7 March 2018

Ophir Energy plc
("Ophir")

2017 Full Year Results

Ophir announces its full year results for the year ended 31 December 2017.

NICK COOPER, CHIEF EXECUTIVE OFFICER, COMMENTED:

"2017 saw Ophir take important steps to adapt and right-size the business, meet key operational targets and replenish our exploration portfolio. Nevertheless, we are disappointed to have not yet achieved the Fortuna project FID despite having made significant progress on the project. The rebalancing of our portfolio and our capex prioritisation away from its prior primary exploration focus has seen Ophir approach sustainability. In 2017 we have grown reserves by 13%, increased net funds flow from production by 46%, reduced gross G&A by a further 17%, increased liquidity by $57 million and by year end we had delivered NAV growth of 6.4%.

"Our 2018 priorities are threefold: to deliver the Fortuna project FID; to further monetise our significant contingent resources; and to grow production and cash flow. Ophir operates a long life, low cost production base and has a strong balance sheet. We sanctioned a fourth phase of development on our Bualuang oil field which will grow production in 2018-19, agreed an increased gas price on our Kerendan field and are in negotiation to double production from this asset by 2020. The Group is well-positioned to take advantage of the opportunities that this down cycle has presented by growing our cash flows and capturing excellent options in proven hydrocarbon systems, as shown by our recent block awards in Equatorial Guinea and Mexico."

2017 SUMMARY

Financial Discipline

- Revenue increased 76% to $189 million (2016: $107 million)
- Unit operating costs (excluding Sinphuhorm) decreased 4% to $12.79 per boe (2016: $13.38 per boe)
- Net funds flow from production increased 46% to $90 million[1] (2016: $62 million), equivalent to $21.30 per boe (2016: $10.53 per boe)
- Right-sized the business with further reductions of G&A by reducing headcount at the London Head Office along with reductions of expatriate employees. G&A costs reduced by 60% over a three-year period.
- Net cash at year-end of $117 million (2016: $160 million)
- Completed refinance of our $250 million reserve based lending facility ending the year with gross liquidity of $427 million[2] (2016: $371 million).

[1] A reconciliation of net funds flow from production is presented within the table in the Financial Review section

[2] As defined in table within financial review section

Resource Monetisation Activities (Pre-development, Development and Producing assets)

- The completion of project financing on the Fortuna project has taken longer than expected, but all other milestones were achieved in 2017 with: the signing of the Umbrella Agreement; the nomination of a preferred supplier for the LNG offtake; and the award of upstream and midstream construction contracts. We will provide further updates in due course.
- The Bualuang Phase IV development FID was approved and will commence in 2H 2018 with an infill drilling programme, followed by the installation of a 12 slot platform in 1H 2019. Rapid payback on $138 million investment.
- Our 2P Reserves increased by 13% to 49.4 mmboe; principally driven by the conversion of 9.9mmboe at Bualuang from 2C to 2P following decision on the Phase IV development.
- In February 2018, an agreement in principle was reached with PLN to increase the gas price on the Kerendan gas sales from the current price of $5.08/mmbtu to $5.65/mmbtu. The recently acquired 3D seismic on the asset have also enabled the start of negotiations with PLN for a second GSA to potentially double production from the asset by 2020.

- Production averaged 11,700 boepd. Production in 2018 is expected to average 11,500 boepd with infill drilling taking place on Bualuang in 2H 2018. In 2019-20, we expect material production growth from our next phases of development on Bualuang and Kerendan.

Exploration Activities

- Exploration portfolio has been refocused to deliver exploration around existing infrastructure to complement recently acquired acreage in Mexico and Equatorial Guinea.
- Seven deep water licences were relinquished in Africa and Asia in 2017.

FINANCIAL SUMMARY

	Units	FY 2017	FY 2016
Realised oil price	$/bo	51.86	37.85
Realised gas price	$/Mscf	5.30	N/A
Revenue	$'millions	188.5	107.2
Kerendan Take-or-Pay	$'million	-	16.5
Operating costs	$/boe	12.8	13.4
Capital Expenditure (including pre-licence expenditure and less disposals, and investments)	$'millions	101.1	155.6
Net funds flow from production	$'millions	90.1	61.7
Net cash	$'millions	117.1	160.1
Closing undrawn debt facilities	$'millions	203.5	10.3
Closing gross liquidity (including undrawn debt facilities)	$'millions	427.3	370.7

A presentation for investors and analysts will be held at 9.30am this morning. A webcast of the event will be available on the company's website: www.ophir-energy.com/investors.

For further enquiries, please contact:

Ophir Energy plc **+ 44 (0) 20 7811 2400**
Geoff Callow, Head of IR and Corporate Communications

Brunswick (PR Adviser to Ophir) **+ 44 (0) 20 7404 5959**
Patrick Handley
Wendel Verbeek

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).

Chief Executive Officer's Strategic Review

The period 2015-17 has been a challenging time for upstream E&P. At Ophir, our response to the downturn was to focus on what we control, namely maximising our margins. After three years of portfolio and cost readjustment and a consistent focus on growing NAV per share, Ophir has emerged from the cyclical downturn well positioned to deliver sustainable returns to shareholders going forward.

