12 March 2019

Ophir Energy plc
("Ophir")

2018 Full Year Results

Ophir announces its full year results for the year ended 31 December 2018.

Commenting on the results, Interim CEO Alan Booth, said:

"2018 saw us make material progress implementing our strategy to create a strong, cash generative production and development base to serve as a platform for further growth and shareholder returns. The most significant achievement being the doubling of our production and cash flow through the acquisition of a South East Asian asset portfolio from Santos. Our ability to transact quickly and as favoured bidder was in part as a result of our strong balance sheet.

"We recently completed operations on our first exploration well in Mexico, in Block 5. The well encountered oil and gas and the results were broadly in line with the company's pre-drill expectations. Further drilling will be required to establish commerciality within the Block. The Company is in advanced discussions with a third party in respect of a cash sale of its Block 5 position.

"In early 2019, the government of Equatorial Guinea decided not to offer a further extension to the Block R licence. Whilst this was a very frustrating outcome, we can assure shareholders that no stone was left unturned in our efforts to realise value for the gas that we discovered in Block R.

"Since the start of 2019, the Board has recommended a cash offer from Medco of 55p per share. The Board believes that this can provide Ophir shareholders with a certain upfront value in cash for the strategy that Ophir set out in September 2018, including rationalising parts of our exploration portfolio, reducing overhead costs and maximising returns to shareholders.

"Notwithstanding the recommended offer from Medco, the Board of Ophir continues to remain focussed on its stated strategy and to maximise returns for shareholders."

HIGHLIGHTS

Strategic

- Completed the acquisition of Southeast Asian production licences from Santos for a total consideration of $205 million. The assets delivered material cash flow returning $117 million (on a proforma basis) of the acquisition cost during 2018.

- Took steps to reduce the cost base through downsizing the London headquarters and relocating to Asia, bringing senior management closer to the key assets.

- Minimised the exposure to frontier exploration: finalising withdrawal from Myanmar, Aru Trough (Indonesia); sold EG-24 in Equatorial Guinea; and withdrawing from Malaysia.

Financial

- Revenue increased 58% to $298 million (2017: $189 million)
- Unit operating costs $11.67 per boe (2017: $11.43 per boe)
- Net funds flow from production increased 55% to $143.5 million (2017: $90.1 million), equivalent to $23.00 per boe (2017: $21.58 per boe)
- Net debt/(cash) at year-end of $35 million (2017: net cash $119 million)
- Government of Equatorial Guinea decided not to further extend the Block R Licence which resulted in an impairment of $614 million
- Completed refinance of the acquisition bridge facility and $250 million reserve based lending facility into a new $350 million, seven year reserves based lending facility
- Ended the year with gross liquidity of $391 million (2017: $427 million).

Operations

- Production (on a proforma basis accounting for the Santos asset acquisition from effective date of 1 Jan 18) averaged 29,700 boepd (2017: 11,800 boepd)
- Worked-over 3.5 million man hours incident free
- Increased 2P Reserves by 42% to 70.1mmboe; principally driven by the acquisition of 23.3mmboe through the Santos acquisition
- Phase 4A development of the Bualuang field, which comprised three new wells and four workovers, was completed successfully and under budget
- Drilled a successful exploration well on the Paus Biru prospect in the Sampang PSC, Indonesia.
- Hydrocarbon Discovery in the Cholula-1 in Mexico block 5
- Took Final Investment Decision on the Meliwis field development in the Madura PSC, Indonesia

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About Ophir:

Ophir Energy is an independent Upstream oil and gas exploration and production company. It is listed on the London Stock Exchange (LEI: 213800LAZOZTKPAV258).

OPERATING REVIEW

During 2018 the Board has been focused on rebalancing the company with one clear goal in mind – maximising cash generation.

This resolve drove the decision to expand the Group's Asian production and development base through the acquisition of a package of assets from Santos. The principal assets acquired were the non-operated Chim Sao and Dua oil fields in Vietnam and the operated fields within the Madura Offshore and Sampang PSCs in Indonesia, both of which have gas production. Broadly speaking, the acquisition more than doubled our production and operating cash flow.

Group production in 2018 was 29,700 boepd, ahead of market expectations of 27,500 boepd. This was a consequence of successful intervention work by the operator, Premier, on the Chim Sao field in Vietnam and outperformance of the fields in the Madura Offshore and Sampang PSCs in Indonesia, partly due to better than forecast reservoir performance and partly due to higher than predicted market demand in East Java.

Production in 2019 is forecast to be 25,000 boepd. This is lower than in 2018 due to a combination of natural decline in ageing reservoirs and some of the outperformance in 2018 being driven by short term increases in gas demand which it is not certain will become a long term trend. Development drilling in 2019 on the Bualuang field is scheduled for the back end of the year so the associated upturn in production will come through in 2020.

Our production base is low cost, with average operating costs of $12 per boe, and generated $168 million of cash from operations (pre-tax and working capital) at $27 per boe.

At the start of the year, we produced from three fields and the majority of our production was from the Bualuang field in the Gulf of Thailand. The addition of the Santos assets has diversified this in terms of geography, hydrocarbon phase and fiscal regime. By the end of the year, we were producing from nine fields in three countries with production approximately split evenly across those countries.

We therefore had a dual focus in 2018: firstly to run our existing operations safely and efficiently; and secondly to integrate the assets acquired from Santos. With Block 12W in Vietnam being non-operated, the focus of integration was on Indonesia where we merged the existing Ophir office with that which we acquired from Santos.

Our other focus of attention was the Block R licence in Equatorial Guinea. We entered the year hoping to secure financing to enable the project to move forward under the joint venture structure with OneLNG (a joint venture between Schlumberger and Golar).

When OneLNG was dissolved in May, we were approached by a number of parties interested in co-investing in the Fortuna project. We engaged with a short-list of counterparties until the end of 2018 but were unable to conclude a transaction prior to year-end. As we had not met the conditions set by the Ministry of Mines and Hydrocarbons, when the licence expired at the end of 2018 the Ministry chose not to grant us a further extension. We therefore exited the Block R licence and subsequently signed a settlement agreement with the government.

Bualuang Field, B8/38 Concession, Thailand, 100% operated interest

Production averaged 8,100 boepd over the year with uptime of 98%. In summer 2018, we started work on the next phase of development known as Phase 4. Phase 4 is split into two parts, in effect 2018 and 2019, which we refer to respectively as Phase 4A and Phase 4B.

The objective of Phase 4A was to boost production from the existing facilities and comprised drilling three new producing wells and four workovers, plus some preparatory project work ahead of Phase 4B, as well as the drilling of an exploration well testing a near-field prospect, B8/38-11 which was unsuccessful (see under following section covering exploration).

The drilling campaign commenced six weeks later than envisaged due to a combination of poor weather and the late arrival of the rig. Once the rig was on location the team did a first class job executing the campaign and completed it safely, 38 days faster than planned and approximately 20% under budget.

Phase 4B will see a new, twelve slot, conductor-supported platform, called the Charlie platform, installed at the Bualuang field. We will also increase the water disposal capacity from 75,000 barrels per day to 100,000 barrels per day; this extra fluid-handling capacity will help with recovery.

