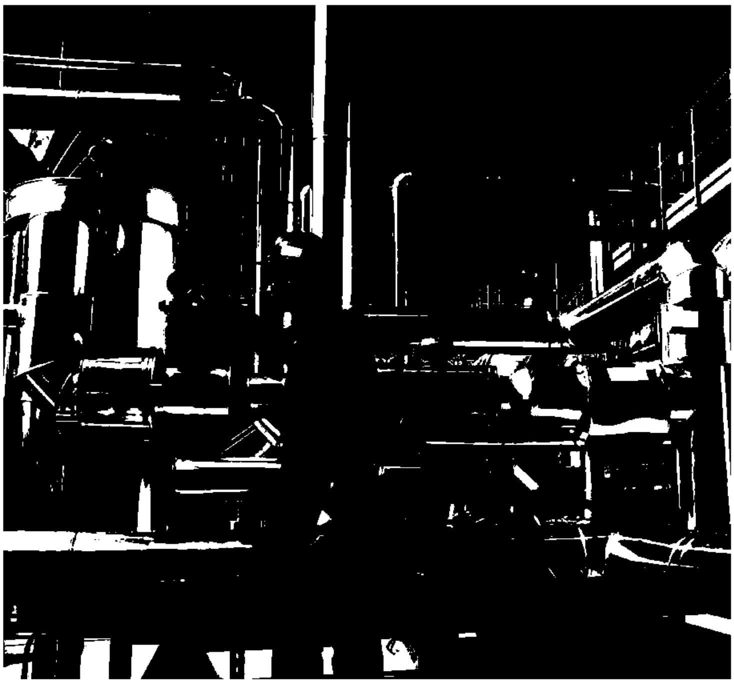
At Römerberg we are in discussions with the mining authority to resolve permitting constraints, which would enable full development of the field. As part of these plans we intend to increase production and upgrade surface facilities.

The Bramberge surface facility refurbishment programme is progressing well and expected to be completed in 2021 with final integration and commissioning planned in December. Since project approval, significant cost reductions have been delivered, resulting in savings of approximately $5 million.

Development activity at Adorf and Römerberg, together with our refurbishment programmes and acquisitions, are expected to support meaningful growth within our German business unit, generating a solid uplift in cash flow generation and long-term value creation.

Cogeneration plants are to be installed at the Rühlertwist and Schneeren fields enabling us to generate power onsite and reduce operating costs.

Exploration
In 2020, we announced positive drilling results from the Ringe-6 and Adorf-Z15 wells. Both discoveries have been successfully brought onstream, with the Adorf-Z15 well adding 800 boepd in the fourth quarter. We are evaluating similar opportunities and plan to drill the Adorf-Z16 well in 2021.



Daily average production

Gas production
(kboepd)

2020	**11.0**
2019	4.5

Liquid production[1]
(kbpd)

2020	**1.5**
2019	1.4

1 Liquid includes oil and condensate and other natural gas liquids

Total production
(kboepd)

2020	**12.5**
2019	5.9

Mehdi Bouguetaia
Managing Director, Algeria

“Touat is a strategically important gas field for Neptune and Algeria. It is Neptune’s single largest investment in North Africa and capable of providing up to 10% of Algeria’s natural gas export supply – and offers opportunities for further growth.”

Mohamed Mounes Shahat
Managing Director, Egypt

“Neptune is well-positioned in Egypt, with stable production, short-term development and long-term exploration opportunities around Block 4.”

Algeria

Production

During 2020, we successfully completed the commissioning process at the Touat project, with the plant handed over to the Groupement TouatGaz (GTG) operational team in the second quarter. The performance of the processing plant has been variable. Following remedial shutdowns in the third quarter, technical issues necessitated a longer-term shutdown of the facility. Remedial work has progressed well and the plant is expected back online by the end of the first quarter of 2021.

Reflecting these issues, production at Touat averaged 7.8 kboepd net to Neptune in 2020. Improving production efficiency and optimising phase one production remain key objectives.

The COVID-19 pandemic has caused significant disruption and poses unique operational and logistical challenges at Touat. Despite this, the organisation has been strengthened and responded well, delivering an improved TRIR performance in 2020. We will continue to focus on delivering further improvements, as well as lowering our environmental impact.

Operating costs in Algeria averaged $10.8/boe in 2020, reflecting lower than expected production. Operating costs in 2021 are expected to remain stable.

Development

Capital expenditure associated with Touat (equity accounted investment) was $24.1 million in 2020 reflecting completion of the primary phase of the field development and gas plant construction project. Investment is expected to remain broadly flat in 2021 as we finalise repairs and commence FEED for the phase 2 development project. Phase 2 is expected to extend plateau production from the late 2020s and will involve the phased development of eight additional fields and the drilling of 16 production wells.

Egypt

Production

In Egypt, production remained stable, averaging 4.7 kboepd in 2020. Production is expected to average around 3.5 kboepd in 2021, reflecting the relinquishment of the Ashrafi concession in November 2020. Production from the Alam El Shawish West concession will be supported by our planned infill and workover campaigns.

Our health and safety performance in Egypt remains excellent and in 2020 our environmental performance improved with a material reduction in flared gas.

Operating costs in the Egypt region were $10.4/boe in 2020 and are expected to decline to less than $7/boe in 2021 due to the expiry of the higher cost Ashrafi concession.

Development

We invested $8 million of development capex in 2020 with investment likely to increase marginally in 2021. We have five development wells planned across our Assil, Bahga, Magd and Karam fields. The Karam-11 well is due to be brought onstream in the third quarter. A further 18 infill locations have been identified for future drilling campaigns.

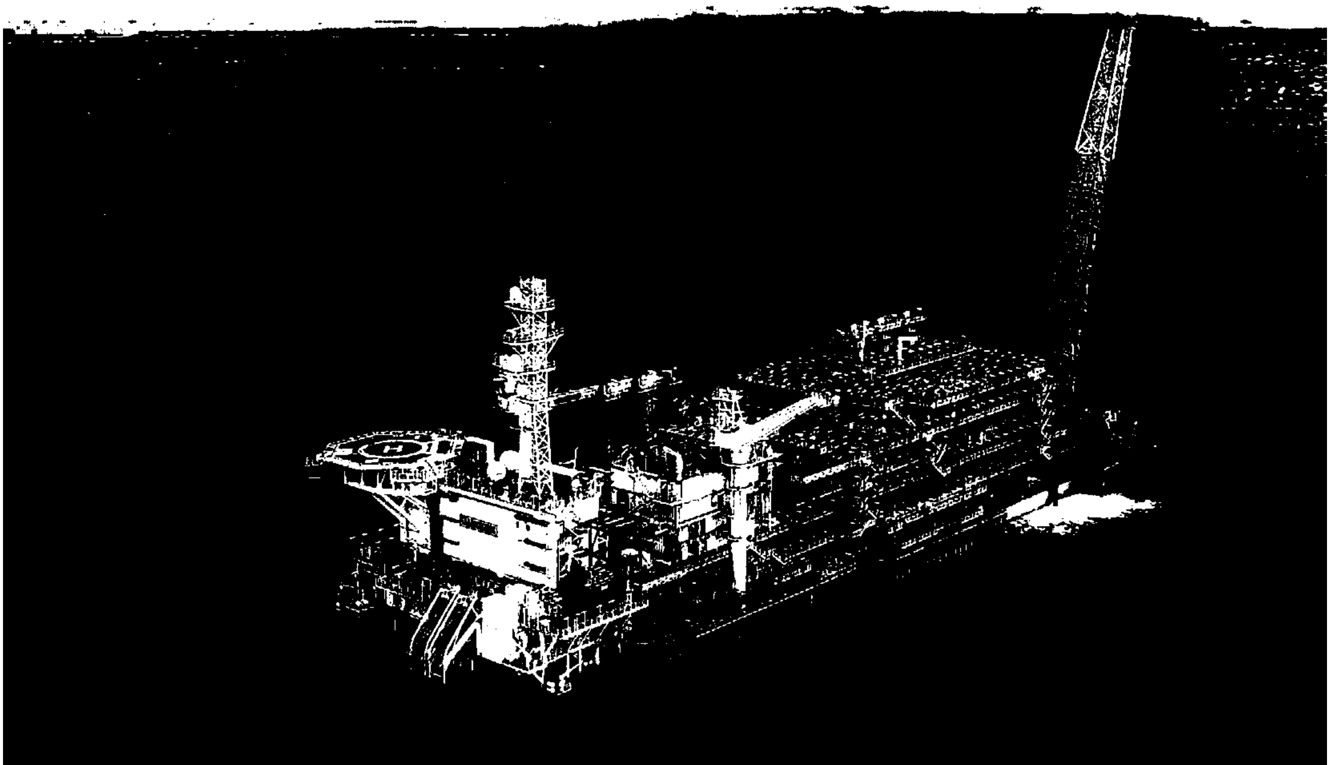
Exploration

The Assil C105 and Bahga C101 Deep prospects are to be drilled towards the end of 2021.

Processing of the OBN seismic survey acquired in early 2020 on the North West El Amal concession, in the southern Gulf of Suez, is due to be completed in mid-2021. Planning for the first exploration well is expected to commence later in the year ahead of possible drilling in late 2022.

Operational review
continued

Indonesia and Australia



Daily average production

Gas production
(kboepd)

2020	**4.6**
2019	3.1

Gas production for sale as LNG
(kboepd)

2020	**13.6**
2019	15.8

Liquid production[1]
(kbpd)

2020	**0.6**
2019	0.6

Total production
(kboepd)

2020	**18.8**
2019	19.5

1 Liquid includes oil and condensate and other natural gas liquids

Eko Lumadyo
Managing Director, Indonesia

> **"Indonesia is already a significant contributor to Neptune's production portfolio, with the Jangkrik field and Merakes project. But it is also an engine for growth, with considerable reserves and resources providing material growth opportunities for the longer term."**

Janet Hann
Managing Director, Australia

> **"The Petrel gas field holds significant contingent resources, that provide Neptune with long-term growth opportunities in a prolific basin."**

Indonesia

Production

Production in Indonesia averaged 18.8 kboepd in 2020. This reflects modest curtailments of planned production due to the deferral of the Merakes project and a period of high inventory in the Bontang LNG facility during the middle of the year. Meanwhile, colder weather has since tightened the Asian gas market significantly and LNG prices have risen substantially over the winter period.

Production in early 2021 was impacted by a planned shutdown of the Jangkrik FPU as part of the Merakes development programme. Following the start of production from Merakes, anticipated in the second quarter, production is expected to average more than 20 kboepd for the remainder of the year. Partial maintenance shutdowns planned at Jangkrik in May and August will be offset by higher volumes at Merakes.

Operating costs declined to $9.4/boe, reflecting completion of the second tie-in point and lower C3/C4 costs for blending. Operating costs are expected to remain at a similar level in 2021.

Development

Development activity in Indonesia was impacted by COVID-19 restrictions in 2020, leading to a suspension of activity during the second and third quarters of the year. The Merakes development programme recommenced in September 2020 and is now close to completion, with all five wells drilled, major topside modules installed and significant subsea infrastructure already completed. Final installation and tie-in work, commissioning and start-up activities are expected to be finalised early in the second quarter ahead of first gas. Merakes will provide back-fill gas production to the Jangkrik FPU and will contribute up to 11 kboepd at plateau. The undeveloped Maha and Merakes East fields will provide further tie-back opportunities as additional production supplies are required to maintain maximum export capacity.

Development capex in Indonesia increased to $142 million in 2020, reflecting development activity at the Merakes project. It is expected to decline substantially in 2021 due to the completion of the Merakes project.

Exploration

Significant exploration potential has been identified in Neptune's acreage in the Kutei basin, which offers considerable growth potential through tie-back and standalone developments. In the second quarter of 2021 the Maha-2 well will be drilled to appraise the existing Maha discovery. The well is expected to be suspended for future development.

Australia

Exploration

Following the acquisition of 3D seismic covering the Petrel field in early 2020, we have now received final processed data. This new and larger geographical data set incorporates advanced acquisition and processing technologies. It will provide a step-change towards the petrophysical delineation of the field area and, ultimately, de-risk our development plans.

We continue to evaluate additional growth opportunities, including M&A, in Australia.

Financial review

Robust financial results and strong capital structure

EBITDAX

$939.8m

Operating cash flow

$915.4m

Average operating cost

$9.5/boe

Net debt/EBITDAX

1.94x

Average realised oil price

$40.3/boe

This report includes the Group results for the 12 months ended 31 December 2020.

Results of operations

$ millions	Year ended 31 December 2020	Year ended 31 December 2019
Revenue	**1,560.1**	2,202.2
Operating (loss)/profit (note a)	**(95.4)**	872.7
Underlying operating profit (note b)	**287.3**	951.0
(Loss)/profit before tax	**(333.1)**	676.8
Taxation	**(65.9)**	(237.8)
Net (loss)/profit after tax	**(399.0)**	439.0
EBITDAX (RBL basis) (note c)	**939.8**	1,600.2
Cash flow from operations, after tax	**915.4**	1,320.6
Adjusted development cash capital expenditure (note d)	**741.4**	1,122.1
Net debt (book value) (RBL basis) (note e)	**1,821.4**	1,490.1
Net debt/EBITDAX (RBL basis) (note e)	**1.94 x**	0.93 x

a) Operating (loss)/profit comprises current operating income after share in net income of entities accounted for using the equity method and is stated before tax and finance costs, but after mark-to-market on commodity contracts and non-recurring items.
b) Underlying operating profit is calculated as operating (loss)/profit before the impact of impairment losses, restructuring costs and pension settlements or curtailments. A full calculation is shown on page 48.
c) EBITDAX comprises net income for the period before income tax expense, financial expenses, financial income, impairment losses, other operating gains and losses, exploration expense and depreciation and amortisation. EBITDAX as defined by the RBL and shareholder agreement includes our share of net income from Touat in 2020 following the repayment of the Touat Vendor Loan. EBITDAX for 2019 excludes our share of net income from Touat. For more detail on the Touat loan and the RBL please see the Financing and Liquidity section on page 49.
d) Includes capital expenditure of $24.1 million for the year (2019: $61.4 million) in respect of the Touat project, held by a joint venture company which Neptune accounts for under the equity method.
e) Net debt excludes Subordinated Neptune Energy Group Limited Loan and Touat project finance facility as defined by the RBL and Shareholder agreements. The Touat project finance facility was repaid at the end of September 2020.

Revenues for the year were $1,560.1 million (2019: $2,202.2 million), reflecting total production from wholly owned subsidiaries of 49.3 mmboe (2019: 52.0 mmboe). Realised prices, before and after hedging are shown in the table below. Production for the full year is lower than 2019 notably in the fourth quarter but the reduction in sales for the year can mainly be attributed to the significantly lower commodity prices notably in the second, third and fourth quarters.

The Brent crude price averaged $43.2 (2019: $64.2) per barrel for the year and our average realised oil price (pre hedging) was $40.3 per barrel (2019: $62.0) for the year. Including hedging our average realised oil price was $46.1 per barrel (2019: $61.5) for the year. The combination of a sharp reduction in demand from the COVID-19 global pandemic and the temporary breakdown of the OPEC+ production alliance caused crude oil prices to be substantially lower during 2020, compared to 2019.

The average realised gas price was $3.1 (2019: $4.7) per mcf (pre hedging) and $4.4 (2019: $5.2) per mcf (post hedging) for the year. The European gas market faced fundamental pressure in 2020 as a mild winter and lower demand stemming from the COVID-19 pandemic led to elevated regional storage levels and lower gas prices.

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

Realised prices for wholly owned and equity accounted affiliates:

	Fourth quarter 2020	Fourth quarter 2019	Year ended 31 December 2020	Year ended 31 December 2019
Excluding impact of hedging:				
Average realised gas price ($/mcf)	**4.8**	4.2	**3.1**	4.7
Average realised LNG price ($/mcf)	**5.8**	8.0	**5.8**	8.3
Average realised oil price ($/bbl)	**41.8**	61.7	**40.3**	62.0
Average realised price, other liquids ($/bbl) (note a)	**27.3**	47.3	**21.9**	39.0
Including impact of hedging:				
Average realised gas price ($/mcf)	**5.3**	4.8	**4.4**	5.2
Average realised LNG price ($/mcf)	**6.6**	8.0	**6.2**	8.3
Average realised oil price ($/bbl)	**46.4**	62.0	**46.1**	61.5
Average realised price, other liquids ($/bbl) (note a)	**27.3**	47.3	**21.9**	39.0

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

In 2020, $9.0 million of other operating income arose in relation to business interruption insurance proceeds for loss of revenue in relation to an incident at Hammerfest LNG plant in Norway where Neptune is a non-operated joint venture partner.

Operating costs were $467.0 million (2019: $533.5 million) for the year to 31 December 2020 and our average operating cost per boe produced was $9.5/boe compared with $10.3/boe for 2019. Operating costs for the purpose of per boe expense are reduced by $70.2 million (2019: $2.1 million increase) for the year to 31 December 2020 to exclude changes in the value of under-lifted entitlement to production, to net-off income from tariffs and services which serve to recover costs, to exclude predevelopment costs and to exclude abandonment costs incurred on non-producing fields. The lower operating costs in the year reflect lower production costs notably in Indonesia where blending costs have reduced and cost outturns have been lower and in Germany where royalties have reduced in certain areas. The impact of resilience and cost efficiency plans in the current market environment are seen with a lower cost base.

The depreciation and amortisation expense was $584.7 million (2019: $624.2 million). The charge represents $11.9/boe produced compared with $12.0/boe produced for the year ended 31 December 2019.

Exploration expense for the year was $91.2 million (2019: $60.4 million) which includes costs incurred on Geological and Geophysical studies to review strategic growth opportunities as well as seismic costs. The higher 2020 charge was primarily due to costs recognised for unsuccessful well evaluations including $11.5 million in Norway, $8.8 million in Germany and $10.2 million in the UK.

General and administration expense of $69.1 million (2019: $68.6 million) for the year to 31 December 2020 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. The gross G&A cost for the group in 2020 has benefitted from the cost efficiency programme.

Share in net loss of entities accounted for under the equity method was $20.0 million (2019: $2.1 million income) for the year ended 31 December 2020. This represents the Touat joint venture, which commenced production in September 2019, of $21.6 million loss (2019: $1.0 million income) and tariff income of one of our Dutch pipeline interests of $1.6 million (2019: $1.1 million). The loss from the Touat joint venture reflects a post-tax impairment of $32.7 million booked by Neptune due to market price conditions.

Group net impairment losses (pre-tax and excluding the Touat impairment mentioned above) for the year were a total of $325.7 million (2019: $59.4 million). Impairment losses in relation to PP&E are $301.5 million and include $197.7 million for a single Cash Generating Unit (CGU) in Indonesia, $91.1 million for a single CGU in the Netherlands and $12.7 million for a single CGU in Germany. These impairments are primarily due to decreases in the long-term price assumptions and underlying reservoir performance. Goodwill impairments in Egypt and Denmark were $14.4 million and there are also $9.8 million of net impairments to intangible assets including $10.0 million for the relinquishment of an exploration licence in Indonesia and $7.7 million for a single CGU in Denmark partly offset by the reversal of an impairment to intangibles in Norway of $7.9 million due to a discovery. The goodwill and CGU in Denmark were acquired as part of the VNG acquisition in 2018.

The $59.4 million impairment loss in 2019 includes impairments of a Netherlands 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.

Other operating gains/(losses) were a loss of $33.6 million (2019: $15.7 million gain) for the year to 31 December 2020. The 2020 loss includes a loss on mark-to-market on commodity contracts other than trading instruments of $4.0 million (2019 gain: $14.2 million), a restructuring charge of $25.3 million (2019: $68.9 million), release of contingent consideration $20.3 million, unsuccessful business combination termination fees $5.0 million and other losses of $20.6 million (2019 $20.4 million gain). There was a one off pension credit of $1.0 million (2019: $50.0 million).

The net restructuring costs recorded in the year include a charge of $33.1 million in relation to the announcement in June to reduce 400 positions across our business and proposals to close offices in Oslo in Norway and Lingen in Germany, offset by a release of $7.8 million relating to 2019 reorganisations. The 2019 $68.9 million restructuring charge relates to group reorganisation costs in Germany and the decision to close the previous corporate office in France.

The release of contingent consideration in 2020 is in relation to two assets in Denmark and Norway that were part of the VNG acquisition. Other losses in 2020 principally relate to a $17.9 million write off of a JV partner debtor. The 2019 $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 Group's operating loss for the year to 31 December 2020 was $95.4 million (2019: $872.7 million profit) before net finance costs. Underlying operating profit is calculated before the impact of impairment losses, restructuring costs and pension curtailment credits. For 2020 underlying operating profit is $287.3 million and for 2019 is $951.0 million.

Financial review continued

$ millions	Year ended 31 December 2020	Year ended 31 December 2019
Operating (loss)/profit before financial items	**(95.4)**	872.7
Add back:		
Share of net loss from investments using equity method – Touat impairment	**32.7**	–
Impairment loss	**325.7**	59.4
Net restructuring cost	**25.3**	68.9
Deduct:		
Pension scheme settlement/ (curtailment credit)	**(1.0)**	(50.0)
Underlying operating profit	**287.3**	951.0

Net financing expenses were $237.7 million (2019: $195.9 million) for the year and include $132.7 million (2019: $122.5 million) of interest expense, unwinding of discount on provisions of $36.1 million (2019: $36.5 million) and $7.1 million (2019: $8.2 million) interest expense in relation to right-of-use lease liabilities. In 2020 a net foreign exchange loss of $59.8 million (2019: $21.4 million loss) arose. The net foreign exchange loss arises on the revaluation of loans and working capital balances for internal funding purposes across the Group and is principally impacted by the exchange rates for Euros, Norwegian Krona, Sterling and US Dollars.

The Group's loss before tax for the year to 31 December 2020 was $333.1 million (2019: $676.8 million profit). EBITDAX (as defined by the RBL and Shareholders Agreements) for the year was $939.8 million, compared with $1,600.2 million for the year ended 31 December 2019. The decrease in EBITDAX principally reflects lower realised commodity prices in the year.

$ millions	Year ended 31 December 2020	Year ended 31 December 2019
Loss/profit before tax	**(333.1)**	676.8
Add back:		
Net financing expenses	**237.7**	195.9
Other operating gains and losses	**33.6**	(15.7)
Net impairment loss	**325.7**	59.4
Exploration expense	**91.2**	60.4
DD&A	**584.7**	624.4
Share of net income from investments using equity method (note a)	**–**	(1.0)
EBITDAX (RBL basis)	**939.8**	1,600.2

a) In 2019 EBITDAX as defined by the RBL and Shareholder agreements excluded our share of net income from Touat.

The Group's total tax charge for 2020 is $65.9 million (2019: $237.8 million), comprising a current tax credit for the year of $286.9 million (2019: $330.4 million charge) and a deferred tax charge for the year of $352.8 million (2019: $92.6 million credit). The total tax charge for the year represents an effective tax rate of (20)% (2019: 35%). The effective tax rate for the year is impacted by the following items.

In the UK, we have revised the expected recovery of our deferred tax balances ($143.0 million deferred tax charge) in response to softening commodity price assumptions, partially offset by the recognition of deferred tax on decommissioning. Additionally, capital uplift allowances in Norway, comprising the new temporary changes to the Norwegian petroleum tax regime, allowing 24% uplift in the investment year ($70.3 million credit) have a positive effect on our tax charge. Finally, the tax charge is impacted by the successful resolution of tax enquiries in Norway and the Netherlands ($16.3 million current tax credit) and the partial recognition of deferred tax on current year taxable losses in Denmark, Germany and the Netherlands ($50.8 million deferred tax credit not recognised).

Net loss for the year ended 31 December 2020 was $399.0 million (2019: $439.0 million profit) on a reported basis.

For the year ended 31 December 2020 $8.1 million of additional capital and operating expenditure was incurred in relation to COVID-19. The organisation will continue to monitor and report significant COVID-19 expenditure.

