PremierOil

Full Year Results for the year ended 31 December 2018

Press Release

Tony Durrant, Chief Executive Officer, commented:

"2018 saw higher production, positive free cash flow and a return to profitability. The Group is ahead of plans to restore balance sheet strength and remains focused on consistently delivering free cash flows. Growth projects such as Tolmount, Zama and Sea Lion, together with promising exploration in Mexico and Indonesia, are being advanced within a disciplined financial framework."

2018 Operational highlights

- Record production of 80.5 kboepd (2017: 75.0 kboepd)
- Catcher oil plateau rates increased to 66 kbopd (gross)
- Tolmount Main (UK) gas project sanctioned; estimated peak production of 58 kboepd (gross)
- Highly prospective new licences secured offshore Mexico and Indonesia
- US$73.4 million of cash receipts from non-core asset disposals

2018 Financial highlights

- US$133.4 million post tax profit (2017: post tax loss of US$253.8 million)
- EBITDAX increased to US$882.3 million, up 50% (2017: US$589.7 million)
- Cash flows from operations of US$777.2 million, up 64% (2017: US$475.3 million)
- Opex of US$10/boe with additional lease costs of US$7/boe; low cost base maintained
- Total capex (development, exploration and abandonment) of US$353 million, below forecast
- US$181 million debt reduction from accelerated conversion of convertible bonds
- Year-end net debt of US$2.3 billion, down US$393 million (2017: US$2.7 billion)
- Covenant leverage ratio reduced to 3.1x (2017: 6.0x)

2019 Outlook

- Production guidance of 75 kboepd, a 5% increase after disposals; 89 kboepd year to date
- Cash margins expected to be 30% higher at comparable commodity pricing
- Opex (excluding lease costs) and capex guidance of US$13/boe and US$340 million, respectively
- Project sanction of Catcher Area additions (Catcher North and Laverda) anticipated 1H
- Zama, Tolmount East appraisal programmes to complete Q3
- Formal loan application for Sea Lion funding to be submitted in Q2
- Material free cash flow, driving further debt reduction of US$250 million to US$350 million

ENQUIRIES

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A presentation to analysts will be held at 9.30am today at the offices of Premier Oil, 23 Lower Belgrave Street, London SW1W 0NR and will be webcast live on the company's website at www.premier-oil.com. A copy of this announcement is available for download from our website at www.premier-oil.com.

PremierOil

Full Year Results for the year ended 31 December 2018

CEO REVIEW

Oil prices increased during the first three quarters of 2018, peaking at US$86.2/bbl in October before falling steeply to close the year at US$50.2/bbl. Against this volatile backdrop, 2018 was another year of solid operational delivery by Premier, resulting in significantly higher cash flows and a return to profit.

Production increased year-on-year averaging 80.5 kboepd, despite material asset sales. This was driven by new production from our operated Catcher Area and continued high operating efficiency across the portfolio.

Production (kboepd)	Working interest		Entitlement	
	2018	2017	**2018**	2017
Indonesia	**13.2**	14.1	**8.7**	10.3
Pakistan	**5.3**	6.5	**5.3**	6.4
UK	**46.8**	39.5	**46.8**	39.5
Vietnam	**15.2**	14.9	**13.0**	13.0
Total	**80.5**	75.0	**73.8**	69.2

Our production portfolio today is concentrated in two main geographical areas: South East Asia (Indonesia and Vietnam) and the UK Continental Shelf. Our operated Asian assets, driven by high uptime and low cost structures, generated material free cash flows for the Group. Singapore demand for our Indonesian gas remained robust and the opportunity remains to develop and deliver additional resource into the Singapore market under our long term gas sales agreements. Our Chim Sáo field in Vietnam continued to outperform and we again increased our reserves estimates for the field at the end of 2018, a third increase since first oil in 2011.

Production from our UK assets, which represents over half the Group's production, grew materially during 2018. This was driven by our Catcher Area which reached increased plateau rates of 66 kbopd (gross) in the fourth quarter, considerably in excess of the 50 kbopd (gross) envisaged at sanction. This strong performance has continued into 2019 and further underpins our confidence in the longer term cash flow generation potential of this asset. At year end, we revised upwards our Catcher Area reserves to include the Catcher North and Laverda accumulations. In addition, with more production history to calibrate our dynamic models and to underwrite a higher recovery, we would hope to be able to revise over time our estimate of the Catcher Area reserves. We also aim to drill infill wells to target unswept areas of the reservoir to extend plateau rates and to ensure that the Catcher Area FPSO continues to operate at full capacity.

The sanction of our operated 500 Bcf (gross) Tolmount Main gas field in August was a significant achievement for the Group. Tolmount Main is, in barrel of oil equivalent terms, of similar size to our Catcher project at sanction. By partnering with infrastructure company Kellas Midstream, we have been able to minimise our share of capital expenditure while retaining our equity exposure to the upside in the project, significantly enhancing the expected returns on our investment. Once on-stream, Tolmount Main will provide the next phase of growth for the UK business unit and will contribute materially to the Group's cash flows, given our tax-advantaged position in the UK.

The HGS (Humber Gathering System) infrastructure through which Tolmount Main volumes will flow has the potential to develop into a significant new production hub over time. It is highly economic for us to deliver additional equity gas resource over the HGS infrastructure and we are on track to spud the Tolmount East appraisal well, which is seeking to confirm resource potential of up to 300 Bcf (gross), in July. We also plan to acquire seismic data over the Greater Tolmount Area during the first half of 2019 to further define prospectivity in the area. In addition, there is the potential to benefit from third party volumes transported over the Tolmount Main platform.

Our largest pre-development project is the fully appraised Sea Lion field which, at over 220 mmboe (gross) of resources in Phase 1 alone, represents a material opportunity for Premier. During 2018 we selected the key contractors for the project, many of whom also worked on our operated Catcher project, and put in place LOIs for the provision of services. Our key contractors, having carried out extensive due diligence, agreed to provide up to US$400 million of financing for Sea Lion Phase 1, underlining the robust nature of the project and the opportunity to be involved in developing the first field in a new basin. The critical path to a final investment decision remains securing a senior debt funding structure, likely involving a combination of export credit financing and project bank funding. The industry continues to follow closely our progress and it remains our preference to bring in an additional equity partner to the project once we have finalised the funding structure.

Our exploration team has done an excellent job of refocusing our portfolio towards lower risk but more impactful opportunities whilst operating within significantly reduced budgetary constraints. A notable success was the Zama discovery in 2017. Much of 2018 was spent preparing for the Zama appraisal campaign as well as progressing early engineering work on potential development concepts. The programme is well underway with encouraging initial results.

We have further enhanced our exploration portfolio through the capture of additional acreage in our basins of choice. We were particularly pleased to have secured the heavily contested Block 30 in Round 3.1 just prior to the new government placing a moratorium on further licensing rounds. We were also successful in securing the Andaman II licence offshore Indonesia in the highly prospective North Sumatra basin. This has attracted considerable industry attention with the opening up of a potential commercialisation route via the onshore Arun gas terminal. Today, our exploration portfolio is capable of delivering a series of high impact wells which have the potential to augment materially the Group's resource base. We have also continued to exit our more mature, legacy positions which do not meet our internal investment hurdles.

Full Year Results for the year ended 31 December 2018

At 31 December 2018, Group proven and probable (2P) reserves and contingent (2C) resources, on a working interest basis, were 867 mmboe (2017: 902 mmboe), including the effect of 2018 production and asset sales. The sanction of the Tolmount Main project added 46 mmboe to 2P reserves. In addition, Premier booked the 3 mmboe (net) 2P reserves related to the Catcher North and Laverda fields while there were also reserve upgrades at Chim Sáo and Elgin Franklin.

	2P reserves (mmboe)	2P reserves + 2C resources (mmboe)
1 January 2018	302	902
Production	(30)	(30)
Net additions, revisions	66	21
Sea Lion recategorisation	(134)	-
Disposals, relinquishments	(10)	(26)
31 December 2018	**194**	**867**

Our proven and probable (2P) reserves, on a working interest basis, reduced to 194 mmboe (2017: 302 mmboe), primarily due to the recategorisation of Sea Lion Phase 1 2P reserves (134 mmboe) as 2C resources following new guidelines issued by the Society of Petroleum Engineers. These point to holding Sea Lion undeveloped resources as contingent until financing for the project and formal approvals have been secured. To rebook the 2C resources of Sea Lion as 2P reserves the funding and other approvals would need to be in place. The booking of the Tolmount Main field as 2P reserves, following its sanction, and an upward revision in our estimate of 2P reserves at Catcher, Chim Sáo and Elgin Franklin, more than offset the impact of 2018 production and disposals. This represents a reserves replacement ratio of 220 per cent, excluding the technical recategorisation of Sea Lion resources.

We are the operator of the majority of our assets which provides us with strong control over future expenditure programmes and the ability to flex our discretionary spend in the event of another downturn in the commodity price. During 2018, development, exploration and abandonment spend was US$353 million, below original guidance, due to deferrals of appraisal and abandonment expenditure and tight cost control. Total 2019 capital expenditure (including abandonment) is expected to be US$340 million. Full year 2018 operating costs were US$10/boe while leasing costs associated with our operated Chim Sáo, Huntington and Catcher FPSOs amounted to US$7/boe. 2019 operating costs are forecast at US$13/boe, slightly higher than 2018, reflecting the impact of disposals of low cost gas production and expected natural decline from fixed cost base assets, while lease costs are expected to be of the order of US$7/boe.

Debt reduction remains a key corporate priority. The Group's strong operational performance supported by its low cost base and a disciplined capex programme resulted in us generating material free cash flow during 2018. This, together with proceeds of US$73 million from selective disposals of non-core assets and the early exchange of the convertible bond, resulted in a reduction of net debt by US$393 million to US$2.33 billion, ahead of the plan agreed with our lenders. We also significantly reduced our covenant leverage ratio (covenant net debt / EBITDA) to 3.1x

(2017: 6.0x) comfortably within the covenant of 5.0x at year end and back in line with many of our peers.

Looking to the year ahead, we have a highly cash generative production base, which is supported by a substantial hedging programme, an improved portfolio mix (underpinned by high margin Catcher barrels) and a tightly controlled cost base. This positions us well to deliver further debt reduction in 2019 while progressing our future growth projects to create material value to all of our stakeholders over the longer term.