Since 2014, we have reduced the magnitude of our annual capital spend and have prioritised our assets that offer the most sustainable, lower risk returns. In keeping with this strategy, our capital allocation priorities are:

- Maximising and expanding cash flow from production assets;
- Monetising contingent resource;
- Refocused exploration and/or returns to shareholders.

In order to maximise margin growth during 2017, we further reduced unit opex, capex and overhead costs. Among the more visible actions was the reduction to the London head office organisation along with a reduction of the executive team, and the decision by the executives to waive their 2017 bonus entitlements. These actions helped us to deliver $21 per boe of net funds flow from production that averaged 11,700 boepd. The rebalancing of our portfolio and our capex prioritisation away from its prior primary exploration focus has seen Ophir approach sustainability. Most importantly, we have achieved these results with a strong safety record.

A firm financial footing

With a strong balance sheet, a robust operating cash flow and an experienced team, we have the capacity to monetise our sizeable contingent resource portfolio. In June we completed a new $250 million reserve based lending facility secured against our producing Asian assets, along with an additional $100 million accordion facility.

Returns based investment

Ophir's operating model is to find resources cheaply and then monetise them smartly. Consequently our deployment of capital and manpower is dictated by where we can maximise returns. With an approximate net 1 billion boe of contingent resources, our overriding priority is to rapidly and safely monetise these substantial discovered hydrocarbons.

We were disappointed that we were unable to FID the Fortuna project as hoped in 2017, but we ended the year having completed all other material steps required to achieve the FID and we made further progress across the rest of our portfolio. Our Bualuang field is moving into a fourth development phase which will drive cash flow growth in 2018-19 and on our Kerendan field we recently reached an agreement in principle to increase gas price and started negotiations for a doubling of production by 2020.

We must be a financially and operationally sustainable business. This requires us to add to our resource base with exploration, albeit with discipline and prudence. Our exploration efforts are now focused on a smaller number of core areas where we are confident of promptly monetising any discoveries. We have selectively picked up new acreage in Equatorial Guinea ("EG") and in Mexico where Ophir is now the biggest independent listed acreage holder in the Mexican offshore.

Fortuna FLNG – cost competitive LNG

Fortuna FLNG is potentially a transformative project for Ophir. For a relatively limited forward investment, we are looking to launch a world class development that will offer significant, annuity-like cash flow for 20+ years. This future cashflow would underpin both further investments and capital returns.

The project financing is the last remaining major milestone before Fortuna can reach FID and it was very frustrating not to achieve this in 2017. However, in partnership with OneLNG, we continue to work to secure the funding that will enable FID to be taken.

We take confidence from Fortuna's robust, low breakeven economics with low development costs and world class flow rates that contribute to arguably the most competitive greenfield LNG project in the world today.

An annual global LNG demand growth of around 4-5%, combined with a forecast slowing of LNG supply growth beyond 2020 and a tightening supply/demand balance has positioned Fortuna well as it enters production from 2022. A benefit of the current commodity price slump is that we have been able to lock in lower unit pricing for the development.

We are working towards reaching first gas in 2022, when we can look forward to annuity-like free cash flows from the asset of approximately $150 million per year at current prices. Importantly, the Company has selected a preferred off-taker on attractive commercial terms, as we announced a Brent-linked, free-on-board offtake agreement with the Gunvor Group ('Gunvor'). Upon execution of the commercial terms Gunvor would underwrite the contract capacity of the Gandria FLNG vessel of 2.2 MMTPA. Under this agreement, we would retain the option for up to two years from FID to secure an alternative, premium priced market for 1.1 MMTPA of this volume. In addition we would retain the option to market the remaining 0.3-0.5 MMTPA of further offtake from the project.

Our vessel for conversion, the Gandria, is expected to enter the shipyard in early March 2018 to commence early works. Separately, Golar's first FLNG vessel, FLNG Hilli Episeyo, left the same shipyard and reached its operating location in Cameroon in November 2017. The vessel is currently being commissioned prior to delivery of its first commercial cargo. The delivery of this first cargo would represent an important step in the de-risking of the midstream component of the Fortuna FLNG project.

Bualuang and Kerendan – reliable production – significant upside

In 2017, we took the investment decision to undertake the fourth development phase of the Bualuang oil field. The initial phase of this development will start with infill drilling in 2018 and will continue in 2019 with the installation of a new platform and then further drilling. This fourth development phase has converted 9.9 MMbo of contingent resource into proved and probable reserves and is expected to deliver rapid payback on the estimated US$138 million total development cost. In addition, the 2017 Bualuang infill drilling programme completed successfully and enabled us to maintain the field's average production across the year at 8,300 boepd.

At the Kerendan gas field, we have been renegotiating the gas price for the current phase one production and taking steps to monetise further gas from the asset beyond the initial contracted amount of 122 Bcf. The onshore 3D seismic survey on Bangkanai and West Bangkanai was completed in December 2017. This data, in combination with the information from the 2014 West Kerendan-1 ("WK-1") well and WK-1 drill stem test, is expected to provide the assurance to SKK Migas (the State regulator) for them to certify further tranches of gas sales. Over the medium term, we see potential to triple gas sales from the field. We will be working on initiatives to realise that potential in 2018.

