Premier Oil plc
“Premier” or the “Company” or the “Group”
18 March 2021

Press Release

Corporate transaction highlights

- Proposed merger with Chrysaor to create Harbour Energy plc, a cash-generative London-listed oil and gas company of scale with a strong balance sheet and significant international growth opportunities

- Forecast net debt of Combined Group on completion of US$2.9 billion (previously US$3.2 billion), reflecting higher commodity prices and full take up of Harbour Energy shares by creditors

- Completion of Chrysaor merger expected 31 March 2021, with shares to be readmitted to trading on 1 April as Harbour Energy plc
  - Shareholder and creditor approvals received, regulatory conditions satisfied and anti-trust clearances granted
  - Court sanction hearing scheduled for 19 March 2021

Premier operational highlights

- 2020 production averaged 61.4 kboepd (2019: 78.4 kboepd); Premier’s 2021 guidance of 61-66 kboepd reiterated (excludes Chrysaor assets)

- Tolmount: platform installed and first of the four development wells successfully completed. First gas on track for Q2 2021, adding 20-25 kboepd (net) once at plateau later in 2021

- Significant growth optionality retained
  - Zama (Mexico): FEED completed, unitisation progressed; project sanction targeted end 2021
  - Tuna (Indonesia): Fully funded appraisal of c. 100 mmboe (gross) field to start in Q2 2021
  - Sea Lion (Falkland Islands) licence extension and farm down arrangements agreed
  - Highly encouraging results from new 3D seismic data sets across Indonesia and Mexico exploration acreage

Premier financial highlights and outlook

- Operating cash flow of US$630 million (2019: US$1,080 million) with a net cash outflow of US$90 million; 2020 year-end net debt of US$2,078 million (2019: US$1,990 million)

- US$1,302 million loss after tax (2019: US$164 million profit after tax) driven by one-off non-cash charges, including US$817 million relating to the partial derecognition of Premier’s UK ring fence tax losses and allowances which are expected to be re-recognised on completion of the Chrysaor merger

- 2020 operating costs (ex-lease costs) of US$12.2/boe and full year total capex (including decommissioning spend) of US$315 million, reflecting full year savings and deferrals of over US$250 million

Full Year Results for the year ended 31 December 2020

- 2021 guidance of US$15/boe operating costs (ex-lease costs) is unchanged. 2021 total capex guidance is expected to be approximately US$300 million capex (previously US$275 million), reflecting phasing of some costs from 2020 and increased Balmoral Area decommissioning spend

- Premier's total gross debt of c. US$2.7 billion, which includes letters of credit and certain hedging liabilities, to be repaid and cancelled on completion of the merger with Chrysaor

Chrysaor 2020 highlights

Chrysaor has published on its website today its full year results for the year ending 31 December 2020 and has provided Premier with the following highlights:

- Production in 2020 of 173 kboepd (2019: 137 kboepd), in line with guidance, and underpinned by a full year's contribution from the assets acquired from ConocoPhillips and exceptionally high uptime; 2021 production forecast of 140-155 kboepd unchanged

- Free cash flow after capex, tax and interest of US$562 million, underpinned by increased production, a strong hedging programme and capex deferrals

- EBITDAX of US$1,784 million (2019: US$1,692 million). Loss after tax of US$778 million (2019: US$218 million profit) reflecting one off non-cash impairment charges of US$1,055 million driven by weaker commodity prices and movements in foreign exchange rates compared to the outlook before the pandemic

- Chrysaor's operating costs (including net tariff costs) averaged US$11.5/boe; 2021 guidance of less than US$15/boe operating costs (including net tariff costs) unchanged

- 2020 total capex (including exploration and decommissioning) was US$718 million, approximately US$575 million lower than forecast at the outset of the year; 2021 capex guidance of US$750-850 million, including US$170 million for decommissioning (pre-tax relief), unchanged

- Significant hedging programme with 74% of 2021 oil volumes and 85% of 2021 gas volumes hedged at an average price of US$58/boe and 44 pence/therm, respectively

The above Chrysaor highlights are not subject to EY audit.

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Notes to editors

Premier's quoted production numbers includes fuel gas whereas Chrysaor's quoted production numbers reflect actual sales.

Full Year Results for the year ended 31 December 2020

Chairman overview

2020 delivered some of the most challenging times for the upstream oil and gas sector. The outbreak of the COVID-19 pandemic and ensuing deep global economic slowdown, together with a geopolitical oil price war, caused significant commodity price weakness and volatility during the first half of the year. Supported by extended record OPEC supply cuts and positive vaccine related news, oil prices recovered into year-end and the global demand and supply position is now more balanced although society's concerns around energy transition and climate change continue to weigh on the sector.

We are proud of the quick action that Premier took in response to the pandemic to ensure the health and safety of our employees and contractors, both offshore and onshore. We adapted working practices and protocols to allow us to continue to operate our business safely. This enabled us to deliver full-year production of 61.4 kboepd and, while that was lower than envisaged at the start of the year, it is testament to the skill and dedication of our teams that we maintained safe and responsible operations despite the difficult operating environment.

The Company also responded quickly to minimise expenditure and protect cash flows. Safety-critical maintenance and capital investments in high-return projects which impacted near-term production were prioritised while discretionary expenditure with longer payback periods was deferred. This, together with the continued underlying performance of Premier's assets, partially mitigated the financial impact of low commodity prices on the Group.

Alongside these actions Premier re-engaged with its creditors to secure a long-term refinancing of the business. In September, Premier was in the process of seeking creditor approval for the refinancing of its debt facilities alongside the acquisition of certain producing assets from BP when the Group was approached by Chrysaor with a merger proposal. Given the market conditions at that time, it was felt that an all share merger with Chrysaor had greater execution certainty for stakeholders than the standalone solution which was dependent upon a significant equity raise. As a result, in October 2020 the Board unanimously recommended the merger to shareholders who approved it at a General Meeting in January 2021. The merger with Chrysaor remains on track to complete at the end of March 2021, upon which Premier Oil plc will be renamed Harbour Energy plc.

Full Year Results for the year ended 31 December 2020

Harbour Energy will bring together two complementary businesses to create the largest London-listed independent oil and gas company, by production and reserves. It will have a cash-generative diversified UK business with a significant operated position. In addition, Harbour Energy will have a broad set of international growth opportunities with the financial flexibility and capacity to realise value from a top-tier development and exploration portfolio as well as from a disciplined M&A strategy. Harbour Energy will have a strong balance sheet from day one and is expected to generate sufficient free cash flow to support shareholder returns, including via a sustainable dividend in the near-term, subject to market conditions.

Environmental, Social and Governance (ESG) issues remained a key priority during 2020 and, for oil and gas companies in particular, the carbon footprint of our industry is a key focus. Premier recognises the need to respond to climate change and the critical role of the energy industry in addressing these environmental challenges. In March, Premier committed to developing all of its operated projects on a carbon neutral basis. Harbour Energy will have the scale and balance sheet to build on Premier's progress in this area, and has committed to attaining the goal of Net Zero across its operations by no later than 2035, well in advance of the UK government goal of 2050.

I, along with my fellow Directors, recognise the challenging circumstances and the personal impact on our employees that has resulted from the COVID-19 pandemic and would like to take this opportunity to thank them for their continued dedication, hard work and support. I would also like to note the significant contributions made by Tony Durrant and Robin Allan, both of whom left Premier in 2020. As we look forward to the start of a new and exciting chapter in Premier's long history, I firmly believe that Harbour Energy has all of the ingredients, including scale, a strong balance sheet and an experienced management team, to allow the Group to prosper whilst playing its part in the energy transition and delivering value for all of its stakeholders.

Full Year Results for the year ended 31 December 2020

CEO Review

During 2020, Premier continued to safeguard its people, completed and installed the Tolmount facilities offshore, and preserved the optionality of its future growth projects whilst maintaining production across its asset base. In addition, Premier successfully negotiated a merger with Chrysaor, securing both long-term value for stakeholders and a stronger balance sheet on completion of the transaction.

Production and development operations

Production averaged 61.4 kboepd during 2020, a reduction on 2019 driven by lower uptime from the Catcher Area, the Group's largest producing asset, and the acceleration of cessation of production from some of Premier's more mature, high-cost UK fields. Increased delivery capacity at year-end was supported by the successful execution of operated infill wells on Catcher and Solan in the UK and four well intervention campaigns in South East Asia.

UK production was 40.6 kboepd. This was underpinned by output from Premier's operated Catcher Area. Despite lower uptime during the year, the Catcher fields exited the year at plateau production rates of 60 kbopd (gross, Premier 50 per cent), three years after first oil. This is significantly ahead of the 18 month plateau at 50 kbopd envisaged at project sanction. Premier's operated South East Asian assets delivered another robust performance in 2020, benefitting from sustained high uptime and a continued low operating cost base.

The Tolmount gas development is on track for first gas in the second quarter of 2021. The Tolmount field will add 20-25 kboepd (net, Premier 50 per cent) of production once at plateau rates, contributing to a forecast Group 2021 production exit rate in excess of 80 kboepd. In addition, Premier has made good progress advancing Tolmount East, with a final investment decision targeted during 2021. Once on-stream, Tolmount East will help maintain and extend plateau production from the Tolmount Area.

Growth projects

Premier has an attractive portfolio of pre-development projects which offer the potential for material future growth. During 2020 Premier sought to minimise and defer expenditure across its operated projects to preserve cash while at the same time continuing to optimise its level of participation in these projects. In the Falkland Islands, Premier continued to progress its operated 250 mmbbls Sea Lion Phase 1 project, albeit at a reduced pace given the macro environment, while offshore Indonesia, the Group successfully farmed down its Tuna PSC to Zarubezhneft who will carry Premier on a two well appraisal programme in 2021.

In Mexico, the Block 7 (Premier 25 per cent interest) partners and Pemex continued to progress the giant Zama field towards a targeted late 2021 project sanction. 2020 saw completion of FEED on the chosen development concept and significant progress in the negotiations regarding the unitisation of the Zama field, which are expected to conclude during the first half of 2021.

While 2020 saw Premier's exploration and appraisal drilling campaigns deferred, the Group was highly encouraged by the seismic data it received across its Indonesian, Mexican and UK licences. Premier is particularly excited about its first exploration well on its Andaman Sea acreage which is scheduled to be drilled in the first half of 2022 and which is targeting a multi-TCF gas play with access to commercial markets.

Harbour Energy will have the ability to fund and realise value from Premier's top-tier development and exploration portfolio. These projects will compete for capital with existing projects within Chrysaor's portfolio as well as new business development opportunities.

Reserves and resources

As at 31 December 2020, the Group's proven and probable (2P) reserves, on a working interest basis, were 151 mmboe (2019: 175 mmboe) and total 2P and 2C resources were 845 mmboe (2019: 847 mmboe).

	2P reserves (mmboe)	**2P reserves and 2C resources (mmboe)**
1 January 2020	175	847
Production	(23)	(23)
Revisions, divestments	(1)	21
31 December 2020	151	845

The reduction in 2P reserves is driven by the impact of 2020 production. Upward revisions in the Group's 2P reserves largely related to the Catcher Area, due to better reservoir performance and gas management strategy. This was offset by negative revisions in Solan (UK) and Natuna Sea Block A (Indonesia) and earlier cessation of production from a number of more mature UK fields.

The Group's 2C resources stood at 845 mmboe at year end. This reflects a revision in 2C resources of 48 mmboe due to Premier's working interest in the Tuna PSC increasing to 100 per cent prior to completion of the farm out to Zarubezhneft post period end. This was partially offset by the removal of 2C resources associated with a number of UK fields which ceased production in 2020.

Finance and proposed merger with Chrysaor

At the outset of the year, Premier expected to generate material free cash flow in 2020, based on its budgeted commodity price assumptions. While Premier was quick to respond to the collapse in oil prices, securing some US$250 million of cost savings and deferrals across opex and capex, the Group reported a cash outflow for the year of US$90 million. This resulted in an increased year-end net debt position of US$2,078 million (2019: US$1,989 million).

In October, Premier announced the proposed merger with Chrysaor, upon completion of which, Chrysaor and its shareholders will repay and cancel all of Premier's existing gross debt and cross currency hedging liabilities. Net debt of the Combined Group on completion is expected to be approximately US$2,900 million.

Formal shareholder and creditor approval and Mexico and Vietnam anti-trust clearances were received post year-end. The UK and Falkland Islands regulatory conditions to the merger were also satisfied in the first quarter of 2021 and the merger remains on track to complete by the end of March 2021.