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 2020, 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 $41.7/barrel for 2021 with upside capped at around $50.5/barrel.

For gas, hedging provides weighted average floor prices of $6.1/mmbtu for 2021 and $6.0/mmbtu for 2022 with upside caps at $7.3/mmbtu and $6.2/mmbtu respectively.

Aggregate post-tax hedge ratio:

	2021	2022	2023
Oil	**37%**	–	–
Gas	**70%**	43%	–
Total weighted average	**53%**	18%	–

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

The estimated net fair value (comprised of current and non-current assets and liabilities) on a mark-to-market basis of all our commodity derivative instruments at 31 December 2020, was an asset of $6.8 million (2019: $182.7 million asset), of which contracts with a net liability of $1.3 million expire in 2021.

Cash flow

Operating cash flow, after cash taxes, for the year to 31 December 2020 was $915.4 million (2019: $1,320.6 million). Cash taxes were $70.2 million received (2019: $361.7 million paid). Cash tax payments in respect of prior year profitability have been more than fully offset by cash tax refunds largely on current year results. The tax refunds result predominately from our Norwegian investment programme and the new temporary Norwegian fiscal changes. The effective rate of cash tax as a percentage of pre-tax operating cash flow was (8)% (2019: 22%).

Capital expenditure

Cash capital expenditure for the year to 31 December 2020, was $801.8 million (2019: $887.4 million), including $84.5 million (2019: $61.9 million) of capitalised exploration expenditure. The 2020 figure includes expenditure in Norway on Njord, Duva/Gjøa P1, Fenja and Gudrun projects as well as expenditure in Indonesia on the Merakes development project. This excludes expenditure at Touat in Algeria, where the joint venture is accounted for under the equity method of accounting as a joint venture. Our statement of cash flows reflects net investment at Touat in terms of the cash injections and capital reductions made with the joint venture company, which were $20.6 million cash inflow in 2020 (2019: $69.0 million outflow).

$ millions	Year ended 31 December 2020	Year ended 31 December 2019
Investing cash flows:		
Development capex (note a)	**717.3**	825.5
Acquisitions – assets	**–**	235.2
Exploration capex	**84.5**	61.9
Acquisitions – exploration	**–**	25.2
Total cash capital expenditure	**801.8**	**1,147.8**

a) Includes Saka carry reimbursement of $2.5 million (2019: $90.6 million).
b) Capex figures are for wholly-owned affiliates only.

Total exploration expenditure comprised the $84.5 million (2019: $61.9 million) cash capex and $60.9 million (2019: $60.4 million) expensed in respect of G&G and seismic costs. Capex expenditure in 2020 has primarily been in the UK and Norway whilst there was significant seismic expenditure in Egypt.

Development cash capex was $717.3 million (2019: $825.5 million). The majority of expenditure was in Norway on the Njord, Duva/Gjøa P1, Fenja and Gudrun projects as well as progressing the Merakes project in Indonesia.

We incurred $40.5 million (2019: $51.7 million) on decommissioning cash expenditure in the year to 31 December 2020, this was in the UK, the Netherlands and Germany.

Acquisitions
There have been no acquisitions in 2020. Although 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 on 14 October 2019, this agreement was terminated in the second quarter of 2020.

In September 2019, the group completed a transaction to acquire interests in certain oil and gas fields in Germany from Wintershall Dea for $1.1 million. The Company was 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.

In December 2019, the group completed a transaction 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.

On 26 August 2019, 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.

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, as defined by the RBL and shareholder agreement, remains modest. The ratio, at the end of the period, equals 1.94x. RBL covenants require this ratio to remain below 3.5.

We funded our business mainly with cash generated from operations and debt facilities. At 31 December 2020, we had the following debt outstanding:

- $1,070 million drawn under the $2.6 billion committed RBL facility, which matures in 2024;
- $850 million 6.625% senior notes, maturing in 2025;
- $108 million 7.250% Subordinated Neptune Energy Group Limited vendor loan with ENGIE E&P International S.A., maturing in 2024;
- $50 million drawn under bilateral short-term bilateral borrowing facilities.

At 31 December 2020, our cash balance totalled $92.5 million (2019: $85.4 million) and our available and undrawn headroom under the RBL facility was $1.2 billion. We also had $9 million of letters of credit drawn under an ancillary facility to the RBL and $89 million in surety bonds outstanding. Our weighted average cost of borrowing for the Group equalled 5%. Our Corporate Credit Rating with Moody's, S&P and Fitch remain at Ba3, BB- and BB respectively. Moody's outlook remains stable and S&P and Fitch remain on negative outlook as a result of the short-term industry outlook. We will continue to seek to strengthen these ratings over time.

All debt, except for the debt drawn under the RBL facility, is carrying a fixed interest rate. A significant portion of the RBL was swapped into fixed rate debt in early 2018. As at 31 December 2020, 68% of the debt portfolio was fixed, reducing Neptune's exposure to increases in the USD Libor interest rate.

On 28 September 2020, Neptune made an early repayment of the Touat Vendor loan of $237 million (including interest of $4.4 million) for an aggregate consideration of $236 million. A gain of $1 million was recognised within finance income. The loan repayment was funded by $26 million of cash and the remainder drawn under the RBL facility. Due to the significant cost difference between the Vendor Loan and the RBL, Neptune will realise cost savings of approximately $12 million per annum. As a result of the loan repayment, the Touat asset has increased the borrowing base and available liquidity under the RBL facility by $275 million.

Financial condition
Operating cash flows were $915.4 million (2019: $1,320.6 million) being impacted by the low commodity prices in the year. Investing cash flows have been reduced in response to the current market conditions and were $765.0 million (2019: $1,194.8 million) for the year being covered by operating cash flows. The financing costs and net debt repayment of $143.3 million (2019: $236.3 million) during the year resulted in a net cash inflow of $7.1 million for the year to 31 December 2020 (2019: $110.5 million outflow). We ended the year with gross interest-bearing debt of $2,021.8 million (book value) and net debt on an RBL basis, (excluding Subordinated Neptune Energy Group Limited loan) of $1,821.4 million. Net debt on an RBL basis has increased due to the repayment of the Touat Vendor Loan as discussed above. This represents a net debt to EBITDAX ratio of 1.94x for the 12 months ended 31 December 2020 (2019: 0.93x). 2019 EBITDAX excludes Touat cash flows.

2021 outlook
With commodity prices stronger than through much of 2020, we expect to generate higher EBITDAX and operating cash flows in 2021. Free cash flow is also expected to increase, as capex spending declines, particularly in the second half of 2021. This is anticipated to result in lower leverage at the end of 2021 as we aim to maintain a ratio of less than 1.5x through the cycle.

Our positive outlook is supported by production guidance of 130-145 kboepd for 2021 and insurance proceeds related to our business interruption insurance claims, which is expected to add a further 10 kboepd on an economic-production equivalent rate. Three new development projects are due to come onstream in 2021, which together with the restart of production from Touat and Snøhvit, is expected to lead to materially higher production at the end of the year.

We will maintain a disciplined approach to capital allocation in 2021, with development capex expected to decline to $700 million and exploration maintained at around $150 million. Opex is anticipated to increase to $11-12/boe in 2021, reflecting lower production and some deferred maintenance activity from 2020, but will decline from 2022 as our new lower cost projects come online.

Financial review continued

Risks and uncertainties
Investment in Neptune involves risks and uncertainties, these are summarised in detail on pages 54-56.

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 cyber threats, political risks, the international capital markets and access to capital and this may influence the speed with which growth can be accomplished.

Going concern
Given the total available liquidity as at 31 December 2020 of $1.3 billion, comprising our cash balance ($92.5 million) and available and undrawn headroom under the RBL facility ($1.2 billion), and capital resources arrangements in place (see note 19), the consolidated accounts have been prepared on a going concern basis.

The going concern basis is supported by future cash flow forecasts which project the Group's available liquidity and compliance with covenants through to 30 June 2022. The cash flow forecasts reflect forecast production consistent with our Board approved plans and externally published guidance and base case commodity prices that are slightly below current market conditions

While the short-term outlook is uncertain due to COVID-19, energy markets have stabilised and commodity prices have recovered from the lows of 2020. We believe the longer-term outlook is positive for the oil and 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, strong balance sheet and hedging provides resilience for the Group against softer commodity prices.

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 short-term commodity price forecasts significantly below current market conditions as well as scenarios that consider the impact of unforeseen production outages. We have also performed a reverse stress test to inform our judgement, which demonstrated that we are resilient to sustained low commodity prices up to 50% below our conservative base case cash flow forecast.

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

Dividend
No dividends have been declared or paid in 2020.

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). 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.

Given the improving commodity and economic outlook, the Board of Directors of Neptune Energy Group Midco Limited have declared a 2021 Interim dividend of $80 million on 24 February 2021. This was enabled through the issue of an $80 million promissory note. This enabled the approval of a 2021 interim dividend settlement of $200 million by the Directors of its ultimate parent entity Neptune Energy Group Limited (NEGL) to its shareholders.

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

This disclosure was included in the Neptune Bond (Notes) prospectus of October 2019.

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

Armand Lumens
Chief Financial Officer
10 March 2021

Effective risk management is fundamental to our success and underpins our growth strategy.

Contents

Risk management

Risk is an inherent part of our business. It is present at every stage of an asset's lifecycle – from exploration to decommissioning. Managing these risks is, therefore, fundamental to our success.

We accept risks because we are confident in our abilities to manage 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 alongside 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 the financial impact of unforeseen and less likely events.

If 2020 proved anything, it is that risk is not static and underlying levels are constantly influenced by emerging external macro-economic trends and events. Like many other companies, our risk profile in 2020 increased relative to 2019, primarily due to the contraction in oil and gas prices and uncertainties caused by the COVID-19 pandemic, global political uncertainty, increasing cyber crime and continuing changes in sentiment to the oil and gas industry, both in society and in the capital markets.

We recognise that such emerging risks could bring rapid and significant disruption to our business. While we cannot always prevent or influence such events, our focus on business resilience, sound risk governance, organisational culture and risk management process, helps us tackle those challenges effectively when they come.

There are positive external trends as well, including increased focus on environmental, social and governance (ESG) issues and on equality, diversity and inclusion. We are also influenced by changing work patterns, increased digitalisation and modernisation in our offices and assets. Progress is also being made on carbon dioxide removal technologies and hydrogen generation. Neptune continues to monitor, respond to and leverage those trends to improve our chances of success and reduce the overall risk profile of the company.

The Board specifically recognises the strategic risks and opportunities posed for Neptune by climate change and the energy transition. We will continue to develop our response to these risks and opportunities from policy, business resilience, business development and disclosure perspectives. We will keep our approach under regular review, taking account of regulatory and technology changes, as well as industry guidance.

Risk governance and culture

The Board exercises its oversight of risks and our risk management process via the Audit and Risk Committee, which oversees key enterprise risks and monitors the effectiveness of the enterprise risk management process.

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

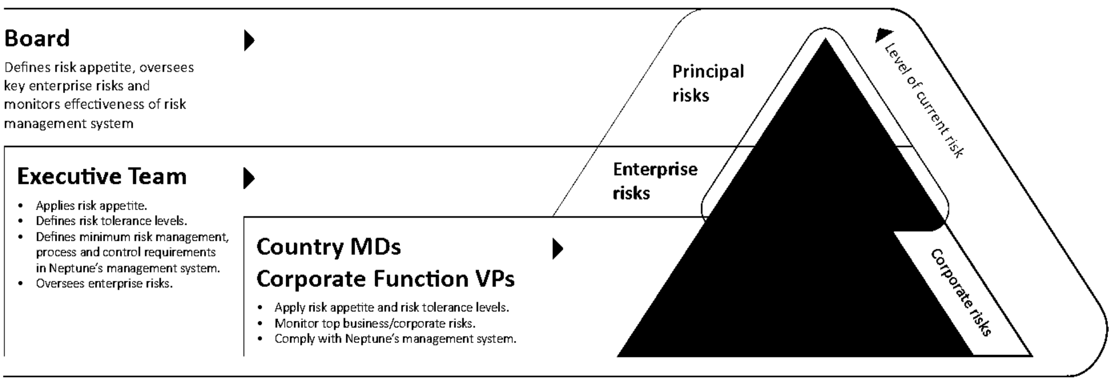
Certain risk oversight responsibilities are delegated to other management committees, or cross-functional teams:

- The Investment Committee assesses risks related to new investment opportunities and material strategic matters.
- The Operational Integrity Committee oversees health, safety, environment, quality and integrity risks in our operations.
- The ESG Committee oversees environmental, social and governance risks.
- The Incident Management Committee oversees learning review and investigation processes in response to safety and misconduct.

The Board's Risk Management Policy and the Group Risk Management Standard set out our expectations on sound risk management and outline common risk management principles. These form the foundation for other governing documents in Neptune's integrated management system, which defines how specific risks are managed. Management of risks is the accountability of line management and corporate functions, which, together with functional oversight and group internal audit, form our 'three lines of defence'.

Through visible leadership and active engagement, our Board and Executive Team promote an open and inclusive culture of high safety performance and ethical conduct, responsible risk taking and effective internal control. Our values and Code of Ethics and Business Integrity, approved by the Board, empower staff and business partners to speak up if they suspect misconduct or violation of expected corporate behaviours.

Risk governance



Risk process – integral part of business management
We believe that everyone at Neptune is responsible for managing risk at different levels. Therefore, we consider risk management a key competency for our workforce. We supply our leaders and teams with a consistent approach to help them identify and assess key business and corporate risks. Those risks are then discussed and considered at every level of the business. We encourage active participation in risk discussions because we believe that sharing different perspectives reduces bias in our risk assessments.

In 2020, we standardised our process for identifying, assessing, responding and reporting risk. It is designed to allow dynamic, risk-based decision-making and effective day-to-day risk management. We will continue to enhance the process in 2021 by adapting our IT risk solution to our new methodology. This will reduce the process burden and increase risk intelligence. Risk reporting templates are standardised across all levels of the organisation and are now an integral part of our planning and performance management cycle. This ensures that risks are discussed in the context of our strategic and business objectives.

We hold risk discussions as part of quarterly business performance reviews to understand changes in risk context and follow through on risk mitigation actions. This assures us that we have an appropriate risk response and that scenario and contingency planning is carried out when needed.

Each identified risk has an owner who is responsible for its assessment, effective control and mitigation strategies. Risk owners are accountable for the implementation of effective risk reduction actions, where needed. Key business risks are then monitored on a regular basis with oversight from country leadership teams.

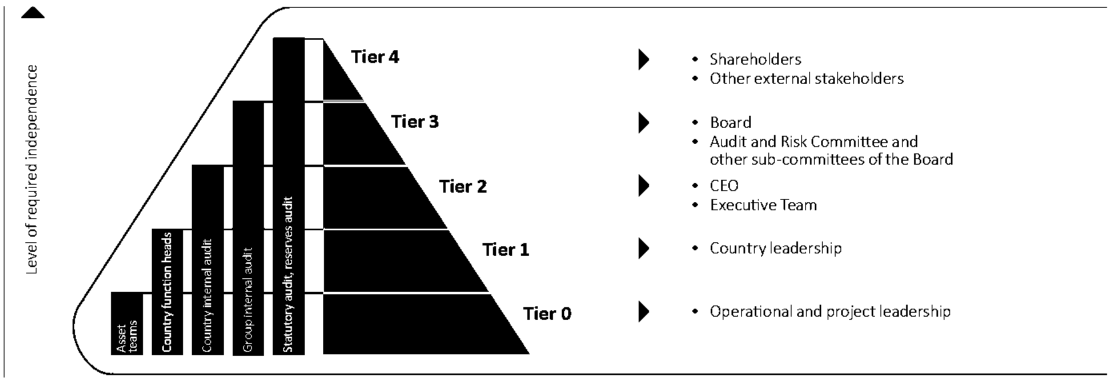
These regular conversations are fundamental in helping us maintain our focus on the risks that matter both in the short term and over a longer-term planning horizon.

Internal control monitoring and assurance
We define and implement internal controls through our integrated management system to ensure all our control requirements are consistent and kept live. The internal control system is tightly linked to the enterprise risk management process. It is also subject to assurance activities via our 'three lines of defence' to confirm that the key controls we have defined are implemented and operating effectively.

The first line of assurance is delivered by asset-level operational and project teams. This is complemented by in-country functional monitoring and assurance activities. Corporate functions and group internal audit then deliver the second and third layers of monitoring and assurance. The effectiveness of the system relies on all assurance levels being effective. In 2021, we will continue to integrate assurance activities across Neptune to ensure appropriate coverage, frequency and depth of audits and reviews.

2020 was the first year of group internal audit activity at Neptune. Early in 2020, we planned a number of risk-based internal audits for the year. Despite the COVID-19 pandemic, several were completed or are in progress. Observations and recommendations are reported to senior management and the Audit and Risk Committee of the Board.

Assurance model



2021 priorities
We review the ways in which we run our business on a continual basis and have identified a number of opportunities to improve our system of risk, internal control and assurance in 2021. The key objective is to consolidate risk, control and assurance processes across the Group by:

- Embedding a Group-wide risk management standard and adapting an IT risk solution to improve risk insights.
- Implementing a Group audit and assurance standard, assurance activity monitoring and monitoring of control improvement actions.
- Further strengthening functional risk and internal control oversight and functional assurance.
- Further consolidating Group requirements in our integrated management system.
- Defining and approving risk appetites for enterprise risks.
- Continuing to develop our approach to assessing the risks associated with the physical impact of climate change and factoring them into our activity planning.

Principal risks and uncertainties

Neptune follows a new revised risk management categorisation, which we implemented in 2020 to ensure greater consistency across the Group. This will also strengthen accountability for risk management and oversight, while enabling value-adding insights. All risks identified in our planning horizon have been categorised in one of several risk classes. In the table below we include our principal risks.

Risk	Our attitude and response to risk	Risk management in 2020
Business risks		
Replenishments of hydrocarbon reserves Delivering on our strategy depends on our ability to replenish our reserves. If we are unable to progress our portfolio options, our replacement of reserves may be affected and not allow us to sustain levels of production and deliver on growth objectives. 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 opportunities. 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. The majority of 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.	During 2020, we made significant discoveries at Dugong in Norway and Isabella in the UK, with other additional successes in Norway and in north-western Germany, which added volumes to our resource base. We maintain a strong portfolio of good exploration discoveries. The COVID-19 pandemic required us to focus our exploration programme on the most value-enhancing opportunities.
Disruption to business due to COVID-19 pandemic and resulting economic impacts Uncertainty around COVID-19 and its widespread impact may affect the health and wellbeing of staff and contractors, and their availability. This may affect the continuity of our operations. Also, it increases business risks around resilience of our key suppliers, customers and partners which may lead to delays, losses, additional costs and increased volatility.	As part of our pandemic response procedures, we implemented COVID-19 screening and, where required, quarantine requirements at our sites to ensure continuity of our operations. We continue monitoring developments around COVID-19 with assistance from our health service provider, International SOS. Regular cross-functional monitoring is also in place for key sources of business risk (suppliers, customers, partners and financial counterparties). However, uncertainty remains about the possibility of further disruption.	In response to the pandemic we followed applicable government and industry guidelines and best practice, ensuring social distancing in office environments and encouraging office-based employees to work from home. At our operations, we introduced screening procedures for offshore personnel, reducing the risk of contamination at offshore facilities. The business also swiftly introduced other resilience measures, such as deferring or cancelling discretionary expenditure, which improved our liquidity position. We also strengthened the way we monitor third-party risks. These positive changes to our organisation will have a long-term impact on the sustainability of the business.
Project delivery We invest in development projects that are capital intensive and, compared to other industries, can take longer to generate returns. 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 response to COVID-19, we, along with our partners, deferred a number of projects to strengthen the resilience of the business where there was a contractual right to do so. For ongoing projects, COVID-19 prevention measures did not affect the delivery of key milestones. However, the level of uncertainty around the availability of key staff and contractors remains. Despite COVID-19 restrictions, all project delivery goals were met on P1, Duva and Fenja, with a safety record that is best-in-class.

Risk	Our attitude and response to risk	Risk management in 2020
Business risks continued		
Production loss Our operated and non-operated producing assets or critical infrastructure may be disrupted by operational incidents or mandated curtailments, leading to an inability to meet production targets.	We attempt to reduce operational disruption risks as much is reasonably possible by enforcing our internal standards and policies. We also maintain a comprehensive business interruption insurance programme to protect our cash flow from such incidents.	Our production volume in 2020 was affected by unplanned outages at non-operated assets in Norway and Algeria, which are protected by our insurance programme. Our operated production performed well with high levels of production efficiency.
Climate change The risks associated with climate change have the potential to affect aspects of Neptune's long-term business model, earnings, cash flow and value of assets. New legal, fiscal and/or regulatory measures could have an impact on project timing, cost base and economics. Demand for fossil fuels may diminish as a result of changes in consumer behaviour and technology. Pressure on financial institutions to limit their exposure to fossil fuel projects may continue to grow. It may become harder to attract new talent, attract funding or retain licences to operate in certain jurisdictions. In the longer term, the physical impact of climate change, such as an increase in the frequency of severe weather events, may adversely affect our operations and supply chain.	We identify, assess and manage climate-related risks through our enterprise risk management system. To prepare for future carbon regulation, we have incorporated an internal carbon price into our risk assessments and investment decisions.	We are adopting the recommendations of the Taskforce on Climate-related Financial Disclosures. We will continue to develop our response to these risks and opportunities from policy, business resilience, business development and disclosure perspectives. We will keep our approach under regular review, taking account of regulatory, policy and technology changes.
Stakeholder risks		
Host country risk Our operated asset base is located around the North Sea in countries that have a long-established oil and gas industry, infrastructure and capability. We also invest in emerging markets, where we can be exposed to increased political, social, fiscal and other regulatory challenges. Host country policies towards the oil and gas industry may impact Neptune's strategy, add to cost base and reduce profit margins, and, ultimately, lead to challenges in the economic viability of projects and assets.	Our leadership team and country management are experienced in managing businesses in challenging environments. We assess the risks of entering new countries carefully 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. As part of our diversification strategy, we plan to continue to balance our investments between OECD and non-OECD countries.	In light of the COVID-19 pandemic, in the short term, EU countries may prioritise security of supply and achieving low-cost gas. In the longer term, a focus on 'green recovery' may become more pronounced, increasing the negative sentiment on fossil fuels. This creates opportunity for hydrogen, electrification and CCS investments. We monitor political and economic pressures, intensified by COVID-19, in host countries.
Joint venture partners' financial health We diversify our business risk through participation in joint venture partnerships. Our partners' financial health may deteriorate resulting in their inability to meet commitments around future capex and possible increases in decommissioning obligations. It may also result in greater joint venture misalignment around future plans and decisions.	Partners' financial health is regularly monitored and early engagement planned if required.	The impact of the COVID-19 pandemic on the industry increases the level of uncertainty around partners' health. Also, the evolving strategies of partners with respect to climate change may result in them altering capital allocation priorities, potentially impacting on Neptune's project objectives. However, no material impact has been observed to date.