In February 2018, a higher gas price of $5.65 per MMbtu was agreed in principle for the current phase one volumes that we are producing today. Negotiations have started for a second phase of gas supply to PLN for a proposed 145MW gas-fired power plant adjacent to the existing plant. It is expected that this will approximately double the current output from 2020. Beyond this, we are examining options for further, third party sales on a similar timeline.

Exploration

This year, we continued to exit countries that could not meet our returns or risk criteria and to focus on fewer plays. We are pleased to have established the biggest footprint offshore Mexico of the listed independent E&Ps. The Mexican Block 5 licence was signed in 2017 and this was followed-up in early 2018 by the award to Ophir of the Block 10 and Block 12 licences. All of these are non-operated positions with high quality partner groups with low committed costs.

Ophir was also successful in securing block EG-24 in 2017. This operated licence is close to infrastructure and prospective for oil. A farmout process is ongoing. Also we will take 'drill or drop' decisions in 2018 on our acreage in Myanmar and Indonesia, with these decisions as ever being based on the risk-reward and our capital discipline.

Across our refocussed portfolio several targets have been identified for potential drilling from 2H 2018. These include lower cost satellite targets adjacent to our Bualuang and Kerendan producing fields.

People and Safety

To meet the targets we have set for the business, we were required to undertake some difficult but important actions in 2017. In particular, we reduced our London office and expatriate head count by approximately 50%, which equated to approximately 15% of our global workforce. This action has resulted in savings of approximately US$12 million per year. The reduction was carefully undertaken in the context of prioritising the monetisation of existing discovered resource, and of shifting the exploration focus onto a more concentrated portfolio. As part of this process, Dr Bill Higgs left the Board of Ophir. I would like to personally thank Bill for his substantial contribution to Ophir and wish him much success in his future endeavours.

The staff reductions Ophir has affected since the acquisition of Salamander Energy has demonstrated the synergies available from such transactions. We are now effectively running the two companies for the costs of one. Moreover, we have retained all competencies and experience essential to the delivery of our core projects.

We have also sought to engender a stronger culture of ownership with our NAV remuneration structure. With this incentive package, every member of the team is focused on delivering the best value for every dollar invested.

Regardless of the size or composition of our workforce, safety remains our absolute priority. This year, and with an additional 1,400 plus contractors working at times on our onshore Kerendan 3D seismic programme, I am very pleased to report that we achieved zero LTIs on over 7 million hours worked. As we note in the Corporate Responsibility section of the report, we reached two significant milestones in 2017: Our Thailand operations achieved three LTI free years through which we undertook multiple drilling programmes and completion of numerous infrastructure upgrades. In Indonesia we reached over two years LTI free, having completed a challenging onshore 3D seismic survey.

A sustainable business

In what has been one of the most challenging down cycles, our team has continued to drive forward projects that we believe will realise material value in the coming years. We have adapted and right-sized our business, and have met most of our operational targets set for 2017.

In the past three years, Ophir has transitioned from an equity-funded explorer towards being a sustainable, full-cycle upstream independent. We entered the downturn with arguably the most fragile business model of our peer group, and we are emerging from it in a far healthier, more robust financial and operational state. Specifically, we have a strong combination of operated projects that are delivering cash, and with our monetisation plans, have the prospect of tripling our current cash-flow over the next five years. Using our balance sheet strength to deliver this plan we can offer both growth and solid returns to our shareholders.

Dr Nick Cooper

Chief Executive Officer

OPERATING REVIEW

Our capital is allocated to projects that offer the best risk weighted return on capital. We are focused on monetising our approximately 1 Bnboe net contingent resource base and on building our cash flow in line with our strategy of becoming a sustainable E&P company. Our 2017 operational activities reflect this and included an infill drilling programme in the Bualuang oil field, completion of an extensive 3D seismic survey to support the development plan for the Kerendan field and the completion of all operational milestones on the Fortuna FLNG project. Importantly, our resource plays have low unit development and production costs and are capable of delivering attractive returns without requiring higher commodity prices. The development of these resources was supported by a production base which averaged 11,700 Mboepd. This delivered revenues of $189 million (excluding Sinphuhorm which was equity accounted), up $82 million or 76% on 2016 and included the first full year of production and cashflow contribution from the Kerendan field. In total, net funds flow from production for the full year was $90 million or $21 per boe.

Looking to 2018 and beyond, capital will be allocated to Fortuna at FID, and to existing opportunities in Indonesia and Thailand that will increase short-term cash flow. Any additional discretionary capital will be allocated either to P&D activities, exploration (if the opportunities offer sufficient risk weighted IRR’s) or to capital returns.

Bualuang, Thailand

Production at the Bualuang oil field averaged 8,300 boepd across the year, which was supported by stable production with uptime of approximately 99%. The completed 2017 infill drilling programme offset the predicted natural well decline. This occurred later than anticipated due to the late rig arrival and a slower than anticipated ramp up of the lower completions. In addition, the water debottlenecking programme was a success, increasing water handling capacity to 75,000 barrels of water a day.

Revenues from Bualuang averaged $52 per barrel for the period compared to $38 per barrel in 2016. The increased average realised oil price arose from both a higher Dubai benchmark price and securing a further lower Dubai discount in the second half of the year with the signing of a new one-year term contract.