The platform is currently under construction in the Naval Shipyard at Sattahip by BJC Heavy Industry and is expected to be lowered into place in June to facilitate the start of drilling in July 2019. During the shutdown for installation, we will take the opportunity to make repairs and upgrades to Alpha and Bravo platform equipment. First oil from the Charlie platform is expected in October 2019 and, on completion of the Phase 4 programme, field production is expected to peak at 14,000 bopd.

Kerendan Field, Bangkanai PSC, Indonesia, 70% operated interest

The Kerendan field has continued to produce steadily in line with expectations at an average daily rate in 2018 of 16.8 MMscfd (gross). We have started to see the beginning of the natural reservoir decline, with the majority of production now coming from two of the four wells. We are planning stimulation through acid fracture work in June 2019, which we hope will restore the productivity of the existing K4 and K6 wells.

Interpretation is well underway on the 3D seismic that was completed at the end of 2017. This has helped to better define the reservoir distribution and together with the latest audit by ERCE indicates that the contingent resources in the field have increased from 457 Bcf (gross) to 583 Bcf. Our internal view is that we have up to 1.9 Tcf of gas in place across the whole Kerendan structure, all connected.

However, to sell any more gas, we need to have the reserves certified by LAPI ITB, an approved Indonesian government body. They are currently completing their work, but we have no reason to believe their opinion will materially differ from our internal view.

Even taking into account that the PSC will expire in 2033, it is clear that there is material potential resource at Kerendan. The challenge is finding new routes to commercialisation, and then finding an engineering solution to satisfy the commercial solution. Our new team in Indonesia is working on this and we believe we have significantly strengthened our expertise in this area post the integration of the former Santos team.

Madura Offshore and Sampang PSCs, Indonesia, 67.5% and 45% operated interests

As part of the Santos package, we acquired these gas assets in East Java.

Madura Offshore contains stable production from the Maleo and Peluang fields, and Ophir has a 67.5% operated interest in the PSC.

Maleo has been producing since 2006 and is past the plateau, in the decline phase. Its output is sold to PGN and PLN through the East Java pipeline. Production was 57% above budget in 2018, partly due to higher gas demand but also due to better reservoir performance, so we see some potential upside. Peluang started producing in 2014 and is on plateau production at the moment. It has also over-produced, at 15% above its budget, mainly due to higher gas demand.

We also have decided to invest in the Meliwis field, discovered in 2016, 11 kilometres south of the Maleo field. The Meliwis development is planned as a single well well-head platform tie-back to Maleo, and would extend the economic field life of the Maleo and Peluang fields. Final investment sign off by the joint venture was achieved in February with the signing of a gas sales agreement. Our share of the PSC is 77.5%, the local partner having declined to participate in the drilling of the successful exploration well.

In Sampang, the Oyong field was found back in 2001 and Wortel five years later. They were put on production in 2007 and 2012 respectively. Oyong is producing gas, Wortel is producing gas and condensate. All production is piped onshore to the processing site at Grati.

Together, the Oyong and Wortel fields produced at 33% above budget during 2018, primarily due to higher than forecast gas demand. We will be looking at revising our subsurface models next year, with a view to adding other gas reservoirs.

We also drilled a successful gas exploration well at Paus Biru-1, 27 km east of Oyong, noted in the exploration commentary below and will be looking to achieve reserves certification in 2019 as a step towards FID. We believe pressure-lowering projects at the Grati processing plant will create further economic value from the fields through extending production life in Oyong and Wortel.

In Sampang there is potential upside from two undeveloped discoveries already on the block. We also see substantial exploration upside within both Sampang and Madura Offshore blocks – however accessing this upside would require PSC extensions as both blocks currently expire in 2027.

Chim Sao/Dua fields, 12W PSC, Vietnam, 31.875% non-operated interest

Part of the Santos acquisition, the Chim Sao and Dua oil fields in Vietnam are operated by Premier Oil. Chim Sao, the main field, has consistently produced over budget in the past few years and continued this trend in 2018 – outperforming budget by 18%.

In the initial development plan, these fields were expected to produce until around 2020. However, due to the continued outperformance, the fields are now expected to produce out until 2030. Premier has begun a field-life extension assessment of all the facilities, most critically the well head platform and main field flow lines which had ten-year design lives (in line with the original development plan). By 2020 the necessary modifications will have been completed.

In 2019 the operator is planning to conduct a series of well interventions that will help offset the natural reservoir decline rates. Ophir is currently building its own field reservoir model and plans to work with the operator in 2019 to determine the optimum way to create value from these fields in the coming years.

Sinphuhorm Gas Field, EU1, E5N and L15/43 Concessions, Thailand, 9.5% operated interest

Operated by PTTEP, production from the Sinphuhorm field averaged 79 MMscfd (gross). This was in line with budget and approximately flat year on year. The trend for lower nominations from the Electricity Generating Authority of Thailand (EGAT) that we saw at the end of 2017 continued in the first quarter of 2018 before demand recovered to more than 100 MMscfd for most of the rest of the year.

Whilst encouraged by the stronger demand witnessed for large parts of 2018, we expect there to remain a certain degree of volatility in the nominations for EGAT during 2019.

Tanzania LNG, Blocks 1 & 4, 20% non-operated interest

Engagement with the Government of Tanzania on the development of the natural gas discoveries in Blocks 1 and 4 offshore Tanzania, continues to focus on establishing key commercial terms for a cost competitive development for the Tanzania Gas and LNG project. The project continues its focus on selecting the optimal integrated upstream and liquefied natural gas project. The Tanzania LNG project is at a stage where detailed planning and multiple agreements need to be agreed between the International Gas companies (IOCs) and the Government.

EXPLORATION

We announced in September that we would be reviewing our exploration programme to reduce both the commitment expenditure, and the exposure to higher risk, frontier exploration that typically takes longer to pay-back.

In the early part of the year, we picked up additional acreage in both Equatorial Guinea and Mexico. In Equatorial Guinea, we were awarded an 80% operated interest in Block EG-24. We subsequently farmed out a 40% interest to Kosmos Energy and then in January 2019 agreed to sell Kosmos our remaining 40% and operatorship.

In Mexico, we started the year with an interest in Block 5, and were awarded Blocks 10 and 12, in the Mexico 2.4 deep water licence round at the end of January 2018.

In Block 5, the main activity has been seismic interpretation and identification of drilling prospects. The Cholula-1 exploration well was drilled during February and March 2019. The well encountered hydrocarbons and further drilling is likely to be required to confirm the commerciality of the block.

In line with our stated objective of reducing our exploration commitments, we are currently in advanced discussions with interested counterparties for the sale of our interest in Block 5 offshore Mexico for a modest profit, although any such deal remains subject to execution of definitive documents, board approvals and customary governmental consents.

For Blocks 10 and 12, we signed the production-sharing contracts in March, purchased seismic data and commenced geological interpretation. These are held on 20% equity non-operated positions.