We have considerable optionality within our portfolio to grow organically and deliver value over the longer term. At the same time, Premier has an excellent track record of delivering value from acquisitions and we continue to evaluate potential acquisition opportunities that enhance our asset base and create synergies with the existing core businesses. With many of the majors and larger independents looking to refocus their portfolios away from the UK North Sea, there is an opportunity for Premier to acquire mid-life, cash flow generative and profitable production assets with potentially significant upsides, which have not been pursued by the previous asset holders. Of course, any potential acquisitions have to be measured against and compete for capital with the existing organic opportunities within our portfolio.

It is our highest priority to continue to operate all of our assets in a safe and responsible manner, to ensure the safety of our workforce and to minimise potential risk to the environment. Not only is it the right thing to do, it is also a prerequisite for maintaining our social and legal licence to operate for the longer term. We are pleased to report that we recorded no serious injuries, no spills and no material process safety events during 2018. We also had record low Greenhouse Gas Intensity at Premier's operated assets. In all our HSES metrics, we aim to deliver continuous improvement and upper quartile performance against our peer group.

The composition of the Board and its committees is continually under review. As Jane Hinkley will reach the ninth anniversary of her appointment during 2019 we are pleased to announce that Barbara Jeremiah, subject to the approvals of shareholders at the AGM in May, will join the Board. It is intended that, following a transitional period, Barbara will take over as Chair of the Remuneration Committee from Jane.

UNITED KINGDOM

The UK delivered record production in 2018 of 46.8 kboepd, up almost 20 per cent on 2017, driven by increased Catcher Area (Premier 50 per cent operated interest) production. In November and December, UK production averaged over 60 kboepd, supported by high uptime across the asset base and increased rates from the Catcher Area, offset by the Babbage Area sale in early December. In August, Premier sanctioned its next UK growth project, the 500 Bcf Tolmount Main gas development (Premier 50 per cent operated interest) which is now in the execution phase.

Production

The Catcher Area FPSO, which produces from the Catcher, Varadero and Burgman fields, reached oil production rates of 60 kbopd (gross) in May, as commissioning of the gas plant was completed. In the fourth quarter, continued strong reservoir performance and increased plant availability, following final commissioning of the FPSO secondary systems, resulted in oil plateau production rates being increased to 66 kbopd and Premier issuing the final acceptance certificate to the FPSO provider. We have safely delivered 38 Catcher cargoes since first oil.

Four further Catcher Area producer wells were drilled during 2018 with the 18th well, a Burgman field producer, completed in October. This concluded a highly successful three year drilling programme which was 33 per cent below budget and delivered well productivity on average 30 per cent higher than forecast. In addition, dynamic data continues to demonstrate good connectivity between the reservoirs and strong pressure support provided by the aquifer and injector wells. The Group remains highly encouraged about the potential overall recovery from the Catcher Area and expects to refine its estimates as more production data is obtained.

The non-operated Elgin-Franklin field (Premier 5.2 per cent non-operated interest) averaged 6.7 kboepd (net), ahead of forecast. Production was boosted by a strong performance from the new wells brought on-stream, successful remedial work on existing wells and continued high operating efficiency. At year end, Premier revised upwards its 2P reserves by 7 mmboe (net) which brings them in line with the operator's estimates and reflecting the inclusion of planned additional infill wells.

Premier's operated Huntington field (Premier 100 per cent operated interest) averaged 5.8 kboepd (net) during 2018, reflecting forecast natural decline and several unplanned shut downs. Modifications to the FPSO were made to facilitate gas import which, together with the conversion of a former production well to a water injector, has improved reservoir deliverability and plant stability. The Huntington field has continued to benefit from high operating efficiency post period end with production averaging over 6 kboepd year to date in 2019.

Production from the Premier-operated Solan field (Premier 100 per cent operated interest) averaged 4.6 kboepd, ahead of forecast, driven by high operating efficiency of over 90 per cent. Premier expects to drill a new producer (P3) in 2020 targeted at increasing production from the Central Northern part of the field. Separately, Premier continues to review the potential for third party volumes over the Solan infrastructure.

The Balmoral Area, comprising the Balmoral, Brenda, Nicol and Stirling fields, delivered 1.3 kboepd (net) in 2018 with production impacted by an extended summer maintenance shut down. Production from the Kyle field (Premier 40 per cent non-operated interest) averaged 1.6 kboepd (net). As a result of cost control and asset performance, cessation of production from the Balmoral Area has now been deferred until 2021 while the lease of the Banff FPSO, which handles Kyle's production, has been extended to August 2019. In the Southern North Sea, the Rita (Premier 74 per cent operated interest) and Hunter (Premier 79 per cent operated interest) fields ceased production in mid-2018 following closure of the Theddlethorpe gas processing terminal.

UK unit field operating costs on a per barrel of oil equivalent reduced to US$13/boe (2017: US$18/boe) while lease costs increased to US$10/boe (2017: US$5/boe). These reflect new production from the leased Catcher FPSO. In 2019, Premier expects UK operating costs (including lease costs) to remain around US$23/boe with the impact of a full year of Catcher production at increased rates offset by natural decline on more mature, fixed cost base assets such as Huntington, Kyle and the Balmoral Area.

Developments

Premier has identified several high value subsea tie-backs and infill drilling locations to maintain and extend production rates from the Catcher Area. Premier expects to sanction the development of the Catcher North and Laverda oil accumulations (Premier 50 per cent operated interest) during the first half of 2019 and, as a result, at year end 2018 booked the 3 mmboe (net) reserves associated with the two fields. The US$70 million (net) project will entail two development wells drilled from a common drill centre and tied back to the Varadero field. Drilling is scheduled to commence in mid-2020 with first oil targeted for early 2021. In addition, Premier expects to drill an infill well on the Varadero field immediately before the Catcher North and Laverda drilling programme to target resources beyond the reach of the initial production wells. Premier plans to acquire 4D seismic across the Catcher Area in the second quarter of 2020 to help confirm additional future infill well locations.

In August, Premier and its partners sanctioned the development of the Tolmount Main gas field (Premier 50 per cent operated interest) in the Southern Gas Basin. The Tolmount Main gas field is expected to produce around 500 Bcf (96 mmboe) (gross) of gas with peak production of up to 300 mmscfd (58 kboepd) (gross).

The Tolmount Main gas project is now well into its execution phase. Construction of the minimal facilities platform commenced in Rosetti Marino's Ravenna yard in December 2018 with fabrication of the primary structural steel and nodes as well as the rolling of the tubulars underway and progressing to plan. Detailed engineering and procurement of the trees, wellheads and subsea pipeline has also started. At Easington, Centrica's onshore receiving terminal, preparation for modifications required for Tolmount gas import has started and significant purchase orders are being placed for engineering work-scopes. The four well development drilling programme is scheduled to commence mid-2020 with the first well expected to come on-stream in the fourth quarter of that year. Premier continues to estimate that its share of the capex to develop Tolmount Main will be around US$120 million, comprising project management and development drilling costs, with the infrastructure joint venture between Kellas Midstream and Dana Petroleum funding the platform, pipeline and the terminal modifications.

Exploration and appraisal

Premier has contracted the Ensco 123 rig to drill the Tolmount East appraisal well in July ahead of drilling the Tolmount Main development wells in 2020. The well is targeting 220 Bcf to 300 Bcf (P50 to P10) of gross unrisked resource in an area to the east of the main Tolmount field which sits above the Tolmount Main gas water contact. On success, the Tolmount East appraisal well will be suspended for use as a future producer to be tied back to the HGS infrastructure. A 3D seismic survey across the Greater Tolmount Area is scheduled to commence later this month. The survey will be used to help optimise development drilling at Tolmount Main as well as the location of a potential Tolmount Far East exploration well, in addition to defining further prospectivity in the area.

Portfolio management

During 2018 Premier continued its programme of non-core asset disposals from the E.ON portfolio with the sale of its 30 per cent interest in the Esmond Transportation System (ETS) to Kellas Management Ltd for total cash proceeds of US$22.9 million (after working capital adjustments). Premier also completed the sale of its interests in the Babbage Area to Verus Petroleum SNS Ltd (Verus) in December 2018 receiving cash proceeds of US$38.7 million, after adjustments for Babbage cash flows collected since the effective date of 1 January 2018. The sale proceeds from both transactions were used to pay down the Company's debt.

VIETNAM

The Vietnam business unit continued to generate material free cash flow for the Group during 2018. This was driven by a strong production performance, underpinned by a better than forecast subsurface performance and sustained high operating efficiency, combined with a continued low operating cost base. On the back of this outperformance, Premier again increased its total recoverable reserves estimate to over 120 mmboe.

Production

Production from Block 12W (Premier 53.13 per cent operated interest), which contains the Chim Sáo and Dua fields, averaged 15.2 kboepd (net), up on the prior corresponding period and above budget. This strong performance was driven by high operating efficiency of the Chim Sáo FPSO and successful ongoing well intervention programmes which offset natural decline from established reservoir horizons.

The Chim Sáo and Dua fields continued to produce with a high operating efficiency of over 90 per cent during 2018 with maintenance programmes completed on schedule. Production from the fields was also boosted by four well intervention campaigns, which perforated new zones in the shallower reservoir sections of existing production wells and resulted in an additional 1 kboepd (net) of production during 2018. The two Chim Sáo infill wells, drilled and completed in December 2017, have also continued to perform strongly contributing over 1 million barrels of net oil production since coming online. As a result of this strong subsurface performance, Premier again increased its reserves estimates of Chim Sáo by 5 mmboe (net) at year end 2018.

Operating costs from Block 12W have remained low at US$5/boe while the lease cost of the FPSO averaged US$6/boe as Premier continues to maintain tight control of its cost base in Vietnam. Premier also continued to sell its Chim Sáo crude at a premium to Brent during 2018.

INDONESIA

The Premier-operated Natuna Sea Block A (NSBA) fields delivered a robust performance in 2018, underpinned by an increased market share within GSA1. This, together with continued low operating costs, led to the Indonesian business generating US$110 million of net cash flows for the Group.

Production and development

Production from Indonesia in 2018 averaged 13.2 kboepd (net) with the Natuna Sea Block A fields (Premier 28.67 per cent operated interest) delivering 12.9 kboepd (net) and the Kakap field (Premier 18.75 non-operated interest), now sold, averaging 0.3 kboepd (net).