Principal risks and uncertainties continued

Risk	Our attitude and response to risk	Risk management in 2020
Health, safety, environment and security		
Health, safety or environmental incident Drilling operations, decommissioning activities as well as wear and tear or accidental damage to subsurface or topside operating installations may cause loss of equipment integrity, leakages of oil or gas, fires, explosions and pollution. A major health, safety or environmental incident may lead to loss of life, loss of reputation, loss of production and revenue as well as additional costs and liabilities.	We aim to avoid this risk at all reasonable cost and reduce it to levels that are as low as reasonably practicable. We maintain a strong safety culture set by the Board, executive and business management. We also 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.	We maintained strong safety performance across personal and process safety indicators. In 2020, we recognised the risk of drift to failure during the time of crisis caused by COVID-19, where attention may be diverted. We have therefore introduced new monitoring for indications of reduced focus on safety.
Financial		
Significant oil and gas price volatility Volatility of oil and gas prices is a key source of financial risk to Neptune. When commodity prices are lower than expected we generate less cash, which can affect 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 structured continuous hedging programme overseen by the Board to ensure we lock in prices for major parts of our production while maintaining access to upside.	Our hedging programme helped de-risk Neptune's revenue streams in 2020 against volatile prices. We have reevaluated the value of our assets and made necessary impairments, which are detailed further in Notes 12 and 14 of the Financial Statements.
Inability to access capital markets The company may be unable to access debt capital markets or equity capital markets, which may affect capital structure and funding.	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.	Debt and equity capital markets have almost fully recovered to pre-COVID-19 levels re-opening capital raising possibilities.
Liquidity The company may be unable to service debt and pay suppliers as invoices become due.	The Board maintains a prudent treasury policy to manage financial risks including liquidity risk. The RBL facility was upsized from $2.3bn to $2.6bn in 2020 and the company has a strong liquidity position of $1.3bn as of December 2020.	Liquidity risk has increased in response to COVID-19, however, it subsequently decreased as markets have partially recovered since the lows of April 2020. Free cash flow generation was maintained throughout 2020, demonstrating Neptune's resilience.
Information systems		
Cyber attack A malicious attack on industrial control systems may lead to their unavailability, lack of access to systems and loss of data. A malicious attack on our office networks may result in office and operations disruption.	Cyber threats are addressed by adhering to standards that include network segregation, secure access, malware protection, regular patching and back-ups.	In response to the increased threat of cyber attacks caused by COVID-19, key cyber control points have been, and are continuously being, enhanced. A targeted awareness campaign reminded our people to remain vigilant of any attack attempts.
Compliance		
Breach of ethical and compliance requirements Breach of ethical and compliance requirements leading to reputational loss, financial losses, additional costs and civil and/or criminal liabilities.	We do not tolerate such risks as they destroy value. Therefore, we attempt to reduce them to as low as reasonably possible by enforcing our internal standards and policies. A compliance programme centred on our Code of Ethics and Business Integrity is rolled out across Neptune on a continuous basis, with company-wide ethics training deployed.	We recognised that general uncertainty and change in working patterns caused by COVID-19 increased external threats of fraud, bribery and corruption. We addressed these potential threats by increasing communication to Neptune staff to raise awareness and reinforce the need to remain vigilant and report any suspicious activity. We also introduced a new whistleblower channel, called Vault, through which our staff can report concerns anonymously.

Companies Act 2006 – Section 172(1) statement

Section 172 of the Companies Act 2006 requires a director of a company to act in the way he or she considers, in good faith, would most likely promote the success of the company for the benefit of its members as a whole, while having regard to among other things, those considerations listed in section 172(1). The directors of the Company are familiar with their duty under section 172 and believe that they fulfilled this duty during 2020.

We set out below some selected examples of how the directors have had regard to the matters set out in section 172(1)(a)-(f) when complying with the section 172 duty and how those factors have influenced the decisions taken by the Board:

(a) **Likely consequences of any decisions in the long term:** During Q1 and Q2 2020, the Board quickly acknowledged the need to respond to the risks posed by the COVID-19 pandemic to the Group's employees, contractors, operations and capital projects as well as the financial risks posed by low commodity prices during this period. To address these risks, the Board implemented a resilience plan (as described on pages 5 and 7), which was designed to respond to the immediate operational and financial pressures facing the Group while also securing the longer-term viability of the Group.

(b) **Interests of the company's employees:** The Board recognised the increased risks to the health and safety of its employees and contractors during the COVID-19 pandemic (both directly and indirectly) and, along with other industry operators, swiftly introduced measures to reduce the risk of infection at the facilities operated by the Group (including rigorous testing of crews before deployment offshore, reduced personnel on offshore facilities and the introduction of protocols to evacuate personnel falling ill). The Group also recognised the indirect risks associated with the pandemic, notably the risk caused by distraction while carrying out potentially hazardous work, and increased its vigilance and response to process safety events and near misses.

The Board made the difficult decision to restructure its businesses in Germany, Norway and the Netherlands resulting in the loss of approximately 400 positions within the Group. The Board decided this was necessary to secure the longer-term viability of the Group as a responsible employer in those countries. The Board engaged with affected employees and their representatives in connection with their decision, the outcome of which included agreeing an appropriate settlement package and provision of outplacement support.

To support the wellbeing of its employees further, the Group launched an employee wellbeing initiative and an employee assistance programme in 2020. See pages 17 and 22 for more information.

(c) **Need to foster the company's business relationships with suppliers, customers and others:** The Group engaged regularly with its suppliers in 2020, primarily through virtual platforms during the COVID-19 pandemic. The frequency of these interactions increased over the year to ensure the Group maintained safe operations across its portfolio. The engagements varied from one-on-one discussions to multi-supplier conferences to address topics such as health and safety and particularly focused on response to the pandemic and how to maintain safe operations.

Performance measures are in place with all major suppliers to the Group that are discussed regularly on weekly and monthly calls. Formal quarterly performance reviews and six-monthly relationship-level meetings were maintained during 2020, and in some cases became more frequent, providing an opportunity for suppliers to give feedback and suggest improvements to the way the Group works with them. In its interactions with suppliers, the Group continued its focus on safe operations with further interventions in relation to safety matters.

(d) **Impact of the company's operations on the community and environment:** The Group recognised early in the COVID-19 pandemic that its host countries and the end customers of its products relied on the Group to maintain operations to ensure the continued provision of essential products (which are required for the generation of electricity and the provision of fuel for transport, among other things). In addition, the Board set industry-leading targets for the carbon intensity and methane intensity of the Group's operations, while also deploying significant resources to launch its New Energy business, which is initially focusing on carbon capture and storage and hydrogen projects. See page 18 for further information.

(e) **Desirability of the company maintaining a reputation for high standards of business conduct:** The Group introduced a new due diligence process for vetting new suppliers and business partners, while also adopting a new sanctions policy and equality, diversity and inclusion policy.

(f) **Need to act fairly as between members of the company:** The Company has a single shareholder, Neptune Energy Group Limited, but also recognises the need to act fairly towards the ultimate shareholders of the Group, as well as the Group's bondholders, lending banks and other providers of financial products. During 2020, in addition to numerous engagements with the Group's ultimate shareholders, the Group's Chief Financial Officer and senior members of the Finance and Executive teams held more than 50 meetings with bondholders and lenders to ensure that their interests were being taken into account.

The Board recognises that not every decision it makes will necessarily result in a positive outcome for all of our stakeholders, for example the organisational restructure. By considering the Company's purpose, vision and values together with its strategic priorities and having a clear process in place for decision-making, the Board does, however, aim to make sure that its decisions are consistent and predictable.

The Board delegates the day-to-day management of the Group to members of the Executive Team and other senior members of staff. The Board regularly reviews 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, equality, diversity and inclusion, social responsibility, governance, compliance and legal matters.

As a result of this, the Board has had an overview of engagement with stakeholders and other relevant factors which allow the directors to understand the nature of the stakeholders' concerns and to comply with their section 172 duty to promote success of the company.

For further detail on Neptune's strategy and engagement with stakeholders see pages 10-11 and 21-27.

This strategic report, consisting of pages 2 to 57 was approved by the Board on 10 March 2021

By order of the Board.

James L House
Chief Executive Officer

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

Contents

Governance

The Company has adopted the Wates Corporate Governance Principles for Large Private Companies (published by the Financial Reporting Council in December 2018).

Having adopted the Wates Corporate Governance Principles in 2019, the Group remained committed to high standards of corporate governance during 2020 to enhance performance, mitigate risks and ensure positive relationships with our key stakeholders. The following statement sets out how the Principles were applied during 2020.

Principle 1 – Purpose and leadership

The Group's vision is to be the leading exploration and production company by meeting society's changing energy needs and creating value for all our stakeholders. During 2020, the Board and the Executive Team reviewed and updated the Group's strategy, taking account of the new challenges, both short term and longer term, posed by the COVID-19 pandemic and other dynamics.

Throughout the year, the Executive Team communicated the ambitions and values of the Group to the wider workforce through regular virtual events with the extended leadership team (comprising some 140 colleagues), while ensuring that the same messages were shared throughout the organisation by means of team meetings, weekly CEO blogs, quarterly all company calls, 'tool box' talks and (where possible) face-to-face briefings and engagement. For example, each member of the Netherlands leadership team delivered face-to-face briefings to members of our offshore team on the importance of recording safety incidents.

Recognising the importance of not just what we do but how we do it, we also developed our three-year environment, social and governance (ESG) roadmap and equality, diversity and inclusion charter in 2020, making it a priority to create a fair, equitable and inclusive culture within the Group. We believe that the best business decisions are made when all of the voices in the room have been heard.

For more information on the Group's purpose, strategy and business model see **pages 10-11**.

Principle 2 – Board composition

■ Board of Directors

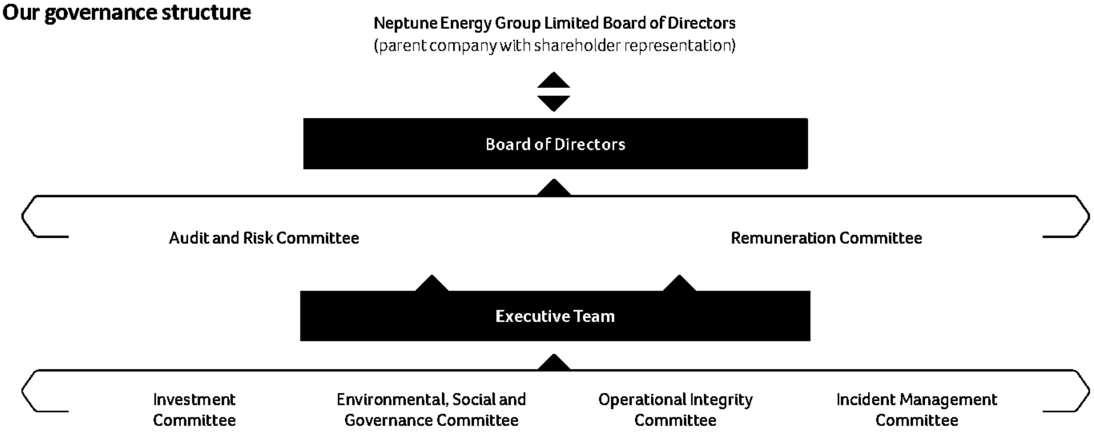
The Company's Board of Directors (the Board), comprises Sam Laidlaw (Executive Chairman), Amanda Chilcott (Group HR Director), Andrea Guerra (VP Subsurface), Jim House (Group Chief Executive Officer) and Armand Lumens (Group Chief Financial Officer). Biographies of the Directors are on pages 62-63.

Amanda Chilcott and Andrea Guerra were elected to the Board in August 2020, increasing the size of the Board to five directors and bringing new areas of expertise and greater diversity to 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 in their decision-making processes. The directors believe that the Board is of an appropriate size and composition for a Company of its nature.

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 see page 66. 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.

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

Our governance structure



Audit and Risk Committee
The Group's Audit and Risk Committee (ARC) assists the Board (and the NEGL Board) in discharging governance responsibilities in respect of external audit, internal audit, risk and internal control and to oversee the integrity of the Group's financial reporting and associated narrative statements. For details of the activities of the ARC in 2020 see pages 64-65.

Remuneration Committee
The Group's Remuneration Committee (RemCo) consists of the members of the NEGL Board as well as the Group Director of HR, with the Group CEO attending by invitation. The RemCo's primary purpose is to develop, maintain and implement remuneration policies. For details of the activities of the RemCo in 2020 see page 66.

■ Executive Team
The Group is managed by the executive leadership team (the Executive Team). This consists of senior management, 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 Executive Team meets weekly in person or by video conference to discuss operational matters, such as production, exploration and projects, as well as overall performance of the Group. The Investment Committee, Environmental, Social and Governance Committee, Operational Integrity Committee and Incident Management Committee, all formed of members of the Executive Team, together with other members of the extended leadership team, have been constituted to inform the decision-making process of the Executive Team.

For information on the Executive Team and their biographies, see **pages 62-63**.

Board activities during the year
In common with many other businesses, the COVID-19 pandemic posed new governance challenges to the Group with, among other things, a switch to almost universal home-working for office-based members of staff. Notwithstanding the move to remote working, the Group continued to work in accordance with its existing management and compliance framework.

Among other things, the Board of Directors began meeting more frequently, elected two new Directors to the Board, further developed the Group's ESG strategy and engaged with several new priorities, including the equality, diversity and inclusion charter.

During the first quarter of 2020, the Group's response to the COVID-19 pandemic and associated government measures swiftly became the key priority of the Executive Team's agenda, with frequent discussion and action to manage the risk posed to members of staff (in particular offshore workers), while also recognising the Group's responsibility to continue safe production operations as the provider of a key service in its countries of operation.

The Executive Team frequently discussed and managed the Group's response to the low commodity price environment seen throughout most of the year. In particular, the Executive Team agreed a wide-ranging resilience plan in response to the challenges posed by the pandemic and spent time redesigning the Group's strategy.

In addition, each of the businesses participated in performance reviews with the Executive Team and other members of the senior leadership team on two occasions in 2020.

Among other things, during 2020 the Board:

- Monitored the Group's performance in the context of the COVID-19 pandemic, notably in terms of HSE, production and resilience planning.
- Discussed the Group's hedging programme.
- Approved the 2021 budget and business plan, including the Group's capital expenditure programme and operating expenditure.
- Considered the Group's financing arrangements, including review of the Group's liquidity position and the repayment of certain debt facilities.
- Considered and approved changes to the Group's strategy in light of the challenges posed by the pandemic and macro environment.
- Reviewed the Group's ESG strategy.
- Adopted the Group's new ED&I policy and charter.
- Approved the 2019 Annual Report and Accounts as well as the quarterly earnings releases in 2020.
- Considered various M&A opportunities.

Senior management

Our depth and breadth of experience

1


1. **Sam Laidlaw**
Executive Chairman
A Chair B E I R Chair

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 has served as Chief Operating Officer of Hess Corporation, with responsibility for global upstream, CEO of Enterprise Oil Plc, Executive Vice President of Chevron Corporation and CEO of Centrica Plc.

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

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

2. **Jim House**
Chief Executive Officer
A B E I Chair

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**
Chief Financial Officer
A B E I

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

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

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

4. **Andrea Guerra**
VP Subsurface
B

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.

5. **Amanda Chilcott**
Group Human Resources Director
B E I

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.

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

6. **Mark Richardson**
VP Projects
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, 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.

7. **David Hemmings**
VP Business Development
I

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**
VP Operations, Europe
I E

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**
VP Operations, North Africa and Asia Pacific
I

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**
Director of Corporate Affairs
E **Chair**

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. **Ben Walker**
General Counsel
A E I

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.

12. **Kick Sterkman**
Group HSEQ Director
A E

Kick Sterkman has 26 years' 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.

13. **Kaveh Pourteymour**
Chief Information Officer
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

Neptune Energy Group Limited Directors

The Board of Directors of our parent company, Neptune Energy Group Limited (NEGL), is constituted by directors nominated by the Group's ultimate shareholders and chaired by our founder, Sam Laidlaw. The directors of the NEGL Board are respected industry leaders and they provide valuable insight into management and governance matters, working closely with members of the Midco Board and Executive Team.

Sam Laidlaw (Executive Chairman): see page 62 for Sam's biography.

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

Jianmin Bao (CIC nominee): Mr Bao is a member of the Executive Committee of CIC. He oversees investment projects in infrastructure, real estate, energy, oil and gas, minerals and related investment funds at CIC. 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 35 years in a variety of senior roles at Perella Weinberg Partners, Basin Capital Partners and Morgan Stanley. He was involved in numerous significant transactions in the energy space, including mergers such as BP/Amoco, Elf/Total and Equinor/Norsk Hydro, privatisations such as Equinor, Rosneft, Gazprom and Sinopec, acquisitions such as BP/ARCO and Shell/ Enterprise and joint ventures such as TNK-BP and LUKArco. He holds an AB from Princeton University (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).

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 the articles of association of the Company. In reaching their decisions, the directors also have regard to their responsibilities under section 172 of the Companies Act 2006, as detailed on page 57. During 2020, the new members of the Board received training on their duties as company directors.

The Board receives regular information relating to health, safety and environmental matters, operations and the financial performance of the Group, both through the cycle of weekly and monthly Executive Team meetings and full Board meetings when required. The various committees also support the Board in its decision-making processes. See page 61 for further information.

The Board established a more regular cycle of meetings during 2020 and, in particular, started meeting ahead of each meeting of the NEGL Board, to discuss the agenda and presentation materials for those meetings.

During the COVID-19 pandemic, the Board recognised the Group's responsibility not only in continuing the supply of key products and services to its host communities, but also to its wider stakeholders including its workforce. Some of the Board's initiatives designed to support our people in 2020 are described on page 22.

Principle 4 – Opportunity and risk

The Group's approach to strategic opportunities and the key risks affecting the Group are set out in the Strategic Report on pages 52-56. The Group in particular recognises the challenges posed by the energy transition and, with its diverse product mix, believes that the transition brings significant opportunities to groups that are able to adapt.

Alongside the benefits presented by its existing gas-weighted portfolio, the Group decided to create its New Energy team in 2020 and, alongside its more traditional exploration and production activities, is actively engaged in hydrogen and carbon capture and storage prototype projects in the Netherlands. See page 18 for further information. In addition, the Group continues to assess M&A opportunities while also participating in carefully selected exploration licence rounds.

See page 52-56 for further information on the Group's approach to risk and risk management, and below for details of the Group Audit and Risk Committee.

Group Audit and Risk Committee

Governance

While also informing the Board, the ARC reports to the NEGL Board and consists of the Executive Chairman (who also acts as the ARC Chair), the other members of the NEGL Board, 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 and Group Financial Controller also attend meetings of the ARC. During 2020, the ARC met more frequently than in previous years and, in addition, members of the NEGL Board or their representatives joined the meetings to provide further challenge and assurance to audit processes and risk management.

The ARC works to a standing agenda of items including external reporting, technical accounting updates, observations, internal controls, internal audit, risk, compliance and disputes.

Financial reporting process and technical accounting
The ARC held four meetings during 2020, which were aligned with the financial reporting calendar and external audit cycle. The ARC (and external auditors) noted that the financial reporting process was smooth and well managed, demonstrating continual improvement as the process was now well established.

The financial reporting team provided regular updates on the financial policies, processes and accounting areas of judgement and the external auditors also provided independent feedback to the Board.

As in previous years, the ARC oversaw updates to the Group Accounting Policy Manual, being the key reference document for defining the Group's accounting policies and guidelines across the Group.

Risk management and internal control
During 2020, the ARC focused particularly on the risks associated with the COVID-19 pandemic and the related operational and financial risks. With the endorsement of the ARC, the Group also adopted a new Risk Management Policy and Risk Management Standard, which set standards across the Group for identifying and managing risks. As part of the updated approach to risk management, standard reporting templates for reporting and monitoring risks across the Group have been adopted and are reported to the ARC on a regular basis. Please see pages 52-56 for further information about the Group's approach to risk management and mitigation.

During 2020, the Group appointed a new Head of Internal Controls for Finance, who, among other things, has set up a new framework for the documentation of key financial processes and testing of financial controls across the Group and country offices. By identifying controls and owners, the framework is intended to ensure responsibility and ownership at the local level (with, among other things, requirements for the finance manager to self-certify in relation to all controls in their area of responsibility, while also highlighting any control failures).

The pandemic restricted the Group's internal audit function's ability to carry out much of the fieldwork planned for 2020. Notwithstanding this, several internal audits were carried out on a remote basis, including audits on the Group's oil spill response management, hydrocarbon management and revenue, cyber security, and ethics and compliance. Audit findings were routinely followed up.

Compliance and disputes
The ARC received regular updates regarding the Group's compliance programme such as the adoption and implementation of new policies (including the Anti-Slavery and Human Trafficking Policy, Sanctions Policy and Equality, Diversity and Inclusion Policy), the Group's new counterparty due diligence procedure and the Group's new online whistleblowing tool (to sit alongside the existing telephone whistleblowing line). The Group Head of Ethics and Compliance also presented regular updates to the ARC on whistleblowing cases and investigations, while the Group's General Counsel provided regular updates on disputes to which the Group was party.

The ARC also considered the following items (among others):

- The terms of appointment of the Group's external auditors, Ernst & Young (EY) and the cessation of any non-audit services by 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, the impairment of 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 2019 and conclusions both on financial statements and on agreed audit focus areas.

ESG Committee
The Group's Environmental, Social and Governance Committee (ESG Committee) (formerly known as the Corporate Responsibility Committee) consists of the Executive Chairman, the Chief Executive Officer, 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, Global Head of Ethics and Compliance, Vice President of Operations, Europe, Director of New Energy and the General Counsel.

During 2020, the ESG Committee continued to review and update the Group's ESG strategy and considered, among other things:

- The Group's new three-year ESG roadmap and prioritisation of issues.
- The Group's carbon and methane intensity targets, which were formally adopted in April 2020.
- Reporting of methane emissions, particularly in light of the Group's membership of the Oil and Gas Methane Partnership.
- Proposals to adopt an internal carbon price.
- Corporate governance matters, including the Group's continued adherence to the Wates Principles.
- The Group's new equality, diversity and inclusion charter.
- Gender pay gap and gender ratio data and initiatives to increase female representation at senior levels within the Group.
- The outcomes of private ESG ratings and the increasing link between ESG performance and finance matters.
- The Group's social purpose, social investment standard and community investment initiatives, particularly in light of the COVID-19 pandemic.
- The Group's partnerships with the Halo Trust, Movement to Work and Mental Health UK.
- Matters relating to employee wellbeing, in particular in relation to mental health during the pandemic.
- The Group's modern slavery statement for the year ended 31 December 2019.

Ethics and compliance
Our ethics and compliance programme is built around seven key areas of focus.

Risk assessment
An annual risk assessment is carried out in all of the locations in which the Group has operations to identify the ethics and compliance risks that may affect our business. Where necessary, the Group takes mitigating actions to address those risks.

Policies and procedures
Our Code of Ethics and Business Integrity is the foundation document around which our policies and procedures are built. During 2020, a number of new policies and procedures were put in place, including the Anti-Fraud Control Framework, the Misconduct and Loss Investigation Procedure, the Sanctions Policy, the Anti-Slavery and Human Trafficking Policy and the Equality, Diversity and Inclusion Policy. In 2021, we will publish our new Anti-Bribery and Corruption Standard, the principles of which are already embedded in our Code of Ethics.

Training
All staff are required to complete online training on our Code of Ethics, whistleblowing policies and data protection. A series of virtual face-to-face data protection training sessions were rolled out to the HR and legal teams in 2020, and this training will be extended to other functions in 2021. A number of ethics awareness presentations were presented to local leadership teams, highlighting the heightened risks of bribery, corruption and fraud during the COVID-19 pandemic. This included training delivered by our digital security team on the heightened risks of 'phishing'. New online refresher training on bribery and corruption will be launched for managers during 2021.

Tone from the top
The development of the ethics and compliance programme is included on the agenda at all ARC and Board meetings. During 2021, a series of bi-monthly, face-to-face training sessions will be delivered for the country leadership teams on different ethics and compliance topics.

Third-party integrity screening
In January 2020, we published procedures for carrying out due diligence on all third parties with whom we do business, and face-to-face training was rolled out for the relevant functions. A risk assessment is carried out in respect of all such third parties, and all medium- or high-risk third parties are screened (on a platform hosted by a third-party provider) in respect of adverse media reports and against sanctions and watch lists. Where any issues arise, these are discussed and appropriate mitigating actions are taken where required.

Investigations
In October 2020, we introduced a new channel through which our staff can report any concerns called the Vault Platform. This enables staff to report

concerns anonymously, if they wish, while still enabling the investigator to communicate with the reporter to obtain sufficient information to carry out the investigation. Notwithstanding the difficulties presented by the COVID-19 pandemic, we have continued to investigate concerns raised regarding unethical behaviours and the new platform has already been used by members of staff.