In the second half of the year, we finalised a trade with Chevron in Myanmar, exchanging equity in our existing block AD03 for equity in their adjacent, shallower water block A5. Following a thorough review of prospectivity across both PSC areas, no commercially viable opportunities were identified and a decision was taken to withdraw from both PSCs.

In the Aru Trough in Indonesia, in the West Papua IV and Aru PSCs, jointly held with Equinor, further geological studies continued, utilising recently acquired 3D seismic data. Given the frontier and deep water nature of the basin a decision was taken to withdraw from both PSCs.

The Madura Offshore and Sampang PSCs include a number of near field exploration prospects. The Paus Biru -1 exploration well resulted in a gas discovery. Paus Biru is approximately 27 kilometres east of the producing Oyong Gas field. We are now preparing a plan of development for submission to the regulator for approval.

In Thailand, we drilled a step out exploration well, B8/38-11 to test a small target to the north of the Bualuang field but the main T2 reservoir target was not well developed in this location and the well was abandoned as a dry hole.

As part of the transaction with Santos, we acquired an exploration licence in Malaysia, which we subsequently exited, and we expect the acquisition of the exploration assets in Vietnam and Bangladesh to close in 2019. These are considered non-core and we will be looking to remove the capital commitments against these licences during 2019.

FINANCIAL REVIEW

Introduction

During 2018, we took significant steps to strengthen the financial performance of the company and move towards becoming self-sustaining. In that regard, it was a year of transition, requiring a number of hard decisions to be taken against a challenging backdrop. We did not shy from those decisions. The company is now better placed financially than at the beginning of 2018 to face the challenges ahead and to deliver its strategic objectives.

Key achievements in 2018 from a financial management perspective included:

- Significantly expanding the company's production and cash flow base. This base is now capable of generating surplus cash flows that can ultimately be deployed into projects that have the potential to deliver material returns on capital employed, or in the absence of such projects, returned to shareholders.

- Reducing exposure to frontier exploration expenditure. We recognised investment into frontier exploration brings with it long term financial commitments that are not commensurate with the risk and, even in the success case, the investments will often take many years to deliver meaningful returns.

- Lowering the company's cost base. We initiated cost reduction programmes across the portfolio including plans to both downsize the corporate headquarters and to relocate it to Asia.

- Preserving a strong balance sheet to provide maximum flexibility for future investment decisions. In December, our reserve based lending facility was both expanded, and the maturity extended.

Financial environment

The financial environment for the UK upstream exploration and production sector in 2018 was one of continual change. The early stability in the first half reversed in the fourth quarter with broader macro political concerns driven by uncertainty over Brexit and continued tension in the trading relationship between the US and China, and growing consensus around the view that the days of low interest rates may be over. The Brent oil price started the year at $67 per bbl, climbing to a peak of $87 per bbl in October, only to decline to a low of $50 per bbl in mid-December with concerns centred around a perceived over supply to the market, and finishing the year at $54 per bbl. In addition, the buoyant debt markets we witnessed in the first half of the year turned-around in the fourth quarter with both bank and debt capital markets contracting. The beginning of 2019 saw the continued recovery of oil prices, reaching a high of $67 per bbl in February 2019.

Despite the broader market concerns, other than the outcome on the Fortuna project, we were able to make progress against our strategic objectives, increasing our production and cash flow base, reducing exposure to frontier exploration expenditure, reducing our operating cost base and strengthening the balance sheet. Delivery on the strategic objectives is discussed in context of the company's financial results below.

Key Financial Indicators

	Units	2018	2017
Income Statement:			
Realised prices[1]:			
Oil and Condensate Gas	$/bbl $/Mscf	66.62 5.94	51.15 5.18
Revenue	$'millions	298.2	188.5
Operating Costs per boe [2]	$/boe	11.67	11.43
Pre-licence and other exploration costs	$'millions	15.5	15.7
Loss before taxation	$'millions	720.0	64.4
Current income tax charge	$'millions	61.9	47.4
Balance Sheet			
Net debt/(cash)[3]	$'millions	34.6	(119.0)
Gross liquidity [4]	$'millions	391.4	427.3
Leverage ratio [5]	times	2.1	1.1
Gearing ratio [6]	%	34	7
Cash Flow Statement			
Cash generated from operations before working capital adjustments	$'millions	167.7	96.9
Income taxes paid	$'millions	70.5	9.5
Net funds flow from production [7]	$'millions	143.5	90.1
Net cash flows generated from/(used in) operating activities per boe [8]	$/boe	17.21	25.42
Investing cash flows: Acquisitions Exploration and Evaluation Oil and Gas Properties Net Investment in Joint Ventures[9]	 $'millions $'millions $'millions $'millions	 137.8 64.6 49.1 (4.8)	 – 95.8 47.2 (6.1)

[1] *Realised prices are calculated as revenue divided by quantities of oil, condensate and gas sold.*

[2] *Operating costs per boe is defined as operating costs divided by working interest production.*

[3] *As per note [24] to the consolidated financial statements.*

[4] *Gross liquidity is defined as cash and cash equivalents plus available undrawn borrowings.*

[5] *Leverage ratio is defined as gross debt divided by cash flow from operations before working capital adjustments.*

[6] *Gearing ratio is defined as gross debt divided by gross debt plus book net equity.*

[7] *Net funds flow from production is defined as set out on following pages.*

[8] *Net cash flows generated from/(used in) operating activities per boe is defined as net cash flows generated from/(used in) operating activities divided by working interest production.*

[9]' *Net investment in joint ventures is calculated as funding provided to joint ventures less dividends received from joint ventures.*

Statement of comprehensive income

Gross profit

Following completion in September of the acquisition of oil and gas properties in Indonesia and Vietnam, and reflecting production for the new licences from the acquisition date, production for 2018 averaged 17,100 boepd (2017: 11,700 boepd). This comprised oil and liquids of 10,500 bpd (2017: 8,700 bpd) realising an average price of $67 per bbl (2017: $51 per bbl) and generating revenue of $244 million (2017: $170 million), net of hedging. Similarly, gas production for the year was 37.2 MMscfd (2017: 16.1 MMscfd) realising an averaging price of $5.94 per Mscf (2017: $5.18 per Mscf) and generating revenue of $55 million (2017: $19 million) and dividend income from Sinphuhorm of $7 million (2017: $7 million). Accordingly, production increased by 46% year on year (2017: 9%) with revenue increased by 58% (2017: 76%).

For 2018, we entered into two commodity price hedge programmes with the financial effect of the hedges predominantly accounted for in revenue. Our strategy is to hedge commodity prices on a defensive basis, protecting downside cash flow exposure to commodity price fluctuations whilst preserving as much upside cash flow exposure as possible. In late 2017, we entered into a programme against our full year 2018 Bualuang production for 3,200 bpd by selling a Brent swap at approximately $60 per bbl and buying a Brent call at approximately $68 per bbl. With Brent prices averaging $72 per bbl during 2018, we booked a charge to revenue of $8 million against the hedge. In August, we entered into a second programme against the newly acquired Vietnam Block 12W production for 2,000 bpd by selling a Brent swap at approximately $70 per bbl and buying a Brent call at approximately $78 per bbl. With Brent pricing averaging $71 per bbl over the period of the hedge, it approximately broke even in 2018. Both programmes combined represented about 13% of our pro-forma total 2018 production and 25% of our pro-forma company's oil and condensate production.