Environmental, Social and Governance (ESG)

A company's success is not only determined by its financial performance, but also by its health, safety and environmental performance. It is the Group's highest priority to continue to operate all of its assets in a safe and responsible manner, to ensure the health and safety of its workforce and to minimise the potential risk to the environment. We have set ourselves ambitious targets to become a carbon neutral enterprise through being Low Carbon by Design and Carbon Neutral by Commitment.

Full Year Results for the year ended 31 December 2020

In 2020, Premier recorded no serious injuries or significant spills and a Total Recordable Injury Rate (TRIR) of 0.68 per million man hours worked. While any injury is one too many, this marks the lowest TRIR recorded by Premier in over 10 years. In addition, Premier's global operated production platforms across the North Sea, Indonesia and Vietnam achieved two years without a lost time injury.

During 2020, Premier's GHG intensity rose slightly to 21.1 kgCO_2e/boe as a result of year-on-year reduction in production. However overall CO_2e gross emissions across the Group's operated assets reduced by some 12 per cent to 820 thousand tonnes, supported by the Group's focus on continuous improvement in its emissions performance and its proactive decision to abandon some of its older fields.

Outlook

As we enter 2021 with improving commodity prices, Premier's focus is on maintaining its safe production performance and competitive cost base whilst delivering first gas from its operated Tolmount project. We look forward to completing the Zama unitisation discussions with Pemex and executing the fully-carried two-well appraisal programme of our Tuna field in Indonesia.

We are also excited about completing the merger with Chrysaor. Harbour Energy will have a low cost base and a robust reserve and resource base. The Combined Group will be well positioned to generate material free cash flow, even at low commodity prices, and to invest for growth on a global stage.

Full Year Results for the year ended 31 December 2020

UK

UK production averaged 40.6 kboepd, a decrease on the prior corresponding period due to lower uptime at Catcher and the acceleration of cessation of production from several of the Group's more mature, higher cost fields. Looking ahead, Tolmount at plateau rates will result in Premier's UK tax advantaged production increasing to over 60 kboepd at the end of 2021.

Catcher Area

Production from Premier's operated Catcher Area averaged 26.1 kboepd (net, Premier 50 per cent) (2019: 33.6 kboepd) during 2020 with the fields continuing to produce at plateau oil rates supported by strong reservoir performance.

The reduction on 2019 was driven by certain one-off equipment failures (gas pre-heater and HVAC switchboard) which resulted in short-term production outages and constrained oil rates for a few weeks in the fourth quarter while a build-up of calcium naphthenate was removed from the produced water plant. The reservoir continues to outperform with the Group recognising a further reserves upgrade at year end.

Through 2020 Premier reinjected produced gas into the reservoir via the existing production wells to evaluate the opportunity for improved oil recovery. Initial trials were positive and a second phase of reinjection continued into 2021 to further define the opportunity. In February 2021 Premier, as operator on behalf of the joint venture partners, initiated the process with the regulator for approval of various reservoir management schemes, including gas reinjection, to increase total oil recovery from the fields. On the expectation that such approvals will be granted, Premier recognised a reserves increase associated with these projects in the current period.

The Varadero infill well (VP1) was successfully drilled and tied-in to production in September. The development of two Catcher Area satellites, Catcher North and Laverda, were deferred as part of the measures taken to minimise 2020 capex with development drilling now expected to commence in early 2022, with first oil scheduled for later that year. These wells add incremental production as the Catcher Area comes off plateau through 2021.

The Group continues to work up additional opportunities within and around the Catcher Area to maximise economic recovery. The 4D seismic survey to be acquired in 2021 will help the understanding of the reservoir recovery mechanisms including optimisation of water flood, gas recovery and high grading of future infill and near field drilling targets.

Other UK producing assets

Production from Premier's operated Solan field averaged 2.0 kboepd (2019: 3.5 kboepd) (Premier 100 per cent interest). The Solan P3 well was brought on-stream in September, on schedule and within budget, and produced at peak rates of over 10 kbopd in November with the electric submersible pump online. Production from the Solan field was shut in following the failure of the emergency generator in December. Production was subsequently restored to sustained rates of approximately 7 kbopd at the end of the year. Post period end, commissioning of the fuel gas system was successfully completed, reducing the asset's carbon footprint and operating costs.

The non-operated Elgin-Franklin Area, which is the UK's largest producing field group, averaged 6.8 kboepd (2019: 6 kboepd) (net, Premier 5.2 per cent interest), significantly ahead of budget. This was due to higher uptime and an active well programme, including the FID well which was successfully brought on-stream in October, three months earlier than scheduled. Production was also supported by an acid wash campaign conducted in August with further stimulation and intervention campaigns planned for 2021.

Ravenspurn North averaged 1.1 kboepd (2019: 1.2 kboepd) (net, Premier 28.8 per cent interest), reflecting high uptime, a shorter annual shutdown and good availability at the Dimlington terminal. This was partially offset by the five well acid stimulation campaign, originally planned for the first quarter of 2020, being deferred to the fourth quarter.

As previously announced, Premier, together with its joint venture partners, decided to cease production from certain mature, high cost UK fields. This included the Balmoral Area and Huntington where field life has already been extended significantly beyond what was anticipated when Premier acquired operatorship of the fields in 2009 and 2016 respectively.

At Huntington, which ceased production in April, the first phase of the decommissioning programme was completed with the sailaway of the FPSO and recovery of the riser systems during 2020, with the FPSO mooring system to be recovered in 2021. The second phase, which will entail recovery of the subsea equipment, is scheduled for 2022. Final production from the operated Balmoral Area, which achieved two years without a lost time injury in September, occurred in November 2020 with sailaway of the FPV scheduled for the second quarter of 2021. Production also ceased from Premier's non-operated Scoter and Merganser fields in December 2020 while the Kyle field, in which Premier has a 40 per cent interest, ceased production in August 2020.

The Greater Tolmount Area

Tolmount, Premier's next UK growth project, is on schedule for first gas during the second quarter of 2021. Good progress was made across the four key project elements (platform, pipelines, terminal modifications and wells) during 2020, despite the challenging operational environment.

In March 2020, the HGS Tolmount platform was two weeks from sailaway when Rosetti's Ravenna yard was shut down by the Italian government in response to the emerging pandemic. As a result, a new installation window was negotiated with the installation contractor, Heerema, and the platform was successfully installed in October 2020. A positive consequence of the five month delay was an unusually high level of completion at sailaway. Hook-up and commissioning is being undertaken in parallel with development drilling, which commenced in the fourth quarter of 2020.

Saipem were successful in managing the impact of COVID-19 with the pipeline lay barge mobilised from Rotterdam as scheduled. The pipelines have been installed, tested, trenched and buried. The tie-in at the terminal end of the pipeline has been made while the offshore tie-in scope will be completed in spring 2021.

At the Easington terminal, the piping scope needed for free flow of Tolmount gas was completed in 2020 and the remaining scope to first gas is on track. Compression is not needed for Tolmount until late 2022 at the earliest, but is scheduled to complete in October 2021.

Valaris 123, the jack up rig contracted to drill the Tolmount wells, was mobilised during the fourth quarter of 2020. Batch drilling of the top holes was completed in January 2021. The first development well, Tolmount NW, reached total depth in February encountering gas bearing reservoir as prognosed. The second development well is drilling ahead with two wells expected to be on-stream at first gas. Once at plateau rates, anticipated later in 2021, the field will add 20-25 kboepd (net) to Premier's production.

Full Year Results for the year ended 31 December 2020

Premier continues to progress Tolmount East towards a final investment decision, expected to be taken in the second quarter of 2021, with first gas targeted for 2023. FEED on the proposed Tolmount East development, initially comprising a single well subsea tie back to the Tolmount platform, was completed in 2020. All the key supply contracts, including for the provision of subsea, umbilicals, risers, flowlines (SURF), subsea controls and wellheads, have been finalised in preparation for their execution as the project approaches sanction decision. Once on-stream Tolmount East (and potentially the near field Mongour discovery which could also be developed as a subsea tieback to the Tolmount infrastructure) will help extend plateau production from the Tolmount area.

Beyond Tolmount East, there is significant prospectivity in the Greater Tolmount Area. The final processed data from the 3D seismic acquired across the Greater Tolmount Area in 2019 was received in the summer. This is being used to mature the Tolmount Far East prospect and to further assess prospectivity to the east and west of the Tolmount field. This includes a number of leads and prospects identified on the two licences adjacent to the Tolmount Field Development Area which Premier was awarded in the UK's 32nd Round in September 2020. In the success case, these leads and prospects could be developed via Tolmount infrastructure.

VIETNAM

Premier's operated Chim Sáo field delivered a robust production performance in 2020. Together with low operating costs, this resulted in the asset continuing to generate free cash flow for the Group.

Production from the Premier-operated Block 12W, which contains the Chim Sáo and Dua fields, averaged 8.6 kboepd (2019: 11.4 kboepd) (net, Premier-operated 53.1 per cent interest) and was in line with expectations. The reduction on the prior year reflects natural decline from the existing wells partially offset by active reservoir management and ongoing well intervention activities.

2020 saw four well intervention campaigns aimed at maximising the ultimate recovery from the Chim Sáo field. This included improved utilisation of gas lift across the Chim Sáo well stock and the perforation of new zones within existing wells. Further well intervention work is planned for 2021 to help slow natural decline and optimise offtake from the Chim Sáo field. Preparations are also underway for a two well infill programme scheduled for 2022. Premier is currently seeking regulatory approvals for the programme ahead of going out to tender for a rig.

Full Year Results for the year ended 31 December 2020

Post period end, Chim Sáo surpassed the milestone of four years without a Lost Time Injury and also completed its 250th tanker offtake, with over 74 mmbbls (gross) of oil sold since first oil (compared to sanctioned reserves of 44 mmbbls (gross).

Chim Sáo cargoes were placed in the market at competitive prices, with an average premium to Brent of more than US$3.5/bbl realised for cargoes lifted during 2020. Field operating costs were US$10/boe (2019: US$9/boe), significantly below budget with opex savings largely offsetting production decline.

INDONESIA

Premier's operated Natuna Sea Block A generated material positive net cash flows for the Group, underpinned by a strong production performance and low operating costs. Elsewhere in Indonesia, Premier completed the farm down of its interest in the Tuna PSC post period end and preparations are underway for the Group's first exploration well on its highly prospective Andaman Sea acreage.

Production and development.

Production from the Premier-operated Natuna Sea Block A averaged 12.2 kboepd (2019: 11.5 kboepd) (net, Premier 28.7 per cent interest), ahead of budget and higher than 2019. This was driven by Natuna Sea Block A capturing a higher market share of its principal gas sales agreement (GSA1) and strong Singapore demand for gas sold under the Group's second gas sales contract (GSA2). In addition, asset reliability and deliverability was excellent throughout the year, despite the slowdown of certain offshore activities due to the outbreak of COVID-19, and supported a year-on-year reduction in GHG emissions from the Group's Indonesian operations.

Singapore demand for Indonesian gas sold under GSA1 averaged 276 BBtud (2019: 285 BBtud), slightly below take or pay levels and driven by low offtake during the third quarter when the price of GSA1 gas was significantly above that of spot LNG. Premier's Anoa, Pelikan, Bison and Gajah Puteri fields, which are dedicated to GSA1, delivered 152 BBtud (gross) (2019: 147 BBtud) during the year and accounted for 56 per cent (2019: 52 per cent) of GSA1 deliveries. This was materially above Natuna Sea Block A's contractual share of 52.5 per cent. Production from the Gajah Baru, Naga and Iguana gas fields, which supply gas into Singapore under GSA2 averaged 64 BBtud (2019: 55 BBtud), slightly above take or pay levels.

Premier's operated 2021 jack-up rig campaign, which will include an Anoa well workover and an Anoa infill well, is on track to start in mid-2021. This programme, together with several low cost additional perforation activities planned for 2021, will help maximise gas delivery from the Natuna Sea Block A fields.

Revenues from Premier's Indonesian operations were partially protected from the impact of the collapse in commodity prices with a significant proportion of the Group's 2020 Indonesian gas entitlement production hedged at c.US$9/mmscf, significantly above realised contract prices during the year.

Exploration and appraisal

In May 2020, Premier agreed a farm down agreement with Zarubezhneft for a 50 per cent interest in the Group's Tuna field, which is estimated to contain c. 100 mmboe and is located in the Natuna Sea adjacent to the Indonesian and Vietnamese maritime border. The farm down agreement was completed post period end in January 2021 following receipt of Indonesian government approval. Under the farm down agreement, Zarubezhneft will carry Premier for its share of a two well campaign to appraise the Tuna field, scheduled to commence in the second quarter of 2021. Premier remains operator of the Tuna PSC, with the Company and Zarubezhneft each having a 50 per cent interest in the licence.