Monitoring and review
Periodic reviews of training records are carried out, to ensure that everyone completes the mandatory online ethics and compliance training. In addition, in Q4 2020, internal audit carried out a review of the ethics and compliance programme and reported on the work required to develop the programme further.

Additional information on these policies, as well as our statement on modern slavery, is available at *neptuneenergy.com.*

Principle 5 – Remuneration

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 Group CEO attending by invitation. The RemCo generally meets three times per year (and on an ad-hoc basis when required) to review and recommend matters relating to remuneration. During 2020, it considered the following matters (among others):

- The implications of the significant change in the economic environment on salary planning across the Group.
- The changes proposed in order to align the organisational structure with the evolved business strategy.
- The output of the 2019 Group scorecard for the purposes of determining the Group performance element for bonus awards paid in respect of 2019.
- Bonuses payable to members of the Executive Team in respect of 2019 performance.
- Design of the 2020 scorecard.
- Appointment of new members, and changes to the existing 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.
- Review of the Executive Team's performance.
- Gender pay gap and pay ratios, and actions to further improve in these areas.
- Market data on reward in comparable companies.

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 are designed to support the Group's commitment to exemplary safety standards and ethical values while rewarding long-term sustainable value creation.

The RemCo aims to ensure that levels of compensation across the Group are sufficiently competitive to retain talent within the Group, as well as benchmarking the remuneration packages of the Executive Team. The RemCo also reviews the Group's performance with regard to diversity and inclusion criteria, including benchmarking the Group against other industry players, while making recommendations as to how to improve in these areas.

Principle 6 – Stakeholders

The Directors recognise the need to take the views of all stakeholders into account when coming to their decisions, particularly in the context of the Group's ambition to be a leading player in the energy transition through its gas-weighted portfolio and New Energy business.

We set out examples of how we engage with some of our key stakeholders, including our people, partners and local communities on pages 21-27 and we include further examples below. We listen to the views and concerns of our stakeholders, which inform the decisions we make, from day-to-day business-level decisions to longer-term strategic matters considered by the Board and our ultimate shareholders.

Shareholders
Although the Company has a single shareholder, NEGL, the Board regularly meets representatives of the shareholders of NEGL to understand their views as well as those of their ultimate investors. For much of 2020, we held fortnightly meetings with representatives of NEGL's shareholders to inform them – and seek their input on – the Group's response to the COVID-19 pandemic and associated economic headwinds. The Group's ultimate shareholders were also actively engaged in reassessing the Group's strategy during 2020, including the Group's new ESG strategy (see page 12). The Directors of NEGL also approved the Group's budget and business plan for 2021 after a series of engagements with representatives of the Company.

Bondholders
We hold regular meetings with Neptune's bondholders and present formal quarterly results presentations. During 2020, we conducted four formal quarterly updates and had around 50 virtual or 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.

Banks and credit agencies
We met with approximately 30 different banks and three credit agencies in 2020 to discuss company performance and funding arrangements. Our banks advise us on debt and equity matters which ultimately drives value for all of our stakeholders.

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

Host governments and regulators
We engage with all host governments directly through meetings with representatives of the Group in our countries of operation and indirectly through their embassies in London and (where relevant) British embassies in country. We play an active role in the development of energy policy in each jurisdiction through briefings and consultation responses. In Indonesia, for example, we held regular meetings with SKK Migas, the Indonesian oil and gas regulator during 2020. These meetings help provide greater visibility of the interests of the Indonesian government and SKK Migas in the decision-making process for evaluating projects.

Similarly, in Australia, we hold annual meetings with the National Offshore Petroleum Safety and Environmental Management Authority to review our activities, particularly with regard to well operation management plans for suspended wells, and our voluntary stewardship plan for a well drilled on a previous title.

In Algeria, we work with the British Embassy and Algerian Transport Ministry to enable charter flights to be conducted while civil aviation is grounded, allowing us to conduct crew changes and maintain operations at site.

Customers
Our customers tend to be large international corporations or state-owned enterprises. However, we also recognise that end customers rely on the products we produce for basic needs such as electricity, heating fuels and transport, and that it is incumbent on the Group to maintain stable and safe operations to meet these needs. In particular, we recognised during the COVID-19 pandemic that it was more important than ever for the Group to maintain steady production to ensure that the basic requirements of our end customers would be met in the very difficult circumstances that prevailed at the time. The Group swiftly adopted new protocols to ensure that safe production could be maintained, while also recognising the need to provide safe working conditions for its employees and contractors. Please see pages 16-17 for further information.

Statement of Directors' responsibilities

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 2020 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 50.
- 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 48 hedging and note 24 on page 112.
- Likely future developments in the business of the Company, see page 33.
- Employment of disabled persons, see page 23.
- Employee engagement, see page 22.
- Greenhouse gas emissions, energy consumption and energy efficiency action, see page 19.
- The research and development activities carried out by the Company, see page 18.
- Our engagement with suppliers, customers and others with whom we do business, see pages 24-27.

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 (2019: $nil) or incur any political expenditure (2019: $nil) during the year.

By order of the Board.

Sam Laidlaw

Sam Laidlaw
Executive Chairman
10 March 2021
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 accounting standards in conformity with the requirements of 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 international accounting standards in conformity with the requirements of the Companies Act 2006 have been followed, subject to any material departures disclosed and explained in the financial statements.
- Prepare the financial statements on the going concern basis unless it is inappropriate to presume that the Company will continue in business.

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

Auditor's report

Independent Auditor's Report to the Members of Neptune Energy Group Midco Limited

Opinion
We have audited the financial statements of Neptune Energy Group Midco Limited ('the parent company') and its subsidiaries (the 'Group') for the year ended 31 December 2020 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 Accounting Standards in conformity with the requirements of the Companies Act 2006 and, as regards the parent company financial statements, as applied in accordance with section 408 of the Companies Act 2006.

In our opinion:

- the financial statements give a true and fair view of the Group's and of the parent company's affairs as at 31 December 2020 and of the Group's loss for the year then ended;
- the Group financial statements have been properly prepared in accordance with International Accounting Standards in conformity with the requirements of the Companies Act 2006;
- the parent company financial statements have been properly prepared in accordance with International Accounting Standards in conformity with the requirements of the Companies Act 2006 as applied in accordance with section 408 of the Companies Act 2006; and
- the financial statements have been prepared in accordance with the requirements of the Companies Act 2006.

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

Conclusions relating to going concern
In auditing the financial statements, we have concluded that the directors' use of the going concern basis of accounting in the preparation of the financial statements is appropriate. Our evaluation of the directors' assessment of the Group and parent company's ability to continue to adopt the going concern basis of accounting included:

- Confirming our understanding of management's going concern assessment process and the key factors and assumptions that were considered in their assessment;
- Obtaining management's going concern assessment, including the cash flow forecast and covenant calculations for the going concern period which covers 18 months from the year ended 31 December 2020. The Group has modelled a number of adverse scenarios in their cash flow forecasts and covenant calculations in order to incorporate unexpected changes to the forecast liquidity of the Group;
- Testing the key factors and assumptions included in each modelled scenario for the cash flow forecast and covenant calculation. We engaged valuations specialists to support us in this review. We considered the appropriateness of the methods used to calculate the cash flow forecasts and covenant calculations. We tested the methodology and calculations in each modelled scenario;
- Considered management's reverse stress test in order to identify what factors would lead to the Group utilising all liquidity or breaching a financial covenant during the going concern period. We assessed the likelihood of these factors in the context of the outlook for commodity prices and against historic market lows as well as our own industry experience;
- Considered any mitigating factors included in the cash flow forecasts and covenant calculations that are within the control of the Group. This included understanding the Company's non-operating cash outflows, such as planned capital expenditure, and evaluating the Company's ability to control these outflows as mitigating actions if required. We also read credit facilities available to the Group, including the maturity dates of those arrangements;
- We checked the consistency of the factors and assumptions adopted in management's going concern assessment with other areas of our audit, including asset impairment reviews; and
- We read the Group's going concern disclosures included in the annual report in order to assess that the disclosures were appropriate and in conformity with the reporting standards.

We observed that the Group has had limited operational disruptions as a result of COVID-19, and this together with the Group's hedging policy and responses to COVID-19, has demonstrated the resilience of the business. The Group has total available liquidity as at 31 December 2020 of $1.3 billion, comprising cash ($92.5 million) and available and undrawn headroom under the RBL facility ($1.2 billion). In all plausible scenarios modelled, the Group has sufficient forecast liquidity and headroom over covenant ratios. On the basis of our insights gained from the market consensus outlook for commodity prices and historic market lows, the likelihood of the factors identified in management's reverse stress test materialising are remote.

Based on the work we have performed, we have not identified any material uncertainties relating to events or conditions that, individually or collectively, may cast significant doubt on the Group and parent company's ability to continue as a going concern for the period to 30 June 2022, sixteen months from when the financial statements are authorised for issue.

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

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

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

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

We have nothing to report in this regard.

Opinions on other matters prescribed by the Companies Act 2006

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

- the information given in the strategic report and the directors' report for the financial year for which the financial statements are prepared is consistent with the financial statements; and
- the strategic report and directors' report have been prepared in accordance with applicable legal requirements.

Matters on which we are required to report by exception

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

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

- adequate accounting records have not been kept by the parent company, or returns adequate for our audit have not been received from branches not visited by us; or
- the parent company financial statements are not in agreement with the accounting records and returns; or
- certain disclosures of directors' remuneration specified by law are not made; or
- we have not received all the information and explanations we require for our audit.

Responsibilities of directors

As explained more fully in the directors' responsibilities statement set out on page 67, the directors are responsible for the preparation of the financial statements and for being satisfied that they give a true and fair view, and for such internal control as the directors determine is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

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

Auditor's responsibilities for the audit of the financial statements

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

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

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

- We obtained an understanding of the legal and regulatory frameworks that are applicable to the Group and determined that the most significant are those that relate to the reporting framework (International Accounting Standards and the Companies Act 2006) and the relevant tax compliance regulations in the jurisdictions in which the Group operates. In addition, the Group has to comply with laws and regulations relating to its domestic and overseas operations, including those related to health and safety, employee matters, data protection, environmental and anti-bribery and corruption practices;
- We understood how the Group is complying with those frameworks by making inquiries of those charged with governance, management, internal audit and those responsible for legal and compliance procedures. We corroborated our inquiries through reading Board minutes, papers provided to the Audit & Risk Committee and correspondence received from regulatory bodies and noted there was no contradictory evidence;
- We assessed the susceptibility of the Group's financial statements to material misstatement, including how fraud might occur by inquiring of management to understand where they considered there was susceptibility to fraud. We also considered performance targets and their propensity to influence efforts made by management to manage earnings. Where this risk was considered to be higher, we performed audit procedures to address each fraud risk or other risk of material misstatement. These procedures included those on revenue recognition and testing manual journal entries and were designed to provide reasonable assurance that the financial statements were free from material fraud or error; and
- Based on this understanding we designed our audit procedures to identify non-compliance with such laws and regulations identified above. Our procedures involved inquiries of both Group and local management; inquiries of those charged with governance; and journal entry testing, with a focus on journals meeting our defined risk criteria.

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

Use of our report

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

Ernst & Young LLP

Steven Dobson (Senior statutory auditor)
for and on behalf of Ernst & Young LLP,
Statutory Auditor
London
10 March 2021

Financial statements

Consolidated financial statements

For the year ended 31 December 2020

Consolidated income statement – Group

Group In millions of $	Notes	Year ended 31 December 2020	Year ended 31 December 2019
Revenue from contracts with customers	3	**1,560.1**	2,202.2
Other operating income	4	**9.0**	–
Revenue and other income		**1,569.1**	2,202.2
Cost of sales	6	**(1,124.9)**	(1,158.9)
Gross profit		**444.2**	1,043.3
Exploration expenses	6	**(91.2)**	(60.4)
General and administration expenses	6	**(69.1)**	(68.6)
Share of net income from investments using equity method	15	**(20.0)**	2.1
Operating profit after equity accounted investments	5	**263.9**	916.4
Net impairment loss	5	**(325.7)**	(59.4)
Other operating (losses)/gains	8	**(33.6)**	15.7
Operating (loss)/profit before financial items		**(95.4)**	872.7
Finance income	9	**12.4**	6.3
Finance costs	9	**(250.1)**	(202.2)
(Loss)/profit before tax		**(333.1)**	676.8
Taxation	11	**(65.9)**	(237.8)
Net (loss)/profit		**(399.0)**	439.0

All profits and losses arise as a result of continuing operations. The accounting policies on pages 76 to 86 together with the notes on pages 87 to 125 form part of these accounts.

Consolidated statement of other comprehensive income – Group

Group In millions of $	Notes	Year ended 31 December 2020	Year ended 31 December 2019
(Loss)/Profit for the year		**(399.0)**	439.0
Other comprehensive income:			
Items that may be reclassified to the income statement:			
Hedge adjustments net of tax (1)	23.3	**(138.3)**	143.9
Share of hedge adjustments within equity accounted investments(2)	23.3	**(3.1)**	–
Foreign currency translation		**141.7**	35.8
		0.3	179.7
Other items not reclassified to the income statement:			
Remeasurement of defined pension obligations, net of tax (3)		**(4.2)**	(20.1)
Other comprehensive (expense)/income		**(3.9)**	159.6
Other comprehensive (loss)/profit for the year, net of tax		**(402.9)**	598.6

(1) Income tax related to hedge adjustments is $32.5 million credit (2019: $36.1 million charge) and is shown net of amounts reclassified to profit or loss or included in finance costs.
(2) Income tax related to share of hedge adjustments within equity accounted investments is $1.0 million credit (2019: nil).
(3) Income tax related to defined benefit obligations is $2.5 million credit (2019: $7.5 million credit).

Consolidated statement of financial position – Group

Group In millions of $	Notes	31 December 2020	31 December 2019
Non-current assets			
Goodwill	12	**649.7**	640.8
Intangible assets	13	**194.9**	150.9
Property, plant and equipment	14	**4,566.2**	4,430.8
Derivative instruments	23	**19.6**	74.9
Investments in entities accounted for using the equity method	15	**557.6**	604.7
Other non-current assets	23	**99.5**	110.6
Equity instruments	23	**21.1**	19.3
Deferred tax assets	11	**577.3**	691.0
Total non-current assets		**6,685.9**	6,723.0
Current assets			
Derivative instruments	23	**55.1**	147.4
Trade and other receivables	17	**526.6**	651.9
Inventories	16	**79.0**	60.4
Cash and cash equivalents	18	**92.5**	85.4
Income tax receivable	23	**153.4**	16.6
Total current assets		**906.6**	961.7
Total assets		**7,592.5**	7,684.7
Share capital	25	**1,977.2**	1,977.2
Hedging reserve	23	**(22.6)**	118.8
Foreign currency translation		**34.7**	(107.0)
Retained earnings/(deficit)		**(506.7)**	(103.5)
Total equity		**1,482.6**	1,885.5
Non-current liabilities			
Provisions	22	**1,870.9**	1,654.2
Long-term borrowings	19	**1,971.8**	1,815.6
Derivative instruments	23	**11.5**	28.6
Income tax payable	23	**71.5**	59.0
Other non-current liabilities	20	**131.3**	164.6
Deferred tax liabilities	11	**988.8**	750.1
Total non-current liabilities		**5,045.8**	4,472.1
Current liabilities			
Provisions	22	**114.9**	113.5
Short-term borrowings	19	**50.0**	124.0
Derivative instruments	23	**60.1**	18.6
Trade and other payables	20	**333.5**	222.7
Income tax payable	23	**28.6**	155.3
Other current liabilities	20	**477.0**	693.0
Total current liabilities		**1,064.1**	1,327.1
Total equity and liabilities		**7,592.5**	7,684.7

The accounts on pages 70 to 125 were approved by the Board and signed on its behalf by:

Armand Lumens
Chief Financial Officer

Financial statements

Consolidated financial statements continued

For the year ended 31 December 2020

Statement of financial position – Company

Company In millions of $	Notes	31 December 2020	31 December 2019
Non-current assets			
Investments	15	**1,977.2**	1,977.2
Inter-company loan receivable	17	**943.2**	939.7
Total non-current assets		**2,920.4**	2,916.9
Current assets			
Cash and cash equivalents	18	**–**	–
Trade and other receivables	17	**216.2**	216.8
Total current assets		**216.2**	216.8
Total assets		**3,136.6**	3,133.7
Share capital	25	**1,977.2**	1,977.2
Retained earnings		**1.4**	1.0
Total equity		**1,978.6**	1,978.2
Non-current liabilities			
Inter-company loan payable	20	**943.2**	939.7
Total non-current liabilities		**943.2**	939.7
Current liabilities			
Other current liabilities	20	**214.8**	215.8
Total current liabilities		**214.8**	215.8
Total equity and liabilities		**3,136.6**	3,133.7

As permitted by Section 408 of the Companies Act 2006, no income statement or statement of comprehensive income is presented for the Company. Profit for the year was $0.4 million (2019: $400.4 million).

Consolidated statement of changes in equity – Group

Group In millions of $	Share capital	Hedging reserve[1][3]	Foreign currency translation[2]	Retained earnings	Total
At 1 January 2019	**1,977.2**	**(25.1)**	**(142.8)**	**(122.4)**	**1,686.9**
Profit for the year	–	–	–	439.0	439.0
Other comprehensive income/(loss)	–	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)
At 31 December 2019	**1,977.2**	**118.8**	**(107.0)**	**(103.5)**	**1,885.5**
Loss for the year	–	–	–	(399.0)	(399.0)
Other comprehensive loss	–	(141.4)	141.7	(4.2)	(3.9)
Total comprehensive loss	**–**	**(141.4)**	**141.7**	**(403.2)**	**(402.9)**
Transactions with owners of the Company:					
Dividends paid (note 10)	–	–	–	–	–
Balance 31 December 2020	**1,977.2**	**(22.6)**	**34.7**	**(506.7)**	**1,482.6**

1) The hedging reserve represents gains and losses on derivatives classified as effective cash flow hedges stated net of tax.
2) The foreign currency translation reserve represents exchange gains and losses arising on translation of foreign currency subsidiaries.
3) Included in the hedging reserves other comprehensive loss in the year of $141.4 million is a loss of $3.1 million net of tax related to hedging undertaken by associated entities.

Statement of changes in equity – Company

In millions of $	Share capital	Retained surplus/ (deficit)	Total
At 1 January 2019	**1,977.2**	**0.6**	**1,977.8**
Profit for the year	–	400.4	400.4
Total comprehensive income for the period	**–**	**400.4**	**400.4**
Transactions with owners of the Company:			
Dividends paid (note 10)	–	(400.0)	(400.0)
At 31 December 2019	**1,977.2**	**1.0**	**1,978.2**
Profit for the year	–	0.4	0.4
Other comprehensive income for the period	–	–	–
Total comprehensive income for the period	**–**	**0.4**	**0.4**
Transactions with owners of the Company:			
Dividends paid (note 10)	–	–	–
Balance 31 December 2020	**1,977.2**	**1.4**	**1,978.6**

Financial statements

Consolidated financial statements continued
For the year ended 31 December 2020

Consolidated cash flow statement – Group

Group In millions of $	Year ended 31 December 2020	Year ended 31 December 2019
Cash flows from operating activities		
(Loss)/Profit before taxation	**(333.1)**	676.8
Adjustments to reconcile profit before tax to net cash flows:		
Depreciation and amortisation	**584.7**	624.2
Unsuccessful exploration costs written off	**30.3**	0.2
Impairment losses	**325.7**	59.4
Finance costs	**250.1**	202.2
Finance income	**(12.4)**	(6.3)
Share of net loss/(income) from equity investments	**20.0**	(2.1)
Other non-cash income and expenses[1]	**25.9**	(1.4)
Fair value movement on commodity-based derivative instruments	**4.0**	(14.2)
Movement in provisions including decommissioning expenditure	**(85.3)**	(89.2)
Working capital adjustments	**35.3**	232.7
Income tax received/(paid) (net)	**70.2**	(361.7)
Net cash flows from operating activities	**915.4**	1,320.6
Cash flows from investing activities		
Expenditure on exploration and evaluation assets	**(84.5)**	(87.1)
Expenditure on property, plant and equipment	**(717.3)**	(1,060.7)
Proceeds from sale of assets	**0.8**	11.6
Dividends received	**2.4**	–
Finance income received	**7.7**	4.2
Net investment made in equity accounted investments	**25.9**	(62.8)
Net cash flows used in investing activities	**(765.0)**	(1,194.8)
Cash flows from financing activities		
Proceeds from loans and borrowings	**1,371.5**	1,566.0
Repayment of borrowings	**(1,307.7)**	(1,439.5)
Repayment of obligations under leases	**(69.4)**	(32.3)
Finance costs paid	**(137.7)**	(130.5)
Dividends paid	**–**	(200.0)
Net cash flows used in financing activities	**(143.3)**	(236.3)
Net increase/(decrease) in cash and cash equivalents	**7.1**	(110.5)
Cash and cash equivalents at 1 January	**85.4**	197.3
Net foreign exchange differences	**–**	(1.4)
Cash and cash equivalents at 31 December	**92.5**	85.4

(1) Other non-cash income and expenses mainly includes restructuring provision costs, pension curtailment credits, release of contingent consideration and other losses and gains, see note 8.

Cash flow statement – Company

Company In millions of $	Notes	Year ended 31 December 2020	Year ended 31 December 2019
Cash flows from operating activities			
Profit before taxation		**0.4**	400.4
Adjustments to reconcile profit before tax to net cash flows:			
Finance costs		**69.1**	52.0
Finance income	9	**(66.1)**	(450.4)
Other non-cash items		**(3.5)**	–
Working capital adjustments		**(0.4)**	0.2
Net cash flows (used in)/from operating activities		**(0.5)**	2.2
Cash flows from investing activities			
Loans made to subsidiaries		**–**	(309.6)
Finance income received		**66.0**	47.3
Dividend received		**–**	200.0
Net cash flows from/(used in) investing activities		**66.0**	(62.3)
Cash flows from financing activities			
Proceeds from loans and borrowings		**–**	307.8
Dividend paid		**–**	(200.0)
Finance costs paid		**(65.5)**	(48.8)
Net cash flows (used in)/from financing activities		**(65.5)**	59.0
Net increase in cash and cash equivalents		**–**	(1.1)
Cash and cash equivalents at 1 January		**–**	1.1
Cash and cash equivalents at 31 December		**–**	–

The notes on pages 87 to 125 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 2020 were authorised for issue in accordance with a resolution of the Board on 10 March 2021.

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 2020 have been prepared in accordance with International Accounting Standards in conformity with the requirements of the Companies Act 2006.

The preparation of financial statements in conformity with the Companies Act 2006 requires the use of certain critical accounting estimates. It also requires management to exercise its judgement in the process of applying the Group's accounting policies. The areas involving a higher degree of judgement or complexity, or areas where assumptions and estimates are significant to the consolidated financial statements, are disclosed below in note 1.3.

The Group has not early-adopted any standard, interpretation or amendment that has been issued but is not yet effective.

Going concern

Given the total available liquidity as at 31 December 2020 of $1.3 billion, comprising our cash balance ($92.5 million) and available and undrawn headroom under the RBL facility ($1.2 billion), and capital resources arrangements in place (see note 19), the consolidated accounts have been prepared on a going concern basis.

The going concern basis is supported by future cash flow forecasts which project the Group's available liquidity and compliance with covenants through to 30 June 2022. The cash flow forecasts reflect forecast production consistent with our Board approved plans and externally published guidance and base case commodity prices that are slightly below current market conditions.

While the short-term outlook is uncertain due to COVID-19, energy markets have stabilised and commodity prices have recovered from the lows of 2020. We believe the longer-term outlook is positive for the oil and 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, strong balance sheet and hedging provides resilience for the Group against softer commodity prices.

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 short-term commodity price forecasts significantly below current market conditions as well as scenarios that consider the impact of unforeseen production outages. We have also performed a reverse stress test to inform our judgement, which demonstrated that we are resilient to sustained low commodity prices up to 50% below our conservative base case cash flow forecast.