Cost of sales totalled $199 million (2017: $148 million) and included operating costs of $73 million or $12 per boe (2017: $49 million or $11 per boe). Cost of sales also included royalties payable of $19 million (2017: $14 million), which arise on a sliding scale of revenue, and depreciation and amortisation of oil and gas properties of $107 million or $19 per boe (2017: $78 million or $20 per boe). Cost of sales in 2017 also included a movement in inventories of oil of $7 million (2018: nil).

Ultimately, we delivered a gross profit of $99 million, or $17 per boe (2017: $41 million or $11 per boe).

Operating loss

The Block R licence in Equatorial Guinea (containing the Fortuna discovery) expired at the end of 2018. In our mid-year results, we impaired the Equatorial Guinea Block R licence, held on our balance sheet under assets classified as held for sale, by $310 million to $300 million recognising the increased uncertainty as to whether value for the licence could be realised before the licence expired. Following expiry of the licence at 2018 year-end, without having secured an option to realise value for the licence, we fully impaired the remaining carrying balance of the licence at year-end. As a consequence, the full impairment charge for the licence totalled $614 million.

We also impaired oil and gas properties by $14 million, in respect of the Bangkanai licence, and investments by $45 million in respect of Sinphuhorm. The impairment to Bangkanai reflects updates to cost estimates of future development phases. In the case of Sinphuhorm, the impairment reflects downward revisions to gas in place assumptions for the wider-field resulting in reduced estimates for contingent resource.

In addition, exploration expenses totalled $130 million (2017: $92 million) and included $100 million (2017: $77 million) of exploration expenditure written off following our decisions to relinquish the West Papua, Aru and North Ganal frontier exploration licences in Indonesia and the Blocks AD03 and A5 licences in Myanmar. Additionally, exploration expenses included pre-licence and other exploration costs of $16 million (2017: $16 million) and exploration inventory written off of $15 million (2017: nil).

General and administration expenses charged to the income statement totalled $11 million (2017: $11 million). Total general and administration expenses reduced year on year by 11% with a resulting 4% reduction to general and administration expenses charged to the income statement.

Following the acquisition of oil and gas properties in Indonesia and Vietnam, a gain on purchase was recorded of $58 million being the excess of the fair value of the net assets acquired over the purchase consideration.

Other operating expenses totalled $41 million (2017: $12 million) and included restructuring costs of $17 million (2017: $2 million) related to the downsizing of the London HQ, licence exit costs of $7 million (2017: $9 million) and corporate transaction costs of $15 million (2017: nil)

We consequently reported an operating loss of $693 million (2017:$54 million).

Loss from continuing operation before taxation

We reported a loss from continuing operations before taxation of $720 million (2017: $64 million), which included net finance charges of $25 million[1] (2017: $13 million). We entered into two new financing arrangements during the year, which resulted in capitalised arrangement and other fees for extinguished borrowings of $11 million (2017: $2 million) being fully amortised in the year. With a net interest expense of $14 million (2017: $11 million), net finance charges totalled $25 million (2017: $13 million) resulting in a higher than normal all-in average cost of borrowings of 12% (2017: 10%).

[1]*Net finance charges includes interest income, amortisation of fees and interest expense*

Loss after taxation

With the acquisition in September of oil and gas properties in Indonesia and Vietnam, the taxation expense increased to $62 million (2017: $48 million) comprising a current income tax charge of $69 million or $11 per boe (2017: $33 million or $8 per boe) and a deferred income tax credit of $7 million (2017: charge $15 million). The current income tax charge comprised Thailand special remuneratory benefit of $22 million (2017: $14 million), and other foreign taxes payable in Thailand, Indonesia and Vietnam of $48 million (2017: $14 million).

We reported a loss after taxation of $782 million or $1.10 per share (2017: $112 million, $0.16 per share).

Balance sheet

Non-current assets

Our non-current assets base increased by $190 million to $1,282 million (2017: decrease $73 million), reflecting predominantly the acquisition of oil and gas properties in Indonesia and Vietnam. The balance also included exploration and evaluation additions of $57 million (2017: $41 million) comprising $13 million in Equatorial Guinea (2017: $16 million), $19 million in Mexico (2017: $9 million), $13 million in Indonesia (2017: $7 million) and $12 million on other assets including Myanmar, Thailand and Tanzania (2017: $9 million).

Oil and gas properties included $278 million (2017: nil) for the acquisitions in Indonesia and Vietnam, which included a non-cash deferred income tax charge gross up of $96 million and profit booked on acquisition of $58 million. Oil and gas properties additions of $60 million (2017: $44 million) included expenditure in Indonesia of $9 million (2017: $13 million), Thailand of $41 million (2017: $31 million) and Vietnam of $10 million (2017: nil).

Other long term receivables increased by $70 million (2017: nil) with the acquisition of the abandonment and site restoration funds as part of the acquisition of oil and gas properties in Indonesia and Vietnam. These accounts accumulate funds over time to meet future decommissioning expenses.

Current assets

Current assets reduced substantially following the full impairment of the Block R licence in Equatorial Guinea, which was an asset classified as held for sale.

The company ended the period with cash and cash equivalents of $323 million (2017: $224 million). With undrawn available borrowings, we closed the year with gross liquidity of $391 million (2017: $427 million).

Non-current liabilities

Non-current liabilities at year-end totalled $748 million (2017: $438 million), an increase of $310 million reflecting increased long-term drawn borrowings of $143 million, and with the acquisition of oil and gas properties in Indonesia and Vietnam, increased provisions for decommissioning of $80 million (2017: $1 million) and deferred income tax liability of $89 million (2017: $15 million). We also reported short-term borrowings of $103 million in current liabilities.

Additionally, we entered into a $130 million, 18 month bridge facility in September to partly fund the acquisition of oil and gas properties in Indonesia and Vietnam. In September we drew-down $103 million of the bridge facility. Subsequently, in December we refinanced the bridge facility and our $250 million seven year reserves based lending facility into a new $350 million seven year reserves based lending facility, with a maturity of 31 December 2025. The borrowing base amount under the new reserves based lending facility was agreed with lenders at $322 million for the availability period 1 January 2019 to 30 June 2019. In July we drew $150 million against the reserves based lending facility, and then in January 2019, we drew a further $100 million.

The proceeds of the draw down in January 2019 were used to fully repay the outstanding amount of $103 million against the bridge facility.

At the end of the year there remained $107 million (2017: $107 million) outstanding for the Nordic bond. The Nordic bond matures on 6 January 2020 and we intend to refinance the bond well ahead of it maturing.

Cash flow statement

Net cash flows generated from operating activity

Cash flow from operations before working capital adjustments increased to $168 million or $27 per boe (2017: $97 million or $23 per boe). After positive working capital movements of $7 million (2017: $19 million) and interest receivable of $3 million (2017: $2 million), offset by taxation payments of $71 million (2017: $9 million), net cash flow generated from operating activity totalled $107 million or $17 per boe (2017: $109 million or $25 per boe).