In addition, Premier and Zarubezhneft have secured Indonesian government approval for a one year extension to the exploration period of the Tuna PSC to allow for appraisal drilling to take place and the subsequent submission of a Plan of Development to the Indonesian government by March 2022.

Elsewhere in Indonesia, the final data from the 2019 3D seismic acquisition programme across Premier's Andaman Sea licences were received during the year and confirmed the highly prospective nature of this acreage. In light of the results from the 3D data, reprocessing of some of the legacy 2D seismic data on Premier's operated Andaman II licence was undertaken and has yielded positive results with additional amplitude supported leads identified. These will now be the target for a future 3D seismic acquisition programme.

Premier plans to drill its first well in the Andaman Sea on its operated Andaman II licence in the first half of 2022. Premier's Andaman Sea position has the potential to deliver multi-TCF of gas and adds a potentially material gas play to the Group's portfolio.

FALKLAND ISLANDS

The weak oil price environment resulted in Premier taking the decision to reduce activities on its Sea Lion Phase 1 project in the first quarter of the year. Sea Lion remains a material opportunity for the Group and a smaller core team has continued to progress a number of regulatory and commercial work streams over the course of the year.

Premier's 2020 priorities for its Sea Lion Phase 1 project, as envisaged at the start of the year, included securing senior debt financing for the project, completing the farm down to Navitas Petroleum and submitting a Field Development Plan for the project to the Falkland Islands Government by the end of the year.

Technical definition of the Sea Lion Phase 1 project, which will develop 250 mmbbls of the 530 mmbbls Sea Lion gross resource, was completed in the first quarter of 2020 and all of the key service and supply contracts were in the process of being finalised. Public consultation on the Environmental Impact Statement had also been completed having been updated to reflect further project optimisation. However, the collapse in commodity prices and the ensuing need to defer discretionary capex, resulted in Premier reducing activity on its operated Sea Lion Phase 1 project in April.

Over the remainder of 2020, a reduced team continued to progress a number of regulatory and commercial work streams. This included developing Sea Lion's net zero emissions plan to ensure the project would be carbon neutral and finalising the terms for Navitas to farm in for a 30 per cent interest in the Sea Lion licences. Under the terms of the farm out agreement, Navitas will share the pre-first oil funding and bring additional sources of senior debt financing to the project. In addition, the previously differing interests between Premier and Rockhopper across the various Sea Lion licences will be harmonised with Premier, Rockhopper and Navitas having a 40 per cent, 30 per cent and 30 per cent interest, respectively, in the Sea Lion licences.

The proposed farm out of the Sea Lion licences to Navitas is subject to the Falkland Islands Government's and, pursuant to the Merger Agreement, Chrysaor's approval. As a result, in December, Premier, Rockhopper and Navitas agreed to extend the exclusivity period for the farm out to enable the merger with Chrysaor to complete and the management of Harbour Energy to make a decision on the farm out.

Post period end, the Falklands Islands Government agreed an extension to each of Premier's licences in the North Falklands Basin, including the Sea Lion Discovery Area. The licences, which had been due to expire on 1 May 2021, have been extended until November 2022.

MEXICO

In Mexico, the Block 7 (Premier 25 per cent interest) partners and Pemex continued to progress the giant Zama field towards project sanction, targeted for late 2021. 2020 activity focused on completing FEED, drafting the field development plan and advancing unitisation ahead of the deadlines dictated by the Block 7 PSC and the hydrocarbon laws of Mexico.

During 2020, the sub-surface teams continued with detailed analysis of the samples and data obtained by the 2018 and 2019 appraisal drilling campaign, confirming the excellent quality and properties of the Zama reservoir rocks and crude oil. Premier believes that this, together with the very high resource density and shallow water setting, will underpin a recovery factor of in excess of 50 per cent from the field. Premier gross recoverable resource estimate for Zama remains unchanged at over 800 mmboe.

It is anticipated that Zama will be developed using two drilling and processing platforms tied back to a floating storage and offloading vessel with the key elements of the development scheme already agreed with Pemex. FEED for the platform support structures (jackets) and topsides processing facilities was completed successfully by McDermott Engineering. An invitation to tender for detailed engineering, leading to procurement, and construction of the jackets and topsides will be issued in 2021. The facilities are low carbon by design with GHG intensity estimated at around 16 $KgCO_2e$/bbl life of field.

Positive progress was also made on the unitisation of the Zama field between the Block 7 partners and Pemex, particularly during the second half of the year. The Mexican Regulators agreed that the Zama reservoir is shared and extends across the boundary between Block 7 and the neighbouring concession operated by Pemex. SENER issued the instruction to unitise Zama in July and an Independent Expert is now in the process of examining the Zama geological and geophysical data ahead of making a determination of the initial tract participation by the end of April 2021. A short extension to the deadline for submission of the unitisation agreement to SENER was granted in December to allow for the expert process and negotiations to conclude.

Beyond Zama, Premier retains exposure to exploration upside in Mexico through its other offshore licence interests, each of which has the potential to deliver material future value for Premier. A 3D seismic survey across Block 30 (Premier 30 per cent interest) was completed in July 2019. The final processed data was received in the second quarter of 2020 and has been interpreted in order to delineate the full extent of the Wahoo prospect, which will be evaluated by the first well drilled on Block 30, targeted for the second half of 2022. Additional prospectivity on the block is being evaluated.

Elsewhere in Mexico, on Premier's 100 per cent operated Burgos Blocks 11 and 13, reprocessing of the existing 3D seismic was completed and interpretation is underway. Prospects in the deeper Mesozoic carbonate play similar to the Arenque field have been identified on the reprocessed data and are now the focus of the evaluation as these could constitute a material play on block. The shallower Oligo-Miocene clastic play remains but is now viewed as higher risk.

EXPLORATION ACTIVITIES

During the year, the COVID-19 pandemic resulted in strict budgetary constraints as a result of which, a number of planned exploration activities were deferred to minimise near-term expenditure. The Group's focus remains on under-explored but proven hydrocarbon provinces that have the potential to develop into new business units over the medium term.

Alaska

In March, Premier participated in the Charlie-1 well in Area A (Premier 60 per cent interest) on the North Slope of Alaska. The well was drilled on budget and successfully extended the Brookian play south, recovering hydrocarbons to surface from conventional pay; however the reservoir fluid was gas-condensate which is more challenging to commercialise in this area than the light oil the well was targeting. As a result, the well was plugged and abandoned without further testing and Premier exited the licence.

Brazil

In Brazil, much of the first quarter was spent preparing for Premier's first exploration well on its operated Block 717 (Premier 50 per cent interest) in the offshore Ceará basin. Premier had contracted the Valaris DS-9 drillship to drill a well targeting the stacked Berimbau/Maraca prospect and the well was due to spud on 1st July. Berimbau is a higher risk, high value prospect with a Pmean to P10 gross unrisked resource estimate of 230-450 mmbbls. Maraca is a lower risk prospect and is estimated to contain 85-165 mmbbls (Pmean-P10) of gross unrisked resource. However, as a result of the COVID-19 pandemic the decision was taken to defer the well and the Valaris contract was terminated. The JV have secured a further nine month extension to the current term in response to the COVID-19 pandemic and its impact. The well is now expected to be drilled in Q1 2022.

Full Year Results for the year ended 31 December 2020

FINANCIAL REVIEW

Business performance

Production averaged 61.4 kboepd in 2020 (2019: 78.4 kboepd), which, coupled with lower commodity prices, resulted in total revenue from all operations of US$949 million compared with US$1,597 million in 2019.

EBITDAX for the period from continuing operations was US$620 million, a decrease of US$610 million compared to the prior period EBITDAX of US$1,230 million. The reduced EBITDAX is due primarily to lower realised commodity prices and production, partially offset by higher realised hedging gains of US$149 million recognised in the period. Underlying operating cost per barrel remained broadly stable in spite of lower production due to tight cost control.

Business performance (continuing operations)	**2020 US$ million**	**2019 US$ million**
Operating (loss)/profit	**(343.8)**	**455.0**
Add: DD&A	**671.3**	**757.9**
Add: Exploration and new venture costs	**293.4**	**21.3**
Less: Profit on disposal of non-current assets	**(1.1)**	**(4.2)**
EBITDAX as reported	**619.8**	**1,230.0**

Net debt has increased to US$2,078.4 million from US$1,989.8 million at the end of 2019.

Income statement

Production and commodity prices

Group production on a working interest basis averaged 61.4 kboepd compared to 78.4 kboepd in 2019. Production was lower than in 2019 due to lower production from the Catcher field following unplanned outages in the year and the cessation of production from certain mature UK fields. Average entitlement production for the period was 57.5 kboepd (2019: 73.9 kboepd).

Premier realised an average oil price for the year of US$42.1/bbl (2019: US$66.3/bbl). Including the effect of oil swaps which settled during 2020, the realised oil price was US$49.4/bbl (2019: US$68.1/bbl).

Premier continued to benefit from positive differentials for its crude oil sales relative to the underlying Brent oil price.

In the UK, average natural gas prices achieved were 34 pence/therm (2019: 42 pence/therm). Gas prices in Singapore, linked to high sulphur fuel oil ('HSFO') pricing and in turn, therefore, linked to crude oil pricing, averaged US$6.6/mscf (2019: US$10.2/mscf). Including the effect of HSFO swaps which settled during 2020, the realised HSFO price was US$8.3/mscf (2019: US$10.2/mscf).

Realised prices - post hedging	**2020**	2019
Oil price (US$/bbl)	**49.4**	68.1
UK natural gas (pence/therm)	**34**	42
Singapore HSFO (US$/mscf)	**8.3**	10.2

Total revenue from all operations decreased to US$949.4 million (2019: US$1,596.5 million).

Cost of operations

Cost of operations comprise operating costs, changes in lifting positions, inventory movement and royalties. Cost of operations for the Group was US$324.7 million for 2020, compared to US$342.8 million for 2019 due to a decrease in operating costs partially offset by stock overlift/underlift movements resulting from the timing of hydrocarbon sales.

	2020 US$ million	2019 US$ million
Operating costs		
Continuing operations	**273.8**	322.6
Discontinuing operations (Pakistan)	**-**	2.4
Operating costs	**273.8**	325.0
Operating cost per barrel (US$ per barrel)	**12.2**	11.4

The decrease in absolute operating costs reflects savings achieved from strict management of discretionary spend, deferral of certain work scopes and lower costs arising from the cessation of production on certain UK fields. Operating costs per barrel, excluding lease costs, increased to US$12/boe (2019: US$11/boe) reflecting lower year-on-year production rather than any increase in underlying operating costs.

Lease expenses in 2020 were US$155.6 million, giving a lease cost per barrel of US$6.9/boe (2019: US$6.9/boe), which is consistent year-on-year.

	2020 **US$ million**	2019 US$ million
Amortisation and depreciation		
Total DD&A	**524.5**	742.9
DD&A per barrel (US$ per barrel)	**23.3**	26.4

Total depreciation has decreased year-on-year to US$524.5 million due to lower production rates and the cessation of production on certain mature fields. The depreciation charge includes US$52.7 million related to an increase in the Group's decommissioning provisions on assets which are carried at nil book value. This is due to a reduction in the rate used to discount provisions to 3.0 per cent (2019: 3.6 per cent) following the reduction in US treasury rates observed in 2020 and not by any material change in the underlying decommissioning cost estimates.

In addition to the amortisation and depreciation charge for the period, the Group recognised an impairment charge of US$143.8 million. US$140.3 million of the current period impairment charge relates to Solan and was driven by a reduction in management's long-term oil price assumption to US$60/bbl real (2019: US$70/bbl real) together with the reduction in reserves associated with future investment decisions.

Exploration expenditure and new ventures

Exploration expense and new venture costs amounted to US$293.4 million (2019: US$21.3 million). This includes exploration expenditure of US$194.1 million written off for costs previously capitalised for exploration prospects in the North Falklands basin, which will not be developed as part of the Sea Lion Phase 1 project. In addition, the drilling of the Charlie-1 well in Area A in Alaska encountered non-commercial gas condensate for which US$27.1 million of costs have been expensed in the period. New venture costs also include costs associated with the corporate actions that were undertaken during the period including the previously proposed acquisition of BP's interests in the Andrew Area and the Shearwater field and the proposed merger with Chrysaor Holdings Limited.

After recognition of these expenditures, the exploration and evaluation assets remaining on the balance sheet at 31 December 2020 amount to US$785.3 million, principally for the Sea Lion asset, our share of the Zama prospect and Block 30 in Mexico and the Tuna PSC in Indonesia.

General and administrative expenses

Net G&A costs of US$8.4 million (2019: US$9.0 million) were comparable with the prior year.