Gas supply by contract (BBtud, gross)	**GSA1**		**GSA2**	
	2018	2017	**2018**	2017
Anoa, Pelikan	153	143	–	–
Gajah Baru, Naga	–	–	80	91
Kakap	4	17	–	–
Total	157	160	80	91

Premier sold an average of 233 BBtud (gross) (2017: 234 BBtud) from its operated Natuna Sea Block A fields during 2018.

Singapore demand for gas sold under GSA1 remained robust, averaging 292 BBtud (2017: 286 BBtud). Premier's Anoa and Pelikan fields delivered 153 BBtud (gross) (2017: 143 BBtud), capturing 52.4 per cent (2017: 49.6 per cent) of GSA1 deliveries, above Natuna Sea Block A's contractual share of 51.7 per cent. Gajah Baru and Naga delivered production of 80 BBtud (gross) (2017: 91 BBtud) under GSA2, representing 100 per cent nomination delivery by Premier. Gross liquids production from the Anoa field was 1.2 kbopd (2017: 1.1 kbopd).

Gas sales from the Kakap field averaged 4 BBtud (gross) (2017: 17 BBtud (gross)) while gross liquids production was 0.7 kbopd (2017: 2.6 kbopd). The reduction on the prior corresponding period reflects the sale of Kakap to Batavia Oil which completed in April.

Premier continues to benefit from a low cost base in Indonesia with operating costs averaging US$6.7/boe for the period.

Development

The development of the Bison, Iguana, Gajah-Pueri (BIG-P) gas fields (Premier 28.67 per cent operated interest) involves a three well subsea tie-back to existing infrastructure and is progressing to budget and to schedule. The Naga and Pelikan deck extensions and the Pelikan and AGX platform spools were successfully installed offshore during the third quarter. Fabrication of the subsea structures commenced in October and will be installed offshore along with the flowlines, flexible risers and umbilicals in mid-2019. A DSV will then complete the final hook up and tie-ins during the second half of the year. Drilling of the three BIG-P development wells is on track to commence in the first half of 2019 with first gas planned for late 2019. Once on-stream, the BIG-P gas fields will support the Group's long term gas contracts into Singapore and will help to maintain production from Natuna Sea Block A.

Exploration and appraisal

In January, Premier was awarded a 40 per cent operated interest in the Andaman II licence in the underexplored but proven North Sumatra basin offshore Aceh in the 2017 Indonesian Licence Round. PGS has commenced a 3D seismic acquisition programme designed to mature the numerous prospects and leads identified on existing 2D seismic, many of which exhibit direct hydrocarbon indicators. Drilling is targeted for late 2020. The licence has the potential to deliver significant gas volumes into North Sumatra and adds a potentially material new gas play to Premier's Indonesian portfolio.

On Natuna Sea Block A, Premier's exploration team is reprocessing existing Anoa 3D datasets and analysing production data from the WL-5X well to assess the ultimate potential of the Lama play beneath the Anoa field and to identify potential infill drilling locations within the Anoa main field.

Elsewhere in Indonesia, Premier and its joint venture partners continue to seek a farm in offer to the Tuna PSC (Premier 65 per cent operated interest) ahead of a two well campaign to appraise the Tuna field.

THE FALKLAND ISLANDS

During 2018, the focus has been on securing LOIs (Letters of Intent) with key contractors and progressing the financing structure for the first phase of the development of the Sea Lion field in the North Falklands Basin ahead of a final investment decision.

The Sea Lion project represents a material opportunity for the Group with around 400 mmboe (net to Premier) to be developed over several phases. Sea Lion Phase 1 (Premier 60 per cent operated interest) will develop over 220 mmbbls of gross resources in PL032, using a conventional FPSO based scheme, similar to Premier's successful Catcher development.

During 2018, Premier completed the selection of its key contractors and put in place LOIs for the provision of key services, including an FPSO, the drilling rig, well services, SURF, subsea production systems and installation services, as well as vendor financing. Premier is now working with its selected contractors to complete FEED and to convert the LOIs into fully termed contracts.

Premier has also continued to progress discussions with senior debt providers, including export credit finance agencies, around the funding structure of the project. In particular, Premier is preparing to submit an application for project funding once FEED has been completed, scheduled for the second quarter of 2019. In addition, it remains the Group's preference to optimise its level of participation in the project by bringing in an additional equity partner once the funding structure has been finalised.

PAKISTAN

Premier's Pakistan business continued to generate positive net cash flows for the Group, supported by high operating efficiency of over 95 per cent and a low cost base.

Production from Premier's six non-operated producing gas fields in Pakistan averaged 5.3 kboepd (2017: 6.2 kboepd) during 2018. The fall in production reflects natural decline in the main gas fields partially offset by better than expected results achieved from the new Kadanwari development wells brought onstream. Premier realised an average price of US$3.4/mscf for its Pakistani gas during the period while operating costs remained low at US$0.9/mscf (US$4.9/boe).

In April 2017, Premier announced the sale of its Pakistan business to Al-Haj Group for US$65.6 million. To date, Premier has received US$40 million of deposits from the buyer and also collected US$25 million in cash flows since the economic date of the transaction (1 January 2017). Premier expects the sale to complete on settlement of final working capital adjustments, which is scheduled for the end of the first quarter of 2019.

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EXPLORATION AND APPRAISAL

In recent years, Premier has sought to rebalance its exploration portfolio away from traditional but now mature areas to under-explored but proven hydrocarbon basins with the potential to develop into new business units over the medium term.

MEXICO

In Mexico, pre-unitisation terms were agreed by all potential partners in the Zama field and approved by the Mexican government in September. The pre-unitisation agreement provides a framework to enable the sharing of data to ensure the safe and optimal appraisal of the Zama field and, in the event a shared reservoir is proven, it establishes a defined process for the overall development of the field and the initial participation of each party.

In September, the Mexican government approved the Block 7 (Premier 25 per cent non-operated interest) appraisal programme, comprising two back-to-back wells and one side track. The first appraisal well, Zama-2, spudded to the north of the Zama discovery well at the end of November. The well penetrated 152 metres of net pay above the oil water contact and encountered a better than anticipated net to gross ratio. The rig subsequently spudded the up-dip vertical Zama-2 well side-track and has encountered the main reservoir on prognosis. A comprehensive coring programme is now being undertaken ahead of a drill stem test with the results expected in early April. The rig will then move to drill the second appraisal well (Zama-3) to evaluate the southern part of the Zama oil field. The results of the appraisal programme will feed into the early engineering work, being undertaken by McDermott and IO, and will help inform the concept select decision ahead of a final investment decision which is targeted for 2020.

In March 2018, Premier was awarded three new licences in Round 3.1, significantly enhancing the Group's acreage position offshore Mexico. Premier, together with its joint venture partners (DEA (operator) and Sapura), secured the highly contested Block 30 (Premier 30 per cent non-operated interest) which is directly to the south west of Premier's Zama discovery in the shallow water Sureste Basin. A block wide 3D seismic acquisition programme is scheduled to commence in June 2019. The programme will further define potential exploration targets, including the high impact Wahoo prospect, which exhibits a flat spot on 2D seismic analogous to the Zama discovery, and the Cabrilla prospect ahead of a drilling campaign in 2020.

Premier also secured a 100 per cent operated interest in two blocks – Blocks 11 and 13 – in the more frontier Burgos Basin, which is directly inboard from the deep water Perdido fold belt. An environmental baseline study across the two blocks was completed in 2018 and the forward plan is to reprocess existing 3D seismic during 2019 with the aim of identifying potential drilling targets.

On Block 2 (Premier 10 per cent non-operated interest) in the Sureste Basin, Premier's option to participate and convert its carried 10 per cent interest to a paying interest of up to 25 per cent equity or to withdraw was triggered in

May 2018. Premier has opted to exit and received final government approval for its withdrawal from the block in February 2019.

BRAZIL

Premier has continued to take an operational lead for environmental licensing and well planning in the offshore Ceará Basin, where the Group plans to drill two wells in 2020.

In the first quarter of 2018 Premier secured approval from the ANP to replace the two well commitment on its operated Block 717 (Premier 50 per cent operated interest) with a single deeper well targeting the stacked Berimbau and Maraca prospects. Premier intends to drill this well in the first half of 2020 as part of a two well campaign with Block 661 (Premier 30 per cent non-operated interest). The 661 well will test the Itarema and Tatajuba prospects. The two wells combined will test in excess of 500 mmbbls of gross prospective resource.

Having matured and evaluated the prospectivity on Block 665 (Premier 50 per cent operated interest) utilising the high quality 3D seismic acquired by Premier and its partner, the decision has been taken to relinquish the licence at the end of the initial term in July 2019.

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FINANCIAL REVIEW

Overview

2018 saw continuing oil price volatility. Brent crude opened the year at US$66.9/bbl, rising to US$86.2/bbl in October before then weakening considerably towards the end of the year to close at US$50.2/bbl at 31 December 2018, which was the lowest observed price in 2018. The average for 2018 was US$71.4/bbl against US$54.2/bbl for 2017. Subsequent to the year-end, prices have strengthened and averaged US$62/bbl in January and February 2019.

Against this economic backdrop we have achieved our best ever full year of production, averaging 80.5 kboepd (2017: 75.0 kboepd), resulting in total revenue from all operations of US$1,438.3 million compared with US$1,102 million in 2017. In addition, we have reduced Net Debt to US$2,330.7 million, following the successful conversion of the Group's convertible bond notes during the year and strong cash flow generation.

Business performance

EBITDAX for the year from continuing operations was US$882.3 million compared to US$589.7 million for 2017. The increase in EBITDAX is mainly due to higher production and realised prices during the year.

Business Performance (continuing operations)	**2018 $ million**	2017 $ million
Operating profit	**531.0**	33.8
Add: Depreciation, depletion, amortisation and impairment	**358.4**	667.8
Add: Exploration expense and pre-licence costs	**35.2**	17.1
Less: Gain on disposal of assets	**(42.3)**	(129.0)
EBITDAX	**882.3**	589.7

Income statement

Production and commodity prices

Group production on a working interest basis averaged 80.5 kboepd compared to 75.0 kboepd in 2017. This was driven by a full year of production from the Catcher field which achieved first oil in December 2017 and outperformance from the Chim Sáo field. Average entitlement production for the period was 73.8 kboepd (2017: 69.2 kboepd).