The company calculates an alternative performance measure, net funds flow from production. The measure eliminates cost of activities not directly related to production and working capital movements from net cash flow generated from operating activity to reflect a measure on an accrued basis and more aligned to production performance.

A reconciliation of net cash flows generated from operating activity to net funds flow from production as follows:

	Units	2018	2017	
Net cash flows generated from operating activity	$'millions	107.4	108.7	
Reclassify from net cash flows generated from operating activity				
Pre-licence and other exploration expenses	$'millions	15.5	15.7	Pre-licence and other exploration costs of $15.5 million (2017: $15.7 million) as per note 6b
General and administration expenses	$'millions	22.9	7.4	General and administration expenses of $10.9 million (2017: $11.3 million) as per the income statement; corporate transaction costs of $14.5 million (2017: nil) as per note 6c; less share based payment of $2.5 million (2017: $3.9 million) as per cash flows statement.
Interest received	$'millions	(2.9)	(2.1)	Interest income on short term bank deposits of $2.9 million (2017: $2.1 million) as per note 7
Dividend received from joint ventures	$'millions	6.6	6.5	As per cash flow statement
Total	$'millions	42.1	27.5	
Reclassify to/from short-term working capital and other balance sheet movements				

	Units	2018	2017	
Taxation payable	$'millions	1.4	(23.2)	Movement in taxation receivable of nil (2017: negative $6.1 million) as per balance sheet, plus movement in taxation payable of negative $6.9 million (2017: negative $17.1 million) as per balance sheet; plus taxation payable of $8.3 million (2017: nil) as per note 11.
Working capital movements	$'millions	(7.3)	(19.2)	Decrease in inventories of $6.9 million (2017: $7.1 million) as per cash flow statement; plus increase in other current and non-current payables of $14.8 million (2017: $2.0 million) as per cash flow statement; less decrease in other current and non-current liabilities of $14.4 million (2017: increase $10.1 million) as per cash flow statement.
Other adjustments	$'millions	(0.5)	(3.7)	
Total	$'millions	(6.0)	(46.1)	
Total net funds flow from production		143.5	90.1	

NB: Since we have increased our production and cash flow base, it is more appropriate to report on an IFRS basis for cash outflows, therefore we have removed the use of funds flow table used in 2017.

Net cash flows used in investing activity

Reflecting the timing of payments for investing activities, net cash flow used in investing activities totalled $247 million (2017: $136 million). This predominantly comprises the acquisition of oil and gas properties in Indonesia and Vietnam of $138 million (2017: nil) other investing cash flows of $114 million (2017: $143 million), partly offset by a credit of $5 million (2017: $6 million) from net investments in joint ventures. The company's principal investing activities are set-out above in non-current assets.

Net cash flows from/used in financing activities

Net cash inflows from financing activities of $239 million (2017: outflow $109 million) reflected changes to our borrowing portfolio as set-out above in non-current assets, after accounting for arrangement and other fees and interest paid of $15 million (2017: $15 million).

Financial outlook

This financial outlook is provided on the premise of the company remaining an independent entity.

On that basis, 2019 production is forecast at 25,000 boepd. We will complete workovers at Kerendan and replace electric submersible pumps at Bualuang, which will temporarily increase operating costs from the base level of $12 per boe to $16 per boe. In November we entered into a further commodity price hedge programme against 2019 Bualuang production for 2,000 bopd by selling a Brent swap for approximately $56 per bbl and buying a Brent call for approximately $66 per bbl. For 2019, we have hedged approximately 16% of our total production, equivalent to 29% of our oil and liquids production. Further hedge programmes may be entered into during 2019 on a defensive basis against production in 2019 and 2020.

Exploration and evaluation expenditure is forecast to reduce in 2019 to $35 million versus the 2018 out-turn of $65 million. 2019 activity assumes certain farm outs as we further reduce our exposure to frontier exploration. Additionally, amounts are provided for settlement of outstanding financial commitments due to host governments where those commitments cannot be offset, deferred or otherwise mitigated.

2019 oil and gas properties expenditure is forecast at $105 million compared to the 2018 out-turn of $49 million and includes Bualuang phase 4 development, with the construction and hook-up of the Charlie platform and with the drilling of up to 12 new infill wells, and Meliwis development expenditure following the FID in 1Q'19.

Allowing for general administration costs, interest charges, and short-term working capital and other balance sheet movements, 2019 year-end net debt is forecast at $60 million.

We expect to end 2019 with outstanding borrowings of $300 million giving rise to, on a gross debt basis, a leverage ratio of 1.3 (net debt basis: 0.2) and gearing ratio of 30% (net debt basis: 7%). 2019 year-end gross liquidity is estimated at $240 million.

The company currently has no distributable reserves absent which, it is unable presently to return capital to shareholders (including share buy-backs). We have commenced a process to determine the potential to create distributable reserves that would allow the company to return capital to shareholders in the future. We will update shareholders following completion of this significant piece of work.

Additionally, we are looking to reduce our outstanding exploration financial commitments due to host governments during 2019 and will provide further updates in due course. Our other obligations against net funds flow from production after investment expenditures will then be limited to general and administration costs and borrowings' debt service (interest plus principal). Surplus cash flows and cash balances will then be available for investment or return to shareholders.

Tony Rouse
Chief Financial Officer
11 March 2019

Consolidated income statement and statement of other comprehensive income
For the year ended 31 December 2018

Consolidated income statement	Notes	2018 $'000	2017 $'000
Continuing operations			
Revenue		298,246	188,527
Cost of sales	5a	(199,208)	(147,577)
Gross profit		**99,038**	**40,950**
Share of profit of investments accounted for using the equity method		4,858	4,181
Impairment (losses)/reversal of oil and gas properties	7	(13,500)	23,681
Impairment of investments accounted for using the equity method		(45,000)	(7,800)
Impairment of non-current assets held for sale		(613,652)	-
Exploration expenses		(130,406)	(91,836)
General and administration expenses		(10,861)	(11,279)
Gain on bargain purchase	3	57,542	-
Other operating expenses	5c	(40,763)	(11,699)
Operating loss		**(692,744)**	**(53,802)**
Net finance expense		(27,187)	(12,907)
Other financial gains		160	2,300
Loss from continuing operations before taxation		**(719,771)**	**(64,409)**
Taxation expense		(61,899)	(47,383)
Loss from continuing operations for the year		**(781,670)**	**(111,792)**
Attributable to:			
Equity holders of the Company		(781,670)	(111,792)
		(781,670)	**(111,792)**
Earnings per ordinary share			
Basic – (Loss)/profit for the period attributable to equity holders of the Company		(110.5)cents	(15.8)cents
Diluted – (Loss)/profit for the period attributable to equity holders of the Company		(110.5)cents	(15.8)cents