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

1.1 New standards, interpretations and amendments adopted by the Group

Interest Rate Benchmark Reform Phase 1 (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.

The guidance published considers reliefs to hedge accounting in the period before the reform (Phase 1). 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.

As the majority of the Group's hedging instruments are commodity based they are not impacted by the proposed amendments. Those few hedging instruments that the Group holds which might have otherwise have 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 Phase 1 amendment has had no impact on the current financial statements of the Group.

Interest Rate Benchmark Reform Phase 2 amendments are effective from 1 January 2021 and provide guidance on how to apply the Phase 2 amendments to various contracts and hedge accounting relationships, including the interaction with the Phase 1 reliefs for hedge accounting. Work is currently underway to assess the impact of Phase 2 Interest Rate Benchmark Reform, however, it is currently not expected that it will have a significant impact on the reported financial statements of the Group.

Several other financial reporting amendments and interpretations apply for the first time in 2020, 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; and
- measurement of recognised tax loss carry-forwards.

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 note 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.

Notes to the consolidated financial statements continued

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

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

See note 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 internal view of management expectations derived from a market consensus for current prices transitioning to a long-term price in 2024 of $60/bbl for Brent crude oil and 50p/therm for NBP gas thereafter inflated by 2% per annum. See note 11 for further information.

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.

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.

Notes to the consolidated financial statements continued

Transactions and balances

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

Group companies

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

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

1.6 Intangible assets

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

1.7 Assets relating to the exploration and production of mineral resources

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

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

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

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

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

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

1.8 Other property, plant and equipment

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

1.9 Depreciation

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

Main depreciation periods (years)

Office and computer equipment	3 to 5 years
Freehold and leasehold improvements [1]	up to 50 years
Plant and machinery	5 to 40 years

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

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

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

Impairment indicators

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

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

- external sources of information:
  - significant changes in the economic, technological, political or market environment in which the entity operates or to which an asset is dedicated;
  - fall in demand; and
  - changes in energy prices and exchange rates.
- internal sources of information:
  - evidence of obsolescence or physical damage not budgeted for in the depreciation/amortisation schedule;
  - worse-than-expected production or cost performance;
  - reduction in reserves and resources, including as a result of unsuccessful results of drilling operations;
  - pending expiry of licence or other rights; and
  - in respect of capitalised exploration and evaluation costs, lack of planned future activity on the prospect or licence.

Measurement of recoverable amount

In order to review the recoverable amount in an impairment test, the assets are grouped, where appropriate, into Cash Generating Units and the carrying amount of each unit is compared with its recoverable amount.

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

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

Notes to the consolidated financial statements continued

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 Group's Joint Arrangement share of the right-of-use- lease liability only when it has a right to control the use of the lease. Where the Group has no control, then no right-of-use lease liability is recognised.

1.11.3 Short-term leases and leases of low-value assets

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

1.12 Inventories

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

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

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

See also 1.19 '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.

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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.

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

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

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

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

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

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

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

Further information regarding segmental analysis is contained in note 5.

1.20 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 Dividends

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.

2. Financial risk management

Group financial risk factors

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

Market risk (foreign exchange risk)

The Group operates internationally and is therefore exposed to foreign exchange risk arising from various currency exposures, primarily with respect to the Pound Sterling (GBP), Norwegian Krone (NOK) and 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.

Capital risk

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

Please refer to our Risk disclosure on pages 54-56.

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 5.

	2020		
Group In millions of $	Production revenue	Other	Total
External customers	**1,506.9**	**53.2**	**1,560.1**
Total Group revenue	**1,506.9**	**53.2**	**1,560.1**

	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

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 $238.2 million, $188.6 million and $153.8 million (2019: $441.0 million, $377.3 million and $255.4 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).

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4. Other operating income

Group In millions of $	Year ended 31 December 2020	Year ended 31 December 2019
Loss of production insurance	**9.0**	–
Total	**9.0**	–

On 26 October 2020, Equinor, the operator of the Hammerfest LNG plant in Norway announced to its joint venture partners that the LNG plant will be closed for up to 12 months for repairs following an incident. The plant processes production from the Snøhvit, Albatross and Askeladd fields. The operator has advised that it may take until 1 October 2021 to restart production. Neptune's loss of revenue is being recovered through business interruption insurance, after an initial period of 60 days.

5. Segmental information

5.1 Net operating profit after equity accounted investments

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

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

	Year ended 31 December 2020							
In millions of $	UK	Norway	Netherlands	Germany	North Africa	Asia Pacific	Corporate	2020 Total
Production revenue by origin	**209.8**	**617.2**	**232.2**	**154.9**	**34.0**	**258.8**	**–**	**1,506.9**
Other revenue	**6.0**	**17.8**	**22.4**	**3.7**	**–**	**–**	**3.3**	**53.2**
Other operating income	**–**	**9.0**	**–**	**–**	**–**	**–**	**–**	**9.0**
Revenue and other income	**215.8**	**644.0**	**254.6**	**158.6**	**34.0**	**258.8**	**3.3**	**1,569.1**
Current operating profit/(loss)	**44.9**	**278.7**	**46.1**	**(48.5)**	**(21.9)**	**1.6**	**(17.0)**	**283.9**
Share of net income from investments using equity method	**–**	**–**	**1.6**	**–**	**(21.6)**	**–**	**–**	**(20.0)**
Net operating profit/(loss) after equity accounted investments	**44.9**	**278.7**	**47.7**	**(48.5)**	**(43.5)**	**1.6**	**(17.0)**	**263.9**
Net impairment loss								**(325.7)**
Mark-to-market on commodity contracts other than trading instruments								**(4.0)**
Group reorganisation costs								**(25.3)**
Other losses								**(4.3)**
Loss before financial items								**(95.4)**
Financial income								**12.4**
Finance costs								**(250.1)**
Loss before tax								**(333.1)**

In millions of $	UK	Norway	Netherlands	Germany	North Africa	Asia Pacific	Corporate	2019 Total
	Year ended 31 December 2019							
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
Other operating income	–	–	–	–	–	–	–	–
Revenue and other income	199.2	1,002.7	314.2	199.9	46.8	439.4	–	2,202.2
Current operating profit/(loss)	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/(loss) after equity accounted investments	60.7	612.5	96.6	(23.5)	13.0	156.0	1.1	916.4
Net impairment loss								(59.4)
Mark-to-market on commodity contracts other than trading instruments								14.2
Group reorganisation costs								(68.9)
Other gains								70.4
Profit before financial items								872.7
Financial income								6.3
Finance costs								(202.2)
Profit before tax								676.8

5.2 EBITDAX by country

EBITDAX as a Non-GAAP measure is the group performance metric used to measure our ability to produce income from our operations in any given year. This measure is reconciled to its statutory equivalent.

In millions of $	UK	Norway	Netherlands	Germany	North Africa	Asia Pacific	Corporate	Total
	Year ended 31 December 2020							
EBITDAX (including equity accounted affiliates)	**151.2**	**461.0**	**129.7**	**48.2**	**(8.1)**	**171.8**	**(14.0)**	**939.8**

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

5.3 Net impairment loss by country

In millions of $	UK	Norway	Netherlands	Germany	North Africa	Asia Pacific	Corporate	Total
	31 December 2020							
Goodwill (note 12)	**–**	**4.2**	**–**	**–**	**10.2**	**–**	**–**	**14.4**
Intangible assets (note 13)	**–**	**(0.2)**	**–**	**–**	**–**	**10.0**	**–**	**9.8**
Property, plant and equipment (note 14)	**–**	**–**	**91.1**	**12.7**	**–**	**197.7**	**–**	**301.5**
Total impairments	**–**	**4.0**	**91.1**	**12.7**	**10.2**	**207.7**	**–**	**325.7**

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In millions of $	UK	Norway	Netherlands	Germany	North Africa	Asia Pacific	Corporate	Total
	31 December 2019							
Goodwill (note 12)	–	–	–	–	–	–	–	–
Intangible assets (note 13)	–	8.8	–	0.1	–	–	–	8.9
Property, plant and equipment (note 14)	–	–	50.4	0.1	–	–	–	50.5
Total impairments	–	8.8	50.4	0.2	–	–	–	59.4

5.4 Net assets

In millions of $	UK	Norway	Netherlands	Germany	North Africa	Asia Pacific	Corporate	Total
	31 December 2020							
Balance sheet								
Assets	**1,329.8**	**3,205.2**	**636.4**	**576.0**	**628.6**	**1,131.8**	**84.7**	**7,592.5**
Liabilities	**(357.2)**	**(1,876.0)**	**(672.9)**	**(704.9)**	**(17.2)**	**(153.8)**	**(2,327.9)**	**(6,109.9)**
Net assets	**972.6**	**1,329.2**	**(36.5)**	**(128.9)**	**611.4**	**978.0**	**(2,243.2)**	**1,482.6**

In millions of $	UK	Norway	Netherlands	Germany	North Africa	Asia Pacific	Corporate	Total
	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

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

5.5 Net capital investment

In millions of $	UK	Norway	Netherlands	Germany	North Africa	Asia Pacific	Corporate	Total
	Year ended 31 December 2020							
Investments accounted under equity method	**–**	**–**	**(1.8)**	**–**	**(45.3)**	**–**	**–**	**(47.1)**
Capital expenditure	**98.2**	**576.5**	**60.0**	**56.0**	**7.9**	**142.5**	**–**	**941.1**
	98.2	**576.5**	**58.2**	**56.0**	**(37.4)**	**142.5**	**–**	**894.0**

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

5.6 Underlying operating profit

For the Group's single class of business (upstream), the underlying operating profit taking into consideration certain one off items is as below:

In millions of $	Year ended 31 December 2020	Year ended 31 December 2019
Operating (loss)/profit before financial items	**(95.4)**	872.7
Add back:		
Share of net loss from investments using equity method – Touat impairment	**32.7**	–
Impairment loss	**325.7**	59.4
Net restructuring cost	**25.3**	68.9
Deduct:		
Pension scheme settlement/(curtailment credit)	**(1.0)**	(50.0)
Underlying operating profit	**287.3**	951.0

6. Operating profit/(loss) before financial items

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

Group In millions of $	Year ended 31 December 2020	Year ended 31 December 2019
Cost of sales		
Movements in over/under lift balances	**43.4**	(17.3)
Production, insurance and transportation costs	**470.1**	517.6
Depreciation of property, plant and equipment	**581.0**	614.6
Amortisation of intangible assets	**3.7**	9.6
Other operating costs	**26.7**	34.4
Exploration expenses		
Exploration and evaluation expenditure	**60.9**	60.2
Unsuccessful exploration expenditure written off	**30.3**	0.2
General and administration expenses include		
Employee costs	**39.0**	58.4
Auditors remuneration:		
Fees payable to the Company's auditor for the audit of the Company's annual accounts	**1.8**	1.6
Audit of the accounts of subsidiary companies	**0.4**	0.5
Non-audit fees	**0.6**	1.3

Ernst & Young LLP has served as Neptune Energy's independent external auditor for the four-year period ended 31 December 2020. The external auditor is subject to reappointment at the year-end Board meeting and has been reappointed for the 2021 period end.

Notes to the consolidated financial statements continued

7. Staff costs

Group In millions of $	Year ended 31 December 2020	Year ended 31 December 2019
Wages and salaries	**196.3**	190.4
Social security costs	**29.8**	29.3
Pension costs	**23.8**	29.9
Other long-term benefits (note 28.1b)	**2.9**	–
Total	**252.8**	249.6

The average number of persons employed during the year (including Directors) was 1,446 (2019: 1,458).

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 $19.0 million (2019: $5.2 million) The increase in charge in 2020 is a result of the opening of a new Dutch defined contribution scheme at the beginning of 2020 which replaced a Dutch defined benefit scheme that was closed and settled at the end of 2019.

7.1 Total Directors' remuneration

The total Directors' remuneration is:

Group In millions of $	Year ended 31 December 2020	Year ended 31 December 2019
Short-term employee benefits	**5.7**	6.2
Other long-term benefits – post-employment benefits	**0.1**	0.1
Total	**5.8**	6.3

Highest paid Directors' remuneration

Group In millions of $	Year ended 31 December 2020	Year ended 31 December 2019
Short-term employee benefits	**2.7**	3.0
Total	**2.7**	3.0

8. Other operating losses/(gains)

Other operating losses/(gains) are those that need to be disclosed separately by virtue of their nature, size or incidence. These include certain remeasurements, business restructuring costs, business combination activity, pension change costs or credits and asset impairments/write backs. In 2020, impairment losses with comparatives are disclosed on the face of the Group income statement due to their relative materiality.

Group In millions of $	Year ended 31 December 2020	Year ended 31 December 2019
Mark-to-market on commodity contracts other than trading instruments:		
Loss/(gain) on commodity derivative instruments at fair value through profit and loss	**(25.8)**	(19.5)
Loss/(gain) on foreign exchange forward at fair value through profit and loss	**–**	(1.7)
Loss/(gain) on foreign exchange swaps at fair value through profit and loss	**11.1**	(6.6)
Loss/(gain) on ineffectiveness on commodity contracts designated as hedges	**0.4**	0.5
Loss/(gain) on excluded components on commodity contracts designated as hedges	**18.3**	13.1
Restructuring provision cost (see note 22)	**25.3**	68.9
Pension schemes settlement/(curtailment credit) (see note 28.4)	**(1.0)**	(50.0)
Release of contingent consideration	**(20.3)**	–
Unsuccessful business combination termination fees	**5.0**	–
Other loss/(gain)	**20.6**	(20.4)
Total other operating losses/(gains)	**33.6**	(15.7)

Other losses in 2020 are principally in relation to the write off of a JV partner debtor. In 2019, other gains included $17.3 million relating to the reduction of the credit loss provision (see note 17).

The release of contingent consideration is primarily due to management no longer expecting certain project milestones, (two assets in Denmark and Norway that were part of the 2018 VNG acquisition), to be achieved due to changes in the field development plans.

9. Finance income and costs
9.1 Finance income

Group In millions of $	Year ended 31 December 2020	Year ended 31 December 2019
Interest income [1]	**7.7**	4.2
Interest income from Joint Arrangements for right-of-use assets	**2.3**	2.1
Dividend income [2]	**2.4**	–
Total finance income	**12.4**	6.3

(1) Interest income includes $1.0 million gain on the settlement of the Touat Vendor loan.
(2) Dividend income relates to a Level 3 non-listed equity instrument.

In the Company, finance income of $66.1 million (2019: $450.4 million) includes no dividend income (2019: $400.0 million).

9.2 Finance cost

Group In millions of $	Year ended 31 December 2020	Year ended 31 December 2019
Interest expense	**132.7**	122.5
Commitment fees	**14.4**	13.6
Unwinding of discount on decommissioning and other provisions	**36.1**	36.5
Interest expense lease liabilities	**7.1**	8.2
Net foreign exchange losses	**59.8**	21.4
Total finance costs	**250.1**	202.2

10. Dividend

Group In millions of $	Year ended 31 December 2020	Year ended 31 December 2019
Aggregate amount of dividends paid in the year	**–**	200.0
Aggregate amount of dividends liable to pay at the balance sheet date	**–**	200.0

Company In millions of $	Year ended 31 December 2020	Year ended 31 December 2019
Aggregate amount of dividends paid in the year	**–**	200.0
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). 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 for 2020 (2019: $nil) for the Company. Refer to note 30 for dividends declared after the balance sheet date.

Notes to the consolidated financial statements continued

11. Taxation

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

Group In millions of $	Year ended 31 December 2020	Year ended 31 December 2019
Current taxation		
(Credit)/Charge for the year	**(240.2)**	364.9
Adjustment in respect of prior years	**(46.7)**	(34.5)
	(286.9)	330.4
Deferred taxation		
Origination and reversal of temporary differences in current year	**352.8**	(92.6)
Total income tax expense recognised in income statement	**65.9**	237.8

The effective tax rate for the Group for 2020 was (20)% (2019: 35%). The effective tax rate is impacted by the following items: derecognition of deferred tax assets in the UK of $143.0 million due to softening commodity price forecasts, partially offset by the recognition of deferred tax on decommissioning; capital uplift allowances in Norway, comprising the new temporary changes to the Norwegian petroleum tax regime, allowing 24% uplift in the investment year ($70.3 million credit); the successful resolution of tax enquiries in Norway and the Netherlands ($16.3 million current tax credit) and the partial recognition of deferred tax on current year taxable losses and carried forward deductions in Denmark, Germany and the Netherlands ($50.8 million deferred tax credit not recognised).

11.1 Reconciliation between theoretical income tax expense and actual tax expense

Group In millions of $	31 December 2020	31 December 2019
(Loss)/profit before taxation	**(333.1)**	676.8
Expected tax charge/(credit) at weighted average statutory rate	**(0.5)**	523.2
Effects on tax charge of:		
Income/expenses taxed or relieved at rates different to the headline statutory rate[1]	**(127.3)**	(33.9)
Non tax-deductible expenditure	**62.4**	23.2
Income not subject to taxation	**(15.9)**	(4.3)
Utilisation of previously unrecognised deferred tax assets	**(4.7)**	(12.6)
Adjustments in respect of prior years	**(46.7)**	(34.5)
Derecognition/(recognition) of deferred tax assets	**158.6**	(291.3)
Non-recognition of deferred tax assets	**52.3**	48.9
Other items[2]	**(12.3)**	19.1
Total income tax charge/(credit)	**65.9**	237.8

(1) Includes the impact of capital uplift allowances, Norway $70.3 million credit, and finance and hedging results taxed or relieved at rates lower than the headline statutory rate.
(2) Includes a tax credit of $2.2 million relating to the impact of a change in tax rates (2019: $3.4 million charge).

The Group operates in a number of jurisdictions. Across these jurisdictions, there is a broad variation in statutory tax rates. The Group's expected tax charge reflects the applicable rates for the countries in which the group earned profits. The tax charge will vary depending on a number of factors, such as the geographic mix of profits and changes to tax rates. During the year, the Group has earned profits in countries with high statutory tax rates (i.e. Norway) and losses in countries with comparatively low statutory tax rates. The Group is making an overall loss for 2020. Due to the geographic mix of profits, losses and tax rates, the expected actual tax charge is exceptionally low for the year.

Included in the table for 2019 are exceptional items largely in relation to deferred tax. These include the impact of the 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 2020	31 December 2019
Difference type		
Actuarial gains	**2.5**	7.5
Cash flow hedges	**32.5**	(36.1)
Net deferred tax income/(expense)	**35.0**	(28.6)

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 2020	**(1,315.8)**	**361.1**	**43.9**	**957.6**	**(105.9)**	**(59.1)**
Reclassification	**(20.6)**	**(0.4)**	**–**	**16.1**	**4.9**	**–**
Credit/(charge) for the year	**(179.2)**	**54.7**	**–**	**(201.4)**	**(26.9)**	**(352.8)**
Charge to equity and other comprehensive income	**–**	**–**	**2.5**	**–**	**32.5**	**35.0**
Currency translation adjustments	**(64.5)**	**16.9**	**3.0**	**14.9**	**(4.9)**	**(34.6)**
At 31 December 2020	**(1,580.1)**	**432.3**	**49.4**	**787.2**	**(100.3)**	**(411.5)**

Deferred tax asset	**577.3**
Deferred tax liabilities	**(988.8)**
Deferred tax liabilities net	**(411.5)**

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)

Significant one-off items impacting deferred taxes in 2020 include, impairment losses in Indonesia and the Netherlands which reduce deferred taxes liabilities on PP&E by $130.8 million. This reduction is offset by capital investment and the new temporary Norwegian fiscal changes.

The movement on tax losses relates almost entirely to the UK. The reduction in deferred tax is due to current year loss utilisation and the derecognition of deferred tax owing to softened commodity price forecasts.

The recognition and recovery of our tax losses is sensitive, amongst other things, to oil and gas prices. The Group has run sensitivity analysis on our commodity price forecasts. Of the total deferred tax recognised in respect of tax losses, $645.8 million relates to the UK. If prices were 10% lower than our current forecast, the deferred tax recognised in respect of UK losses would reduce by $113.5 million. If prices were 10% higher than our current forecast, the deferred tax recognised in respect of UK tax losses would increase by $107.4 million.

There were no net deferred tax assets and liabilities recognised in the Company for 2020 or 2019.

Notes to the consolidated financial statements continued

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

Group In millions of $	31 December 2020	31 December 2019
Unused tax losses	**2,440.3**	1,631.9
Other deductible temporary differences	**681.4**	506.3
Total temporary difference for which no deferred tax asset is recognised	**3,121.7**	2,138.2

Of the above unrecognised deductible temporary differences, $3,089.9 million (2019: $2,119.3 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 2020	31 December 2019
Cost at 1 January	**640.8**	648.2
Currency translation adjustments	**23.7**	(7.4)
Cost at 31 December	**664.5**	640.8
Impairment losses at 1 January		
Impairment loss	**(14.4)**	–
Currency translation adjustments	**(0.4)**	–
Impairment losses at 31 December	**(14.8)**	–
Net book value at 31 December	**649.7**	640.8

The goodwill arose on the acquisition in 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 in 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.

Country of CGU In millions of $	Trigger for 2020 impairment	2020 impairment	Post-tax discount rate	2020 CGU recoverable amount
Egypt	**a**	**10.2**	**12%**	**–**
Denmark	**b**	**4.2**	**10%**	**–**
Total		**14.4**		

a. Decrease due to long-term price assumptions.
b. Changes in the field development plan.

The goodwill assigned to Norway is $561.8 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.

During the year, goodwill relating to Denmark and Egypt has been fully impaired. The remaining goodwill is assigned to the Netherlands and Germany group of CGUs. The carrying amount of the goodwill allocated to these cash-generating units 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 CGUs consistent with a Level 3 fair value measurement as defined in note 23.1. 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 derived from a market consensus for current prices transitioning to a long-term price in 2024 of $60/bbl for Brent crude oil and 50p/therm for NBP gas thereafter inflated by 2% per annum.

The Group's recoverable value of assets is sensitive, inter alia, to oil and gas prices. The Group has run sensitivity analysis 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 $95 million (2019: $35 million). If the prices were to decrease by approximately 9% (2019: 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.

13. Intangible assets

Group In millions of $	Exploration and evaluation	Other	Total
Cost at 1 January 2019	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
Additions	82.7	1.9	84.6
Unsuccessful exploration expenditure	(30.4)	–	(30.4)
Impairment loss	(17.7)	–	(17.7)
Reversal of impairment loss	7.9	–	7.9
Transfers (to)/from property, plant and equipment	(3.8)	0.1	(3.7)
Currency translation adjustments	6.8	1.4	8.2
Cost at 31 December 2020	**184.1**	**32.0**	**216.1**
Amortisation at 1 January 2019	–	(6.7)	(6.7)
Charge for the year	–	(9.6)	(9.6)
Currency translation adjustments	–	–	–
Amortisation at 31 December 2019	–	(16.3)	(16.3)
Charge for the year	–	(3.7)	(3.7)
Currency translation adjustments	–	(1.2)	(1.2)
Amortisation at 31 December 2020	**–**	**(21.2)**	**(21.2)**
Net book value at 31 December 2020	**184.1**	**10.8**	**194.9**
Net book value at 31 December 2019	138.6	12.3	150.9

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

Country of CGU In millions of $	Trigger for 2020 impairment/ (reversal)	2020 impairment/ (reversal)	Post-tax discount rate	2020 CGU recoverable amount
Norway	a	(7.9)	8%	26.3
Denmark	b	7.7	10%	2.5
Indonesia	c	10.0	11%	–
Total		**9.8**		

a. Due to a new discovery within the area.
b. Changes in the field development plan.
c. Licence relinquishment.

Notes to the consolidated financial statements continued

Country of CGU In millions of $	Trigger for 2019 impairment/ (reversal)	2019 impairment/ (reversal)	Post-tax discount rate	2019 CGU recoverable amount
Norway	d	8.8	8%	–
Other		0.1		
Total		8.9		

d. Appraisal well write off.