Premier realised an average oil price for the year of US$67.9/bbl (2017: US$52.9/bbl). Including the effect of oil swaps which settled during 2018, the realised oil price was US$63.5/bbl (2017: US$52.1/bbl). In the UK, average natural gas prices achieved were 57 pence/therm (2017: 47 pence/therm), which included 58.2 million therms which were sold under fixed price master sales agreements. Gas prices in Singapore, linked to high sulphur fuel oil ('HSFO') pricing and in turn, therefore, linked to crude oil pricing, averaged US$11.2/mscf (2017: US$8.4/mscf).

Realised prices	2018	2017
Oil price (US$/bbl) post hedging	**63.5**	52.1
UK natural gas (pence/therm)	**57**	47
Singapore HSFO (US$/mscf)	**11.2**	8.4

Total revenue from all operations (including Pakistan) increased to US$1,438.3 million (2017: US$1,102 million). From continuing operations (excluding Pakistan), sales revenue increased to US$1,397.5 million from US$1,043.1 million for the prior year.

Cost of operations

Cost of operations comprises operating costs, changes in lifting positions, inventory movements and royalties. Cost of operations for the Group from continuing operations was US$500.0 million for 2018, compared to US$455.4 million for 2017.

Operating Costs	2018 $ million	2017 $ million
Continuing operations	**487.5**	438.4
Discontinuing operations (Pakistan)	**9.5**	9.6
Operating costs	**497.0**	448.0
Operating costs per barrel	**16.9**	16.4

Amortisation and depreciation of oil and gas properties	2018 $ million	2017 $ million
Continuing operations	**386.5**	409.0
Discontinuing operations (Pakistan)	**-**	7.2
Total	**386.5**	416.2
Depreciation, depletion and amortisation (‘DD&A’) per barrel	**13.2**	15.2

The increase in absolute operating costs reflects a full year production contribution from the Catcher field. Ongoing cost reduction initiatives, successful contract renegotiations and strict management of discretionary spend continue to deliver low and stable operating costs. Full year 2018 total operating costs were below the low end of US$17-US$18/boe guidance at US$16.9/boe (2017: US$16.4/bbl). The DD&A charge has reduced to US$13.2/bbl (2017: US$15.2/bbl).

Impairment of oil and gas properties

A non-cash net impairment reversal credit of US$35.2 million (pre-tax) (US$25.0 million post-tax) has been recognised in the income statement. This relates to the Solan field in the UK North Sea as a result of a reduction in the expected gross decommissioning cost attributable to the asset, giving rise to a reversal of previously recognised impairment of US$55.7 million. This reversal has been partially offset by an impairment charge of US$20.5 million for the Huntington asset. After recognition of the net impairment charge there is US$2,245.6 million capitalised in relation to PP&E assets and US$240.8 million for goodwill.

Exploration expenditure and pre-licence costs

Exploration expense and pre-licence expenditure costs amounted to US$35.2 million (2017: US$17.1 million), primarily relating to historical costs incurred on the Block 2 licence in Mexico, the Sunbeam prospect in the UK and Block 665 licence in Brazil. After recognition of these expenditures, the exploration and evaluation assets remaining on the balance sheet at 31 December 2018 amount to US$812.6 million, principally for the Sea Lion asset and our share of the Zama prospect and Block 30 in Mexico. US$224.5 million of costs in relation to the Tolmount project previously recognised within exploration assets, which mostly represents fair value allocated to the project on acquisition from E.ON, have been reclassified to PP&E in the year following sanction of the project in 2018.

General and administrative expenses

Net G&A costs of US$14.0 million (2017: US$16.8 million) were comparable with the prior year.

Finance gains and charges

Net finance gains and charges of US$372.8 million, have increased compared to the prior year (US$316.4 million). The step up in the interest margin on our financing facilities following the completion of the refinancing in July 2017 has been partially offset by a reduction in the fair value of the Group's outstanding equity and synthetic warrants to US$31.8 million from US$59.8 million at 31 December 2017. Cash interest expense in the period was US$228.7 million (2017: US$223.7 million).

Taxation

The Group's total tax charge for 2018 from continuing operations is US$53.1 million (2017: credit of US$96.1 million) which comprises a current tax charge for the period of US$90.6 million and a non-cash deferred tax credit for the period of US$37.5 million.

The total tax charge represents an effective tax rate of 33.5 per cent (2017: 26.2 per cent). The effective tax rate for the year is primarily impacted by three specific UK deferred tax items. The first is the impact of ring fence expenditure supplement claims in the UK during the year (US$76.6 million credit). The second is the impact of the Babbage disposal resulting in a clawback of UK tax allowances (US$30.4 million charge) and the third is foreign exchange movements on historical deferred tax balances (US$17.8 million charge). After adjusting for the net impact of the above items of US$28.4 million, the underlying Group tax charge for the period is US$81.5 million and an effective tax rate of 51.5 per cent.

The Group has a net deferred tax asset of US$1,294.6 million at 31 December 2018 (2017: US$1,297.5 million), which is broadly comparable with the prior year.

Profit after tax

Profit after tax is US$133.4 million (2017: loss of US$253.8 million) resulting in a basic earnings per share of 17.3 cents from continuing and discontinued operations (2017: loss of 49.4 cents). The profit after tax in the year is driven principally by the increased sales revenue and consequent impact on operating profits.

Cash flows

Cash flow from operating activities was US$777.2 million (2017: US$475.3 million) after accounting for tax payments of US$128.8 million (2017: US$69.6 million) and before the movement in joint venture cash balances in the period of US$54.4 million. The increase in operating cash flows was largely driven by higher production, sales volumes and realised prices.

Capital expenditure in 2018 totalled US$279.8 million (2017: US$275.6 million).

Capital expenditure	**2018 $ million**	2017 $ million
Fields/development projects	**234.3**	236.8
Exploration and evaluation	**43.6**	37.6
Other	**1.9**	1.2
Total	**279.8**	275.6

The principal development project was the Catcher field in the UK. The majority of exploration spend was related to the commencement of the appraisal drilling programme on the Zama prospect in Mexico and the licence payment on Block 30. In addition, cash expenditure for decommissioning activity in the period was US$72.7 million (2017: US$25.7 million). Further to this, US$17.7 million (2017: US$16.7 million) of cash was placed into long-term abandonment escrow accounts for future decommissioning activities.

Total 2019 development and exploration capex is expected to be US$290 million of which c. US$70 million relates to the BIG-P development and c. US$100 million to exploration and appraisal (including US$60 million for the Zama appraisal programme and US$20 million for the Tolmount East appraisal well). Abandonment spend in 2019 is expected to be US$50 million, before taking into account the benefits of tax relief, and primarily relates to abandonment activities in the UK North Sea.

Discontinued operations, disposals and assets held for sale

During the year, Premier completed the previously announced sales of its interests in the Babbage field in the UK, the Kakap field in Indonesia and its 30 per cent non-operated interest in the Esmond Transportation System (ETS). A net gain on disposal of US$42.3 million has been recognised in the period.

During 2018, Premier received a further US$10 million cash deposit from Al-Haj, in addition to the US$25 million deposit received in 2017. Due to the expectation of the completion of the disposal, the business unit continued to be classified as a disposal group held for sale and presented separately in the current and prior year balance sheet. Results for the disposal group in both the current and prior periods have been presented as a discontinued operation. Subsequent to the year-end, Premier received a further US$5 million deposit from Al-Haj, bringing total cash received to date of US$40 million, against the headline consideration of US$65.6 million.

Balance sheet position

Net debt

Net debt at 31 December 2018 amounted to US$2,330.7 million (31 December 2017: US$2,724.2 million), with cash resources of US$244.6 million (31 December 2017: US$365.4 million). The maturity of all of Premier's facilities at year-end is May 2021.

Following completion of the Wytch Farm disposal in December 2017, net cash proceeds received of US$176 million were used to pay down and cancel the equivalent value of the RCF debt facility in January 2018. Furthermore, the total available RCF facility was reduced by a further US$39 million in December 2018 by the cash proceeds received from the Babbage disposal. Following these two disposals, the total available RCF facility reduced from US$2,050 million to US$1,835 million at year-end.

In January 2018, Premier invited convertible bondholders to exercise their exchange rights in respect of any and all of their bonds. 87.5 per cent or US$205.8 million of the US$235.2 million bonds outstanding were accepted for early exchange with an incentive amount of US$50 per US$1,000 in principal of bonds. The exchange resulted in the issue of 231,882,091 Ordinary Shares, which included 7,578,343 incentive shares. Completion of this offer, resulted in a remaining convertible bond liability of US$28.8 million.

Following this, in July 2018, the Group announced its intention to exercise the mandatory conversion option in the remaining outstanding convertible bonds. The exercise of this option converted all of the remaining US$28.8 million outstanding convertible bonds into approximately 31.4 million new Ordinary Shares of Premier. This resulted in Premier's convertible bond liability being fully extinguished in September 2018.

At 31 December 2018, after the exclusion of US$30.2 million of cash held on behalf of our JV partners, Premier retained cash of US$214.4 million. Combined with undrawn facilities of US$355.2 million, the Group had liquidity of US$569.6 million at the year-end (31 December 2017: US$541.2 million). Subsequent to the year-end, in January 2019, a further US$100.3 million of the Group's RCF debt facility was cancelled by Premier, which will result in reduced commitment fee costs for the Group in 2019.

Provisions

The Group's decommissioning provision decreased to US$1,214.5 million at 31 December 2018, down from US$1,432.1 million at the end of 2017. The reduction is driven by a reduction in the forecast for the gross cost estimate for the Solan asset and expenditure in the year.

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 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 took advantage of the improved oil price environment observed at times during 2018 to increase its hedging position in 2019 and 2020 to protect future free cash flows and covenant compliance. The Group's current hedge position to the end of 31 December 2019 is as follows:

Oil swaps/forwards	2019 1H	2019 2H
Volume (mmbbls)	3.77	3.84
Average price	68.5	69.2

The fair value of open oil swaps at 31 December 2018 was an asset of US$102.0 million (2017: liability of US$31.7 million), which is expected to be released to the income statement during 2019 as the related barrels are lifted. During

2018, forward oil swaps of 5.9 mmbbls expired resulting in a net charge of US$71.2 million (2017: US$11.4 million) which has been included in sales revenue for the year.