Consolidated statement of other comprehensive income	2018 $'000	2017 $'000
Loss from continuing operations for the year	**(781,670)**	**(111,792)**
Other comprehensive income/(loss)		
Other comprehensive income/(loss) to be reclassified to profit or loss in subsequent periods:		
Exchange differences on retranslation of foreign operations net of tax	(31)	-
Cash flow hedges marked to market	5,584	(5,882)
Cash flow hedges reclassified to the income statement	7,968	-
Other comprehensive income/(loss) for the year, net of tax	13,521	(5,882)
Total comprehensive loss for the year, net of tax:	**(768,149)**	**(117,674)**
Attributable to:		
Equity holders of the Company	**(768,149)**	**(117,674)**
	(768,149)	**(117,674)**

Consolidated statement of financial position

As at 31 December 2018

	Notes	**2018 $'000**	2017 $'000
Non-current assets			
Exploration and evaluation assets	6	196,142	247,944
Oil and gas properties	7	917,088	699,669
Other property, plant and equipment		1,380	2,211
Investments accounted for using the equity method		76,084	120,964
Other long term receivables		91,068	21,205
		1,281,762	**1,091,993**
Current assets			
Assets classified as held for sale		-	604,432
Inventory		33,517	40,647
Derivative financial instruments		9,970	-
Taxation receivable		9,140	9,125
Trade and other receivables		58,976	24,656
Cash and cash equivalents		323,414	223,779
		435,017	**902,639**
Total assets		**1,716,779**	**1,994,632**
Current liabilities			
Trade and other payables		(98,984)	(52,374)
Interest-bearing bank borrowings due within one year		(103,200)	–
Taxation payable		(37,195)	(30,282)
Provisions		(33,604)	(9,399)
Derivative financial instruments		-	(3,582)
		(272,983)	**(95,637)**
Non-current liabilities			
Trade and other payables		(14,739)	(15,279)
Interest-bearing bank borrowings		(142,499)	-
Bonds payable		(106,650)	(106,651)
Provisions		(130,676)	(51,265)
Deferred tax liability		(353,548)	(264,491)
Net defined benefit liability		(14)	-
		(748,126)	**(437,686)**
Total liabilities		**(1,021,109)**	**(533,323)**
Net assets		**695,670**	**1,461,309**
Capital and reserves			
Called up share capital		3,061	3,061
Reserves		692,609	1,458,528
Equity attributable to equity shareholders of the Company		**695,670**	**1,461,589**
Non-controlling interest		–	(280)
Total equity		**695,670**	**1,461,309**

The consolidated financial statements of Ophir Energy plc (registered number 05047425) were approved by the Board of Directors on 8 March 2019

On behalf of the Board:

Tony Rouse
Chief Financial Officer

Consolidated statement of changes in equity
For the year ended 31 December 2018

	Called up share capital $’000	Treasury shares $’000	Other reserves $’000	Non- controlling interest $’000	Total equity $’000
As at 1 January 2017	**3,061**	**(153)**	**1,572,449**	**(280)**	**1,575,077**
Loss for the period, net of tax	–	–	(111,792)	–	(111,792)
Other comprehensive loss, net of tax	–	–	(5,882)	–	(5,882)
Total comprehensive loss, net of tax	–	–	(117,674)	–	(117,674)
Exercise of options	–	1	–	–	1
Share-based payment	–	–	3,905	–	3,905
As at 31 December 2017	**3,061**	**(152)**	**1,458,680**	**(280)**	**1,461,309**
Loss for the period, net of tax	–	–	(781,670)	–	(781,670)
Other comprehensive loss, net of tax	–	–	13,521	–	13,521
Total comprehensive loss, net of tax	–	–	(768,149)	–	(768,149)
Disposal of subsidiary	–	–	(280)	280	–
Exercise of options	–	3	–	–	3
Share-based payment	–	–	2,507	–	2,507
As at 31 December 2018	**3,061**	**(149)**	**692,758**	–	**695,670**

Consolidated statement of cash flows
For the year ended 31 December 2018

	2018 $'000	2017 $'000
Operating activities		
Loss before taxation	(719,771)	(64,409)
Adjustments to reconcile loss before taxation to net cash provided by operating activities		
Exploration expenditure written off and loss on exploration inventory	114,942	76,108
Gain on bargain purchase	(57,542)	-
Impairment of non-current assets held for sale	613,652	-
Depreciation and amortisation	107,876	79,230
Net impairment/(reversal) on oil and gas properties	13,500	(23,681)
Impairment of investments accounted for using the equity method	45,000	7,800
Share of profits from joint ventures	(4,858)	(4,181)
Net finance expenses	27,158	14,724
Net foreign currency loss/(gain)	29	(1,817)
Share based payment expense	2,507	3,905
Increase in provisions	24,197	9,381
Other non-cash losses/(gains)	1,015	(180)
Cash flow from operations before working capital adjustments	**167,705**	**96,880**
Decrease in inventories	6,918	7,123
Increase in other current and non-current payables	14,750	1,962
(Increase)/decrease in other current and non-current assets	(14,375)	10,147
Cash generated from operations	**174,998**	**116,112**
Interest received	2,949	2,057
Income taxes paid	(70,528)	(9,485)
Net cash flows generated from operating activities	**107,419**	**108,684**
Investing activities		
Additions to Exploration and Evaluation assets	(64,587)	(95,827)
Additions to oil and gas assets and other property, plant and equipment	(49,140)	(47,179)
Funding provided to joint ventures	(1,824)	(370)
Dividends received from joint ventures	6,562	6,523
Acquisitions, net of cash acquired	(137,847)	-
Proceeds from disposals of assets	-	428
Net cash flows used in investing activities	**(246,836)**	**(136,425)**
Financing activities		
Interest paid	(14,591)	(15,217)
Proceeds/(repayment) of debt	253,200	(93,656)
Net issue/(repurchase) of shares	4	1
Net cash inflows/(outflows) from financing activities	**238,613**	**(108,872)**
Effect of exchange rates on cash and cash equivalents	439	(32)
Increase/(decrease) in cash and cash equivalents	99,635	(136,645)
Cash and cash equivalents at the beginning of the year	223,779	360,424
Cash and cash equivalents at the end of the year	**323,414**	**223,779**

Notes to the financial statements

1. Corporate information

Ophir Energy plc (the 'Company' and ultimate parent of the Group) is a public limited company domiciled and incorporated in England and Wales with company number 05047425. The Company's registered offices are located at 123 Victoria Street, London SW1E 6DE.

The principal activity of the Group is the development of offshore oil and gas exploration assets. The Company has an extensive and diverse portfolio of exploration interests across Africa, Mexico and Southeast Asia.

The Group's consolidated financial statements for the year ended 31 December 2018 were authorised for issue by the Board of Directors on 8 March 2019 and the consolidated statement of financial position was signed on the Board's behalf by Tony Rouse.

2. Basis of preparation and significant accounting policies

The consolidated financial statements of the Group have been prepared in accordance with IFRS as issued by the International Accounting Standards Board and adopted by the European Union (EU), IFRIC Interpretations and the Companies Act 2006 applicable to companies reporting under IFRS.

The consolidated financial statements are prepared on a going concern basis.