Finance gains and charges

Net finance gains and charges of US$261.5 million have reduced compared to the prior year (US$352.5 million). This is due to lower interest charges following a fall in LIBOR rates during the year and a fair value gain realised in respect of the Group's outstanding equity warrants. Included within finance charges are costs of US$32.0 million associated with refinancing activities during the period. Cash interest expense in the period was US$230.4 million (2019: US$251.9 million).

Taxation

The Group's total tax charge for 2020 from continuing operations is US$696.9 million (2019: credit of US$52.5 million) which comprises a current tax charge for the period of US$33.1 million and a non-cash deferred tax charge for the period of US$663.8 million.

The total tax credit represents an effective tax rate charge of negative 115.1 per cent (2019: credit of 51.2 per cent). The effective tax rate is predominantly driven by the derecognition of UK ring fence tax losses and allowances due to a reduction in management's oil and gas price assumptions and the exclusion of future taxable profits associated with the previously proposed BP acquisitions when assessing recoverability of deferred tax assets ('DTA'). Despite the merger being expected to complete in March 2021, future taxable profits associated with Chrysaor's assets are not reflected in the DTA recoverability assessment at year-end as the relevant accounting standard does not permit the accounting acquiree to take credit for future taxable profits associated with a proposed business combination.

Due to the fall in oil and gas prices and the presence of impairment indicators, the Group re-ran its corporate model to assess whether it is appropriate to continue to recognise the Group's deferred tax losses and allowances at 31 December 2020. The results of the corporate model concluded that it was no longer appropriate to recognise an amount of US$817.2 million in respect of ring fence tax losses, decommissioning asset and investment allowances. Premier retains access to these tax losses in the event forecast taxable profits were to increase in the future and expects to recognise these ring fence tax losses and investment allowances in full upon completion of the proposed merger with Chrysaor, when revising the corporate model to include the cash flows of the enlarged Group.

The Group has a net deferred tax asset of US$763.4 million at 31 December 2020 (2019: US$1,426.2 million).

Loss after tax

Loss after tax is US$1,302.2 million (2019: profit of US$164.3 million) resulting in a basic loss per share of 146.7 cents from continuing and discontinued operations (2019: earning of 19.9 cents). The loss after tax in the year is driven by the lower production volumes and realised prices, significant charges in relation to exploration and new venture expenditure (US$293.4 million), the partial derecognition of the Group's deferred tax asset (US$827.1 million) and the impairment of PP&E assets (US$94.6 million, post-tax).

Cash flows

Cash flow from operating activities was US$630.1 million (2019: US$1,080.0 million) after accounting for net tax receipts of US$2.0 million (2019: payments of US$61.2 million) and before the movement in joint venture cash balances in the period of US$19.5 million. The decrease is driven by reduced production and realised commodity prices in the period.

Capital expenditure in 2020 totalled US$266.6 million (2019: US$241.4 million).

Capital expenditure	**2020 US$ million**	2019 US$ million
Fields/development projects	**178.4**	101.7
Exploration and evaluation	**85.6**	136.9
Other	**2.6**	2.8
Total	**266.6**	241.4

The principal development expenditure was in respect of the UK where work continued on the Tolmount development and the Solan P3 and Catcher VP1 wells were both drilled and brought on-stream. Development drilling at Catcher North and Laverda, originally scheduled for 2020, was deferred as part of measures taken to manage the Group's capital expenditure.

The largest parts of the E&E capital expenditure in the period were the Charlie-1 appraisal well in Alaska which was plugged and abandoned after encountering non-commercial gas condensate, and ongoing pre-development expenditure on the Sea Lion Phase 1 project in the Falkland Islands. In addition, cash expenditure for decommissioning activity in the period was US$48.9 million (2019: US$35.3 million) and a further US$5.4 million of cash placed into long-term abandonment accounts for future decommissioning (2019: US$9.9 million).

Total development and E&E expenditure relating to Premier's existing assets for 2021 is estimated at US$180 million principally related to development drilling on Tolmount and Catcher, and exploration and appraisal activities in Mexico and Indonesia. Premier share of costs of the two well appraisal programme on the Tuna discoveries in Indonesia are carried by Zabruzhneft up to an agreed cap. Decommissioning spend is estimated at US$120 million reflecting the cessation of production at various UK fields during 2020.

Discontinued operations, disposals and assets held for sale

The Group completed the sale of its Pakistan business to the Al-Haj Group in March 2019 for a total consideration of US$65.6 million. The results of the Pakistan Business Unit in the prior period are presented as a discontinued operation.

Balance sheet position

Net debt

Net debt at 31 December 2020 amounted to US$2,078.4 million (31 December 2019: US$1,989.8 million), with cash resources of US$108.3 million (31 December 2019: US$198.1 million). The maturity of all of Premier's facilities is May 2021. During the year, Premier made debt repayments of US$52.3 million partly offset by drawings under its RCF facility of US$35.0 million. The Group cancelled US$129.5 million of its RCF debt facility during the period.

Full Year Results for the year ended 31 December 2020

Premier retains cash at 31 December 2020 of US$72.0 million and undrawn facilities of US$219.3 million, giving liquidity of US$291.3 million (31 December 2019: US$549.2 million) when excluding cash of US$36.3 million held on behalf of joint venture partners or as security for letters of credit.

During the period the Group issued 82.2 million shares to one of Premier's creditors, ARCM, resulting in equity proceeds of US$27.0 million.

Provisions

The Group's decommissioning provision increased to US$1,372.1 million at 31 December 2020, up from US$1,303.4 million at the end of 2019. The increase is driven by a reduction in the discount rate used to determine the net present value of the decommissioning provision, following the reduction in US treasury rates observed in 2020 and not by any material change in the underlying decommissioning costs estimates. The increase has been partly offset by decommissioning activity undertaken during the period following the cessation of production from certain mature UK fields.

Non-IFRS measures

The Group uses certain measures of performance that are not specifically defined under IFRS or other generally accepted accounting principles. The non-IFRS measures used within this Financial Review are EBITDAX, Operating cost per barrel, DD&A per barrel, Net debt and Liquidity and are defined in the glossary.

Financial risk management

Commodity prices

Premier continued to take advantage of hedging to protect free cash flows. The Group's current hedge position is as follows:

Oil

Swaps/forwards	**2021 1H**	**2021 2H**
Volume (mmbbls)	1.4	0.3
Average price (US$/bbl)	53	61

UK gas

Swaps/forwards/options	2021 1H	2021 2H	2022	2023
Volume (million therms)	57	68	80	-
Average price (p/therm)[1]	45	40	42[1]	-

[1] Average price is a mixture of swap and option floor pricing and excludes impact of deferred option premiums.

At 31 December 2020, the fair value of open oil and gas instruments was a net asset of US$5.2 million (31 December 2019: asset of US$29.2 million), which is expected to be released to the income statement during 2021 and 2022 as the related barrels are lifted or therms delivered

During 2020, expiration of forward oil and gas swaps resulted in a net credit of US$149.5 million (2019: credit of US$45.6 million) which has been included in sales revenue for the year.

Foreign exchange

Premier's functional and reporting currency is US dollars. Exchange rate exposures relate only to local currency receipts, and expenditures within individual business units. Local currency needs are acquired on a short-term basis. At the year-end, the Group recorded a mark-to-market loss of US$6.6 million on its outstanding foreign exchange contracts (2019: gain of US$6.2 million). The Group currently has £150.0 million of retail bonds, €63.0 million long-term senior loan notes and a £100.0 million term loan in issuance which have been hedged under cross currency swaps in US dollars at average fixed rates of US$1.64:£ and US$1.37:€. The fair value of the cross currency swap liability at 31 December 2020 is US$88.7 million (2019: US$123.6 million).

Interest rates

The Group has various financing instruments including senior loan notes, UK retail bonds, term loans and revolving credit facilities. On average, the effective interest rate on drawn funds for the period, recognised in the income statement, was 7.4 per cent.

Insurance

The Group undertakes a significant insurance programme to reduce the potential impact of physical risks associated with its exploration, development and production activities. Business interruption cover is purchased for a proportion of the cash flow from producing fields for a maximum period of 18 months. During 2020, there were no insurance claims and nil cash proceeds were received in relation to settled insurance claims (2019: US$2.3 million).

Proposed Merger with Chrysaor Holdings Ltd

On 6 October 2020, the Group publicly announced the proposed merger of Premier Oil plc ("Premier") and Chrysaor Holdings Limited ("Chrysaor") and the reorganisation of Premier's existing finance arrangements.

The merger of Premier and Chrysaor Holdings Limited will create Harbour Energy plc ('Harbour'), the largest independent oil and gas company listed on the London Stock Exchange with combined production of over 200 kboepd and will bring together two complementary businesses to create a combined group with a strong balance sheet and significant international growth opportunities.

The Board of Directors of the Enlarged Group will comprise 11 Directors including six independent non-executive Directors. All appointments have been agreed and announced, including the appointments of Blair Thomas as Chairman and Linda Cook as CEO.

Upon completion of the transaction, Premier's existing creditors will receive a cash payment of US$1.23 billion in satisfaction of part of Premier's existing debt and cross-currency swaps and Premier will issue new shares to the existing creditors to satisfy the balance of the Premier Group's existing debt and cross-currency swaps. In addition, existing creditors will receive (i) new shares in Harbour and/or (ii) a cash alternative which is capped at a maximum of US$175 million.

Under the terms of the transaction Premier's creditors were able to elect to subscribe in cash at a pre-agreed price for those new shares in the enlarged group which would have been issued to other senior creditors if they had not elected the Cash-Out Option (the 'Top-Up Election'). Based on the elections made by senior creditors, it is anticipated that the cash alternative of US$175 million will be retained by the enlarged group as the take-up of the cash alternative option is expected to be less than US$175 million and the number of shares subscribed for under the Top-Up Election exceeded the number of shares which are expected to be available under the Top-Up Election.

As a result the merger is expected to result in Premier's stakeholders owning up to 23 per cent of the Enlarged Group and existing Chrysaor shareholders owning at least 77 per cent. Premier's stakeholders include its existing shareholders which are expected to own 5 per cent of the Enlarged Group.

Significant progress has been made towards obtaining the necessary approvals for the transaction. Premier shareholder approval was obtained at a General Meeting on 12 January 2021 and Premier's creditors voted in favour of the restructuring plans on 22 February 2021. The restructuring plans remain subject to approval by the Scottish Court of Session with the sanction hearing currently scheduled to commence on 19 March 2021. All regulatory conditions relating to the merger have now been satisfied and all of the requisite anti-trust approvals have been received.

The Enlarged Group will have significant scale and diversification, through the combination of material operated and non-operated cash generative production hubs in the UK North Sea. Premier's financial position will be transformed, delivering an Enlarged Group with a strong and sustainable financing structure. The merger will also realise substantial cost and tax synergies, accelerating the use of Premier's existing circa US$4.1 billion of UK tax losses and unlocking significant value for shareholders.

Going concern

The Group monitors its capital position and its liquidity risk regularly throughout the year to ensure that it has access to sufficient funds to meet forecast cash requirements. Cash forecasts are regularly produced based on, inter alia, the Group's latest life of field production and expenditure forecasts, management's best estimate of future commodity prices (based on recent forward curves, adjusted for the Group's hedging programme) and the Group's borrowing facilities. Sensitivities are run to reflect different scenarios including, but not limited to, changes in oil and gas production rates, possible reductions in commodity prices and delays or cost overruns on major development projects. This is done to identify risks to liquidity and covenant compliance and enable management to formulate appropriate and timely mitigation strategies in order to manage the risk of funds shortfalls or covenant breaches and to ensure the Group's ability to continue as a going concern.

The proposed merger of Premier and Chrysaor and the reorganisation of Premier's existing finance arrangements ("Debt Restructuring") (together, "the Corporate Actions") are expected to complete on 31st March 2021.

The Corporate Actions include the:

- Merger of Premier and Chrysaor (together, "the Enlarged Group") through a reverse takeover ("the Merger");
- The issue of approximately 17.59 billion new ordinary shares in Premier, approximately 14.25 billion of which will be issued to Chrysaor's shareholders in exchange for the acquisition by Premier of 100 per cent of the issued share capital of Chrysaor; and
- Cancellation, repayment and release of Premier's US$2.7 billion of total gross debt and certain hedging liabilities, which currently mature on 31 May 2021, for a cash payment of US$1.23 billion, together with new ordinary shares in Premier and, if creditors had so elected, a share of a further cash payment capped at approximately US$175 million.

The cash payments to creditors are expected to be funded through a combination of existing cash balances and Chrysaor's borrowing facilities.