14. Property, plant and equipment

Group In millions of $	Oil and gas properties	Other fixed assets	Total
Cost at 1 January 2019	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
Additions	853.3	3.2	856.5
Asset derecognition[1]	(6.6)	–	(6.6)
Disposals	(21.3)	(1.1)	(22.4)
Transfers from intangible assets	3.0	0.7	3.7
Currency translation adjustments	266.1	6.0	272.1
Cost at 31 December 2020	6,721.8	94.6	6,816.4
Accumulated depreciation at 1 January 2019	(628.9)	(2.5)	(631.4)
Charge for year [2],[3]	(605.5)	(11.7)	(617.2)
Impairment loss	(50.5)	–	(50.5)
Disposals	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)
Charge for year [2],[3]	(587.6)	(11.7)	(599.3)
Impairment loss	(301.3)	(0.2)	(301.5)
Asset derecognition	3.8	–	3.8
Disposals	21.3	1.1	22.4
Currency translation adjustments	(91.7)	(1.6)	(93.3)
Amortisation at 31 December 2020	**(2,223.9)**	**(26.3)**	**(2,250.2)**
Net book value at 31 December 2020	**4,497.9**	**68.3**	**4,566.2**
Net book value at 31 December 2019	4,358.9	71.9	4,430.8

1) The derecognition of assets arises in Norway in relation to the fire at the non-operated Hammerfest LNG facility.
2) Includes capitalised depreciation of $18.3 million (2019: $2.6 million) related to right-of-use assets in Norway and the UK.
3) 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 cash generating units (CGU) consistent with a Level 3 fair value measurement. In determining the fair value, the Group has used a post-tax discount rate of 8-12% based on a country specific weighted average cost of capital. Oil and gas prices are based on an internal view of management expectations derived from a market consensus for current prices transitioning to a long-term price in 2024 of $60/bbl for Brent crude oil and 50p/therm for NBP gas thereafter inflated by 2% per annum.

Country of CGU In millions of $	Trigger for 2020 impairment	2020 pre-tax impairment	Post-tax discount rate	2020 CGU recoverable amount
Netherlands (1)	a	91.1	10%	92.8
Indonesia	a	197.7	11%	533.2
Germany	b	12.7	10%	–
Total		301.5		

a. Decrease due to long-term price assumptions and underlying reservoir performance.
b. Decrease due to long-term price assumptions.

2020 incremental price and discount rate sensitivity impairment analysis on CGU recoverable amount (post-tax):

	2020 CGU recoverable amount	Oil and Gas price		Post-tax discount rate	
Country of CGU In millions of $		Plus 10%	Minus 10%	Plus 1%	Minus 1%
Netherlands (1)	92.8	25.4	(21.1)	(1.6)	1.8
Indonesia	533.2	44.5	(46.5)	(15.5)	16.5
Germany	–	–	–	–	–
Total	626.0	69.9	(67.6)	(17.1)	18.3

For the Indonesia CGU, sensitivity analyses indicate that if reserves were to fall by 10% an additional post-tax impairment of $50.5 million would have occurred and an increase of reserves by 10% would have led to a reduction of the post-tax impairment of $42.5 million. For the Netherlands CGU, sensitivity analyses indicate that if reserves were to fall by 10% an additional post-tax impairment of $21.1 million would have occurred and an increase of reserves by 10% would have led to a reduction of the post-tax impairment of $25.2 million.

Country of CGU In millions of $	Trigger for 2019 impairment	2019 pre-tax impairment	Post-tax discount rate	2019 CGU recoverable amount
Netherlands (1)	b	42.3	10%	152.3
Netherlands (2)	c	8.1	10%	–
Other		0.1		
Total		50.5		

b. Decrease due to underlying reservoir performance and long-term price assumptions.
c. Decrease due to redetermination of field.

2019 incremental price and discount rate sensitivity impairment analysis on CGU recoverable amount (post-tax):

	2019 CGU recoverable amount	Oil and Gas price		Post-tax discount rate	
Country of CGU In millions of $		Plus 10%	Minus 10%	Plus 1%	Minus 1%
Netherlands (1)	152.3	14.5	(15.3)	(5.1)	4.9

15. Investments

Group In millions of $	Equity	Total
Cost at 1 January 2019	540.9	540.9
Additions	63.8	63.8
Cost at 31 December 2019	604.7	604.7
Net movements	(47.1)	(47.1)
Cost at 31 December 2020	557.6	557.6

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Interest in joint ventures

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

Group In millions of $	31 December 2020	31 December 2019
At 1 January	**604.7**	540.9
Share of results in the year	**(20.0)**	2.1
Dividends paid	**(5.2)**	(6.2)
Hedging recognised in other comprehensive income	**(3.1)**	–
Equity injection contribution	**26.2**	69.0
Share capital repayment	**(46.9)**	–
Currency translation adjustments	**1.9**	(1.1)
At 31 December	**557.6**	604.7

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

Neptune Energy Touat B.V. In millions of $	31 December 2020	31 December 2019
Non-current assets	**1,045.7**	1,128.5
Current assets	**79.9**	90.6
Current liabilities	**(86.6)**	(92.0)
Non-current liabilities	**(46.1)**	(50.2)
Equity	**992.9**	1,076.9
Group's share of equity – 54%	**536.2**	581.5
Group's carrying amount of the investment	**536.2**	581.5

Neptune Energy Touat B.V. In millions of $	2020	2019
Revenue from investments	**116.8**	25.6
Other income	**32.0**	6.6
Cost of sales	**(116.2)**	(20.0)
Gross profit	**32.6**	12.2
General and administration expenses	**(11.6)**	(11.6)
Operating profit	**21.0**	0.6
Impairment loss	**(60.6)**	–
Operating profit before financial items	**(39.6)**	0.6
Finance income	**8.7**	0.5
Finance costs	**(8.4)**	–
(Loss)/Profit before tax	**(39.3)**	1.1
Taxation	**(0.8)**	0.7
Profit for the year	**(40.1)**	1.8
Other comprehensive loss that may be reclassified to profit or loss in subsequent periods, net of tax	**(5.7)**	–
Total comprehensive income for the year	**(45.8)**	1.8
Group's share of (loss)/profit for the year – 54%	**(21.6)**	1.0
Group's share of other comprehensive loss – 54%	**(3.1)**	–
Group's share of total comprehensive loss – 54%	**(24.7)**	1.0

Included within current assets are cash and cash equivalents of $12.2 million (2019: $1.4 million).
Included within current assets are derivative contracts of $1.4 million (2019: nil).
Included within current liabilities are derivative contracts of $7.3 million (2019: nil).
Included within cost of sales is depreciation of oil and gas assets of $68.7 million (2019: $12.1 million).
The Touat development had capital commitments of $23.3 million (2019: $39.2 million) for which the Group has a corresponding commitment, as 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 31 December 2019 and 31 December 2020	**1,977.2**	**1,977.2**

16. Inventories

Group In millions of $	31 December 2020	31 December 2019
Hydrocarbons – stock of gas	**3.8**	7.0
Raw materials and consumables	**75.2**	53.4
Total	**79.0**	60.4

The Company held no inventories in 2020 or 2019.

Included within raw materials and consumables is $20.5 million (2019: $18.9 million) in respect of provisions for deterioration and obsolescence.

17. Trade and other receivables

Group In millions of $	31 December 2020	31 December 2019
Amounts falling due within one year		
Trade receivables	**184.6**	290.7
Under-lift position	**57.4**	89.4
Other taxes receivable	**8.3**	12.1
Other receivables	**272.1**	252.6
Prepayments and accrued income	**4.2**	7.1
Total	**526.6**	651.9

Trade receivables are stated net of credit loss provisions of $6.3 million (2019: $5.1 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).

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

Company In millions of $	31 December 2020	31 December 2019
Amounts falling due within one year		
Receivable from subsidiaries	**216.2**	215.4
Receivable from parent company	**–**	1.1
Other current assets	**–**	0.3
Current assets	**216.2**	216.8
Amounts falling due after one year		
Inter-company loan receivable	**943.2**	939.7
Non-current assets	**943.2**	939.7
Total	**1,159.4**	1,156.5

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Included within amounts receivable from subsidiaries is $200.0 million (2019: $200.0 million) 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 2020	31 December 2019
Cash at bank and in hand	**79.7**	75.1
Restricted cash	**12.8**	10.3
Total cash and cash equivalents	**92.5**	85.4

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 2020 (31 December 2019: $nil).

19. Borrowings

Group In millions of $	Interest rate 2020 %	Interest rate 2019 %	Maturity	31 December 2020	31 December 2019
Non-current interest-bearing loans and borrowings					
Reserve Based Lending facility	**2.647**	4.213	2024	**1,028.6**	643.7
Touat project finance facility	**8.000**	6.000	2024	**–**	232.2
Subordinated Neptune Energy Group Limited loan	**7.750**	7.750	2024	**107.9**	107.9
Senior Notes	**6.625**	6.625	2025	**835.3**	831.8
Total non-current				**1,971.8**	1,815.6
Current interest-bearing loans and borrowings					
Touat project finance facility	**8.000**	6.000	2020	**–**	24.0
DNB uncommitted facility	**1.830**	3.286	2021	**50.0**	50.0
Citi Bank uncommitted facility	**–**	2.336	2020	**–**	50.0
Total current				**50.0**	124.0
Total				**2,021.8**	1,939.6

The movements in borrowings are described in the table below:

Group In millions of $	31 December 2020
At 1 January 2020	**1,939.6**
Associated cash flows	
Repayment of borrowings	**(1,307.7)**
Drawdown of borrowings	**1,371.5**
Debt arrangement fees	**(5.8)**
Non-cash movements	
Capitalised interest	**16.5**
Movement in accrued interest	**(6.6)**
Amortisation of debt arrangement fees	**14.3**
At 31 December 2020	**2,021.8**

Certain subsidiaries within the Group have a Reserve Based Lending facility (RBL) with total aggregate commitments of $2.0 billion at the start of the year. The outstanding debt is repayable in line with the amortisation of bank commitments over the period from 1 April 2022 to the final maturity date of 11 May 2024, or such time as is determined by reference to the remaining reserves of the assets, whichever is earlier. The maximum amount that the relevant subsidiaries (the RBL Group) can drawdown under this facility (the borrowing base) is subject to a consolidated cash flow and debt service projection, which is subject to an annual redetermination process in March. On this date there is a redetermination of the available size of the facility, which takes into account, among other things, the most up-to-date forecast of the RBL Group's production. The facility 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.

During 2020, Neptune Energy amended its $2.0 billion RBL credit facility with its bank syndicate. Principal changes included the addition of the Merakes, Indonesia and Touat, Algeria assets to the borrowing base. As a result of these changes, the borrowing base increased from $2.0 billion to $2.3 billion, until the next redetermination date in March 2021. In addition, the first scheduled repayment was delayed from 2021 to 2022, while the final facility maturity date remains unchanged in May 2024. Neptune Energy also exercised the accordion option to upsize the total commitments under the RBL credit facility from $2.0 billion to $2.6 billion. As at 31 December 2020, total drawings under the facility were $1,070 million.

On 28 September 2020, Neptune made an early repayment of the Touat Vendor loan of $237 million (including interest of $4.4 million) for an aggregate consideration of $236 million. A gain of $1 million was recognised within finance income. The loan repayment was funded by $26 million of cash and the remainder drawn under the RBL facility. Due to the significant cost difference between the Vendor Loan and the RBL, Neptune will realise cost savings of approximately $12 million per annum.

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 in 2025 which represent an additional issuance of notes of the series of which an aggregate principal amount of $550 million were previously issued.

20. Trade payables and other liabilities

Group In millions of $	31 December 2020	31 December 2019
Trade and other payables	**333.5**	222.7
Other current liabilities	**327.6**	567.5
Lease liabilities	**98.5**	72.3
Wages and social security	**50.9**	53.2
Current trade payables and accruals	**810.5**	915.7
Other non-current liabilities	**41.7**	64.9
Lease liabilities	**89.6**	99.7
Non-current trade payables and accruals	**131.3**	164.6
Total	**941.8**	1,080.3

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 (2019: $200.0 million) in respect of a promissory note issued on 11 December 2019 to the immediate and ultimate parent undertaking in respect of the 2019 interim dividend declared (see note 10); the remainder of the balance is principally related to joint venture funding.

Company In millions of $	31 December 2020	31 December 2019
Trade and other payables	–	1.2
Payable to parent company	**207.4**	207.4
Interest payable to subsidiary	**7.4**	7.2
Current trade payables and accruals	**214.8**	215.8
Subordinated Neptune Energy Group Limited loan	**107.9**	107.9
Inter-company loan payable > 1 year	**835.3**	831.8
Non-current trade payables and accruals	**943.2**	939.7
Total	**1,158.0**	1,155.5

Included within amounts payable to parent company is $200.0 million (2019: $200.0 million) 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.

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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, PP&E leases are less than 2 years, while transportation assets have leases between one and four 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
Disposals	(0.7)	–	(0.7)
Depreciation expense	(16.1)	(8.6)	(24.7)
Currency translation adjustments	–	(0.2)	(0.2)
At 31 December 2019	66.8	42.6	109.4
Additions	29.5	2.1	31.6
Depreciation expense	(31.7)	(8.2)	(39.9)
Currency translation adjustments	3.1	2.0	5.1
At 31 December 2020	**67.7**	**38.5**	**106.2**

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 2020	31 December 2019
At 1 January	**(172.0)**	(145.3)
Additions	**(84.2)**	(57.6)
Disposals	**0.9**	0.6
Interest(1)	**(8.0)**	(8.2)
Payments(2)	**77.4**	40.5
Other	**1.3**	(0.5)
Currency translation adjustments	**(3.5)**	(1.5)
At 31 December	**(188.1)**	(172.0)

(1) Includes $0.9 million (2019: $nil) of capitalised interest.
(2) The payments include $8.0 million (2019: $8.2 million) relating to interest and $69.4 million (2019: $32.3 million) relating to principal repayments.

Group In millions of $	31 December 2020	31 December 2019
Within one year	**98.5**	72.3
Current trade payables and other liabilities (see note 20)	**98.5**	72.3
Between two and five years	**68.1**	90.5
More than five years	**21.5**	9.2
Non-current trade payables and other liabilities (see note 20)	**89.6**	99.7

The following are the amounts recognised in profit or loss:

Group In millions of $	31 December 2020	31 December 2019
Depreciation expense of right-of-use assets	(39.9)	(24.7)
Interest income from Joint Arrangements for right-of-use assets	2.3	2.1
Interest expense right-of-use assets	(8.0)	(8.2)
Expense relating to short term leases	(0.1)	–
Expense relating to leases of low-value assets	(0.6)	(0.4)
Income from subleasing right-of-use assets	–	6.1
Total amount recognised in profit and loss	**(46.3)**	(25.1)

The Group has total cash outflows for leases of $77.4 million (2019: $40.5 million). The future cash outflows relating to leases that have not yet commenced are disclosed in note 26.1.

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22. Provisions

Group In millions of $	Decommissioning	Restructuring	Total employee benefit obligations	Other	Total
At 1 January 2020	1,500.8	66.6	195.0	5.3	1,767.7
Charge for the year	8.9	33.1	8.6	–	50.6
Unwinding of discount	33.7	–	2.4	–	36.1
Additions	82.4	8.5	1.0	–	91.9
Change in discount rate	(5.6)	–	6.3	–	0.7
Reclassifications	–	–	6.6	–	6.6
Utilisation/paid	(40.5)	(30.9)	(13.3)	(0.7)	(85.4)
Unused provisions released to income statement	(1.2)	(7.8)	(1.0)	–	(10.0)
Currency translation	105.3	4.6	17.4	0.3	127.6
At 31 December 2020	1,683.8	74.1	223.0	4.9	1,985.8

There were no provisions for the Company in both 2020 and 2019.

Group In millions of $	31 December 2020	31 December 2019
Current		
Restructuring	52.7	41.8
Post-employment benefit and other long-term benefits	11.3	11.4
Decommissioning	46.0	55.0
Other	4.9	5.3
Current total	**114.9**	113.5
Non-current		
Restructuring	21.4	24.8
Post-employment benefit and other long-term benefits	211.7	183.6
Decommissioning	1,637.8	1,445.8
Non-current total	**1,870.9**	1,654.2
Total	**1,985.8**	1,767.7

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.

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The restructuring provision is in relation to the decision in 2019 to close the corporate office in France and also the announcement in June 2020 to reduce 400 positions across our business including proposals to close offices in Oslo in Norway and Lingen in Germany.

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 1.1% to 3.5% in 2020. The discount rate range used in 2019 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 2020 including their maturity. For items held at amortised cost there is no significant difference between their fair value and amortised cost value.

	31 December 2020			
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	**2.4**	**0.6**	–	**3.0**
Commodity derivatives in qualifying hedging relationships[1]	**52.7**	**19.0**	–	**71.7**
Equity instruments designated at fair value through OCI				
10.58% interest in Erdgas-Verkaufs-Gesellschaft mbH, Münster	–	–	**21.1**	**21.1**
Financial assets at amortised cost				
Trade and other receivables	**526.6**	–	–	**526.6**
Income tax receivable	**153.4**	–	–	**153.4**
Other non-current assets[2]	–	**99.5**	–	**99.5**
Total	**735.1**	**119.1**	**21.1**	**875.3**

(1) Of the $52.7 million due under one year, $21.0 million is due within six months.
(2) Other non-current assets mainly represents amounts receivable from Joint Venture partners

Group In millions of $	31 December 2019 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 was due within six months.

Company In millions of $	31 December 2020 Less than one year	Between two and five years	More than five years	Total
Financial assets at amortised cost				
Inter-company loan receivable	**–**	**943.2**	**–**	**943.2**
Receivable from subsidiaries	**216.2**	**–**	**–**	**216.2**
Total	**216.2**	**943.2**	**–**	**1,159.4**

Company 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

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

Set out below is an overview of financial liabilities, held by the Group as at 31 December 2020 including their maturity. The Senior Notes held by the Group have a fair value of $825.3 million, compared with the carrying amount of $835.3 million (2019: a fair value of $850.4 million, compared with the carrying amount of $831.8 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.

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Group In millions of $	31 December 2020 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)	54.0	11.5	–	65.5
Commodity derivatives at fair value through profit and loss	2.4	–	–	2.4
Interest rate derivatives in qualifying hedging relationships	3.7	–	–	3.7
Contingent consideration of the VNG Norge AS acquisition	2.6	–	–	2.6
Financial liabilities at amortised cost				
Short-term borrowings				
DNB uncommitted facility	50.0	–	–	50.0
Long-term borrowings				
Reserve Based Lending facility	–	1,028.6	–	1,028.6
Senior Notes	–	835.3	–	835.3
Subordinated Neptune Energy Group Limited loan	–	107.9	–	107.9
Trade and other payables	333.5	–	–	333.5
Wages and social security	50.9	–	–	50.9
Lease liabilities	98.5	68.1	21.5	188.1
Income taxes payable	28.6	71.5	–	100.1
Other liabilities	325.0	41.7	–	366.7
Total	949.2	2,164.6	21.5	3,135.3

(1) Of the $54.0 million, $25.7 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 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 Based 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
Income 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.

Company In millions of $	31 December 2020 Less than one year	Between two and five years	More than five years	Total
Financial liabilities at amortised cost				
Inter-company loan	**–**	**943.2**	**–**	**943.2**
Payable to parent company	**207.4**	**–**	**–**	**207.4**
Payable to subsidiary	**7.4**	**–**	**–**	**7.4**
Total	**214.8**	**943.2**	**–**	**1,158.0**

Company 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

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 2020 and 2019.

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

Group In millions of $	31 December 2020 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-20**	**71.7**	**71.7**	**–**
Commodity derivatives at fair value through profit and loss	**31-Dec-20**	**3.0**	**3.0**	**–**
Non-listed equity instruments				
10.58% interest in Erdgas-Verkaufs-Gesellschaft mbH, Münster	**31-Dec-20**	**21.1**	**–**	**21.1**
Total		**95.8**	**74.7**	**21.1**

Group In millions of $	31 December 2019 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-Verkaufs-Gesellschaft mbH, Münster	31-Dec-19	19.3	–	19.3
Total		241.6	222.3	19.3

The valuation of Neptune's interest in Erdgas-Verkaufs-Gesellschaft mbH, 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.

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

Group In millions of $	31 December 2020 Date of valuation	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-20**	**65.5**	**65.5**	**–**
Commodity derivatives at fair value through profit and loss	**31-Dec-20**	**2.4**	**2.4**	**–**
Interest rate derivatives in qualifying hedging relationships	**31-Dec-20**	**3.7**	**3.7**	**–**
Contingent consideration of the VNG Norge AS acquisition	**31-Dec-20**	**2.6**	**–**	**2.6**
Total		**74.2**	**71.6**	**2.6**

Group In millions of $	Date of valuation	Total	Significant observable inputs (Level 2)	Significant unobservable inputs (Level 3)
	31 December 2019			
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

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 Other Comprehensive Income in accordance with Level 3 are shown below:

	Group		Company	
In millions of $	31 December 2020	31 December 2019	31 December 2020	31 December 2019
Fair value at 1 January	**19.3**	19.7	**–**	–
Currency translation adjustments	**1.8**	(0.4)	**–**	–
Fair value at 31 December	**21.1**	19.3	**–**	–

A 5% change in the EBITDA multiple to the Level 3 instrument above as applied would result in a $1.1 million change in valuation (2019: $1.0 million change).

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 2020	31 December 2019	31 December 2019	31 December 2019
Fair value at 1 January	**(23.2)**	(24.3)	**–**	–
Gain on derecognition of contingent consideration payable [1]	**20.3**	–	**–**	–
Cash paid	**2.6**	–	**–**	–
(Losses)/gains recognised in other comprehensive income	**(2.3)**	1.1	**–**	–
Fair value at 31 December	**(2.6)**	(23.2)	**–**	–

(1) Includes unrealised gain or (losses) recognised in profit or loss attributable to balances held at the end of the reporting period.

The gain on the derecognition of contingent consideration payable has arisen as management no longer expect certain project milestones, related to two assets in Denmark and Norway that were part of the VNG acquisition, will now be achieved. The remaining contingent consideration is based on management's expectation on achieving certain project milestones. The possible range for the contingent consideration for all reasonable outcomes is $nil to $2.6 million.

Notes to the consolidated financial statements continued

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	Total hedge reserve
At 1 January 2020	**(123.7)**	**(0.7)**	**5.6**	**(118.8)**
Add: costs of hedging deferred and recognised in OCI	**(149.4)**	**57.3**	**(1.9)**	**(94.0)**
Less: reclassified from OCI to profit or loss or included in finance costs	**283.1**	**(18.3)**	**–**	**264.8**
Less: deferred tax	**(1.4)**	**(31.1)**	**–**	**(32.5)**
Less: share of hedge adjustments within equity accounted investments deferred and recognised in OCI	**2.9**	**0.2**	**–**	**3.1**
At 31 December 2020	**11.5**	**7.4**	**3.7**	**22.6**

Group In millions of $	Cash flow commodity hedge reserve	Cost of commodity hedging reserve	Cash flow interest rate hedge 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)

Excluded from the table above is a profit of $0.4 million (2019: profit of $0.5 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 2020 and 2019.

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 2020 with comparatives as at 31 December 2019.

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 2020 and 2019 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 smoothening the impact of gas and oil price volatility on earnings by reducing exposure to market prices. It thereby improves the earnings predictability of the Group.

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

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. In addition in 2020 we have expanded the hedging programme to include Neptune Energy Touat B.V. an equity accounted investment.