We anticipate cash flow to further increase with the decision to commence the fourth development phase of the field. The capital cost of Phase IV is expected to be US$138 million between 2018 and 2020. The initial phase has five well activities planned for 2018 from the existing Alpha and Bravo platform, comprising three re-drills using existing slots and two well workovers. All drilling targets will be informed by the 3D seismic data we acquired in 2015, and a resultant 4D signal. These will help us secure significant, additional value from the field. In 2019 we are planning to add an additional 12 well slots with the installation of the Charlie platform, a wellhead structure, bridge-linked to our existing Alpha and Bravo production platforms.

In light of the 2017 infill drilling and the addition of production from the deeper T2 reservoir interval, Ophir is looking at several near field prospects with possible drilling in 2018. We have also identified a new satellite exploration target which we are analysing for potential drilling in 2018.

Kerendan, Indonesia

The Kerendan gas field started production in the first half of 2016 but took longer than forecast to ramp up to the full contracted volumes in 2017 due to offtake commissioning delays. Kerendan averaged 15.1 MMscfd (gross) across the year and at year end was producing the full daily contract quantity of 19.2 MMscfd.

The field generated revenue of $19 million at an average gas realisation price of $5.30 per Mscf.

In addition to ramping up production, the focus in 2017 was monetising further gas from the asset beyond the first contracted amount of 122 Bcf. The onshore 3D seismic survey in the Bangkanai and West Bangkanai PSCs was completed in December 2017, covering 560 square kilometres. This new seismic data, in combination with the data from the West Kerendan-1 (“WK-1”) well and the WK-1 drill stem test, is expected to provide the necessary information to facilitate monetisation of up to 457 Bcf of discovered, but uncontracted, gross contingent resource in the Kerendan field. This would move these hydrocarbons from resources to reserves classification. We anticipate this could result in production potentially as high as 80 MMscfd by end of 2022.

In February 2018, Ophir agreed, in principle, a higher gas price with PLN for the current Phase one production at $5.65/MMbtu, an increase from the current level of $5.08/MMbtu.

To this end, negotiations have started with PLN to supply a second phase of gas to a new build power plant from 2020. Ophir is also investigating further third party gas sales from 2020.

Sinphuhorm, Thailand

The Sinphuhorm gas field produced an average of 78 MMscfd for the year primarily as a consequence of lower nominations from the Energy Generating Authority of Thailand (EGAT).

In common with gas fields across Thailand, the cause of lower nominations appears to be related to competing sources of energy including spot LNG purchases by PTT replacing domestic sources of gas supply. The nominations returned to normal levels in the third quarter of the year, but dropped again in the fourth quarter due to extended turbine maintenance and lower demand.

In 2018, we anticipate undertaking the PH-10 well workover (to maintain production capacity) and looking out to 2021, an appraisal well will be considered by the partnership to underpin a GSA extension. In addition, as gas has been discovered in APICO acreage L15/43 outside the field boundaries, we expect unitisation discussions to progress in 2018.

Fortuna FLNG Project, Equatorial Guinea

With the exception of the project funding, all major workstreams required to achieve FID of the Fortuna FLNG Project were accomplished in 2017. The number of important agreements reached this year is a testament to the strong co-ordination between Ophir's project team and our partners.

It is frustrating that the financing was not secured in 2017 but alongside our partners in the project we continue to work hard to close out this remaining milestone. Once the project funding has been finalised, the Board of Ophir will take the FID, which will also be subject to approval by Ophir's shareholders after which the approval of the President of Equatorial Guinea will be sought.

During 2017, the project partners signed an Umbrella Agreement ('UA') that established the full legal and fiscal framework for the project. The UA reconfirms the participation rights of GEPetrol as partners for 20% of the upstream portion of the project, and for a future potential participation of up to 30% ownership of the midstream FLNG vessel by the Republic of Equatorial Guinea or a designated State company. Importantly, these participations create alignment with the Government of Equatorial Guinea throughout the project value chain – from upstream through to LNG marketing.

The Gunvor Group were identified as the preferred offtaker. Upon execution of the LNG purchase agreement Gunvor would be committed to taking the full nameplate capacity of the Gandria FLNG vessel of 2.2 MMTPA, which will be purchased on a Brent-linked, free on board ("FOB") basis for a 10-year term. The contract structure also allows flexibility for up to 1.1 MMTPA of the Fortuna capacity to be marketed on an alternate basis. Consequently, the agreement would give the Fortuna partners, alongside the State of Equatorial Guinea, the potential to sell volumes to higher priced gas markets in Africa and beyond, whilst retaining a share in the profits of such sales.

We awarded the upstream construction contract for the project to Subsea Integration Alliance (a partnership between OneSubsea, a Schlumberger company, and Subsea 7). In addition, the primary contract for the FLNG Gandria was entered into with Singapore's Keppel Shipyard Limited. The FLNG Hilli Episeyo, which is Golar's first FLNG conversion and the sister ship to the Gandria, left the Keppel yard and is currently being commissioned in the field in Cameroon prior to delivery of its first commercial cargo. The delivery of this first cargo will represent an important step in the de-risking of the Fortuna midstream FLNG solution.