Base case assessment

Management's going concern assessment considered the ability of the Group to continue as a going concern from the date of approval of the 2020 Annual Report and Accounts ('ARA') through to 31 March 2022 ('the going concern period'). The Group's base case going concern assessment assumes: completion of the Corporate Actions on 31 March 2021; an oil price of US$51/bbl and US$55/bbl in 2021 and 2022, respectively; and production in line with approved asset plans. Under the terms of the Corporate Actions, following settlement of Premier's existing debt, the ongoing capital requirements of the Enlarged Group will be financed by Chrysaor's existing financing arrangements, comprising its US$4.5 billion Reserve Base Lending ('RBL') facility and US$400 million junior debt facility.

The RBL facility has a final maturity of November 2027 and contains certain financial covenants relating to the ratio of consolidated total net debt to consolidated EBITDAX on a historic and forward-looking basis, which will be tested semi-annually. The amount available under the facility will be re-determined annually based on a valuation of the Group's borrowing base assets when applying certain forward-looking assumptions, as defined in the borrowing agreement. The junior debt facility is repayable in instalments between June 2022 and June 2026 and is not subject to any financial covenants.

Under management's base case, the Enlarged Group is forecasted to have sufficient financial headroom throughout the going concern period.

Sensitivity analysis

Whilst assuming completion of the Corporate Actions on 31st March 2021, management has run downside scenarios on the cash flows of the Enlarged Group, where oil and gas prices are reduced by a flat US$10/bbl and where total production of the Enlarged Group is forecast to reduce by 10 per cent throughout the going concern period. In the downside scenarios applied to the base case forecast, individually and in combination, the Enlarged Group is forecasted to have sufficient financial headroom throughout the going concern period.

Should the Corporate Actions fail to complete

The proposed Corporate Actions are subject to a number of conditions that must be satisfied to proceed, including shareholder approval, regulatory approval, approval of the Debt Restructuring by creditors and Court sanction of the Debt Restructuring. As highlighted in the section covering the proposed Merger, shareholder approval of the Corporate Actions was received on 12 January 2021, all necessary regulatory approvals are now in place and the requisite level of Premier's creditors voted in favour of the Debt Restructuring at the creditor meeting on 22 February 2021. A court hearing to sanction the Debt Restructuring is scheduled to take place on 19 March 2021. Court sanction of the Debt Restructuring represents the key outstanding milestone, shortly after which it is expected that the Corporate Actions will complete.

Should the Corporate Actions fail to complete, the maturity of Premier's existing debt facilities may, at Premier's option, be extended from 31 May 2021 to 31 March 2022 ("Interim Maturity Extension"). Since July 2020, the financial covenant tests associated with Premier's existing borrowing facilities have been deferred, initially under the terms of an agreement with the requisite majorities of the Group's creditors and, from 6 October 2020, under the terms of a support letter executed by the requisite majority of creditors ("Support Letter"). Without these deferrals, the Group would have breached the financial covenants contained in its financing agreements in respect of the testing periods ended on 30 June 2020, 30 September 2020 and 31 December 2020. The financial covenant deferrals in the Support Letter remain in place until 30 September 2021 (or such later dates as may be agreed by Premier and a requisite threshold of creditors, provided that such date may not be later that 1 December 2021) ("Long-Stop Date") or completion of the Merger.

Should the financial covenant deferrals expire, the Group will immediately be in breach of its existing financial covenants. Therefore, in the event that the Corporate Actions do not complete, the ability of the Group to continue trading will depend upon: (i) a significant portion of its creditors providing further financial covenant deferrals; and (ii) the Group agreeing either: (a) an alternative plan for the implementation of the Corporate Actions with its creditors and Chrysaor; or (b) an alternative plan to address its existing debt facilities and certain hedging liabilities with its creditors. Failure to obtain future covenant deferrals and/or execute an alternative debt restructuring would result in Premier's existing debt facilities and certain hedging liabilities becoming payable in the going concern period and, in such circumstances, the Group would not be able to repay these amounts.

Conclusion

Based on all required shareholder and regulatory approval processes being complete and the requisite level of Premier's creditors having voted in favour of the Debt Restructuring, the Directors expect to complete the Corporate Actions on 31 March 2021. Assuming the Corporate Actions complete, the Directors have a reasonable expectation that the Company has adequate resources to continue in operational existence throughout the going concern period. In the unlikely event that the Corporate Actions do not complete, management believe it is likely that the lenders will provide the required support to allow the Company time to complete an alternative restructuring of its existing debt facilities. Therefore, the Directors continue to adopt the going concern basis of accounting in preparing these consolidated financial statements and the financial statements do not include the adjustments that would result if the Group were unable to continue as a going concern.

However, successful completion of the Corporate Actions is subject to the Court sanctioning the Debt Restructuring and is outside the Group's control. The uncertainties regarding (1) management's ability to complete the Corporate Actions; and (2) should the Corporate Actions fail to complete, management's ability to complete an alternative restructuring of its existing debt facilities and certain hedging liabilities and obtain covenant deferrals or waivers in the intervening period to prevent its existing debt falling due within the going concern period, create material uncertainties that may cast significant doubt on the Company's ability to continue as a going concern.

Business risks

Premier's business may be impacted by various risks leading to failure to achieve strategic targets for growth, loss of financial standing, cash flow and earnings, and reputation. Not all of these risks are wholly within the Company's control and the Company may be affected by risks which are not yet manifest or reasonably foreseeable.

Effective risk management is critical to achieving our strategic objectives and protecting our personnel, assets, the communities where we operate and with whom we interact, and our reputation. Premier therefore has a comprehensive approach to risk management.

A critical part of the risk management process is to assess the impact and likelihood of risks occurring so that appropriate mitigation plans can be developed and implemented. Risk severity matrices are developed across Premier's business to facilitate assessment of risk. The specific risks identified by project and asset teams, business units and corporate functions are consolidated and amalgamated to provide an oversight of key risk factors at each level, from operations through business unit management to the Executive Committee and the Board.

For all the known risks facing the business, Premier attempts to minimise the likelihood and mitigate the impact. According to the nature of the risk, Premier may elect to take or tolerate risk, treat risk with controls and mitigating actions, transfer risk to third parties, or terminate risk by ceasing particular activities or operations. Premier has a zero tolerance to financial fraud or ethics non-compliance, and ensures that HSES risks are managed to levels that are as low as reasonably practicable, whilst managing exploration and development risks on a portfolio basis.

The Group has identified its principal risks for the next 12 months as being:

- Commodity price volatility
- Access to capital
- Health, safety, environment and security
- Production and development delivery and decommissioning execution
- Merger completion and integration
- Climate change
- Joint venture partner alignment and supply chain delivery
- Organisational capability
- Exploration success and reserves addition
- Host government: political and fiscal risks

Further information detailing the way in which these risks are mitigated is provided on the Company's website www.premier-oil.com.

Richard Rose

Finance Director

Full Year Results for the year ended 31 December 2020

Consolidated Income Statement

For the year ended 31 December 2020

	2020 US$ million	2019 US$ million
Continuing operations		
Sales revenues	**949.4**	1,584.7
Other operating income/(costs)	**3.5**	(2.9)
Costs of operation	**(324.7)**	(342.8)
Depreciation, depletion, amortisation and impairment	**(671.3)**	(757.9)
Exploration expenses and new ventures	**(293.4)**	(21.3)
Profit on disposal of non-current assets	**1.1**	4.2
General and administration costs	**(8.4)**	(9.0)
Operating (loss)/profit	**(343.8)**	455.0
Interest revenue, finance and other gains	**84.8**	31.4
Finance costs, other finance expenses and losses	**(346.3)**	(383.9)
(Loss)/profit before tax from continuing operations	**(605.3)**	102.5
Tax (charge)/credit	**(696.9)**	52.5
(Loss)/profit for the year from continuing operations	**(1,302.2)**	155.0
Discontinued operations		
Profit for the year from discontinued operations	**-**	9.3
(Loss)/profit after tax	**(1,302.2)**	164.3
(Loss)/earnings per share (cents):		
From continuing operations		
Basic	**(146.7)**	18.8
Diluted	**(146.7)**	17.2
From continuing and discontinued operations		
Basic	**(146.7)**	19.9
Diluted	**(146.7)**	18.2

Full Year Results for the year ended 31 December 2020

Consolidated Statement of Comprehensive Income

For the year ended 31 December 2020

	2020 US$ million	2019 US$ million
(Loss)/profit for the year	**(1,302.2)**	164.3
Cash flow hedges on commodity swaps and options:		
Gains/(losses) arising during the year	**112.6**	(50.8)
Less: reclassification adjustments for gains in the year	**(149.5)**	(45.6)
	(36.9)	(96.4)
Cash flow hedges on foreign exchange swaps:		
Losses arising during the year	**(12.4)**	(13.4)
Add: reclassification adjustments for losses in the year	**19.8**	10.3
	7.4	(3.1)
Tax relating to components of other comprehensive income	**1.9**	25.0
Exchange differences on translation of foreign operations	**(9.3)**	(3.8)
Gain on long-term employee benefit plans[1]	**0.3**	0.2
Other comprehensive expenses	**(36.6)**	(78.1)
Total comprehensive (loss)/income for the year	**(1,338.8)**	86.2

[1] Not expected to be reclassified subsequently to income statement.

All comprehensive (loss)/income is attributable to the equity holders of the parent.

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Full Year Results for the year ended 31 December 2020

Consolidated Balance Sheet
As at 31 December 2020

	2020 US$ million	2019 US$ million
Non-current assets:		
Intangible exploration and evaluation assets	**785.3**	934.0
Property, plant and equipment	**2,101.8**	2,481.8
Goodwill	**240.8**	240.8
Long-term receivables	**248.2**	231.1
Deferred tax assets	**869.7**	1,556.1
	4,245.8	5,443.8
Current assets:		
Inventories	**12.7**	16.3
Trade and other receivables	**279.1**	378.9
Derivative financial instruments	**14.1**	55.3
Cash and cash equivalents	**108.3**	198.1
	414.2	648.6
Total assets	**4,660.0**	6,092.4
Current liabilities:		
Trade and other payables	**(399.5)**	(356.2)
Lease liabilities	**(74.3)**	(149.7)
Short-term provisions	**(116.9)**	(76.8)
Derivative financial instruments	**(95.9)**	(98.8)
Short-term debt	**(2,181.0)**	-
Deferred income	**(15.7)**	(15.3)
	(2,883.3)	(696.8)
Net current liabilities	**(2,469.1)**	(48.2)
Non-current liabilities:		
Long-term debt	**-**	(2,169.8)
Deferred tax liabilities	**(106.3)**	(129.9)
Lease liabilities	**(525.3)**	(582.8)
Deferred income	**(22.8)**	(60.5)
Derivative financial instruments	**-**	(62.3)
Long-term provisions	**(1,285.2)**	(1,258.8)
	(1,939.6)	(4,264.1)
Total liabilities	**(4,822.9)**	(4,960.9)
Net (liabilities)/assets	**(162.9)**	1,131.5
Equity and reserves:		
Share capital	**171.1**	156.5
Share premium account	**517.5**	499.4
Other reserves	**(851.5)**	475.6
	(162.9)	1,131.5

Consolidated Statement of Changes in Equity

For the year ended 31 December 2020

	Attributable to the equity holders of the parent			
	Share capital US$ million	**Share premium account US$ million**	**Other reserves US$ million**	**Total US$ million**
At 1 January 2019	154.2	491.7	380.1	1,026.0
Issue of Ordinary Shares	2.3	7.7	0.9	10.9
Purchase of ESOP Trust shares	-	-	(3.6)	(3.6)
Provision for share-based payments	-	-	12.0	12.0
Profit for the year	-	-	164.3	164.3
Other comprehensive expense	-	-	(78.1)	(78.1)
At 1 January 2020	156.5	499.4	475.6	1,131.5
Issue of Ordinary Shares	14.6	18.1	1.9	34.6
Purchase of ESOP Trust shares	-	-	(1.5)	(1.5)
Provision for share-based payments	-	-	11.3	11.3
Loss for the year	-	-	(1,302.2)	(1,302.2)
Other comprehensive expense	-	-	(36.6)	(36.6)
At 31 December 2020	**171.1**	**517.5**	**(851.5)**	**(162.9)**

Consolidated Cash Flow Statement
For the year ended 31 December 2020

	2020 US$ million	2019 US$ million
Net cash from operating activities	**610.6**	1,108.7
Investing activities:		
Capital expenditure	**(266.6)**	(241.4)
Decommissioning pre-funding	**(5.4)**	(9.9)
Decommissioning expenditure	**(48.9)**	(35.3)
Receipts from sublease income	**26.7**	20.2
Proceeds from disposal of oil and gas properties	**2.7**	4.2
Net cash used in investing activities	**(291.5)**	(262.2)
Financing activities:		
Issuance of Ordinary Shares	**30.2**	4.7
Net (purchase)/release of ESOP Trust shares	**(0.4)**	1.1
Warrant cash consideration	**-**	(13.8)
Proceeds from drawdown of bank loans	**35.0**	-
Repayment of bank loans	**(52.3)**	(399.7)
Lease liability payments	**(181.0)**	(224.7)
Interest paid	**(230.4)**	(251.9)
Net cash from financing activities	**(398.9)**	(884.3)
Currency translation differences relating to cash and cash equivalents	**(10.0)**	(8.7)
Net decrease in cash and cash equivalents	**(89.8)**	(46.5)
Cash and cash equivalents at the beginning of the year	**198.1**	244.6
Cash and cash equivalents at the end of the year	**108.3**	198.1

Full Year Results for the year ended 31 December 2020

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
For the year ended 31 December 2020

1. General information

Premier Oil plc is a limited liability company incorporated in Scotland and listed on the London Stock Exchange. The address of the registered office is 4th Floor, Saltire Court, 20 Castle Terrace, Edinburgh EH1 2EN, United Kingdom. This preliminary announcement was authorised for issue in accordance with a resolution of the Board of Directors on 17 March 2021.