The consolidated financial statements have been prepared under the historical cost convention, modified by the revaluation of certain derivative instruments measured at fair value. The consolidated financial statements are presented in US Dollars rounded to the nearest thousand dollars ($'000) except as otherwise indicated.

Comparative figures for the period to 31 December 2017 are for the year ended on that date.

The abbreviated financial statements do not include all the information and disclosures required in the annual financial statements, and should be read in conjunction with the consolidated financial statements in the Ophir Energy plc Annual Report and Accounts for the year ended 31 December 2018.

New International Financial Reporting Standards adopted

The Group has adopted the following relevant new and amended IFRS and IFRIC interpretations as of 1 January 2018:

- IFRS 9 'Financial Instruments'
- IFRS 15 'Revenue from Contracts with Customers'

There are no other new or amended standards or interpretations adopted during the year that have a significant impact on the financial statements.

IFRS 9 'Financial Instruments'

IFRS 9 provides a single classification and measurement approach for financial assets that reflects the business model in which they are managed and their cash flow characteristics. Under the new standard the group's financial assets are classified as measured at amortised cost, fair value through profit or loss, or fair value through other comprehensive income. For financial liabilities the existing classification and measurement requirements of IAS 39 are largely retained. Whilst financial assets have been reclassified into the categories required by IFRS 9, the group has not identified any impacts on the measurement of its financial assets and financial liabilities as a result of the classification and measurement requirements of the new standard. Trade receivables are held to collect contractual cash flows and are expected to give rise to cash flows representing solely payments of principal and interest. Thus, the Group has continued to measure these at amortised cost under IFRS 9.

Under IFRS 9, impairments of financial assets classified as measured at amortised cost are recognised on an expected credit loss (ECL) basis which incorporates forward-looking information when assessing credit risk. Movements in the expected loss reserve are recognised in profit or loss. Due to the short-term nature and high quality of the financial assets, the Group has not recognised any impacts on the adoption of IFRS 9.

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. IFRS 9 also introduces a new way of treating fair value movements on the time value of certain hedging instruments. Whereas under IAS 39 these movements were recognised in profit or loss, under IFRS 9 they are initially recognised in equity to the extent that they relate to the hedged item. An adjustment to the 2018 opening balance sheet has been made to transfer $2.3 million of gains from retained earnings to the hedging reserve for relevant hedging instruments existing on transition. As permitted by IFRS 9 comparatives were not restated.

IFRS 15 'Revenue from Contracts with Customers'

Under IFRS 15, revenue from contracts with customers is recognised as or when 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 and gas sold by the group coincides with title passing to the customer and the customer taking physical possession. The group have applied the modified retrospective approach and there is no transition impact. The group satisfies its performance obligations at a point in time. The accounting for revenue under IFRS 15 does not, therefore, represent a change from the group's previous practice for recognising revenue from sales to customers. An analysis of revenue from contracts with customers by product is presented by product and segment in note 4.

3. Business combinations

Acquisition of Producing Assets from Santos Limited

On 6 September 2018, Ophir completed the acquisition of a package of Southeast Asian assets from Santos. Ophir acquired interests in three producing assets: (i) a 31.875% working interest in the Block 12W PSC in Vietnam; (ii) a 45% operated interest in the Sampang PSC in Indonesia; and (iii) a 67.5% operated interest in the Madura Offshore PSC in Indonesia for a total cash consideration of $148.7 million. The acquisition was part of Ophir's strategy to grow its production base further in order to self-fund its selective exploration, appraisal and development activities.

A gain on bargain purchase of $57.5 million was recognised on the acquisition being the excess of the fair value of net assets acquired as set out below, over the purchase consideration. The net asset fair values, in line with accounting standards, were determined, where applicable, and particularly in respect of oil and gas properties, by reference to oil and gas prices as reflected in the prevailing market view on the day of completion, as well as using estimates of proved oil and gas reserves and unproved volumes including timing of production, discount rates and exchange rates. Oil prices were based on the forward price curve for the first 3 years and $60 per barrel inflated at 2.5% for the remaining life of the asset. Gas prices were based on the relevant gas sales agreements in place at the time of acquisition.

Fair value of net assets acquired	$'000
Assets	
Non-current assets	
Oil & gas properties	278,102
Other long term receivables	75,260
Defined benefit asset	969
	354,331
Current assets	
Inventory	7,029
Trade and other receivables	24,906
Cash and cash equivalents	9,402
	41,337
Total assets	395,668
Liabilities	
Current liabilities	
Trade and other payables	(15,842)
Taxation payable	(8,269)
	(24,111)
Non-current liabilities	
Long term provisions	(68,951)
Deferred tax liability	(96,393)
	(165,344)
Total liabilities	(189,455)
Total	206,213

The gross amount of trade and other receivables equates to the fair value and it is expected that the full contractual amounts can be collected.

Acquisition costs of $6.5 million were recognised in other operating expenses in the Consolidated Statement of Income.

The acquired production assets contributed $85.1 million of revenue and $84.9 million of profit before tax (including the gain on bargain purchase) to the Consolidated Statement of Income since the date of acquisition. Had the acquisition date been 1 January 2018, the acquired production assets would have contributed $267.1 million of revenue and $229.5m of profit before tax (including the gain on bargain purchase) to the Consolidated Statement of Income.

4. Segmental analysis

The Group's reportable and geographical segments are Africa, Asia and Other. The other segment relates substantially to activities in the UK.

Segment revenues and results

The following is an analysis of the Group's revenue and assets by reportable segment:

Year ended 31 December 2018	Africa $'000	Asia $'000	Other $'000	Total $'000
Oil revenue from contracts with customers	-	251,670	-	251,670
Gas revenue from contracts with customers	-	54,544	-	54,544
Loss relating to oil derivatives	-	(7,968)	-	(7,968)
Depreciation and amortisation	-	(107,241)	(635)	(107,876)
Impairment of exploration costs	(1,206)	(98,788)	-	(99,994)
Impairment of oil and gas properties	-	(13,500)	-	(13,500)
Impairment of investments accounted for using the equity method	-	(45,000)	-	(45,000)
Impairment of non-current assets held for sale	(613,652)	-	-	(613,652)
Share of profit of equity-accounted joint venture	-	4,858	-	4,858
Segment Results				
Operating loss	(623,797)	(60,794)	(8,153)	(692,744)
Finance income	-	280	2,669	2,949
Finance expense	(377)	(1,299)	(28,460)	(30,136)
Other financial gains	-	160	-	160
Loss before tax	(624,174)	(61,653)	(33,944)	(719,771)
Taxation	(1,341)	(60,558)	-	(61,899)
Loss after tax	(625,515)	(122,211)	(33,944)	(781,670)
	As at 31 December 2018			
Total assets and total liabilities				
Total assets	113,462	1,511,119	92,198	1,716,779
Total liabilities	(39,751)	(948,779)	(32,579)	(1,021,109)
Investments accounted for using the equity method	-	76,084	-	76,084
	Year ended 31 December 2018			
Additions to non-current assets	17,872	80,226	19,407	117,505