On our journey to first gas in 2022, we will be working with our partners to complete the required development wells and subsea infrastructure and complete the conversion and commissioning of the Gandria into an FLNG vessel.

Exploration

Ophir has previously run a portfolio of four core operating countries and up to eight exploration countries. This exploration portfolio has now been reduced to concentrate our efforts and to better drive value. Accordingly, we exited seven deepwater PSCs: the DW2A PSC in Malaysia and the Mbeli, Ntsina, Nkouere, Nkawa, Manga and Gnondo PSCs in Gabon. At the start of 2018 we also took the decision to exit from Block 513 in Cote d'Ivoire.

We are presently concentrating our exploration into lower risk, infrastructure led activities and will limit our deepwater footprints to a subset of the existing portfolio. To this end, during 2017 we added new acreage in both Equatorial Guinea and Mexico. We formally signed the PSC for Block 5 in Mexico, which was awarded in 2016 where we have a 23.3% interest, with Murphy Oil the operator. This block is located around 30 km north of, and in the same basin as, Block 7 where the Zama oil discovery occurred in July 2017. This was the first offshore bid round in Mexico since the government's move to liberalise the energy sector and provide greater access for international companies. Block 5 is located within an under-explored, proven oil basin, and it was the most contested acreage in the bid round. We are interpreting the 3D data on this block ahead of expected drilling in 2019.

Further to this, in a subsequent licensing round in early 2018 Ophir was awarded 20% interests in the Block 10 and Block 12 licences in the Ridges basin in Mexico. This provides Ophir with a leading position across multiple plays in a proven, but under-explored, hydrocarbon province.

Separately, we also agreed PSC terms for Block EG-24 in Equatorial Guinea. This licence is on trend with a number of producing oil fields and we are in the process of farming down this acreage. We will complete a 3D seismic survey in 2018. In Myanmar, we have agreed to broaden our footprint in 2018 through a transaction with Chevron (subject to government approval) that will result in Ophir having a 42% interest in both blocks AD-03 and A-5. We will make a decision in 1H 2018 as to whether to drill across the combined acreage position. In the West Papua IV and Aru PSCs in Eastern Indonesia a decision whether to drill a well will be made in 1H 2018 following extensive analysis of recent seismic data. In 2017, we drilled the Ayame-1X exploration well in Cote d'Ivoire. No moveable hydrocarbons were encountered, and the well was plugged and abandoned as a dry hole.

Overall, we anticipate that when the Fortuna FLNG project is on-stream in 2022, Ophir’s cash flow generation will support an active, exploration drilling programme. Prior to that, Ophir’s discretionary spend will be paced in order to preserve balance sheet capacity, prioritising the Fortuna FLNG project and the expansion of our Asian producing assets.

FINANCIAL REVIEW

	Units	FY 2016	FY 2017	FY 2018 Forecast
Total Production	Mboepd	10.8	11.7	11.5
Bualuang	Mboepd	8.7	8.4	
Kerendan	Mboepd	0.2	2.1	
Sinphuhorm	Mboepd	1.9	1.2	
Realised commodity prices				
Realised oil price	$/bo	37.85	51.86	
Realised gas price (excluding Sinphuhorm)	$/Mscf	-	5.30	
Net sources of funds:				
Revenue	$'millions	107.2	188.5	
Kerendan Take-or-Pay[1]	$'millions	16.5	-	
Cost of production (operating expenses, royalty and inventories)	$'millions	(42.7)	(70.0)	
Investment income	$'millions	4.4	4.2	
Current income tax charge	$'millions	(23.7)	(32.6)	
Net funds flow from production[2]	$'millions	61.7	90.1	90.0
Net uses of funds:				
Capital Expenditure (including pre-licence expenditure and additions to E&E and O&G)[3]	$'millions	155.6	101.1	150.0
Corporate administration cost	$'millions	13.4	11.3	
Net interest charges (before capitalised interest)	$'millions	14.3	13.2	
Net uses of funds[2]	$'millions	183.3	125.6	
Financing cash flow and debt:				
Closing net cash	$'millions	160.1	117.1	>0
Closing borrowings	$'millions	200.3	106.7	
Closing undrawn debt facilities	$'millions	10.3	203.5	
Closing gross liquidity (including undrawn debt facilities)	$'millions	370.7	427.3	320.0

[1] Kerendan Take-or-pay is the movement between the non-current – trade and other payables balance of $15.3m (2016:10.3m) against the current – trade and other payables balance, take of pay portion of $1.2m (2016: $6.2m)

[2] Net funds flow from production and net uses of funds have been presented to eliminate the effects of short-term working capital adjustments

[3] Capex is adjusted to eliminate non-cash amounts for decommissioning for 2017 of $0.7 million (2016: $19.2 million) and capitalised interest for 2017 of nil (2016:8.7 million)

Summary

Ophir's deployment of capital is driven by a focus on returns. Our overriding priority is to rapidly and safely monetise our substantial, low risk assets, along with the retained capacity to fund selective exploration in core geographies.

The principal financial challenge facing Ophir is to ensure that we preserve balance sheet strength and maintain sufficient liquidity until 2022, when the Fortuna project should be on stream, leading to a step change in our cash flow. The focus for capital allocation until this point will be monetising the approximate 1 billion boe of discovered resource.