The financial information for the year ended 31 December 2020 set out in this announcement does not constitute statutory accounts within the meaning of Section 434 of the Companies Act 2006. Statutory accounts for the year ended 31 December 2019 were approved by the Board of Directors on 4 March 2020 and delivered to the Registrar of Companies and those for 2020 will be delivered following the Company's Annual General Meeting ('AGM'). The auditor has reported on the 2020 accounts; their audit report was unqualified, but did draw attention to the material uncertainties that exist which may cast significant doubt on the Group's ability to continue as a going concern. Further information relating to the going concern assumption is provided in the Financial Review, including details on the material uncertainties.

Basis of preparation

The financial information has been prepared in accordance with international accounting standards in conformity with the requirements of the Companies Act 2006 and International Financial Reporting Standards adopted pursuant to Regulation (EC) No. 1606/2002 as it applies in the European Union ('IFRS'). However, this announcement does not itself contain sufficient information to comply with IFRS. The Company will publish full financial statements that comply with IFRS at the end of March 2021 on the Company's website.

The financial information has been prepared under the historical cost convention except for the revaluation of financial instruments and certain oil and gas properties at the transition date to IFRS. These financial statements are presented in US dollars since that is the currency in which the majority of the Group's transactions are denominated.

The financial information has been prepared on the going concern basis. Further information relating to the going concern assumption is provided in the Financial Review, including details on the material uncertainties in relation to (1) management's ability to complete the Corporate Actions; and (2) should the Corporate Actions fail to complete, management's ability to complete an alternative restructuring of its existing debt facilities and certain hedging liabilities and obtain covenant deferrals or waivers in the intervening period to prevent its existing debt falling due within the going concern period.

PremierOil

Full Year Results for the year ended 31 December 2020

Accounting Policies

The accounting policies applied in this announcement are consistent with those of the annual financial statements for the year ended 31 December 2019, as described in those annual financial statements. A number of amendments to existing standards and interpretations were applicable from 1 January 2020. The adoption of these amendments did not have a material impact on the Group's financial statements for the year ended 31 December 2020.

2. Operating segments

The Group's operations are located and managed in five business units; namely the Falkland Islands, Indonesia, Vietnam, the United Kingdom, and the Rest of the World. The results for Pakistan, the disposal of which completed in the prior year, are reported as a discontinued operation in the prior year.

Some of the business units currently do not generate revenue or have any material operating income.

The Group is only engaged in one business of upstream oil and gas exploration and production.

	2020 US$ million	2019 US$ million
Revenue:		
Indonesia	**144.7**	172.2
Vietnam	**103.7**	198.6
United Kingdom	**701.0**	1,213.9
Total Group sales revenue	**949.4**	1,584.7
Interest and other finance revenue	**0.8**	2.4
Total Group revenue from continuing operations	**950.2**	1,587.1
Group operating (loss)/profit:		
Indonesia	**59.8**	90.9
Vietnam	**19.4**	96.2
United Kingdom	**(109.9)**	291.7
Rest of the World[1]	**(235.4)**	(0.9)
Unallocated [2]	**(77.7)**	(22.9)
Group operating (loss)/profit	**(343.8)**	455.0
Interest revenue, finance and other gains	**84.8**	31.4
Finance costs, other finance expenses and losses	**(346.3)**	(383.9)
(Loss)/profit before tax from continuing operations	**(605.3)**	102.5
Tax	**(696.9)**	52.5
(Loss)/profit after tax from continuing operations	**(1,302.2)**	155.0
Profit from discontinued operations	**-**	9.3

	2020 US$ million	2019 US$ million
Balance sheet		
Segment assets:		
Falkland Islands	**504.4**	680.0
Indonesia	**430.0**	481.5
Vietnam	**378.2**	437.8
United Kingdom	**3,040.8**	4,060.3
Rest of the World	**179.7**	179.4
Unallocated[2]	**126.9**	253.4
Total assets	**4,660.0**	6,092.4
Liabilities:		
Falkland Islands	**(5.6)**	(13.0)
Indonesia	**(206.7)**	(216.5)
Vietnam	**(281.2)**	(324.3)
United Kingdom	**(2,020.7)**	(2,041.7)
Rest of the World	**(31.8)**	(34.5)
Unallocated[2]	**(2,276.9)**	(2,330.9)
Total liabilities	**(4,822.9)**	(4,960.9)
Other information		
Capital additions and acquisitions:		
Falkland Islands	**24.7**	30.0
Indonesia	**11.6**	72.1
Pakistan	**-**	1.3
Vietnam	**2.4**	5.0
United Kingdom	**276.3**	142.6
Rest of the World	**58.5**	61.2
Total capital additions and acquisitions	**373.5**	312.2

	2020 US$ million	2019 US$ million
Depreciation, depletion, amortisation and impairment: [3]		
Indonesia	**50.1**	44.5
Vietnam	**44.1**	60.0
United Kingdom	**566.6**	652.6
Rest of the World	**10.5**	0.8
Total DD&A and impairment (continuing operations)	**671.3**	757.9

[1] The Group operating loss relating to the Rest of the World is primarily driven by the write-off to non-Sea Lion Falkland Islands exploration and evaluation assets in the period.

[2] Unallocated expenditure, assets and liabilities include amounts of a corporate nature and not specifically attributable to a geographical segment. These items include corporate general and administration costs, new venture and pre-licence exploration costs, cash and cash equivalents, mark-to market valuations of commodity contracts, warrants and other short and long-term debt.

[3] Includes DD&A in respect of right-of-use assets.

Out of the total Group worldwide sales revenues of US$949.4 million (2019: US$1,584.7 million), revenues of US$701.0 million (2019: US$1,213.9 million) arose from sales of oil and gas to customers located in the UK. Included within the total revenues were revenues of US$799.9 million (2019: US$1,539.1 million) from contracts with customers. This was in addition to hedging gains of US$149.5 million (2019: US$45.6 million).

Included in assets of the United Kingdom segment are non-current assets (excluding deferred tax assets) of US$2,000.1 million (2019: US$2,286.3 million). Included in depreciation, depletion, amortisation and impairment is an impairment charge in relation to the UK of US$143.8 million (2019: US$41.5 million net charge).

Revenue from two customers (2019: three customers) each exceeded 10 per cent of the Group's consolidated revenue. Sales to one customer in the UK amounted to US$128.8 million (2019: two customers for US$318.8 million and US$187.3 million). Sales to one customer in Indonesia totalled US$113.0 million (2019: one customer amounting to US$160.4 million).

3. Costs of operation

	2020 US$ million	2019 US$ million
Operating costs	**273.8**	322.6
Gas purchases	**18.4**	21.6
Stock overlift/(underlift) movement	**28.0**	(10.5)
Royalties	**4.5**	9.1
	324.7	342.8

4. Tax

	2020 US$ million	2019 US$ million
Current tax:		
UK corporation tax on profits	**(22.6)**	(6.0)
Overseas tax	**44.6**	81.6
Adjustments in respect of prior years	**11.1**	(24.5)
Total current tax	**33.1**	51.1
Deferred tax:		
UK corporation tax	**687.3**	(94.0)
Overseas tax	**(23.5)**	(9.6)
Total deferred tax	**663.8**	(103.6)
Tax charge/(credit) on (loss)/profit on ordinary activities	**696.9**	(52.5)

The tax charge for the year can be reconciled to the (loss)/profit per the consolidated income statement as follows:

	2020 US$ million	2019 US$ million
Group (loss)/profit on ordinary activities before tax	**(605.3)**	102.5
Group (loss)/profit on ordinary activities before tax at 32.8% weighted average rate (2019: 46.0%)	**(198.5)**	47.2
Tax effects of:		
(Income)/expenses that are not (taxable)/deductible in determining taxable profit[1]	**64.7**	16.2
Financing costs disallowed for UK supplementary charge	**20.3**	19.4
Non-deductible field expenditure	**-**	11.3
Tax and tax credits not related to (loss)/profit before tax (mainly ring fenced expenditure supplement)	**(12.1)**	(89.2)
Unrecognised tax losses[2]	**827.1**	10.0
Effect of change in foreign exchange	**1.8**	0.3
Adjustments in respect of prior years	**(9.1)**	(40.3)
Recognition that decommissioning provision will unwind at 50%	**2.7**	(8.0)
Recognition of deferred tax asset	**-**	(19.4)
Tax charge/(credit) for the year	**696.9**	(52.5)
Effective tax rate for the year	**(115.1%)**	(51.2%)

[1] Includes the tax effect of the US$194 million exploration write-off in respect of the Falkland Islands licences.

[2] Includes US$817 million of unrecognised deferred tax asset in respect of ring fence tax losses, decommissioning asset and allowances.

The UK deferred tax charge arises primarily due to the derecognition of previously recognised UK ring fence tax losses and allowances. It is no longer appropriate to recognise a deferred tax asset of US$817.2 million of the Group's ring fence tax losses, decommissioning asset and allowances at 31 December 2020 based on expected future profitability. The future taxable profits represent those solely relating to Premier's existing assets and do not include those assets associated with the proposed merger. The reduction from the prior year primarily relates to the exclusion of taxable profits associated with previously proposed acquisitions and the reduction in management's long-term price assumptions.

More detail on assumptions applied in assessing the recoverability of deferred tax assets is provided in note 5.

The weighted average rate is calculated based on the tax rates weighted according to the profit or loss before tax earned by the Group in each jurisdiction. The change in the weighted average rate year-on-year relates to the mix of profit and loss in each jurisdiction.

The future effective tax rate for the Group is impacted by the mix of jurisdictions in which the Group operates (with corporation tax rates ranging from 19 per cent to 44 per cent), assumptions around future oil prices and changes to tax rates and legislation.

Post balance sheet event note

On 3 March 2021 it was announced in the UK budget that the UK non-ring fence corporation tax rate will increase from 19 per cent to 25 per cent with effect from 2023. The Group do not currently recognise any deferred tax assets in respect of UK non-ring fence tax losses and therefore this rate change did not impact the disclosed results.

5. Deferred tax

	2020 US$ million	2019 US$ million
Deferred tax assets	**869.7**	1,556.1
Deferred tax liabilities	**(106.3)**	(129.9)
	763.4	1,426.2

	At 1 January 2020 US$ million	**Exchange movements US$ million**	**(Charged) /credited to income statement US$ million**	**Credited to retained earnings US$ million**	**At 31 December 2020 US$ million**
UK deferred corporation tax:					
Fixed assets and allowances	(513.4)	-	44.2	-	(469.2)
Decommissioning	439.6	(0.4)	(8.9)	-	430.3
Tax losses and allowances	1,536.6	(0.6)	(688.2)	-	847.8
Investment allowance	82.5	-	(46.7)	-	35.8
Derivative financial instruments	10.8	-	12.4	1.9	25.1
Total UK deferred corporation tax	**1,556.1**	**(1.0)**	**(687.2)**	**1.9**	**869.8**
Overseas deferred tax[1]	**(129.9)**	**-**	**23.5**	**-**	**(106.4)**
Total	**1,426.2**	**(1.0)**	**(663.7)**	**1.9**	**763.4**

	At 1 January 2019 US$ million	Exchange movements US$ million	(Charged) /credited to income statement US$ million	Credited to retained earnings US$ million	At 31 December 2019 US$ million
UK deferred corporation tax:					
Fixed assets and allowances	(609.2)	0.1	95.7	-	(513.4)
Decommissioning	376.8	2.1	60.7	-	439.6
Tax losses and allowances	1,602.5	0.8	(66.7)	-	1,536.6
Investment allowance	77.8	0.1	4.6	-	82.5
Derivative financial instruments	(13.8)	(0.1)	(0.3)	25.0	10.8
Total UK deferred corporation tax	**1,434.1**	**3.0**	**94.0**	**25.0**	**1,556.1**
Overseas deferred tax[1]	**(139.5)**	**-**	**9.6**	**-**	**(129.9)**
Total	**1,294.6**	**3.0**	**103.6**	**25.0**	**1,426.2**

[1] The overseas deferred tax relates mainly to temporary differences associated with fixed asset balances.