Notes to the consolidated financial statements continued

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

	31 December 2020			31 December 2019		
Group	Volumes	Average price	Period of hedge	Volumes	Average price	Period of hedge
OIL HEDGES VS BRENT	mmbbl	$/bbl		mmbbl	$/bbl	
Commodity cap	**5.0**	**50.4**	**up to 1 year**	2.5	76.0	up to 1 year
Commodity floor	**5.0**	**41.3**	**up to 1 year**	2.5	60.5	up to 1 year
Commodity swap	**0.5**	**49.7**	**up to 0.5 years**	1.9	60.4	up to 1 year
GAS HEDGES VS NBP	000's mmbtu	$/mmbtu		000's mmbtu	$/mmbtu	
Commodity cap	**27,450**	**8.56**	**up to 1.5 years**	57,848	8.33	up to 2.5 years
Commodity floor	**27,450**	**6.43**	**up to 1.5 years**	57,848	6.31	up to 2.5 years
Commodity swap	**39,960**	**5.73**	**up to 1.5 years**	29,520	5.64	up to 3 years
GAS HEDGES VS TTF	000's mmbtu	$/mmbtu		000's mmbtu	$/mmbtu	
Commodity cap	**21,589**	**7.75**	**up to 1.5 years**	47,460	7.49	up to 2.5 years
Commodity floor	**21,589**	**6.37**	**up to 1.5 years**	47,460	5.81	up to 2.5 years
Commodity swap	**20,268**	**5.87**	**Up to 2 years**	21,396	5.63	up to 3 years
EMISSION HEDGES VS EUA	000's tonnes	€/tonnes		000's tonnes	€/tonnes	
Commodity forward	**400**	**27.45**	**up to 2 years**	52	6.0	up to 1 year

There were no financial derivatives held by the Company in 2020 and 2019.

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.

At 31 December 2020 the aggregate post-tax hedge ratio for the Group's wholly owned subsidiaries was:

	2021	2022	2023
Oil	40%	–	–
Gas	70%	43%	–

At 31 December 2019 the aggregate post-tax hedge ratio for the Groups wholly owned subsidiaries was:

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

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.

Group In millions of $	Price movement	31 December 2020 Pre-tax loss/ (gain) on income	31 December 2020 Pre-tax loss/ (gain) on equity	31 December 2019 Pre-tax loss/ (gain) on income	31 December 2019 Pre-tax loss/ (gain) on equity
SENSITIVITY ANALYSIS Effect on profit before tax and on the pre-tax equity					
Gas price	+10% pence/therm increase	**–**	**57.9**	–	41.2
Gas price	-10% pence/therm decrease	**–**	**(58.0)**	–	(41.9)
Brent oil price	+10%/bbl increase	**1.9**	**20.1**	(0.1)	46.6
Brent oil price	-10%/bbl decrease	**(1.5)**	**(15.2)**	(0.3)	(48.3)
Carbon dioxide European Union Allowance	+10%/eua increase	**(1.6)**	**–**	–	–
Carbon dioxide European Union Allowance	-10%/eua decrease	**1.6**	**–**	–	–

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 affecting its operating and financing activities. Currency risk comprises (i) transaction risk arising in the ordinary course of business, (ii) specific transaction risks related to investments, mergers-acquisitions projects and (iii) the risk arising on the consolidation in USD of subsidiary financial statements with a functional currency other than the USD.

The Group held no US$ NOK forwards as at 31 December 2020 (2019: US$122 million).

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

Group In millions of $	31 December2020 Pre-tax loss/ (gain) on income	31 December2020 Pre-tax loss/ (gain) on equity	31 December 2019 Pre-tax loss/ (gain) on income	31 December 2019 Pre-tax loss/ (gain) on equity
SENSITIVITY ANALYSIS Effect on profit before tax and on the pre-tax equity				
+10% NOK	**–**	**–**	(33.9)	–
-10% NOK	**–**	**–**	33.9	–

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:

Group	31 December 2020 Currency	31 December 2020 Terms	31 December 2020 Period of hedge	31 December 2019 Currency	31 December 2019 Terms	31 December 2019 Period of hedge
Interest rate swaps	**$400 million**	**Average 2.59%**	**Within 1 year**	$400 million	Average 2.59%	Between 1-3 years

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

Group in millions of $ Effect on profit before tax and on the pre-tax equity	31 December 2020 Pre-tax loss/ (gain) on income	 Pre-tax loss/ (gain) on equity	31 December 2019 Pre-tax loss/ (gain) on income	 Pre-tax loss/ (gain) on equity
+100 basis points	–	(1.5)	–	(5.2)
-100 basis points	–	0.2	–	5.4

25. Called up share capital

Group and Company	Number	$ million
Allotted, called up and fully paid $1 shares		
At 31 December 2019 and 31 December 2020	**1,977,175,201**	**1,977.2**

26. Commitment and contingencies

26.1 Lease commitments

The Group has lease contracts that have not yet commenced as at 31 December 2020. The future lease payments for these non-cancellable lease contracts are $3.5 million (2019: $14.0 million) within one year, $5.1 million (2019: $15.7 million) within two to five years and $5.3 million (2019: nil) in more than five years.

The Group has financial commitments in respect of capacity bookings as at 31 December 2020. The future payments for these contracts are $23.4 million (2019: $15.5 million) within one year, $56.3 million (2019: $54.7 million) within two to five years and $8.2 million (2019: $12.7 million) in more than five years.

26.2 Capital commitments

In millions of $	Group 31 December 2020	 31 December 2019	Company 31 December 2020	 31 December 2019
Amounts due:				
Within one year	**428.4**	393.4	**–**	–
After one year but within two years	**52.3**	29.8	**–**	–
After two years but not more than five years	**14.3**	–	**–**	–
More than five years	**5.3**	–	**–**	–
Total	**500.3**	423.2	**–**	–

As at 31 December 2020, the Group had commitments for future capital expenditure amounting to $500.3 million (2019: $423.2 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 2020, the Group has no contingent liabilities (2019: $nil). As at 31 December 2020, a contingent asset exists in Norway and Algeria, being our equity accounted investment in relation to loss of production and future recovery through business interruption insurance. At 31 December 2020, due to several variable factors (including principally the ultimate length of the outages), it is not possible to provide an estimate of the amount of the associated contingent assets (2019: $nil).

The Company had no contingencies in either 2020 or 2019.

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 2020 and 2019 the Group has not identified any material contingent liabilities as all are deemed remote in nature.

There are no material pending legal proceedings for the Company as at 31 December 2020 (2019: 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 2020, the Group undertook the following transactions with related parties:

		2020	2020	2019	2019
Related party undertaking $ millions	Nature of transactions	Purchases	Accounts payable	Purchases	Accounts payable
TMF Norway Energy AS (CVC investor)	Services	**2.4**	**0.2**	–	–
Essential Project Solutions	Services	**0.3**	**–**	–	–
ONE-Dyas B.V. (Carlyle investor)	Oil and Gas	**2.0**	**–**	9.8	–
Black Platinum Energy	Oil and Gas	**7.3**	**–**	–	–

		2020	2020	2019	2019
Related party undertaking $ millions	Nature of transactions	Sales	Accounts receivable	Sales	Accounts receivable
ONE-Dyas B.V. (Carlyle investor)	Oil and Gas	**7.7**	**0.5**	6.7	0.6

Terms and conditions of transactions with related parties

The finance income and expenses from related parties are made on terms equivalent to those that prevail in arm's length transactions. Outstanding balances at the year-end are unsecured. There have been no guarantees provided or received from any related party receivables or payables. For the periods ended 31 December 2020 and 31 December 2019, 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 of $	2020	2019
Short-term employee benefits	**5.7**	6.2
Long-term employee benefits – post-employment benefits	**0.1**	0.1
Total compensation to key management personnel	**5.8**	6.3

At 31 December 2020 there is a promissory note for $200.0 million (2019: $200.0 million) payable to the parent company Neptune Energy Group Limited in respect of an interim dividend declared on 11 December 2019 (see note 10 and note 20).

There are no other related party transactions.

Company

There are no related party transactions other than inter-company interest, loans and the promissory note as described in note 10 and note 20.

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 2020 and 31 December 2019, 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.

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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.

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

28.1a Post employee benefit obligations – description of the main pension plans

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

The Group provides pension benefits to its employees that are in line with common market practice in the countries where Neptune operates. These consist of both defined contribution and defined benefit arrangements. The latter are either career average or final salary based on employee pensionable earnings and length of service. The plan in the UK is 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, the majority of employees of Neptune Energy Nederland B.V. and its Dutch subsidiaries were building up benefits in a defined benefit pension plan. 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 recognised in 2019 of $31 million. Benefits accruing after 1 January 2020 are provided via a defined contribution plan. The liabilities built up in the plan before 31 December 2019 are fully covered by an insurance policy. It has been determined that negligible risk remains to the Group for this plan and therefore the $230.5 million liabilities have been treated as fully settled during 2020 as the liabilities were fully covered by the insurance policy asset of $230.5 million. This event had no income statement or net balance sheet impact.

Germany
Neptune Energy Deutschland has seven defined benefit plans and two long-term benefit plans, corresponding to different groups of employees successively incorporated in the Company. The defined benefit plans are financed by book reserves and only one plan is open to new entrants. The Group is currently undergoing a restructuring exercise in Germany as a result of which a large number of employees will no longer be covered by the plans for pension benefits resulting in a curtailment event in 2020. This has given rise to an income statement gain in 2020 of $1.0 million.

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 S.A. 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 this, except for the ANE (Avantage en Nature Energie) plan, the majority of defined benefit plan liabilities were removed for employees who have been made redundant reflecting the fact that commitments for Neptune only cover employees while on the IEG payroll. This removal was treated as a settlement gain in 2019. Two of the defined benefit plans are funded. The Group believe they will be able to recover any remaining surplus for the IFC/IMR (retirement indemnity) arrangement after all the benefits have been paid and hence a net balance sheet asset has been recognised.

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 five other unfunded plans which are also administered by Storebrand.

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

28.1b Other long-term employee benefits – description of the long-term incentive plan

A number of employees participate in a long-term incentive plan, under which they can receive cash payments spread over a period of 2.5 years dependant on a number of performance criteria having being met over a three year assessment period. There are employees in this plan from several different territories. Awards are made on an annual basis at the discretion of the Board. The first award was granted in 2019 and the liabilities have been included in the disclosures for the first time in 2020 as the performance criteria that have been measured to date indicate that a future payment from the scheme is now likely.

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. Following the settlement of the Netherlands pension plan, very few of the Group's plans are now funded.

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 employment benefit obligations
A – Change in projected benefit obligations				
Projected benefit obligations at 1 January 2020	(430.8)	(7.4)	(7.6)	(445.8)
Transfers	(6.6)	–	–	(6.6)
Service cost	(5.9)	–	(2.7)	(8.6)
Past service cost	–	–	(1.0)	(1.0)
Settlements/curtailments [4]	231.5	–	–	231.5
Interest cost on benefit obligations	(2.6)	(0.1)	–	(2.7)
Financial actuarial gains and losses	(8.6)	(0.3)	(0.1)	(9.0)
Actuarial gains and losses due to experience	3.3	2.5	–	5.8
Benefits paid	9.5	0.4	3.1	13.0
Other including translation adjustments	(17.2)	(0.5)	(0.5)	(18.2)
Projected benefit obligation at 31 December 2020 A	(227.4)	(5.4)	(8.8)	(241.6)

Group In millions of $	Pension benefit obligations [1]	Other post-employment benefit obligations [2]	Long-term benefit obligations [3]	Total employment benefit obligations
B – Change in fair value of plan assets				
Fair value of plan assets at 1 January 2020	250.8	–	–	250.8
Transfers	–	–	–	–
Interest income on plan assets	0.2	–	–	0.2
Settlement/curtailments [4]	(230.5)	–	–	(230.5)
Financial actuarial gain and losses	(3.1)	–	–	(3.1)
Contributions received	9.8	0.4	3.1	13.3
Benefits paid	(9.5)	(0.4)	(3.1)	(13.0)
Other including translation adjustments	0.9	–	–	0.9
Fair value of plan assets at 31 December 2020 B	18.6	–	–	18.6

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Group In millions of $				
C – Funded status A+B				
Net benefit obligation	(208.8)	(5.4)	(8.8)	(223.0)

At 31 December 2020 the pre-paid benefit cost was $nil (2019: $nil).

(1) Pensions and retirement bonuses.
(2) Gratuities and other post-employment benefits.
(3) Length of service awards and other long-term benefits.
(4) Included in settlement/curtailments in 2020 is the derecognition of matching scheme assets and liabilities of $230.5 million following the closure in 2019 of the Dutch defined benefit pension scheme.

Group In millions of $	Pension benefit obligations (1)	Other post-employment benefit obligations (2)	Long-term benefit obligations (3)	Total employment benefit obligations
A – Change in projected benefit obligations				
Projected benefit obligations at 1 January 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 employment 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.

(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 2020	31 December 2019
Current service cost	**8.6**	14.0
Past service cost	**1.0**	–
Net interest expense	**2.5**	3.6
Actuarial gains and losses on long-term benefit obligations	**0.4**	0.1
Non-recurring items[1]	**(1.0)**	(54.7)
Total	**11.5**	(37.0)

(1) Non-recurring items includes settlement and curtailment gains of $1.0 million (2019: $50.0 million).

28.5 Reconciliation of balance sheet surplus/(deficit) over the year

Group In millions of $	31 December 2020	31 December 2019
Deficit at start of year	**(195.0)**	(232.5)
Expense (charge)/credit	**(11.5)**	37.0
Employer contributions	**13.3**	24.7
Transfers	**(6.6)**	–
Actuarial gain/(loss) recognised in OCI	**(6.7)**	(27.6)
Currency translation gain/(loss)	**(16.5)**	3.4
Deficit at end of year	**(223.0)**	(195.0)

28.6 Funding

The funding of these obligations at 31 December 2020 can be analysed as follows:

Group In millions of $	Projected benefit obligation	Fair value of plan assets	Total net obligation
Underfunded plans	**(17.9)**	**17.3**	**(0.6)**
Unfunded plans	**(223.5)**	**–**	**(223.5)**
Plans in surplus	**(0.2)**	**1.3**	**1.1**
At 31 December 2020	**(241.6)**	**18.6**	**(223.0)**

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)

Financial Statements

Notes to the consolidated financial statements continued

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

% of total	31 December 2020	31 December 2019
Cash	**1**	–
Bonds	**9**	–
Equity investments	**4**	1
Convertible bonds	**1**	–
Insurance contracts	**85**	98
Property	**–**	–
Other	**–**	1
Total	**100**	100

The majority of the scheme assets are held in an insurance contract in Norway. The change in the percentage allocation of planned assets since 2019 is a consequence of the closure in 2019 and subsequent derecognition in 2020 of the Dutch pension liability which had been fully funded via an insurance contract.

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.

2020 assumptions:

Eurozone

Group	Pension benefit obligations[1]	Other post-employment benefit obligations[2]	Long-term benefit obligations[3]
Discount rate	0% to 0.50%	0% to 0.70%	0%
Inflation rate	1.80%	1.80%	1.80%

Norway

Group	Pension benefit obligations[1]	Other post-employment benefit obligations[2]	Long-term benefit obligations[3]
Discount rate	1.70%	–	–
Inflation rate	1.50%	–	–

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%	–	–

(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 2020. 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 2020.

Pension risk analysis

The main risks the Group faces are:

The majority of 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

The table below illustrates how the Group's defined benefit liabilities would change (excluding the impact of inflation rate and interest rate hedging), as at 31 December 2020, in the event of the following changes in the key assumptions.

Sensitivities to key assumptions $m	31 December 2020
Increase of 0.5% rate in discount assumption	**(16.1)**
Decrease of 0.5% rate in discount assumption	**18.4**
Increase of 0.5% rate in inflation assumption	**13.9**
Decrease of 0.5% rate in inflation assumption	**(13.1)**
Increase in 1 year of life expectancy	**15.1**
Decrease in 1 year of life expectancy	**(14.9)**

Notes to the consolidated financial statements continued

Future benefit payments
The aggregate duration of the Group's defined benefit obligations is 14.7 years at 31 December 2020. The expected future benefit outgo is as follows:

Future benefit payments $m	31 December 2020
Next year: paid from scheme assets	**0.6**
Next year: paid directly by employer	**11.3**
Expected in year 2022	**11.4**
Expected in year 2023	**10.8**
Expected in year 2024	**10.7**
Expected in year 2025	**9.7**
Expected in year 2026 to 2029 (total)	**43.5**

The amount expected to be paid by the Group in 2021 is $11.3 million. These payments are to meet benefits expected from unfunded plans.

29. Principal subsidiary undertakings, joint ventures, associates

At 31 December 2020, 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
Gaz de France Exploration Libya B.V.	Netherlands	H	100%	100%	Oil and gas
GDF SUEZ E&P Eastern Indonesia B.V.	Netherlands	H	100%	100%	Oil and gas
GDF SUEZ Exploration Mauritania B.V.	Netherlands	H	100%	100%	Oil and gas
Neptune Energy Alam El Shawish B.V.	Netherlands	H	100%	100%	Oil and gas
Neptune Energy Arguni I B.V.	Netherlands	H	100%	100%	Oil and gas
Neptune Energy Ashrafi B.V.	Netherlands	H	100%	100%	Oil and gas
Neptune Energy E&P Holdings Netherlands B.V.	Netherlands	H	100%	100%	Holding Company
Neptune Energy East Ganal B.V.	Netherlands	H	100%	100%	Oil and gas
Neptune Energy East Sepinggan B.V.	Netherlands	H	100%	100%	Oil and gas
Neptune Energy Egypt B.V.	Netherlands	H	100%	100%	Oil and gas
Neptune Energy Exploration B.V.	Netherlands	H	100%	100%	Oil and gas
Neptune Energy Facilities Netherlands B.V.	Netherlands	H	100%	100%	Oil and gas
Neptune Energy Germany B.V.	Netherlands	H	100%	100%	Oil and gas
Neptune Energy Holding Netherlands B.V.	Netherlands	H	100%	100%	Holding Company
Neptune Energy Jakarta B.V.	Netherlands	H	100%	100%	Oil and gas
Neptune Energy Muara Bakau B.V.	Netherlands	H	100%	100%	Oil and gas
Neptune Energy Netherlands Administration B.V.	Netherlands	H	100%	100%	Oil and gas

Company name	Country of incorporation	Registered office	Holding	Proportion of voting rights and shares held	Main activity
Neptune Energy Netherlands B.V.	Netherlands	H	100%	100%	Oil and gas
Neptune Energy North Ganal B.V.	Netherlands	H	100%	100%	Oil and gas
Neptune Energy North West El Amal B.V.	Netherlands	H	100%	100%	Oil and gas
Neptune Energy Participation Netherlands B.V.	Netherlands	H	100%	100%	Oil and gas
Neptune Energy South West Alamein B.V.	Netherlands	H	100%	100%	Oil and gas
Neptune Energy Touat B.V.	Netherlands	H	54%	54%	Oil and gas
Neptune Energy Touat Holding B.V.	Netherlands	H	100%	100%	Oil and gas
Neptune Energy West Ganal B.V.	Netherlands	H	100%	100%	Oil and gas
ENGIE Sud Est Illizi B.V.	Netherlands	H	100%	100%	Oil and gas
Neptune Energy Norge AS	Norway	C	100%	100%	Oil and gas
Neptune E&P UK Ltd	UK	I	100%	100%	Oil and gas
Neptune E&P UKCS Ltd	UK	I	100%	100%	Oil and gas
Neptune Energy Bondco plc	UK	I	100%	100%	Financing Company
Neptune Energy Capital Limited	UK	I	100%	100%	Financing Company
Neptune Energy Finance Limited	UK	I	100%	100%	Financing Company
Neptune Energy Group Holdings Limited	UK	I	100%	100%	Holding Company
Neptune Energy Group Resourcing Limited	UK	I	100%	100%	Service Company
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

Group

On 19 February 2021 Neptune announced a sale and purchase agreement with Wintershall Dea for the acquisition of interests in six producing oil and gas fields in Germany. The effective date of this transaction was 1 January 2020. The transaction adds 13 mmboe of 2P reserves and around 1.8 kboepd of production.

Given the improving commodity and economic outlook, the Board of Directors of Neptune Energy Group Midco Limited have declared a 2021 Interim dividend of $80 million on 24 February 2021. This was enabled through the issue of an $80 million promissory note. The promissory note is payable on demand but bears no interest. The $200 million promissory note issued in respect of the final 2019 dividend announced on 11 December 2019 was settled on 25 February 2021.

Company

As above, on 24 February 2021, the Board of Directors of Neptune Energy Group Midco Limited have declared an $80 million interim dividend for the financial year 2021, following receipt of an $80 million interim dividend from its direct subsidiary, Neptune Energy Group Holdings Limited. The 2021 interim dividend from Neptune Energy Group Holdings Limited was enabled through the issuance of an $80 million promissory note for the benefit of Neptune Energy Group Midco Limited issued on 24 February 2021. Neptune Energy Group Midco Limited enabled the dividend to its parent company Neptune Energy Group Limited also through the issuance of an $80 million promissory note on 24 February 2021. Both promissory notes are payable on demand but bear no interest.

In addition, a $200 million promissory note in respect of the 2019 dividend received from Neptune Energy Group Holdings Limited relating to the dividend it announced on 11 December 2019 was settled on 25 February 2021. This enabled the company to settle the $200 million promissory note issued in respect of the final 2019 dividend to Neptune Energy Group Limited announced on 11 December 2019, also on 25 February 2021.

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 2019	491	142	633
Acquisitions [5]	14	0	14
Revisions, extensions and discoveries	1	5	6
Production	(41)	(11)	(52)
2P reserves at 31 December 2020	**465**	**136**	**601**

	Contingent resources (mmboe)		
	Europe	North Africa and Asia Pacific	Total Neptune Energy
2C resources at 31 December 2019	130	173	302
Acquisitions	3	0	3
Revisions, extensions and discoveries	140	7	147
2C resources at 31 December 2020	**273**	**180**	**452**

1) The above are management estimates, majority of which are independently audited by ERCe.
2) Numbers may not add up due to rounding differences.
3) 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.
4) 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.
5) On 19 February 2021 Neptune announced a sale and purchase agreement with Wintershall Dea for the acquisition of interests in six producing oil and gas fields in Germany. The effective date of this transaction was 1 January 2020.

General information

In this report, unless otherwise indicated, our production, reserves and resources figures are presented on a basis including our ownership share of volumes of companies that we account for under the equity accounting method, in particular, for the interest held in the Touat project in Algeria through a joint venture company. Production for interests held under production sharing contracts is reported on an appropriate unit of production basis.

Forward-looking statements

The discussion in this report includes forward-looking statements which, although based on assumptions that we consider reasonable, are subject to risks and uncertainties which could cause actual events or conditions to materially differ from those expressed or implied by the forward-looking statements. While these forward-looking statements are based on our internal expectations, estimates, projections, assumptions and beliefs as at the date of such statements or information, including, among other things, assumptions with respect to production, future capital expenditures and cash flow, we caution you that the assumptions used in the preparation of such information may prove to be incorrect and no assurance can be given that our expectations, or the assumptions underlying these expectations, will prove to be correct. Any forward-looking statements that we make in this report speak only as of the date of such statement or the date of this report.

Alternative performance measures

This report contains non-GAAP and non-IFRS measures and ratios that are not required by, or presented in accordance with, any generally accepted accounting principles (GAAP) or IFRS. These non-IFRS and non-GAAP measures and ratios may not be comparable to other similarly titled measures of other companies and have limitations as analytical tools and should not be considered in isolation or as a substitute for analysis of our operating results as reported under IFRS or GAAP. Non-IFRS and non-GAAP measures and ratios are not measurements of our performance or liquidity under IFRS or GAAP and should not be considered as alternatives to operating profit or profit from continuing operations or any other performance measures derived in accordance with IFRS or GAAP or as alternatives to cash flow from operating, investing or financing activities.