Preserving our balance sheet strength was a priority in 2017 and we took steps to lowering our capital and operating cost base. Through staff and costs reductions, implemented predominantly in our London office, administration costs were reduced by $12 million per annum, which will take full effect in 2018. Overall, gross administration costs have been reduced by approximately 60% since the start of 2015.

The Brent oil price averaged $55 per bbl in January 2017, weakening to an average of $47 per bbl in June 2017 before recovering to an average of $64 per bbl in December 2017. Whilst very difficult to predict, the outlook for commodity prices remains reasonably firm for 2018.

Net sources of funds

Working interest production for 2017 averaged 11,700 boepd for the year and generated net funds flow from production of $90 million (2016: $62 million).

Revenue from Bualuang totalled $169 million or $52 per bbl (2016: $107 million or $38 per barrel). Revenue from Kerendan totalled $19 million or $5.30 per Mscf.

In late 2017, Ophir implemented a commodity price hedging programme in respect of its 2018 production. A Brent-swap was purchased at an average price of $59 per bbl and a call was purchased at an average price of $67 per bbl, both trades for 3,200 bopd. The hedge represents approximately 27% of forecast 2018 production. Along with the hedge programme and an improved commodity price outlook for 2018, full year net funds flow from production is forecast at $90 million or $21/boe.

Uses of funds

Ophir's primary investments during 2017 were:

- Exploration: $41 million (2016: $76 million) comprising predominantly:
    - Cote d'Ivoire Block CI-513 – drilling exploration well ($13 million)
    - Mexico Block 5 – seismic data and interpretation ($9 million)
    - Indonesia West Papua IV and Aru blocks – seismic data and well planning ($7 million)
    - Malaysia PM322 – seismic acquisition ($8 million)

- Pre-development, development and production: $60 million (2016: $80 million) comprising predominantly:
  - Equatorial Guinea Fortuna – pre-FID costs ($16 million)
  - Indonesia Kerendan – 3D seismic acquisition ($13 million)
  - Thailand Bualuang – drilling three infill wells ($31 million)

Of the $41 million exploration expenditure in 2017, $21 million (2016: $6 million) was charged and written-off to the income statement in addition to a $55 million (2016: $94 million) write-off of prior year expenditure.

Net interest charges and finance costs amounted to $13 million (2016: $14 million) against average gross debt of $153 million (2016: $230 million)[1], giving rise to an average cost of debt of 9.9% for 2017 (2016: 7.1%)[2]. This was higher than 2016 with the deleveraging that occurred in 2017 and the repayment of the cheaper reserves based lending facility. This however lowered the total cost of borrowings, whilst preserving liquidity, by reducing our negative cash carrying cost.

Overall, net uses of funds for 2017 totalled $126 million (2016: $183 million). Looking ahead, capital expenditure for 2018 is forecast at $150 million with capital currently allocated to the following activities:

- Blocks 5,10 and 12, Mexico – seismic capture and interpretation ($15 million)
- Kerendan, Indonesia – civil works and perforating water wells ($10 million)
- Bualuang, Thailand – three well infill drilling programme – ($40 million)
- Fortuna, Equatorial Guinea – FID and investment into Joint Venture – ($55 million)

Longer term, Ophir's future financial work programme commitments to host governments beyond 2018 are limited to $27 million.

[1] Calculated as the weighted average cost of borrowings from 31 December 2016 – 31 December 2017
[2] Calculated as interest payable over average gross debt

Debt and net debt

2017 net funds flow totalled $43 million (2016: $195 million) giving rise to year-end 2017 net cash of $117 million (year-end 2016: $160 million).

During 2017, Ophir completed the refinance of its reserves based lending facility into a new seven year, $250 million (plus accordion of $100 million), senior secured facility with a maturity of mid-2024. The available balance on the facility at the balance sheet date of $204 million remained undrawn at year-end 2017. Gross liquidity at year-end 2017 increased to $427 million from $371 million at year-end 2016. Ophir's debt leverage remains low with a full year 2017 liquidity ratio (gross debt/EBITDAX) of 1.0 and year-end gearing of 7% (gross debt / gross debt + equity).

The balance sheet therefore remains strong providing sufficient funds to meet the planned capital expenditure programmes. Work on refinancing the outstanding $107 million Nordic bond commenced in late-2017 and is expected to complete in 2018, following FID of the Fortuna project. Ophir estimates that it will end 2018 in a marginally net cash position with gross liquidity at year-end 2018 of $320 million.