The Group's deferred tax assets at 31 December 2020 are recognised to the extent that taxable profits are expected to arise in the future against which the UK ring fence tax losses and allowances can be utilised. In accordance with paragraph 37 of IAS 12 - 'Income Taxes', the Group reassessed its deferred tax assets at 31 December 2020 with respect to UK ring fence tax losses and allowances. The corporate model used to assess whether it is appropriate to recognise the Group's deferred tax losses and allowances was re-run, using an oil price assumption of US$51/bbl in 2021, US$55/bbl in 2022 and US$60/bbl in 'real' terms thereafter (2019: US$65/bbl in 2020 and 2021, US$70/bbl in 2022 and US$70/bbl in ‘real’ terms thereafter) and gas price assumption of 37.5p/therm in 2021, 42.5p/therm in 2022 and 42.5p/therm in ‘real’ terms thereafter. These price assumptions are consistent with that used when assessing the Group's underlying assets for impairment. As at 31 December 2019, approximately US$267 million of the recognised deferred tax asset was supported by future taxable profits associated with previously proposed acquisitions which have since been terminated. As at 31 December 2020, the future taxable profits in the corporate model represent those relating to Premier’s existing assets and do not include those associated with the proposed merger. The proposed merger will represent a reverse takeover by Chrysaor and, therefore, Premier will represent the accounting acquiree. On the basis that Premier will represent the accounting acquiree, and therefore does not have control of the future taxable profits of the enlarged group as at the balance sheet date, future taxable profits associated with the merger were not included in the corporate model as at 31 December 2020. The results of the corporate model concluded that it is no longer appropriate to recognise a deferred tax asset of US$817.2 million of the Group’s UK ring fence tax losses, decommissioning asset and allowances at 31 December 2020 based on expected future profitability.

The reduction from the prior year primarily relates to the exclusion of taxable profits associated with previously proposed acquisitions and the reduction in management's long-term price assumptions.

In addition to the above, there are carried forward non-ring fence UK tax losses of approximately US$425.3 million (2019: US$376.4 million) and overseas tax losses of US$288.7 million (2019: US$267.7 million) for which a deferred tax asset has not been recognised.

None of the UK tax losses (ring fence and non-ring fence) have a fixed expiry date for tax purposes.

No deferred tax has been provided on unremitted earnings of overseas subsidiaries, following a change in UK tax legislation in 2009 which exempted foreign dividends from the scope of UK corporation tax, where certain conditions are satisfied.

The recognition of the Group's UK deferred tax asset is sensitive to commodity prices. A US$5/bbl reduction in the long-term oil price would result in an additional deferred tax asset derecognition charge of US$40 million. A 5p/therm reduction in the long-term gas price would result in an additional deferred tax asset derecognition charge of US$86 million.

6. (Loss)/earnings per share

The calculation of basic (loss)/earnings per share is based on the (loss)/profit after tax and the weighted average number of Ordinary Shares in issue during the year. Basic and diluted earnings per share are calculated as follows:

	2020 US$ million	2019 US$ million
(Loss)/earnings		
(Loss)/earnings for the purpose of diluted earnings per share on continuing operations	**(1,302.2)**	155.0
Profit from discontinued operations	**-**	9.3
(Loss)/earnings for the purpose of diluted earnings per share on continuing and discontinued operations	**(1,302.2)**	164.3
Number of shares (millions)		
Weighted average number of Ordinary Shares for the purpose of basic earnings per share	**887.7**	826.2
Effects of dilutive potential Ordinary Shares:		
Contingently issuable shares (2020: anti-dilutive)	**-**	76.9
Weighted average number of Ordinary Shares for the purpose of diluted earnings per share	**887.7**	903.1
(Loss)/earnings per share from continuing operations (cents)		
Basic	**(146.7)**	18.8
Diluted	**(146.7)**	17.2
Earnings per share from discontinued operations (cents)		
Basic	**-**	1.1
Diluted	**-**	1.0

As at 31 December 2020, there are 57.8 million potentially dilutive contingently issuable shares related to unexercised equity warrants and share options, the inclusion of which gives rise to an anti-dilutive loss per share.

7. Intangible exploration and evaluation ('E&E') assets

Oil and Gas Properties	Total US$ million
Cost:	
At 1 January 2019	812.6
Exchange movements	1.3
Additions during the year	129.3
Transfer to PP&E	(1.9)
Exploration expense[1]	(7.3)
At 31 December 2019	934.0
Exchange movements	(12.5)
Additions during the year	85.5
Exploration expense[1]	(221.7)
At 31 December 2020	785.3

[1] Expensed in the income statement together with new venture expenditure of US$69.3 million (2019: US$14.0 million) and US$2.4 million of E&E expenditure that was charged directly to the income statement, resulting in a total exploration expense and new venture costs of US$293.4 million. In the current period, new venture expenditure includes costs incurred in respect to Corporate Actions, including previously proposed acquisitions and the proposed merger with Chrysaor.

The amounts for intangible E&E assets represent costs incurred on active exploration projects. These amounts are written off to the income statement as exploration expense unless commercial reserves are established or the determination process is not completed and there are no indications of impairment.

The outcome of ongoing exploration, and therefore whether the carrying value of E&E assets will ultimately be recovered, is inherently uncertain. To the extent that we have an active licence to continue to explore for resources and have an intention to continue exploration activity, the exploration cost associated with the licence will remain capitalised as an E&E asset on the balance sheet. Once exploration activity has completed and we have no further intention to explore the licence for resources, costs capitalised up to that point will be expensed and no further costs associated with the licence will be capitalised.

During the year, exploration expenditure of US$194.1 million has been written off for costs previously capitalised for exploration prospects in the North Falklands basin which will not be developed as part of the Sea Lion Phase 1 project. In addition, the drilling of the Charlie-1 well in Area A in Alaska encountered non-commercial gas condensate for which US$27.1 million of costs have been expensed in the year. The balance carried forward is predominantly in relation to the Sea Lion (Falkland Islands) and Tuna (Indonesia) projects, as well as our share of expenditure on the Zama prospect in Mexico.

Based on the continuation of commercial and technical evaluation activities and in the absence of data to suggest that the carrying value of capitalised expenditure incurred to date could not be recovered in full, capitalised E&E costs in respect to Sea Lion (Falkland Islands) continue to be carried on the balance sheet. During 2020, terms of a farm-out, which remains subject to approval, were agreed with Navitas Petroleum LP and planning for the development of Sea Lion continued to be progressed, albeit at a reduced level given the macro environment. A joint venture approved work programme and budget is in place for 2021 and an extension of the Sea Lion licence to November 2022 has been agreed by the Falkland Islands Government. Should the proposed merger with Chrysaor complete, it is anticipated that the enlarged group will have significant financial resources to support a future development decision. However, this will remain subject to the completion of technical and commercial evaluation activities by the Board of the enlarged group. Because the proposed merger will represent a reverse takeover by Chrysaor, on completion Sea Lion will be measured at fair value, which could differ to its current carrying value. Should the merger not complete, Premier would have to identify alternative finance options for Sea Lion. In those circumstances, the lack of a clear financing solution for the project would be considered as an indicator of impairment.

8. Property, plant and equipment

	Oil and gas properties US$ million	Right-of-use assets US$ million	Other fixed assets US$ million	Total US$ million
Cost:				
At 1 January 2019	7,807.6	803.3	57.3	8,668.2
Exchange movements	(1.7)	(0.6)	1.1	(1.2)
Re-measurement of lease liabilities	-	8.3	-	8.3
Additions and changes in decommissioning estimates	180.1	-	2.8	182.9
Transferred from E&E	1.9	-	-	1.9
Disposals	(1.3)	-	-	(1.3)
At 31 December 2019	7,986.6	811.0	61.2	8,858.8
Exchange movements	(0.7)	1.0	0.7	1.0
Re-measurement of lease liabilities	-	2.5	-	2.5
Additions and changes in decommissioning estimates	285.3	-	2.7	288.0
At 31 December 2020	**8,271.2**	**814.5**	**64.6**	**9,150.3**
Amortisation, depreciation and impairment:				
At 1 January 2019	5,568.2	-	51.1	5,619.3
Exchange movements	(1.1)	-	0.9	(0.2)
Charge for the year	489.4	223.0	4.0	716.4
Net impairment credit	41.5	-	-	41.5
At 31 December 2019	6,098.0	223.0	56.0	6,377.0
Exchange movements	(0.8)	0.3	0.7	0.2
Charge for the year	399.6	124.9	3.0	527.5
Impairment charge	143.8	-	-	143.8
At 31 December 2020	**6,640.6**	**348.2**	**59.7**	**7,048.5**
Net book value:				
At 31 December 2019	1,888.6	588.0	5.2	2,481.8
At 31 December 2020	**1,630.6**	**466.3**	**4.9**	**2,101.8**

Finance costs that have been capitalised within oil and gas properties during the year total US$3.5 million (2019: US$4.3 million), at a weighted average interest rate of 7.4 per cent (2019: 8.2 per cent).

Amortisation and depreciation of oil and gas properties is calculated on a unit-of-production basis, using the ratio of oil and gas production in the period to the estimated quantities of proved and probable reserves on an entitlement basis at the end of the period plus production in the period, on a field-by-field basis. Proved and probable reserve estimates are based on a number of underlying assumptions including oil and gas prices, future costs, oil and gas in place and reservoir performance, which are inherently uncertain. Management uses established industry techniques to generate its estimates and regularly references its estimates against those of joint venture partners or external consultants. However, the amount of reserves that will ultimately be recovered from any field cannot be known with certainty until the end of the field's life.

The current period charge includes US$52.7 million relating to the net effect of changes in decommissioning provisions on assets previously depreciated to nil net book value as a result of a change in decommissioning discount rates.

Impairment charge

In the period, Group-wide indicators of impairment, being a reduction in management's long-term oil and gas price assumptions and decommissioning discount rate, were identified. The impairment charge in the current year primarily relates to Solan (UK) as a result of a reduction in management's long-term oil price assumption and a decrease in reserves associated with future investments decisions. The impairment charge of US$143.8 million (pre-tax) (2019: net impairment charge of US$41.5 million) was calculated by comparing the future discounted pre-tax cash flows expected to be derived from production of commercial reserves (the value-in-use) against the carrying value of the cash-generating unit. When testing producing assets for impairment, future cash flows were estimated using the following oil price assumption: US$51/bbl in 2021, US$55/bbl in 2022 and US$60/bbl in 'real' terms thereafter (2019: US$65/bbl in 2020 and 2021, US$70/bbl in 2022 followed by a long-term price of US$70/bbl (real) thereafter) and were discounted using a pre-tax discount rate of 9 per cent for the UK assets (2019: 9 per cent) and 12.5 per cent for the non-UK assets (2019: 12.5 per cent). Assumptions involved in impairment measurement include estimates of commercial reserves and production volumes, future oil and gas prices, discount rates and the level and timing of expenditures, all of which are inherently uncertain.

Sensitivity

A US$5/bbl reduction in the long-term oil price (to US$55/bbl (real)) would increase the impairment charge by US$72.1 million, of which US$67.1 million would be in respect of goodwill associated with the Catcher cash-generating unit. A 1 per cent increase in the discount rates used when determining the value-in-use for each oil and gas property would increase the impairment charge by US$12.3 million of which US$10.9 million would be in respect to goodwill associated with the Catcher cash-generating unit.

Goodwill

Goodwill of US$240.8 million has been specifically assigned to the Catcher field in the UK, which is considered the cash-generating unit for the purposes of any impairment testing of this goodwill. The Group tests goodwill annually for impairment, or more frequently if there are indications that goodwill might be impaired. The recoverable amounts are determined from value-in-use calculations with the same key assumptions as noted above for the impairment calculations. The discount rate used is 9 per cent (2019: 9 per cent). The value-in-use forecast takes into consideration cash flows which are expected to arise during the life of the Catcher field as a whole, currently expected to be around 2028. This period exceeds five years but is believed to be appropriate as it is underpinned by estimates of commercial reserves provided by our in-house reservoir engineers using industry standard reservoir estimation techniques. The headroom between the recoverable amount and the carrying amount of the Catcher cash-generating unit, including the goodwill, is US$15.2 million (2019: US$203.8 million).