In addition, the Group currently has forward UK gas sales of 48.8 mm therms at an average price of 61 pence/therm that will be physically settled during 2019. Furthermore, Premier has hedged part of its Indonesian gas production through the sale of 330,000 MT of HSFO Sing 180 in 2019 and 2020 at an average price of US$378/MT.

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$17.2 million on its outstanding foreign exchange contracts (2017: gain of US$32.5 million). The Group currently has £150.0 million 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:€.

Interest rates

The Group has various financing instruments including senior loan notes, convertible bonds, UK retail bonds, term loans and revolving credit facilities. Currently, approximately 60 per cent of total borrowings are fixed or have been fixed using interest rate options. On average, the cost of drawn funds for the year was 7.6 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 2018, US$1.4 million of cash proceeds were received (net to Premier) in relation to settled insurance claims (2017: US$7.2 million).

Going concern

The Group monitors its funding position and its liquidity risk throughout the year to ensure 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.

Management's base case forecast assumes an oil price of US$60/bbl and US$65/bbl in 2019 and 2020, respectively and production in line with prevailing rates. The Group has run downside scenarios, where oil and gas prices are reduced by a flat US$5/bbl throughout the going concern period and where total group production is forecast to reduce by 10 per cent.

At 31 December 2018 the Group continued to have significant headroom on its financing facilities and cash on hand. The base case forecasts show that the Group will have sufficient financial headroom for the 12 months from the date of approval of the 2018 Annual Report and Accounts. In the downside scenarios ran, no covenant breach is forecasted in the going concern period. If more severe sustained downside cases were to materialise then, in the absence of any mitigating actions, a breach of one or more of the financial covenants may arise during the 12 month going concern assessment period. Potential mitigating actions could include further non-core asset disposals, additional hedging activity or deferral of expenditure.

Accordingly, after making enquiries and considering the risks described above, the Directors have a reasonable expectation that the Company has adequate resources to continue in operational existence for the foreseeable future. Accordingly, the Directors continue to adopt the going concern basis of accounting in preparing these consolidated financial statements.

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:

- Further oil price weakness and volatility.
- Underperformance of Catcher asset.
- Failure to maintain schedule of Tolmount project.
- Negative drilling results from key appraisal assets.
- Ability to fund existing and planned growth projects.
- Breach of banking covenants if oil prices fall or assets underperform.
- Timing and uncertainty of decommissioning liabilities.
- Continued ability to maintain core competencies.
- Political and security instability in countries of current and planned activity.
- Rising costs if oil prices recover could limit access to services.

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

PremierOil

Full Year Results for the year ended 31 December 2018

Consolidated Income Statement
For the year ended 31 December 2018

	2018 $ million	2017 $ million
Continuing operations		
Sales revenues	**1,397.5**	1,043.1
Other operating (costs)/income	**(1.2)**	18.8
Costs of operation	**(500.0)**	(455.4)
Depreciation, depletion, amortisation and impairment	**(358.4)**	(667.8)
Exploration expense and pre-licence costs	**(35.2)**	(17.1)
Profit on disposal of non-current assets	**42.3**	129.0
General and administration costs	**(14.0)**	(16.8)
Operating profit	**531.0**	33.8
Interest revenue, finance and other gains	**27.8**	12.6
Finance costs, other finance expenses and losses	**(400.6)**	(329.0)
Loss on substantial modification	**-**	(83.7)
Profit/(loss) before tax from continuing operations	**158.2**	(366.3)
Tax (charge)/credit	**(53.1)**	96.1
Profit/(loss) for the year from continuing operations	**105.1**	(270.2)
Discontinued operations		
Profit for the year from discontinued operations	**28.3**	16.4
Profit/(loss) after tax	**133.4**	(253.8)
Earnings/(loss) per share (cents):		
From continuing operations		
Basic	**13.6**	(52.6)
Diluted	**12.2**	(52.6)
From continuing and discontinued operations		
Basic	**17.3**	(49.4)
Diluted	**15.5**	(49.4)

Consolidated Statement of Comprehensive Income
For the year ended 31 December 2018

	2018 $ million	2017 $ million
Profit/(loss) for the year	**133.4**	(253.8)
Cash flow hedges on commodity swaps:		
Gains/(losses) arising during the year	**85.7**	(25.6)
Add: reclassification adjustments for losses in the year	**71.2**	11.4
	156.9	(14.2)
Cash flow hedges on interest rate and foreign exchange swaps:		
Gains/(losses) arising during the year	**21.5**	(33.9)
Less: reclassification adjustments for (gains)/losses in the year	**(11.4)**	23.1
	10.1	(10.8)
Tax relating to components of other comprehensive income	**(33.8)**	7.5
Exchange differences on translation of foreign operations	**7.4**	(4.9)
Other comprehensive income/(expense)	**140.6**	(22.4)
Total comprehensive income/(expense) for the year	**274.0**	(276.2)

All comprehensive income is attributable to the equity holders of the parent.

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Full Year Results for the year ended 31 December 2018

Consolidated Balance Sheet
As at 31 December 2018

	2018 $ million	2017 $ million
Non-current assets:		
Intangible exploration and evaluation assets	**812.6**	1,061.9
Property, plant and equipment	**2,245.6**	2,381.0
Goodwill	**240.8**	240.8
Long-term receivables	**159.8**	160.8
Deferred tax assets	**1,434.1**	1,461.5
	4,892.9	5,306.0
Current assets:		
Inventories	**12.5**	13.5
Trade and other receivables	**282.3**	340.6
Derivative financial instruments	**127.4**	14.5
Cash and cash equivalents	**244.6**	365.4
Assets held for sale	**55.2**	96.6
	722.0	830.6
Total assets	**5,614.9**	6,136.6
Current liabilities:		
Trade and other payables	**(375.6)**	(572.9)
Short-term provisions	**(46.0)**	(91.2)
Derivative financial instruments	**(41.4)**	(99.8)
Deferred income	**(11.0)**	(13.1)
Liabilities directly associated with assets held for sale	**(21.9)**	(46.6)
	(495.9)	(823.6)
Net current assets	**226.1**	7.0
Non-current liabilities:		
Long-term debt	**(2,552.0)**	(2,972.6)
Deferred tax liabilities	**(139.5)**	(164.0)
Deferred income	**(76.0)**	(80.3)
Derivative financial instruments	**(129.4)**	(108.3)
Long-term provisions	**(1,196.1)**	(1,370.9)
	(4,093.0)	(4,696.1)
Total liabilities	**(4,588.9)**	(5,519.7)
Net assets	**1,026.0**	616.9
Equity and reserves:		
Share capital	**154.2**	109.0
Share premium account	**491.7**	284.5
Other reserves	**380.1**	223.4
	1,026.0	616.9

Consolidated Statement of Changes in Equity

For the year ended 31 December 2018

	Share capital $ million	Share premium account $ million	Other reserves $ million	Total $ million
At 1 January 2017	106.7	275.4	427.0	809.1
Issue of Ordinary Shares	2.3	9.1	1.1	12.5
Purchase of ESOP Trust shares	-	-	(0.2)	(0.2)
Provision for share-based payments	-	-	14.5	14.5
Incremental equity component of revised convertible bonds	-	-	57.2	57.2
Loss for the year	-	-	(253.8)	(253.8)
Other comprehensive expense	-	-	(22.4)	(22.4)
At 31 December 2017	109.0	284.5	223.4	616.9
Adjustment on adoption of IFRS 9[1]	-	-	(82.0)	(82.0)
At 1 January 2018	109.0	284.5	141.4	534.9
Issue of Ordinary Shares	45.2	207.2	7.7	260.1
Purchase of ESOP Trust shares	-	-	(1.5)	(1.5)
Provision for share-based payments	-	-	14.6	14.6
Conversion of convertible bonds	-	-	(56.1)	(56.1)
Profit for the year	-	-	133.4	133.4
Other comprehensive income	-	-	140.6	140.6
At 31 December 2018	**154.2**	**491.7**	**380.1**	**1,026.0**

[1] As described in note 1.

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Full Year Results for the year ended 31 December 2018

Consolidated Cash Flow Statement
For the year ended 31 December 2018

	2018 $ million	2017 $ million
Net cash from operating activities	**722.8**	496.0
Investing activities:		
Capital expenditure	**(279.8)**	(275.6)
Decommissioning pre-funding	**(17.8)**	(16.7)
Decommissioning expenditure	**(72.7)**	(25.7)
Proceeds from disposal of oil and gas properties	**73.4**	202.3
Net cash used in investing activities	**(296.9)**	(115.7)
Financing activities:		
Issuance of Ordinary shares	**13.8**	0.8
Net purchase of ESOP Trust shares	**(1.5)**	(0.2)
Proceeds from drawdown of long-term bank loans	**105.0**	45.0
Repayment of long-term bank loans	**(415.3)**	-
Debt arrangement fees	**-**	(86.0)
Interest paid	**(228.7)**	(223.7)
Net cash from financing activities	**(526.7)**	(264.1)
Currency translation differences relating to cash and cash equivalents	**(20.0)**	(6.7)
Net (decrease)/increase in cash and cash equivalents	**(120.8)**	109.5
Cash and cash equivalents at the beginning of the year	**365.4**	255.9
Cash and cash equivalents at the end of the year	**244.6**	365.4

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
For the year ended 31 December 2018

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 6 March 2019.

The financial information for the year ended 31 December 2018 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 2017 were approved by the Board of Directors on 7 March 2018 and delivered to the Registrar of Companies and those for 2018 will be delivered following the Company's Annual General Meeting ('AGM'). The auditor has reported on the 2018 accounts and their audit report was unqualified.

Basis of preparation

The financial information has been prepared in accordance with the recognition and measurement criteria of International Financial Reporting Standards ('IFRS') adopted for use in the European Union. However, this announcement does not itself contain sufficient information to comply with IFRS. The Company will publish full financial statements that comply with IFRS in April 2019.

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.

Accounting Policies

The accounting policies applied in these condensed financial statements are consistent with those of the annual financial statements for the year ended 31 December 2017, as described in those annual financial statements, except for the adoption of IFRS 9 Financial Instruments and IFRS 15 Revenue from Contracts with Customers.