Year ended 31 December 2017	Africa $'000	Asia $'000	Other $'000	Total $'000
Oil revenue from contracts with customers	–	169,461	–	169,461
Gas revenue from contracts with customers	-	19,066	-	19,066
Gain/(loss) relating to oil derivatives	-	-	-	-
Depreciation and amortisation	–	(77,529)	(542)	(78,071)
Impairment of exploration costs	(60,744)	(15,887)	(21)	(76,652)
Impairment of oil and gas properties	–	23,681	–	23,681
Impairment of investments accounted for using the equity method	–	7,800	–	7,800
Share of profit of equity-accounted joint venture	–	4,181	–	4,181
Segment Results				
Operating (loss)/profit	(58,783)	34,604	(29,623)	(53,802)
Finance income	9	93	1,955	2,057
Finance expense	148	(994)	(14,118)	(14,964)
Other financial gains	–	–	2,300	2,300
(Loss)/profit before tax	(58,626)	33,703	(39,486)	(64,409)
Taxation	5,296	(52,676)	(3)	(47,383)
Loss after tax	(53,330)	(18,973)	(39,489)	(111,792)
	As at 31 December 2017			
Total assets and total liabilities				
Total assets	729,337	1,113,555	151,740	1,994,632
Total liabilities	(45,443)	(479,495)	(8,385)	(533,323)
Investments accounted for using the equity method	-	120,964	-	120,964
	Year ended 31 December 2017			
Additions to non-current assets	13,384	62,780	8,736	84,900

Non-current operating assets

The non-current operating assets for the UK are $0.8 million (2017: $1.5 million). The non-UK, non-current operating assets are $1,114 million (2017: $948.3 million). Included in the non-UK, non-current operating assets is Thailand which makes up $409.0 million (2017: $414.9 million), Indonesia $374.6 million (2017: $284.9 million), Tanzania £110.1 million (2017: $106.0 million).

5. Operating (loss)/profit before taxation

The Group's operating (loss)/profit before taxation included the following items:

	Year ended 31 Dec 2018 $'000	Year ended 31 Dec 2017 $'000
(a) Cost of sales:		
– Operating costs	72,764	48,864
– Royalty payable	19,308	14,057
– Depreciation and amortisation of oil and gas properties	107,041	77,529
– Movement in inventories of oil	95	7,127
	199,208	147,577
(b) Exploration expenses:		
– Pre-licence and other exploration costs	15,464	15,728
– Exploration expenditure written off (Note 6)	99,994	76,652
– Impairment/(reversal) and loss on disposal of exploration inventory	14,948	(544)
	130,406	91,836
(c) Other operating expense:		
– Loss/(profit) on disposal of assets	1,015	(180)
– Depreciation of other property, plant & equipment	200	288
– Provision for exiting contracts	7,350	8,900
– Restructuring costs[1]	17,415	1,935
– Other	309	756
– Corporate transaction expense[2]	14,474	-
	40,763	11,699

[1] Restructuring costs consist of onerous leases of $9.5 million and redundancy and other staff related costs of $7.9 million

[2] Corporate transaction expenses consist of $6.5 million in relation to the acquisition of assets from Santos (see note 3) and $8.0 million incurred in relation to the potential acquisition of Ophir by PT Medco Energi Global PTE Ltd

(d) General & administration expenses include:		
– Operating lease payments	2,843	3,424
– Share-based payment expense	2,507	3,905
	5,350	7,329

6. Exploration and evaluation assets

	Year ended 31 Dec 2018 $'000	Year ended 31 Dec 2017 $'000
Cost		
Balance at the beginning of the year	247,944	310,229
Additions[1]	57,411	40,788
Disposal of asset	-	(150)
Transfers to oil and gas properties	-	(10,608)
Reclassified as assets held for sale	(9,219)	(15,663)
Expenditure written off[2]	(99,994)	(76,652)
Balance at the end of the year	196,142	247,944

1. Additions for the year ended 31 December 2018 included exploration activities in: Mexico Block 10 ($9.7 million), Equatorial Guinea – Block R ($9.2 million subsequently reclassified as an asset held for sale and written off), Mexico Block 5 ($7.5 million), Paus Biru ($6.2 million), West Bangkanai ($4.2 million), Tanzania Block 1 ($3.4 million), Ophir Equatorial Guinea (EG-24) ($3.4 million), Myanmar ($3.1 million) and Mexico Block 12 ($2.2 million).

   Additions for the year ended 31 December 2017 included exploration activities in: Equatorial Guinea – Block R ($15.7 million subsequently reclassified as an asset held for sale), Myanmar ($2.9 million), West Papua IV ($4.6 million) and Mexico Block 5 ($8.5 million).

2. Expenditure written off in the year was $100 million mainly attributable to Myanmar ($43 million), West Papua IV ($31.3 million), Aru ($8.6 million), North Ganal ($7.3 million) and North East Bangkanai ($4.5 million).

   Expenditure written off in 2017 was $77 million mainly attributable to Cote d'Ivoire ($32 million) and Gabon ($32 million).

   The CGU applied for the purpose of the impairment assessment is the Blocks. The recoverable amount of each Block was nil. This was based on management's estimate of value in use. The trigger for expenditure write off was management's assessment that no further expenditure on exploration and evaluation of hydrocarbons in the Block was budgeted or planned within the current licence terms.

7. Oil and gas properties

	Year ended 31 Dec 2018 $'000	Year ended 31 Dec 2017 $'000
Cost		
Balance at the beginning of the year	929,795	875,278
Acquisition of subsidiary	278,102	-
Additions[1]	60,051	43,909
Transfers from Exploration and evaluation assets	-	10,608
Balance at the end of the year	1,267,948	929,795
Depreciation and amortisation		
Balance at the beginning of the year	(230,126)	(176,278)
Charge for the year	(107,234)	(77,529)
Impairment (charge)/reversal[2]	(13,500)	23,681
Balance at the end of the year	(350,860)	(230,126)
Net book value		
Balance at the beginning of the year	699,669	699,000
Balance at the end of the year	917,088	699,669

1 Additions in 2018 are stated net of a $7.9 million (2017:nil) decommissioning remeasurement

2 The 2018 impairment charge was due to revisions to cost estimates of future development phases on the Bangkanai asset in Indonesia. The Bangkanai asset has a recoverable amount of $248 million based on management's estimate of value in use. The discount rate used was 12% (pre-tax)
The 2017 Impairment reversal was due to further increased reserves related to the Bualuang infill drilling results in Thailand which had a recoverable amount of $424 million in 2017 based on management's estimate of value in use. The discount rate used was 22% (pre-tax).

8. Net debt

	Year ended 31 Dec 2018 $'000	Year ended 31 Dec 2017 $'000
Amounts due on maturity:		
Interest bearing bank loans	(245,699)	–
Bonds payable	(106,650)	(106,651)
Total borrowings	(352,349)	(106,651)
Less: Issue costs not yet amortised	(7,501)	-
Less: Fair value adjustments at initial recognition	1,850	1,850
Total gross debt	(358,000)	(104,801)
Less: cash and cash equivalents	323,414	223,779
Total net(debt)/ cash	(34,586)	118,978