The key assumptions applied in the measurement of the value-in-use of the Catcher asset are discount rate, oil prices and forecasted recoverable reserves. A change in any of these key assumptions would cause the asset's carrying amount to exceed its recoverable amount as disclosed above.

Right-of-use assets

There were no new leases entered into during the period. The re-measurement above represents the net impact of re-measurements of the Catcher FPSO lease which were driven by changes in assumed Cessation of Production ('COP') dates during the year based on field performance and the extension of the Chim Sáo lease by two years to 2030 to reflect revised COP date.

In addition to the above the Group has a net investment in sublease of US$57.1 million (2019: US$75.7 million), of which US$53.1 million is classified as a long-term receivable and US$4.0 million as trade and other receivables. The net investment in sublease represents our joint operations partners' share of lease liabilities on lease arrangements for which Premier has entered into in its role as operator as sole signatory on behalf of the joint operation and the asset is controlled by the joint operation.

Income of US$4.2 million, which predominantly represents unwinding of the net investment in sublease, has been recognised as finance income in the year.

9. Leases

	2020 US$ million	2019 US$ million
At 1 January	**732.5**	899.6
Re-measurement	**6.9**	8.3
Finance costs	**45.7**	50.0
Lease payments	**(186.3)**	(224.7)
Exchange differences	**0.8**	(0.7)
At 31 December	**599.6**	**732.5**
Classified as:		
Short-term	**74.3**	149.7
Non-current	**525.3**	582.8

Expenses related to both short-term and low value lease arrangements are considered to be immaterial for reporting purposes. During the period variable lease costs of US$6.6 million (2019: US$23.3 million) were expensed. Lease liabilities have been classified as either short-term or non-current in the balance sheet according to whether they are expected to be settled within 12 months of the balance sheet date.

The significant portion of the Group's lease liabilities represent lease arrangements for FPSO vessels on the Catcher and Chim Sáo assets. The lease liabilities, and associated right-of-use-assets have been calculated by reference to in-substance fixed lease payments in the underlying agreements incurred throughout the non-cancellable period of the lease along with periods covered by options to extend the lease where the Group is reasonably certain that such options will be exercised. When assessing whether extension options were likely to be exercised, assumptions are consistent with those applied when testing for impairment.

There were no new leases entered into during the period. The re-measurement above represents the net impact of re-measurements of the Catcher FPSO lease which were driven by changes in assumed Cessation of Production ('COP') dates during the year based on field performance and the extension of the Chim Sáo lease by two years to 2030 to reflect the revised COP date.

Under the modified retrospective transition method, lease payments were discounted at 1 January 2019 using an incremental borrowing rate representing the rate of interest that Premier would have to pay to borrow over a similar term, and with a similar security, the funds necessary to obtain an asset of a similar value to the right-of-use asset in a similar economic environment. The incremental borrowing rate applied to each lease was determined by taking into account the risk-free rate, adjusted for factors such as the credit rating linked to the life of the underlying lease agreement. The weighted average incremental borrowing rate applied by Premier upon transition was 7.2 per cent. Incremental borrowing rates applied to individual leases ranged between 7.2 per cent and 9.2 per cent.

10. Notes to the cash flow statement

	2020 US$ million	2019 US$ million
(Loss)/profit before tax for the year	**(605.3)**	102.5
Adjustments for:		
Depreciation, depletion, amortisation and impairment	**671.3**	757.9
Other operating (income)/costs	**(3.5)**	2.9
Exploration expense	**227.1**	7.3
Provision for share-based payments	**6.3**	7.1
Interest revenue and finance gains	**(84.8)**	(31.4)
Finance costs and other finance expenses	**346.3**	383.9
Profit on disposal of non-current assets	**(1.1)**	(4.2)
Operating cash flows before movements in working capital	**556.3**	1,226.0
Decrease/(increase) in inventories	**3.6**	(3.8)
Decrease/(increase) in receivables	**54.3**	(74.9)
Increase/(decrease) in payables	**12.7**	(19.5)
Cash generated by operations	**626.9**	1,127.8
Income taxes received	**2.0**	(61.2)
Interest income received	**1.2**	6.2
Net cash from continuing operating activities	**630.1**	1,072.8
Net cash from discontinued operating activities	**-**	7.2
Net cash from operating activities	**630.1**	1,080.0
Movement in JV cash	**(19.5)**	28.7
Total net cash from operating activities	**610.6**	1,108.7

Analysis of changes in net debt:

	2020 US$ million	2019 US$ million
a) Reconciliation of net cash flow to movement in net debt:		
Movement in cash and cash equivalents	**(89.8)**	(46.5)
Proceeds from drawdown of bank loans	**(35.0)**	-
Repayment of bank loans	**52.3**	399.7
Non-cash movements on debt and case balances (primarily foreign exchange)	**(16.1)**	(12.3)
(Increase)/reduction in net debt in the year	**(88.6)**	340.9
Opening net debt	**(1,989.8)**	(2,330.7)
Closing net debt	**(2,078.4)**	(1,989.8)
b) Analysis of net debt:		
Cash and cash equivalents	**108.3**	198.1
Borrowings	**(2,186.7)**	(2,187.9)
Total net debt	**(2,078.4)**	(1,989.8)

The carrying amounts of the borrowings on the balance sheet are stated net of the unamortised portion of the refinancing fees of US$5.7 million (2019: US$18.1 million).

11. Subsequent Events

Proposed Merger with Chrysaor Holdings Limited

Subsequent to year-end, the proposed merger with Chrysaor Holdings Ltd has been progressed as planned with completion expected to occur 31 March 2021.

During January 2021 a convening hearing was held in connection with the restructuring plans required to implement the merger. At the hearing the court granted Premier's request to start the restructuring plans process and the Group convened creditor meetings for February 2021. At these meetings the restructuring plans to implement the merger were approved by the requisite proportion of lenders. The restructuring plans remain subject to approval by the Scottish Court of Session with the sanction hearing scheduled to commence on 19 March 2021.

All elections were received from senior lenders in respect of the take-up of a partial cash alternative capped at US$175 million (the 'Cash-Out Option'). As a result of the elections, the take-up of the Cash-Out Options is expected to be less than US$175 million and will be satisfied through funds received from senior creditors able to elect to subscribe for new shares, in cash at a pre-agreed price, which would have been issued to other creditors if they had not elected the

Cash-Out Option. Therefore, the enlarged group expects to retain the US$175 million of cash that it may otherwise have needed to use to fund the Cash-Out Option.

The satisfaction of all regulatory conditions and the receipt of anti-trust approval was progressed with all necessary conditions met and approvals granted by 22 February 2021.

12. External audit

This preliminary announcement is consistent with the audited financial statements of the Group for the year-ended 31 December 2020.

13. Publication of financial statements

It is anticipated that the full Annual Report and Financial Statements will be published on the Company's website at the end of March 2021 (www.premier-oil.com).

14. Annual General Meeting

It is anticipated that the Annual General Meeting will be held on Wednesday 23 June 2021.

Full Year Results for the year ended 31 December 2020

Glossary

Non-IFRS measures

The Group uses certain measures of performance that are not specifically defined under IFRS or other generally accepted accounting principles. These non-IFRS measures are EBITDAX, Operating cost per barrel, DD&A per barrel, Net Debt and Liquidity and are defined below.

- **EBITDAX:** Earnings before interest, tax, depreciation, amortisation, impairment, exploration spend and other one off items. In the current year it also excludes the gain on disposal recognised in the income statement. This is a useful indicator of underlying business performance.
- **Free cash flow:** Positive cash flow generation from operating, investing and financing activities excluding drawdowns from and repayments of borrowing facilities and equity issuances.
- **Operating cost per barrel:** Operating costs for the year divided by working interest production. This is a useful indicator of ongoing operating costs from the Group's producing assets.
- **DD&A per barrel:** Amortisation and depreciation of oil and gas properties and right-of-use assets for the year divided by working interest production. This is a useful indicator of ongoing rates of depreciation and amortisation of the Group's producing assets.
- **Net Debt:** The net of cash and cash equivalents and long-term debt recognised on the balance sheet. This is an indicator of the Group's indebtedness and capital structure.
- **Liquidity:** The sum of cash and cash equivalents on the balance sheet, and the undrawn amounts available to the Group on our principal facilities, including letters of credit facilities, less our JV partners' share of cash balances. This is a key measure of the Group's financial flexibility and ability to fund day to day operations.

Each of the above non-IFRS measures are presented within the Financial Review with detail on how they are reconciled to the statutory financial statements.

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Full Year Results for the year ended 31 December 2020

OIL AND GAS RESERVES

Working interest reserves at 31 December 2020

Working interest basis													
	Falkland Islands		**Indonesia**		**UK**		**Vietnam**		**Mexico**		**Total**		
	Oil and NGLs	Gas	Oil and NGLs	Gas	Oil and NGLs	Gas	Oil and NGLs	Gas	Oil and NGLs	Gas	Oil and NGLs	Gas	Oil and NGLs and Gas
	mmbbls	bcf	mmbbls	bcf	mmbbls	bcf	mmbbls	bcf	mmbbls	bcf	mmbbls	bcf	mmboe
Group proved plus probable reserves:													
At 1 January 2020	-	-	1.09	156.79	56.84	357.30	14.16	19.39	-	-	72.09	533.48	174.73
Revisions	-	-	(0.30)	(17.10)	3.92	(12.54)	1.55	3.88	-	-	5.17	(25.76)	(0.65)
Discoveries and extensions	-	-	-	-	-	-	-	-	-	-	-	-	-
Acquisitions and divestments	-	-	-	-	(0.08)	(0.01)	-	-	-	-	(0.08)	(0.01)	(0.08)
Production	-	-	(0.23)	(22.12)	(11.99)	(15.42)	(2.52)	(3.15)	-	-	(14.74)	(40.69)	(22.62)
At 31 December 2020	-	-	0.56	117.57	48.69	329.33	13.19	20.12	-	-	62.44	467.02	151.38
Total Group developed and undeveloped reserves													
Proved on production	-	-	0.41	72.31	22.74	45.45	7.52	10.85	-	-	30.67	128.61	54.95
Proved approved/justified for development	-	-	0.07	19.99	7.80	155.66	0.55	1.95	-	-	8.42	177.60	42.40
Probably on production	-	-	0.01	9.96	12.44	16.81	4.52	5.26	-	-	16.97	32.03	22.94
Probably approved/justified for development	-	-	0.07	15.31	5.71	111.41	0.60	2.06	-	-	6.38	128.78	31.09
At 31 December 2020	-	-	0.56	117.57	48.69	329.33	13.19	20.12	-	-	62.44	467.02	151.38

1 Revision of gas in Indonesia based on observed depletion behaviour in Gajah Puteri field and observed water ingress on other Natuna A gas fields.

2 Revisions in the UK relate to better reservoir performance observed in the Catcher Area, offset by revisions in Solan; earlier anticipated Cessation of Production ('CoP') on Ravenspurn North and Johnston, and earlier actual CoP in the Balmoral Area, Huntington and Kyle.

3 Vietnam revision reflects a slightly better decline based on production behaviour with a later CoP than anticipated last year.

4 Proved plus probable gas includes 38.8bcf of fuel gas.

5. The Zama field (Mexico), Tuna field (Indonesia), Sea Lion (Falkland Islands) and Tolmount East (UK) remain categorised as contingent resources and consequently have no booked reserves.

6 The divestment in the UK relates to the reduction in working interest in Laverda from 54 per cent to 50 per cent.

Premier categorises petroleum resources in accordance with the June 2018 SPE/WPC/AAPG/SPEE/SEG/SPWLA/EAGE Petroleum Resource Management System ('SPE PRMS'). Proved and probable reserves are based on operator, third-party reports and internal estimates and are defined in accordance with the Statement of Recommended Practice ('SORP') issued by the Oil Industry Accounting Committee ('OI-AC'), dated July 2001.

The Group provides for amortisation of costs relating to evaluated properties based on direct interests on an entitlement basis, which incorporates the terms of the PSCs in Indonesia and Vietnam. On an entitlement basis, reserves were 143.5 mmboe as at 31 December 2020 (2019: 164.4 mmboe). This was calculated at year-end 2020, using the following oil price assumption: US$51/bbl in 2021, US$55/bbl in 2022 and US$60/bbl in real terms thereafter (2019: US$65/bbl in 2020 and 2021, US$70/bbl in 2022 and US$70/bbl in real terms thereafter).