1. General information *(continued)*

IFRS 9 'Financial Instruments'

The overall impact on transition to IFRS 9 was an US$82 million increase in long-term debt and corresponding reduction in net assets. This adjustment relates entirely to an adjustment to the Group's accounting for its refinancing that completed in July 2017. On adoption of IFRS 9, additional interest charges for facilities that were not deemed to be substantially modified have been expensed at the point of completion of the refinancing. Under the previous accounting policies these additional interest charges had been expected to be amortised to the income statement on an effective interest rate basis over the life of the facilities. Under IFRS 9, this would have increased the interest charge recognised in 2017 by US$82 million, with a corresponding reduction in net assets at 31 December 2017. Going forward, this reduces Premier's forecast interest charges by c. US$20 million per annum. The impact on the current period balance sheet is to increase long-term debt and reduce retained earnings by US$82 million. As permitted by IFRS 9 comparatives have not been restated.

For certain line items in the balance sheet the closing balance at 31 December 2017 as previously reported and the opening balance at 1 January 2018 therefore differ (see statement of changes in equity). The Group's accounting policy has been revised to reflect the requirements of IFRS 9. However, excluding the impact on the accounting treatment applied to the Group's 2017 refinancing, the Standard has not had a significant impact. The Group's accounting policy for IFRS 9 is set out below:

(a) Classification of financial assets and financial liabilities

IFRS 9 requires the use of two criteria to determine the classification of financial assets: the entity's business model for the financial assets and the contractual cash flow characteristics of the financial assets. The Standard goes on to identify three categories of financial assets - amortised cost; fair value through profit or loss (FVTPL); and fair value through other comprehensive income (FVOCI). The accounting for the Group's financial liabilities remains largely the same as it was under IAS 39. Similar to the requirements of IAS 39, IFRS 9 requires contingent consideration liabilities to be treated as financial instruments measured at fair value, with the changes in fair value recognised in the statement of profit or loss.

Under IFRS 9, embedded derivatives are no longer separated from a host financial asset. Instead, financial assets are classified based on their contractual terms and the Group's business model. The accounting for derivatives embedded in financial liabilities and in non-financial host contracts has not changed from that required by IAS 39.

1. General information *(continued)*

(b) Impairment

IFRS 9 mandates the use of an expected credit loss model to calculate impairment losses rather than an incurred loss model, and therefore it is not necessary for a credit event to have occurred before credit losses are recognised. The new impairment model applies to the Group's financial assets and loan commitments. No changes to the impairment provisions were made on transition to IFRS 9.

The IFRS 9 impairment model requiring the recognition of 'expected credit losses', in contrast to the requirement to recognise 'incurred credit losses' under IAS 39, has not had a material impact on the Group's financial statements.

Trade receivables are generally settled on a short time frame and the Group's other financial assets are due from counterparties without material credit risk concerns at the time of transition.

(c) Hedge accounting

The hedge accounting requirements of IFRS 9 have been simplified and are more closely aligned to an entity's risk management strategy. Under IFRS 9 all existing hedging relationships will qualify as continuing hedging relationships and the Group also intends to apply hedge accounting prospectively to certain of its commodity price risk management activities for which hedge accounting was not possible under IAS 39. This had no impact on the 2018 opening balance sheet.

IFRS 15 'Revenue from Contracts with Customers'

Premier has elected to apply the 'modified retrospective' approach to transition permitted by IFRS 15 under which comparative financial information is not restated. The Standard did not have a material effect on the Group's financial statements as at 1 January 2018 and so no transition adjustment has been made. The standard has not had a material impact on the Group's accounting policy in respect to revenue as previously disclosed in the 2017 financial statements.

Revenue from contracts with customers for the 2018 period is presented in Note 2. Amounts presented for comparative periods in 2017 include revenues determined in accordance with the Group's previous accounting policies relating to revenue. The total amounts presented do not, therefore, represent the revenue from contracts with customers that would have been reported for those periods had IFRS 15 been applied using a fully retrospective approach to transition but the differences are not material.

The Group's accounting policy for IFRS 15 is set out below:

1. General information *(continued)*

Under IFRS 15, revenue from contracts with customers is recognized when or as the Group satisfies a performance obligation by transferring a promised good or service to a customer. A good or service is transferred when the customer obtains control of that good or service. The transfer of control of oil, natural gas, natural gas liquids, and other items sold by the Group usually coincides with title passing to the customer and the customer taking physical possession. The Group principally satisfies its performance obligations at a point in time and the amounts of revenue recognized relating to performance obligations satisfied over time are not significant.

A number of additional new standards, amendments to existing standards and interpretations were effective from 1 January 2018. The adoption of these amendments did not have a material impact on the Group's condensed financial statements for the year ended 31 December 2018.

There are also a number of amendments to accounting standards and new interpretations issued by the International Accounting Standards Board which will be applicable from 1 January 2019 onwards. These are not expected to have a material impact on the accounting policies, methods of computation or presentation applied by the Group, except for IFRS 16 Leases.

Further details on new International Financial Reporting Standards adopted and yet to be adopted will be disclosed in the 2018 Annual Report and Accounts.

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 are reported as a discontinued operation.

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.

	2018 $ million	2017 $ million
Revenue:		
Indonesia	**192.8**	171.8
Vietnam	**272.4**	210.7
United Kingdom	**931.5**	655.9
Rest of the World[1]	**0.8**	4.7
Total Group sales revenue	**1,397.5**	1,043.1
Other operating income - United Kingdom	**-**	18.8
Interest and other finance revenue	**7.6**	1.7
Total Group revenue from continuing operations	**1,405.1**	1,063.6
Group operating profit:		
Indonesia	**111.8**	65.3
Vietnam	**142.2**	82.6
United Kingdom	**326.2**	(86.4)
Rest of the World[1]	**(29.6)**	(5.0)
Unallocated[2]	**(19.6)**	(22.7)
Group operating profit	**531.0**	33.8
Interest revenue, finance and other gains	**27.8**	12.6
Finance costs and other finance expenses	**(400.6)**	(329.0)
Loss on substantial modification	**-**	(83.7)
Profit/(loss) before tax from continuing operations	**158.2**	(366.3)
Tax	**(53.1)**	96.1
Profit/(loss) after tax from continuing operations	**105.1**	(270.2)
Profit from discontinued operations	**28.3**	16.4

2. Operating segments *(continued)*

	2018 $ million	2017 $ million
Balance sheet		
Segment assets:		
Falkland Islands	**648.1**	633.1
Indonesia	**417.7**	440.4
Vietnam	**312.0**	374.4
United Kingdom	**3,706.1**	4,116.2
Rest of the World	**103.8**	96.0
Assets held for sale	**55.2**	96.6
Unallocated[2]	**372.0**	379.9
Total assets	**5,614.9**	6,136.6
Liabilities:		
Falkland Islands	**(12.8)**	(8.2)
Indonesia	**(174.0)**	(223.9)
Vietnam	**(174.1)**	(203.4)
United Kingdom	**(1,431.9)**	(1,802.1)
Rest of the World	**(51.4)**	(54.8)
Liabilities directly associated with assets held for sale	**(21.9)**	(46.6)
Unallocated[2]	**(2,722.8)**	(3,180.7)
Total liabilities	**(4,588.9)**	(5,519.7)
Other information		
Capital additions and acquisitions:		
Falkland Islands	**15.1**	12.9
Indonesia	**24.5**	7.4
Pakistan	**4.1**	10.5
Vietnam	**(0.1)**	20.2
United Kingdom[4]	**(50.3)**	444.3
Rest of the World[1]	**37.2**	25.3
Total capital additions and acquisitions	**30.5**	520.6

2. Operating segments *(continued)*

	2018 $ million	2017 $ million
Depreciation, depletion, amortisation and impairment:		
Indonesia	**46.6**	57.2
Vietnam	**55.6**	64.5
United Kingdom	**254.8**	542.9
Rest of the World[1]	**1.4**	3.2
Total DD&A and impairment (continuing operations)	**358.4**	667.8
Total DD&A and impairment (discontinued operations)	**-**	7.3

1 Segmental income, assets, liabilities and capital additions for Mauritania have been included within the Rest of the World.

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, pre-licence exploration costs, cash and cash equivalents, mark-to market valuations of commodity contracts and interest rate swaps and options, convertible bonds, warrants and other long-term debt.

3 Depreciation, depletion and amortisation for the Pakistan business unit was charged until 30 June 2017, which was the date of reclassification of an asset held for sale.

4 Includes revisions to decommissioning estimates in the year

Out of the total Group worldwide sales revenues of US$1,397.5 million (2017: US$1,043.1 million), revenues of US$931.5 million (2017: US$655.9 million) arose from sales of oil and gas to customers located in the UK. Included within the total revenues were revenues of US$1,468.7 million (2017: US$1,054.4 million) from contracts with customers. This was offset by hedging losses of US$71.2 million (2017: US$11.3 million).

Included in assets arising from the United Kingdom segment are non-current assets (excluding deferred tax assets) of US$2,090.5 million (2017: US$2,455.7 million) located in the UK. Included in depreciation, depletion, amortisation and impairment is a net impairment credit in relation to the UK of US$35.2 million (2017: US$252.2 million net charge).

Revenue from three customers (2017: three customers) each exceeded 10 per cent of the Group's consolidated revenue. Sales to two customers in the UK amounted to US$454.7 million (2017: two customers US$361.7 million). Sales to one customer in Indonesia totalled US$186.5 million (2017: one customer amounting to US$168.3 million).

3. Cost of operation

	2018 **$ million**	2017 $ million
Operating costs	**487.5**	438.4
Gas purchases	**9.6**	5.5
Stock overlift/underlift movement	**(11.1)**	1.3
Royalties	**14.0**	10.2
	500.0	455.4

4. Tax

	2018 **$ million**	2017 $ million
Current tax:		
UK corporation tax on profits	**(23.2)**	(0.8)
UK petroleum revenue tax	**-**	(8.2)
Overseas tax	**120.7**	75.6
Adjustments in respect of prior years	**(6.9)**	8.2
Total current tax	**90.6**	74.8
Deferred tax:		
UK corporation tax	**(13.5)**	(146.2)
Overseas tax	**(24.0)**	(24.7)
Total deferred tax	**(37.5)**	(170.9)
Tax charge/(credit) on profit/(loss) on ordinary activities	**53.1**	(96.1)

4. Tax *(continued)*

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

	2018 $ million	2017 $ million
Group profit/(loss) on ordinary activities before tax	**158.2**	(366.3)
Group profit/(loss) on ordinary activities before tax at 44.7% weighted average rate (2017: 29.1%)	**70.8**	(106.6)
Tax effects of:		
Income/expenses that are not taxable/deductible in determining taxable profit	**(8.7)**	40.6
Financing costs disallowed for UK supplementary charge	**22.6**	16.4
Non-deductible field expenditure	**6.1**	36.1
Tax and tax credits not related to profit before tax (mainly Ring Fenced Expenditure Supplement)	**(46.1)**	(69.9)
Group relief	**2.7**	-
Unrecognised tax losses	**14.8**	6.1
Effect of change in foreign exchange	**17.8**	-
Adjustments in respect of prior years	**(31.2)**	(3.2)
Utilisation and recognition of tax losses not previously recognised	**-**	(0.8)
Effect of differences in tax rates	**(0.4)**	(0.5)
Recognition that decommissioning provision will unwind at 50%	**4.7**	(14.3)
Tax charge/(credit) for the year	**53.1**	(96.1)
Effective tax rate for the year	**33.5%**	26.2%

The UK deferred tax credit arises due to ring fence expenditure supplement and is offset by other items impacting deferred tax. The overseas deferred tax credit arises on fixed asset balances.