Consolidated income statement and statement of other comprehensive income
For the year ended 31 December 2017

Consolidated income statement	Notes	2017 $'000	2016 $'000
Continuing operations			
Revenue		188,527	107,178
Cost of sales		(147,577)	(95,443)
Gross profit		**40,950**	**11,735**
Share of profit of investments accounted for using the equity method		4,181	4,417
Impairment reversal of oil and gas properties	5	23,681	84,100
Impairment of investments accounted for using the equity method		(7,800)	–
Exploration expenses		(91,836)	(135,252)
Other operating (expenses)/gains		(11,699)	19,945
General and administration expenses		(11,279)	(13,428)
Operating loss		**(53,802)**	**(28,483)**
Net finance expense		(12,907)	(21,595)
Other financial gains		2,300	–
Loss from continuing operations before taxation		**(64,409)**	**(50,078)**
Taxation expense		(47,383)	(27,368)
Loss from continuing operations for the year		**(111,792)**	**(77,446)**
Attributable to:			
Equity holders of the Company		(111,792)	(77,446)
		(111,792)	**(77,446)**
Earnings per ordinary share			
Basic – (Loss)/profit for the period attributable to equity holders of the Company		(15.8)cents	(11.0)cents
Diluted – (Loss)/profit for the period attributable to equity holders of the Company		(15.8)cents	(11.0)cents

Consolidated statement of other comprehensive income			
Loss from continuing operations for the year		**(111,792)**	**(77,446)**
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		(5,882)	–
Other comprehensive income/(loss) for the year, net of tax		(5,882)	31
Total comprehensive loss for the year, net of tax:		**(117,674)**	**(77,415)**
Attributable to:			
Equity holders of the Company		(117,674)	**(77,415)**
		(117,674)	**(77,415)**

Consolidated statement of financial position
As at 31 December 2017

	Notes	**2017 $'000**	2016 $'000
Non-current assets			
Exploration and evaluation assets	4	247,944	310,229
Oil and gas properties	5	699,669	699,000
Other property, plant and equipment		2,211	3,706
Investments accounted for using the equity method		120,964	130,736
Other long term receivables		21,205	21,103
		1,091,993	**1,164,774**
Current assets			
Assets classified as held for sale		604,432	588,770
Inventory		40,647	46,738
Taxation receivable		9,125	15,178
Trade and other receivables		24,656	32,319
Cash and cash equivalents		223,779	360,424
		902,639	**1,043,429**
Total assets		**1,994,632**	**2,208,203**
Current liabilities			
Trade and other payables		(52,374)	(93,398)
Interest-bearing bank borrowings due within one year		–	(9,741)
Taxation payable		(30,282)	(13,226)
Provisions		(9,399)	(15,833)
Derivative financial instruments		(3,582)	-
		(95,637)	**(132,198)**
Non-current liabilities			
Trade and other payables		(15,279)	(10,285)
Interest-bearing bank borrowings		–	(83,915)
Bonds payable		(106,651)	(106,651)
Provisions		(51,265)	(50,550)
Deferred tax liability		(264,491)	(249,527)
		(437,686)	**(500,928)**
Total liabilities		**(533,323)**	**(633,126)**
Net assets		**1,461,309**	**1,575,077**
Capital and reserves			
Called up share capital		3,061	3,061
Reserves		1,458,528	1,572,296
Equity attributable to equity shareholders of the Company		**1,461,589**	**1,575,357**
Non-controlling interest		(280)	(280)
Total equity		**1,461,309**	**1,575,077**

The consolidated financial statements of Ophir Energy plc (registered number 05047425) were approved by the Board of Directors on 6 March 2018.

On behalf of the Board:

Nick Cooper
Chief Executive Officer

Tony Rouse
Chief Financial Officer

Consolidated statement of changes in equity
For the year ended 31 December 2017

	Called up share capital $’000	Treasury shares $’000	Other reserves $’000	Non- controlling interest $’000	Total equity $’000
As at 1 January 2016	**3,061**	**(155)**	**1,646,878**	**(280)**	**1,649,504**
Loss for the period, net of tax	–	–	(77,446)	–	(77,446)
Other comprehensive loss, net of tax	–	–	31	–	31
Total comprehensive loss, net of tax	–	–	(77,415)	–	(77,415)
Exercise of options	–	2	–	–	2
Share-based payment	–	–	2,986	–	2,986
As at 31 December 2016	**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**

Consolidated statement of cash flows
For the year ended 31 December 2017

	2017 $'000	2016[1] $'000
Operating activities		
Loss before taxation	(64,409)	(50,078)
Adjustments to reconcile loss before taxation to net cash provided by operating activities		
Exploration expenses	76,108	114,776
Depreciation and amortisation	79,230	55,238
Net impairment reversal	(16,061)	(84,100)
Share of profits from joint ventures	(4,181)	(4,417)
Net finance expenses and other financial gains	14,724	8,172
Net foreign currency (gain)/loss	(1,817)	13,424
Share based payment expense	3,905	2,986
(Decrease)/increase in provisions	9,381	(19,322)
Cash flow from operations before working capital adjustments	**96,880**	**36,679**
Decrease/(increase) in inventories	7,123	(9,584)
Increase/(decrease) in other current and non-current payables	1,962	(2,212)
Decrease in other current and non-current assets	10,147	5,502
Cash generated from operations	**116,112**	**30,385**
Interest received	2,057	1,959
Income taxes paid	(9,485)	(41,360)
Net cash flows generated from/(used in) operating activities	**108,684**	**(9,016)**
Investing activities		
Additions to Exploration and Evaluation assets	(95,827)	(154,977)
Additions to oil and gas assets and other property, plant and equipment	(47,179)	(18,585)
Dividends received from joint ventures	6,523	5,164
Funding provided to joint ventures	(370)	(1,283)
Proceeds from disposals of assets	428	-
Net cash flows used in investing activities	**(136,425)**	**(169,681)**
Financing activities		
Interest paid	(15,217)	(16,275)
Repayment of debt	(93,656)	(59,352)
Net issue/(repurchase) of shares	1	2
Net cash outflows from financing activities	**(108,872)**	**(75,625)**
Effect of exchange rates on cash and cash equivalents	(32)	177
Decrease in cash and cash equivalents	(136,645)	(254,145)
Cash and cash equivalents at the beginning of the year	360,424	614,569
Cash and cash equivalents at the end of the year	**223,779**	**360,424**