Glossary of terms

2C resources are the best estimate of contingent resources

2P reserves are the best estimate of proved plus probable reserves

ARC the Group Audit and Risk Committee

bbl barrel of oil

boe barrel of oil equivalent

capex capital expenditure

CCS carbon capture and storage

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

ED&I equality, diversity and inclusion

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

FEED front end engineering and design

FTE full-time equivalent

G&A general and administrative expenses

G&G geological and geophysical

GVA gross value added

HSE health, safety and environment

HSEQ health, safety, environment and quality management

IEA International Energy Agency

IOGP International Association of Oil & Gas Producers

IPIECA the global oil and gas industry association for advancing environmental and social performance

kboepd thousand barrels of oil equivalent per day

kbpd thousand barrels per day

LNG liquefied natural gas

LTIF lost time injury frequency, 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

OGMP Oil and Gas Methane Partnership

opex operating expenditure

PSER process safety event rate

RBL our Reserves Based Lending facility

SDGs UN Sustainable Development Goals

SURF subsea umbilicals, risers and flowlines used in deepwater exploration

TCFD Task Force on Climate-related Financial Disclosures

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

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Neptune Energy Group Midco Limited is a private limited company registered in England and Wales (No. 10684661).

Corporate website
See *neptuneenergy.com* for annual reports and results announcements, as well as information on our operations and our ESG performance.

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Neptune Energy Norge AS
Board of Directors' Report 2020

Neptune Energy Norge AS ("the Company") is engaged in the exploration for and production of oil and gas on the Norwegian Continental Shelf (NCS). The Company's head office is located in Sandnes. The company also has offices in Oslo, Florø and Trondheim. At year end the Company had 325 employees.

Neptune Energy Norge AS is active within the full Exploration & Production value chain; from organic growth through Awards in Predefined Areas (APA rounds), exploration license maturation and drilling activity, development projects and production.

The Company holds participating interest in 69 licenses on the NCS, is the operator of the Gjøa field and the development projects Gjøa/P1, Duva and Fenja, as well as partner in several producing fields.

2020 was a year with high activity level. Despite the low commodity prices and the impact of the COVID – 19 pandemic, the Company has been able to meet the planned milestones for the project activities that the Company is engaged in. The highlight of 2020 was the discovery made in PL882 called Dugong. The discovery was the third largest on the NCS in 2020 and the Company wishes to appraise and continue with preparing a development of this discovery through 2021 and 2022.

Exploration

Neptune Energy holds interests in about 40 exploration licenses in Norway. In 2020 Exploration participated in drilling of four exploration wells (3 operated) and had a discovery rate of 75%. Two of the discoveries was located in Neptune operated licenses, the most important one being the high-impact Dugong oil discovery- done in a new exploration region for Neptune located in the very prolific Tampen area. Discovered resources is estimated between 40 and 108 mill boe (gross, recoverable) and was the third biggest discovery in Norway in 2020.

The second operated discovery was located in the Fenja core area and explored potential additional resources for the Fenja development. The well resulted in a small oil discovery (1-20 mmboe) which possible could be matured to additional reserves for Fenja. The third discovery Sigrun East (6-17 mmboe, Neptune partner) is located in the Gudrun area. The fourth exploration well (Grind, Neptune operator) was drilled in the Heidrun area and was dry. The well had high-impact stand potential, but due to the results Neptune is now planning to relinquish all our licenses in the Heidrun area.

In January 2020, the company was awarded 13 new licenses in the APA 2019 licensing round, an all-time high for Neptune in Norway. The licenses, 4 as operator and 9 as partner, are mainly located in core areas like Gjøa (4 licenses) and Fenja (3 licenses) and in Neptune production areas like Gudrun (2 licenses) and Brage (1 license). Awards were also secured in new exploration focus areas like Heidrun (2 licenses) and Sleipner areas (1 license). The award was an important step forward building a sustainable exploration portfolio close to existing infrastructure in Norway.

The exploration activity is an important part of the company's strategy for organic growth. For 2020 exploration spend was high due to an increased numbers of wells drilled. For the next 2 years the exploration spend will be reduced due to the revised exploration strategy for Norway, focusing in existing core production areas.

Reserves and resources

The Company had 294 mmboe of proved plus probable (2P) net reserves at the end of 2020. The total reserve replacement ratio for 2020 is 87%. The total 2P reserves has decreased from 337 mmboe YE2019 to 294 mmboe YE2020. The reserve adds in 2020 have happened through sanction of new wells on Duva (5.9 mmboe), Gjøa P1 (1.2 mmboe), Ivar Aasen (0.3 mmboe) and Brage (0.2 mmboe), offset by negative technical revisions (30.4 mmboe) of the assets performance and drilling results.

The total 2C contingent resources are estimated to 103.7 mmboe. Most of the contingent resources are discovery/development projects from non-operated assets.

Development

Duva and Gjøa P1

The Duva reservoir is located approximately 14 km North-East of the Gjøa Field in the North Sea. The Duva PDO was submitted to the Ministry of Petroleum and Energy on 21st February 2019.

The P1 reservoir is located within the Gjøa license block (PL153). An application for a PDO exemption was submitted to the Ministry of Petroleum and Energy on 21st February 2019.

During 2020 the integrated fast track projects have successfully installed all subsea equipment for the Duva and P1 fields. Templates, pipelines, umbilicals and risers have been installed safely and efficiently in a very busy marine campaign in the Gjøa field with simultaneous operations with drilling operations and 3rd party activities (Nova project).

Covid19 challenges has resulted in a delayed topside completion due to bed restrictions, Gjøa P1 production startup remain on target for Q1 2021 whilst Duva has suffered some delay and is targeting startup in Q3 2021.

Fenja

The Fenja field is located 36km south west of the Njord field in the Norwegian Sea and will be developed with two four slot templates tied back to the Njord A platform. Plan for Development and Operations was approved in April 2018.

In 2020 the first 9km of the Electrical Heat Traced production pipeline was successfully installed and tested. The onshore completion of the pipeline stalks was delayed mainly due to Covid19 restrictions at base. The delay of Host facility Njord allowed the pipeline fabrication to take the extra time required to complete fabrication with the required quality for the critical pipeline.

In 2021 the remaining part (~27km) of the production pipeline will be installed and completed and production drilling will commence. Expected start-up is Q2 2022 following the completion and startup of the Host Njord.

Njord and Bauge

The Njord Future Project, operated by Equinor, will perform the redevelopment of the Njord and Hyme fields. Njord A and Njord B are currently towed to shore for upgrade/refurbishment. The Bauge discovery, operated by Equinor, was made in late 2013 and will be developed as a subsea tie back to Njord A. Bauge is currently being executed in parallel with the Njord Future project. Njord will remain an important area of investment in 2021, and expected start-up for Njord is Q1 2022, followed by Hyme, Bauge and Fenja shortly thereafter.

Grosbeak

The Grosbeak was discovered in 2009 and is located 6 km northeast of Fram and 23 km southwest of Gjøa. Grosbeak is located across three licenses, of which Neptune Energy is partner in two.

Operations

Gjøa

Net production from the Gjøa field in 2020 was 7.1 mmboe vs budget of 5.5 mmboe. The overall regularity was 86% including both planned and unplanned shutdowns. The main contributors to the downtime were a 15-day scheduled shutdown in May and a 17-day scheduled shutdown in August for the Duva and Nova development projects and maintenance at the St. Fergus terminal. Different initiatives were taken in 2020 to optimize annual production. Amongst others, production optimization gave increased well rates and extended well life, continuous focus on operations gave higher regularity, and the total number of planned shutdown days were reduced from 60 to 32 days. Total production was impacted negatively by a 5-day strike in October.

Vega

Vega is a subsea tie-back to Gjøa, operated by WintershallDEA. The three Vega structures were unitized in 2020, giving Neptune a working interest of 3.3% in the Vega Unit. Net production from the Vega Unit in 2020 was 0.45

mmboe vs budget of 0.23 mmboe. The main contributors to higher annual production are linked to the new commercial terms in the unitization agreement and the increased uptime on Gjøa.

Snøhvit
Net production from the Snøhvit field in 2020 was 3.5 mmboe. Production has been shut down since 28 September 2020 due to a fire at the Hammerfest LNG plant. A project organisation, Cold Return, has been established to bring Snøhvit back on production in March 2022. The Askeladd project progressed as planned and three development wells were successfully completed in April.

Gudrun
Net production from the Gudrun field in 2020 was 4.6 mmboe.In 2020, a new infill well in the Draupne 1 reservoir (A-15) was completed and put on stream end April. Gudrun East A-8 well was ready for completion end of year. In addition, topside facility work for the water injection project progressed through the year and top holes were drilled for one water producer and two water injectors. In May, Gudrun sanctioned participation in the part-electrification of Sleipner, which will improve the environmental footprint in the area.

Sigrun East discovery made in Q1 2020. Studies ongoing for possible tie-back of Sigrun & Sigrun East to Gudrun.

Fram area
Net production from the Fram field in 2020 was 2.9 mmboe. The Troll C Gas Module (TCGM) started up in February 2020. The Byrding field produced at stable rates close to 0.1 mmboe in 2020. H-North did not produce in 2020. H-Nord production is planned to resume after Byrding back-pressure has been reduced.

Ivar Aasen
Net production from the Ivar Aasen field in 2020 was 0.7 mmboe, . Two producers were drilled in 2020: one multilateral to drain the Skagerak 2 Formation in the western part of the field, and one multilateral to drain the Skagerak 2 Formation in the eastern part of the field. Both wells were completed at the end of 2020. The aim of the wells is to help maintaining plateau production at Ivar Aasen.

Draugen
Net production from the Draugen field in 2020 was 0.5 mmboe. The Draugen Long Term Power project which allows for gas import from the Aasgard Transport pipeline, and reduced need for diesel fuel, was completed in October.

Hasselmus subsea development project is progressing. Possible electrification of Draugen is being studied.

Brage
Net production from the Brage field in 2020 was 0.2 mmboe. Two infill wells were successfully drilled and completed in 2020; A-36AB (Sognefjord Fm.) started production in February; A-12B (Statfjord Fm.) started production in May.

Neptune Energy Denmark ApS
Neptune Energy Denmark ApS is a wholly owned subsidiary of Neptune Energy Norge AS. The only asset in this subsidiary is the Solsort discovery, currently being evaluated for development.

Working environment

At year end the Company had 325 employees. In accordance with applicable laws and regulations the Company registers its employees' absence due to illness. During 2020 absence due to illness has been 2,67%.

The Company has a continuous focus on the working environment to mitigate risks and to develop a safe and good place to work. This has been of special importance during the last three years of restructuring and change of ownership. Overall, the working environment is considered to be good.

The Company conducts an annual global people satisfaction survey (The Pulse) with the aim to follow-up on the employee's satisfaction and wellbeing. The Pulse had questions covering a range of topics including safety, leadership, development, well-being and diversity, line management, and ethics and integrity. Results have been analysed globally and locally in order to develop different action plans in 2020 for improvements locally and across Neptune.

Regarding health and safety, the Company had 24 recorded injuries, and 4 incidents of first aid on Gjøa in 2020.

Gender equality

The Board of Directors is attentive to society's expectations and the legal requirements with which the Company is expected to comply in order to promote gender equality and prevent differential treatment of women and men. There is a continuous effort to adhere to these requirements.

At the year-end 97 of the company's 325 employees were women. At the end of 2020 one out of six members of the Board of Directors were women. A total of 10 new employees were recruited in 2020 (8 men, 2 women). All salaries are established without prejudice. A total of 4 employees work part-time. There are no differences in the working hour regulations for women and men.

Discrimination

The Equality and Anti-discrimination Act's objective is to promote gender equality, ensure equal opportunities and rights, and to prevent discrimination due to ethnicity, national origin, descent, skin colour, language, religion and faith. The Company is working actively, with determination and systematics to promote the act's purpose within its business. Included in the activities are recruiting, salary and working conditions, promotions, development opportunities and protection against harassment. The Company aims to be a workplace with no discrimination due to reduced functional ability and is working actively to design and implement the physical conditions in such a manner that as many as possible may utilize the various functions within the workplace. Individual adjustments of workplace and responsibility are made for employees or new applicants with reduced functional ability.

Environment

Gjøa field

The Gjøa facilities are designed to cause as little environmental impact as possible. Electricity from shore is the main source of power for the Gjøa installation, and there is a single fuel low Nitrous Oxide (NOx) turbine operating the gas export compressor. In addition, a waste heat recovery unit is installed. Closed flaring during regular operations also contributes to a reduction of environmental impact.

Gjøa has continuous focus on reducing the concentration of oil in produced water and the status of the oil concentration is presented in the daily report. In 2020 the average oil concentration in produced water discharged to sea was 3,85 mg/l; well below the authority requirement of 30 mg/l.

The emissions and discharges to the environment from operations at Gjøa are reported to the environmental authorities according to current regulations. 91% of chemicals discharged to sea were green chemicals and are not expected to cause any environmental impact. The company emphasizes the use of environmentally friendly chemicals. In 2019 here was a discharge of yellow chemicals of 187 tons. The discharge of 2,4 tons of red component and 1,6 kg of black component is within the existing permit given by the Norwegian Environment Agency. The discharge of red and black chemicals originates mainly from the use of self-generated hypochlorite and lubricating oil respectively.

Gjøa has a low EIF (Environmental Impact Factor) - 8 in the latest calculation. The main contributor to the EIF is the corrosion inhibitor and natural components found in the produced water at Gjøa (BTEX, phenol).

There were three accidental spills to sea during 2020; all involving BOP-fluid (yellow environmental classification) related to the drilling activities at Gjøa P1. The spills were not considered to have significant environmental impact.

The Gjøa field generated 335 tons of non-hazardous waste and 11967 tons of hazardous waste in 2020, most of which originated from the drilling operations at P1. Reducing the amount of waste to landfill is a priority. In 2020 95 % of the non-hazardous waste was recovered.

The key environmental indicators of emissions to air were:

Flaring	0,74 million standard cubic meters (Sm3)

Fuel gas consumption	45 million Sm3
Diesel consumption	7476 tons
CO_2 emissions	127 829 tons
NOx emissions	331 tons

Duva field

Drilling operations at the Duva field started in November 2019. Four top-holes and one geopilot were drilled during November/December 2019. In May/June 2020 the middle sections of the production wells were drilled.

The emissions and discharges to the environment from drilling operations at Duva are reported to the environmental authorities according to current regulations. 97% of chemicals discharged to sea were green chemicals and there was a discharge of yellow components of 2,8 tons and red components of 0,7 kg. All the discharges were within the existing permit given by the Norwegian Environment Agency and are not expected to cause environmental impact. There were no discharges of black chemicals during the drilling operations.

There were two accidental spills to sea during 2020: involving BOP-fluid and cement (yellow and green environmental classification). The spills were not considered to have any environmental impact.

The Duva drilling operations generated 71 tons of non-hazardous waste and 4652 tons of hazardous waste in 2020.

The key environmental indicators of emissions to air were:

Diesel consumption	1424 tons
CO_2 emissions	4510 tons
NOx emissions	55 tons

Fenja field

Drilling operations at the Fenja field started in April 2020. One shallow gas pilot, three top-holes, three geopilots and three 36'' sections were drilled during April- October 2020.

The emissions and discharges to the environment from drilling operations at Fenja are reported to the environmental authorities according to current regulations. Both water-based and oil-based drilling fluid have been used. When using water-based drilling fluid, both drilling fluid and cuttings have been discharged to sea.

The total discharge to sea from drilling operations in 2020 was 2689 tons of green chemicals and 5 tons of yellow chemicals. All discharges were within the existing permit given by the Norwegian Environment Agency and are not expected to cause environmental impact. There were no discharges of red or black chemicals during the drilling operations.

There were no accidental spills to sea during the drilling operation.

The Fenja drilling operations generated 147 tons of non-hazardous waste and 9628 tons of hazardous waste in 2020.

The key environmental indicators of emissions to air were:
Diesel consumption: 5940 tons
CO_2 emissions: 18816 tons
NOx emissions: 307 tons

Exploration

Neptune Energy drilled two exploration wells and one side-track in 2020.

The emissions and discharges to the environment from the exploration drilling operations are reported to the environmental authorities according to current regulations. 93% of chemicals discharged to sea were green chemicals and there were discharges of yellow and red chemicals, respectively 52,6 tons and 0,085 tons. All the discharges were within the existing permit given by the Norwegian Environment Agency and are not expected to cause environmental impact. There were no discharges of black chemicals during the drilling operations.

There was one accidental spill to sea during 2020 involving BOP-fluid (yellow environmental classification). The spills were not considered to have any environmental impact.

The exploration drilling operations generated 73 tons of non-hazardous waste and 3997 tons of hazardous waste in 2020.

The key environmental indicators of emissions to air were:

Diesel consumption	2867 tons
CO_2 emissions	9084 tons
NOx emissions	127 tons

Financial market, credit and liquidity risks

As of 31 December 2020, current and other long-term liabilities amounted to NOK 4,235 million and NOK 15,667 million respectively.

The financial position of the Company will always be influenced by fluctuations in the price of crude oil and gas and in currency exchange rates. The Company has guidelines for entering into derivative contracts in order to manage the commodity price market risk exposure, utilising commodity based derivative contracts consisting of market swaps for oil and gas products. The Company's financial position means that it would be able to withstand a period of reduced oil prices and fluctuations in exchange rates.

The Company regards its credit risk as low since the majority of its sales are to other large corporations. The Company has not realised losses on receivables during the preceding years.

The total exposure related to currency, interest and price fluctuations is monitored and evaluated as part of the overall evaluation of the Company's total exposure. Possible actions are implemented in accordance with the Company's existing procedures.

The pre-tax rate of return (operating profit/average total assets) in 2020 was 12 per cent, compared with 27 per cent in 2019. The rate of return after tax was 7 per cent in 2020, compared with 8 per cent in 2019.

The differences between pre-tax income and cash flow from operations are due to differences in the timing of tax expenditures and depreciation.

Financial aspects

The Company produced 20.0 mmboe in 2020. Total sales in 2020 amounted to 20.8 mmboe, giving total revenues of NOK 5,047 million.

Out of the total 20.8 mmboe sold, 6.6 mmboe consisted of crude oil and condensate. Revenues from crude oil and condensate sales were NOK 2,425 million compared to NOK 4,523 million in 2019.

The Company sold 1.8 billion Sm3 of gas including Snøhvit LNG in 2020. Revenues from gas and LNG amounted to NOK 1,988 million compared to NOK 3,136 million in 2019.

The revenue from sale of Natural Gas Liquid (NGL) and Liquefied Petroleum Gas (LPG) mix amounted to NOK 634 million in 2020 compared to NOK 924 million in 2019. A total of 3.3 mmboe of these products were sold in 2020.

The Company's net income for 2020 was NOK 30 million higher than 2019. The ordinary pre-tax profit for 2020 was NOK 2,441 million, compared to NOK 4,834 million in 2019. After NOK -2,329 million for current tax expenditures and NOK 3,208 million for deferred tax expenditure, net income amounted to NOK 1,562 million, compared to NOK 1,532 million in 2019.

Net cash flow from operating activities in 2020 was NOK 5,050 million, compared to NOK 5,883 million in 2019. Capital investments in 2020 amounted to NOK 5,062 million, compared to NOK 4,514 million in 2019. The majority of the investments were made on Fenja, P1, Duva and Njord. The total cash balance is considered satisfactory by the company.

The Company delivered a strong performance in 2020, both financial and operational. The company targets growing the daily production up to 100 000 boe/day during the next years contributing to the Groups target of a daily production of 200 000/boe a day. The growth in production will be enabled by production start of the current developments.

Going Concern

The COVID-19 crisis increases the risk regarding the going concern assumption for most companies. In response to the pandemic, we followed applicable government and industry guidelines and best practice, also taking an active role in industry bodies to contribute to a prudent and common approach in the industry.

Through implementation of measures related to the pandemic, a continuous high activity level has been maintained across Neptune Energy's activities in Norway, both onshore and offshore. This includes drilling operations, production on Gjøa and project related operations in yards onshore and from construction vessels offshore. For our offshore personnel we successfully set up a test-clinic at the heliport in Florø and implemented mandatory testing procedures, reducing the risk of contamination at offshore facilities. A criticality assessment of main contractors and suppliers has been carried out, enabling us to identify issues that required special attention in the special circumstances.

Although the risk has increased, the assessment is that the company is able to continue as a going concern. In accordance with the Accounting Act § 3-3a, the Board of Directors confirm that the financial statements have been prepared under the assumption of going concern. The Board considers the financial position and the liquidity of the company to be sound. Cash flow from operations, combined with available funding within the Neptune Group, is expected to be more than sufficient to finance the company's commitments in 2021.

Allocation of net income

The Board of Directors, having no knowledge of any matters not disclosed that could be of significance when evaluating the Company's position, recommends the following allocation of net income:

Net result 2020	NOK	1,561,927,314
To Retained Earnings	NOK	5,427,314
Dividend	NOK	1,556,500,000

If the General Assembly follows the Board of Directors' recommendation above, total equity will be NOK 2,860 million, giving an equity ratio of 12.5%.

Sandnes, 4th of June 2021

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Chairman of the Board

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Harald Peter Knöbl
Board member

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INDEPENDENT AUDITOR'S REPORT

To the Board of Directors of Neptune Energy Norge AS

Report on the audit of the financial statements

Opinion

We have audited the financial statements of Neptune Energy Norge AS, which comprise the balance sheet as at 31 December 2020, the income statement, and statements of cash flows for the year then ended and notes to the financial statements, including a summary of significant accounting policies.

In our opinion, the financial statements have been prepared in accordance with laws and regulations and present fairly, in all material respects, the financial position of the Company as at 31 December 2020 and its financial performance and cash flows for the year then ended in accordance with the Norwegian Accounting Act and accounting standards and practices generally accepted in Norway.

Basis for opinion

We conducted our audit in accordance with laws, regulations, and auditing standards and practices generally accepted in Norway, including International Standards on Auditing (ISAs). Our responsibilities under those standards are further described in the *Auditor's responsibilities for the audit of the financial statements* section of our report. We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the financial statements in Norway, and we have fulfilled our ethical responsibilities as required by law and regulations. We have also complied with our other ethical obligations 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.

Other information

Other information consists of the information included in the Company's annual report other than the financial statements and our auditor's report thereon. The Board of Directors and Chief Executive Officer (management) are responsible for the other information. Our opinion on the audit of the financial statements does not cover the other information, and 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, based on the work we have performed, we conclude that there is a material misstatement of this other information, we are required to report that fact. We have nothing to report in this regard.

Responsibilities of management for the financial statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with the Norwegian Accounting Act and accounting standards and practices generally accepted in Norway, and for such internal control as management determines 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, management is responsible for assessing the 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 management either intends to liquidate the Company or to cease operations, or has 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

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includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with laws, regulations, and auditing standards and practices generally accepted in Norway, including International Standards on Auditing (ISAs) 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.

As part of an audit in accordance with law, regulations and generally accepted auditing principles in Norway, including ISAs, we exercise professional judgment and maintain professional scepticism throughout the audit. We also

- identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control;
- obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control;
- evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management;
- conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Company to cease to continue as a going concern;
- evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

Report on other legal and regulatory requirements

Opinion on the Board of Directors' report

Based on our audit of the financial statements as described above, it is our opinion that the information presented in the Board of Directors' report concerning the financial statements, the going concern assumption, and proposal for the allocation of the result is consistent with the financial statements and complies with the law and regulations.

Opinion on registration and documentation

Based on our audit of the financial statements as described above, and control procedures we have considered necessary in accordance with the International Standard on Assurance Engagements (ISAE) 3000, *Assurance Engagements Other than Audits or Reviews of Historical Financial Information*, it is our opinion that management has fulfilled its duty to ensure that the Company's accounting information is properly recorded and documented as required by law and bookkeeping standards and practices accepted in Norway.

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Stavanger, 16 June 2021
ERNST & YOUNG AS

The auditor's report is signed electronically

Tor Inge Skjellevik
State Authorised Public Accountant (Norway)

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The signatures in this document are legally binding. The document is signed using Penneo™ secure digital signature. The identity of the signers has been recorded, and are listed below.

"By my signature I confirm all dates and content in this document."

Tor Inge Skjellevik
Statsautorisert revisor
On behalf of: Ernst & Young AS
Serial number: 9578-5997-4-259359
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