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 55 per cent), assumptions around future oil prices and changes to tax rates and legislation.

5. Discontinued operations, disposals and assets held for sale

	2018 **$ million**	2017 $ million
Assets held for:		
Pakistan Business Unit	**55.2**	52.2
Esmond Transportation System ('ETS')	**-**	27.0
Kakap field	**-**	17.4
Total assets classified as held for sale	**55.2**	96.6
Liabilities held for:		
Pakistan Business Unit	**(21.9)**	(25.4)
Esmond Transportation System ('ETS')	**-**	(7.0)
Kakap field	**-**	(14.2)
Total liabilities classified as held for sale	**(21.9)**	(46.6)

Disposals

During the period, Premier completed the previously announced sales of its interest in the Kakap field, its 30 per cent non-operated interest in the Esmond Transportation System ('ETS') and its interest in the Babbage Area. A net gain for these disposals has been recognised in the income statement for the year. The gain recognised has been partially offset by a charge of US$5.6 million due to a write-off of a contingent consideration receivable from Kris Energy in relation to the Aceh disposal by Premier in 2014.

Discontinued operations – Pakistan Business Unit

In April 2017, Premier announced it had reached agreement and signed an SPA with Al-Haj Energy Limited ('Al-Haj') for the sale of Premier Oil Pakistan Holdings BV, which comprises Premier's Pakistan Business Unit, for a cash consideration of US$65.6 million. During the year, Al-Haj paid a deposit to Premier of US$10.0 million, on top of the US$25.0 million deposit received in 2017.

The disposal of the Pakistan Business Unit is expected to complete in 2019 and, as this is within 12 months of the balance sheet date, the business unit continued to be classified as a disposal group held for sale in the year-end balance sheets.

5. Discontinued operations, disposals and assets held for sale *(continued)*

The results of the disposal group which have been included as discontinued operations in the consolidated income statement were as follows:

	2018 $ million	2017 $ million
Revenue	**40.8**	40.8
Expenses	**(15.0)**	(22.4)
Profit before tax	**25.8**	18.4
Attributable tax credit/(charge)	**2.5**	(2.0)
Net profit for the period from discontinued operations	**28.3**	16.4

During the year to 31 December 2018, the Pakistan disposal group contributed US$29.0 million (2017 US$16.8 million) to the Group's net operating cash flows and paid US$5.0 million (2017 US$6.8 million) in respect of investing activities). There were no financing cash flows in either the current or the prior years.

The effect of the disposal group on segments results is disclosed in note 2. The major classes of assets and liabilities comprising the disposal group classified as held for sale are as follows:

	2018 $ million	2017 $ million
Property, plant and equipment	**27.6**	23.3
Long-term receivables	**0.2**	0.4
Deferred tax asset	**1.9**	0.8
Inventory	**8.2**	9.0
Trade and other receivables	**16.8**	17.8
Cash	**0.5**	0.9
Pakistan assets classified as held for sale	**55.2**	52.2
Trade and other payables	**(5.2)**	(7.8)
Long-term provisions	**(16.7)**	(17.6)
Pakistan liabilities classified as held for sale	**(21.9)**	(25.4)
Net assets of disposal group	**33.3**	26.8

Following completion of the disposal, Premier will retain a provision of US$16.4 million for potential costs in relation to the business unit for the period of ownership by Premier prior to the disposal. The provision is not included in the discontinued operations assets and liabilities in the table above.

6. Earnings/ (loss) per share

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

	2018 $ million	2017 $ million
Earnings / (loss)		
Earnings/(loss) for the purpose of diluted earnings/(loss) per share on continuing operations	**105.1**	(270.2)
Profit from discontinued operations	**28.3**	16.4
Earnings/(loss) for the purposes of diluted earnings/(loss) per share on continuing and discontinued operations	**133.4**	(253.8)
Number of shares (millions)		
Weighted average number of Ordinary Shares for the purposes of basic earnings per share	**774.0**	513.7
Effects of dilutive potential Ordinary Shares:		
Contingently issuable shares (2017: anti-dilutive)	**88.3**	-
Weighted average number of Ordinary Shares for the purposes of diluted earnings per share	**862.3**	513.7
Earnings/(loss) per share from continuing operations (cents)		
Basic	**13.6**	(52.6)
Diluted	**12.2**	(52.6)
Earnings per share from discontinued operations (cents)		
Basic	**3.7**	3.2
Diluted	**3.3**	3.2

The inclusion of the contingently issuable shares in the current year produces diluted earnings per share for both continuing and discontinued operations (2017: anti-dilutive). At 31 December 2018 there were 88.3 million potential Ordinary Shares in the Company that are underlying the Company's equity warrants and share options that may dilute earnings per share in the future. These have been included in the calculation of diluted earnings per share.

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

Oil and Gas Properties	Total $ million
Cost:	
At 1 January 2017	1,011.4
Exchange movements	(0.9)
Additions during the year	63.1
Acquisition of subsidiaries	(0.5)
Exploration expense [1]	(11.2)
At 31 December 2017	1,061.9
Exchange movements	(5.6)
Additions during the year	62.1
Transfer to PP&E	(274.2)
Disposals	(1.4)
Assets classified as held for sale	(0.6)
Exploration expense[1]	(29.6)
At 31 December 2018	812.6

1 Expensed in the income statement with pre-licence expenses of US$5.6 million in 2018 (2017: US$5.9 million)

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. Assets written off in the year include costs incurred in Mexico on the Block 2 license, the Sunbeam prospect in the UK and Block 665 in Brazil.

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 until that point will be expensed and no further costs associated with the licence will be capitalised.

During the year, the costs associated with the Tolmount project were transferred to PP&E following project sanction in August. The balance carried forward is predominantly in relation to the Group's prospects in the Falkland Islands and the non-operated Zama prospect and Block 30 in Mexico.

8. Property, plant and equipment

	Oil and gas properties $ million	Other fixed assets $ million	Total $ million
Cost:			
At 1 January 2017	8,028.6	64.3	8,092.9
Exchange movements	4.6	2.4	7.0
Additions and changes in decommissioning during the year	445.4	2.3	447.7
Asset acquisition	9.8	-	9.8
Assets classified as held for sale	(489.6)	(1.7)	(491.3)
Disposals	(409.4)	(0.6)	(410.0)
At 31 December 2017	7,589.4	66.7	7,656.1
Exchange movements	1.2	(2.1)	(0.9)
Additions and changes in decommissioning during the year	(33.5)	1.9	(31.6)
Transferred from E&E	274.2	-	274.2
Assets transferred as held for sale	(4.1)	-	(4.1)
Disposals	(19.6)	(9.2)	(28.8)
At 31 December 2018	**7,807.6**	**57.3**	**7,864.9**
Amortisation and depreciation:			
At 1 January 2017	5,318.9	47.8	5,366.7
Exchange movements	(0.3)	1.9	1.6
Charge for the year	416.2	6.7	422.9
Net impairment charge	252.2	-	252.2
Assets classified as held for sale	(434.6)	(0.9)	(435.5)
Disposals	(332.1)	(0.6)	(332.7)
At 31 December 2017	5,220.3	54.9	5,275.2
Exchange movements	2.1	(1.7)	0.4
Charge for the year	386.5	7.1	393.6
Net impairment credit	(35.2)	-	(35.2)
Disposals	(5.5)	(9.2)	(14.7)
At 31 December 2018	**5,568.2**	**51.1**	**5,619.3**
Net book value:			
At 31 December 2017	**2,369.1**	**11.8**	**2,380.9**
At 31 December 2018	**2,239.4**	**6.2**	**2,245.6**

Finance costs that have been capitalised within oil and gas properties during the year total US$1.2 million (2017: US$41.3 million), at a weighted average interest rate of 7.6 per cent (2017: 7.3 per cent).

8. Property, plant and equipment *(continued)*

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.

Impairment charge

The impairment charge in the current year relates entirely to the Huntington asset in the UK. The impairment charge of US$20.5 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 asset. The future cash flows were estimated using the following oil price assumption: US$60/bbl in 2019, US$65/bbl in 2020, US$70/bbl in 2021 and US$75/bbl in 'real' terms thereafter (2017: two years at forward curve, year three at US$70/bbl followed by a long-term price of US$75/bbl (real)) and were discounted using a pre-tax discount rate of 9 per cent for the UK assets (2017: 9 per cent) and 12.5 per cent for the non-UK assets (2017: 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.

The principal cause of the impairment charge being recognised in the year was as a result of an increase in the expected decommissioning costs attributed to the asset. The prior year impairment charge was principally driven by a downgrade in 2P reserves on the Solan asset.

Reversal of previously recognised impairment charges

Under the requirements of IAS 36, if there is an indication that a factor that resulted in an impairment charge may have changed or been reversed, then the previously recognised impairment charge may no longer exist or may have decreased. For a number of assets, due to an increase in the near-term oil price assumption (based on the Dated Brent forward curve), we have reassessed the recoverable amount of the asset to assess whether an increase in the recoverable amount (value-in-use) is indicative of a reversal of a previously recognised impairment charge. The future cash flows were determined using the same assumptions as those used for the impairment charge outlined above.

Reversal of previously recognised impairment charges *(continued)*

A reversal of impairment of US$55.7 million has been credited to the income statement for the year, which has been partially offset by the impairment charge recognised. The impairment reversal relates entirely to Solan in the UK as a result of a reduction in the expected gross decommissioning cost attributed to the asset. The recoverable amount of Solan at 31 December 2018 was US$171.4 million. The prior year reversal of impairment was driven by a one year extension of COP on the Huntington asset.

Sensitivity

A 1 per cent increase in the discount rates used when determining the value-in-use for each oil and gas property would result in a reduction in the net impairment reversal of approximately US$6.1 million. A US$5/bbl reduction in the long-term oil price (to US$70/bbl (real)) would reduce the net impairment reversal by approximately US$19.5 million.

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 (2017: 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 2026. 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, including the goodwill is US$166.8 million. The key assumptions to which the calculation of value-in-use of the Catcher asset are discount rate, oil prices, forecasted recoverable reserves and estimated future costs. No reasonably possible change in any of these key assumptions would cause the asset’s carrying amount to exceed its recoverable amount.

9. Deferred income

In June 2015, Premier received US$100.0 million from FlowStream in return for granting them 15 per cent of production from the Solan field until sufficient barrels have been delivered to achieve the rate of return within the agreement. This balance is being released to the income statement within revenue as barrels are delivered to FlowStream from production from Solan. The balance has reduced by US$16.2 million during the year reflecting barrels delivered to FlowStream and a charge to finance costs of US$9.8 million.

The portion of the deferred income that is expected to be delivered to FlowStream within the next 12 months has been classified as a current liability.

10. Borrowings

The Group's loans are carried at amortised cost as follows:

	2018 $ million			2017 $ million		
	Carrying value	Fees	Total	Carrying value	Fees	Total
Bank loans	1,846.7	(21.0)	1,825.7	2,165.0	(106.9)	2,058.1
Senior loan notes	538.1	-	538.1	541.6	-	541.6
Retail bonds	190.5	(2.3)	188.2	202.5	(10.1)	192.4
Convertible bonds	-	-	-	180.5	-	180.5
Total borrowings	2,575.3	(23.3)	2,552.0	3,089.6	(117.0)	2,972.6
Due within one year			-			-
Due after more than one year			2,552.0			2,972.6
Total borrowings			2,552.0			2,972.6

At the year-end, the Group's principal credit facilities comprised:

- Bank loans: US$2.5 billion revolving and letter of credit facility ('RCF'), US$150 million and £100 million term loans (together the 'Term Loan')
- Senior loan notes: US$335 million and €63.6 million of US Private Placement ('USPP') notes and US$130 million converted loan facility; and
- £150 million of retail bonds.

All of the above facilities mature in May 2021.Refinancing of all the above facilities completed in July 2017. On completion, a loss of US$83.7 million was recognised in relation to the facilities that were deemed to be substantially modified in accordance with IAS 39. In addition, an adoption of IFRS 9 at 1 January 2018, additional interest charges of US$82 million had to be recognised in 2017, with a corresponding reduction in net assets at 31 December 2017. As permitted by IFRS 9 comparatives have not been restated (see note 1).

10. Borrowings *(continued)*

Convertible bonds

In January 2018, Premier invited convertible bondholders to exercise their exchange rights in respect of any and all of their bonds. 87.5 per cent or US$205.8 million of the US$235.2 million bonds outstanding were accepted for early exchange with an incentive amount of US$50 per US$1,000 in principal of bonds. The exchange resulted in the issue of 231,882,091 Ordinary Shares, which included 7,578,343 incentive shares. Completion of this offer, resulted in a remaining convertible bond liability of US$28.8 million.

Following this, in July 2018, the Group announced its intention to exercise the mandatory conversion option in the remaining outstanding convertible bonds. The exercise of this option converted all the remaining US$28.8 million outstanding convertible bonds into approximately 31.4 million new Ordinary Shares of Premier. This resulted in Premier's convertible bond liability being fully extinguished in September 2018.

11. Notes to the cash flow statement

	2018 $ million	2017 $ million
Profit/(loss) before tax for the year	**158.2**	(366.3)
Adjustments for:		
Depreciation, depletion, amortisation and impairment	**358.4**	667.8
Other operating (income)/costs	**1.2**	(18.8)
Exploration expense	**29.6**	11.2
Provision for share-based payments	**10.8**	8.6
Interest revenue and finance gains	**(27.8)**	(12.6)
Finance costs and other finance expenses	**400.6**	412.7
Profit on disposal of non-current assets	**(42.3)**	(129.0)
Operating cash flows before movements in working capital	**888.7**	573.6
Decrease/(increase) in inventories	**1.2**	(1.2)
Decrease/(increase) in receivables	**72.6**	(182.0)
(Decrease)/ increase in payables	**(93.0)**	136.6
Cash generated by operations	**869.5**	527.0
Income taxes paid	**(128.8)**	(69.6)
Interest income received	**7.5**	1.1
Net cash from continuing operating activities	**748.2**	458.5
Net cash from discontinued operating activities	**29.0**	16.8
Net cash from operating activities	**777.2**	475.3
Movement in JV cash	**(54.4)**	20.7
Total net cash from operating activities	**722.8**	496.0

11. Notes to the cash flow statement *(continued)*

Analysis of changes in net debt:

	2018 $ million	2017 $ million
a) Reconciliation of net cash flow to movement in net debt:		
Movement in cash and cash equivalents	**(120.8)**	109.5
Proceeds from drawdown of long-term bank loans	**(105.0)**	(45.0)
Repayment of long-term bank loans	**415.3**	-
USPP make-whole adjustment	**-**	(41.3)
Adjustment to revised fair value of convertible bonds	**-**	58.6
Conversion of convertible bonds	**181.9**	5.5
Non-cash movements on debt and cash balances (predominantly FX)	**22.1**	(46.3)
Reduction in net debt in the year	**393.5**	41.0
Opening net debt	**(2,724.2)**	(2,765.2)
Closing net debt	**(2,330.7)**	(2,724.2)
b) Analysis of net debt:		
Cash and cash equivalents	**244.6**	365.4
Borrowings	**(2,575.3)**	(3,089.6)
Total net debt	**(2,330.7)**	(2,724.2)

The carrying amounts of the borrowings on the balance sheet are stated net of the unamortised portion of the refinancing fees of US$23.3 million (2017: US$117.0 million) and the impact of IFRS 9.

12. Subsequent Events

Assets held for sale

In February 2019, Premier received a further US$5 million cash deposit from Al-Haj in relation to the disposal of the Pakistan business unit. This brought the total cash deposit received by Premier to date of US$40 million, against the headline consideration of US$65.6 million.

Debt Reduction

Subsequent to the year-end, in January 2019, a further US$100.3 million of the RCF debt facility was cancelled by Premier, which will result in reduced commitment fee costs for the Group in 2019.

13. External audit

This preliminary announcement is consistent with the audited financial statements of the Group for the year-ended 31 December 2018.

14. Publication of financial statements

It is anticipated that the full Annual Report and Financial Statements will be published in April 2019. Copies will be available from this date at the Company's head office, 23 Lower Belgrave Street, London SW1W 0NR, and on the Company's website (www.premier-oil.com).

15. Annual General Meeting

The Annual General Meeting will be held at the King's Fund, 11-13 Cavendish Square, London W1G 0AN on Wednesday 16 May 2019 at 11:00 am

Full Year Results for the year ended 31 December 2018

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.
- **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 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.

Full Year Results for the year ended 31 December 2018

OIL AND GAS RESERVES

Working interest reserves at 31 December 2018

Working interest basis													
	Falkland Islands		**Indonesia**		**Pakistan/ Mauritania**		**UK**		**Vietnam**		**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[4]	Oil, NGLs and gas
	mmbbls	bcf	mmbbls	bcf	mmbbls	bcf	mmbbls	bcf	mmbbls	bcf	mmbbls	bcf	mmboe
Group proved plus probable reserves:													
At 1 January 2018	126.46	43.83	1.48	199.43	0.08	51.21	68.99	144.38	19.17	26.55	216.18	465.4	301.84
Revisions[1]	(126.46)	(43.83)	0.07	(6.60)	(0.01)	(4.26)	12.01	262.76	2.87	2.16	(111.52)	210.23	(68.74)
Discoveries and extensions[2]	-	-	-	-	-	-	-	-	-	-	-	-	-
Acquisitions and divestments[3]	-	-	(0.40)	(7.40)	-	-	-	(43.91)	-	-	(0.40)	(51.31)	(9.87)
Production	-	-	(0.12)	(24.67)	(0.02)	(12.06)	(12.95)	(21.07)	(4.42)	(5.45)	(17.51)	(63.25)	(29.55)
At 31 December 2018	-	-	1.03	160.76	0.05	34.89	68.05	342.16	17.62	23.26	86.75	561.07	193.68
Total Group developed and undeveloped reserves													
Proved on production	-	-	0.48	94.81	0.04	26.01	34.32	65.03	16.09	20.74	50.93	206.59	90.38
Proved approved/justified for development	-	-	0.36	49.01	-	-	12.46	138.96	0.03	0.49	12.85	188.46	48.96
Probable on production	-	-	-	-	0.01	8.88	16.39	23.95	1.48	1.61	17.88	34.44	23.99
Probable approved/justified for development	-	-	0.19	16.94	-	-	4.88	114.22	0.02	0.42	5.09	131.58	30.35
At 31 December 2018	-	-	1.03	160.76	0.05	34.89	68.05	342.16	17.62	23.26	86.75	561.07	193.68

Notes:

1 The most significant revisions in the year relate to Sea Lion and Tolmount. Sealion has been reclassified from Reserves (Justified for Development) to Contingent Resources (Development Pending) to align with the new SPE-PRMS Standards issued in June 2018.The booking of the Tolmount Main field as 2P reserves reflects the sanction of the project in 2018.

2 The Zama discovery in Mexico is classified as contingent resource and does not appear in this table

3 Divestment of Babbage (UK) and Kakap (Indonesia)

4 Proved plus probable gas includes 96.3 bcf of fuel gas reserves (2017: 95 bcf).

Premier Oil plc 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 ('OIAC'), 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 181.5 mmboe as at 31 December 2018 (2017: 284.9 mmboe). This was calculated at year-end 2018, using the following oil price assumption: US$60/bbl in 2019, US$65/bbl in 2020, US$70/bbl in 2021 and US$75/bbl in 'real' terms thereafter (2017: Dated Brent forward curve for 2018 and 2019, US$70/bbl in 2020 and US$75/bbl in 'real' terms thereafter).