[1] Investing cash outflows as reported in 2016 have been corrected to reflect a decrease in outflows of $20.5 million for pre-licence exploration expenditure which has been reclassified as an operating cash outflow. The reclassification is to aid comparison of periods.

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 and Southeast Asia.

The Group's consolidated financial statements for the year ended 31 December 2017 were authorised for issue by the Board of Directors on 6 March 2018 and the consolidated statement of financial position was signed on the Board's behalf by Nick Cooper and 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 2016 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 2017.

3. 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 2017			
	Africa $'000	Asia $'000	Other $'000	Total $'000
Revenue sales of crude oil and gas	–	188,527	–	188,527
Depreciation and amortisation	–	(77,529)	(542)	(78,071)
Impairment of exploration costs	(60,744)	(15,887)	(21)	(76,652)
Reversal of 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
Operating profit/(loss)	(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
Profit/(loss) before tax	(58,626)	33,703	(39,486)	(64,409)
Taxation	5,296	(52,676)	(3)	(47,383)
Profit/(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

	Year ended 31 December 2016			
	Africa $'000	Asia $'000	Other $'000	Total $'000
Revenue sales of crude oil	–	107,178	–	107,178
Depreciation and amortisation	(12)	(53,197)	(2,093)	(55,302)
Impairment of exploration costs	(3,749)	(96,391)	–	(100,140)
Impairment of oil and gas properties	–	84,100	–	84,100
Impairment of investments accounted for using the equity method	–	–	–	–
Share of profit of equity-accounted joint venture	–	4,417	–	4,417
Operating (loss)/profit	12,404	(5,864)	(35,023)	(28,483)
Finance income	–	97	1,862	1,959
Finance expense	(462)	(22,057)	(1,035)	(23,554)
Other financial gains	–	–	–	–
Loss before tax	11,942	(27,824)	(34,196)	(50,078)
Taxation	(9,944)	(17,384)	(40)	(27,368)
Loss after tax	1,998	(45,208)	(34,236)	(77,446)
	As at 31 December 2016			
Total assets and total liabilities				
Total assets	778,065	1,148,674	281,464	2,208,203
Total liabilities	(111,207)	(517,504)	(4,415)	(633,126)
Investments accounted for using the equity method	–	130,736	–	130,736
	Year ended 31 December 2016			
Additions to non-current assets	100,654	24,342	819	125,815

Non-current operating assets

The non-current operating assets for the UK are $1.5 million (2016: $2.7 million). The non-UK, non-current operating assets are $948.3 million (2016: $1,010.2 million). Included in the non-UK, non-current operating assets is Thailand which makes up $414.9 million (2016: $421.3 million), Indonesia $284.9 million (2016: 288.4 million), Tanzania $106.0 million (2016: $120.5 million).

4. Exploration and evaluation assets

	Year ended 31 Dec 2017 $'000	Year ended 31 Dec 2016 $'000
Cost		
Balance at the beginning of the year	310,229	879,914
Additions[1]	40,788	119,225
Disposal of asset	(150)	–
Transfers to oil and gas properties	(10,608)	–
Reclassified as assets held for sale	(15,663)	(588,770)
Expenditure written off[2]	(76,652)	(100,140)
Balance at the end of the year	247,944	310,229

1. Additions for the year ended 31 December 2017 include 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). Additions for the year ended 2016 included exploration activities in: Equatorial Guinea – Block R ($41.5 million), Côte d'Ivoire – 513 ($19.6 million), Tanzania – Blocks 1 & 4 ($22.7 million), Myanmar – Block AD03 ($8.7 million) and Malaysia –Block 2A ($7.7 million).
2. Expenditure written off in the year 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.

   Expenditure written off for the year ended 31 December 2016 was $100 million. The significant write offs included within the $100.0 million was in respect of Thailand – G4/50: loss of $57.6m and Indonesia: loss of $37m. 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.

The Group generally estimates value in use using a discounted cash flow model. Future cash flows are discounted to their present values using a pre-tax discount rate ranging between 8% - 22% (2016: 15%). Adjustments to cash flows are made to reflect the risks specific to the CGU.

5. Oil and gas properties

	Year ended 31 Dec 2017 $'000	Year ended 31 Dec 2016 $'000
Cost		
Balance at the beginning of the year	875,278	869,852
Additions[1]	43,909	5,426
Transfers from Exploration and evaluation assets	10,608	–
Balance at the end of the year	929,795	875,278
Depreciation and amortisation		
Balance at the beginning of the year	(176,278)	(207,675)
Charge for the year	(77,529)	(52,703)
Impairment reversal[2]	23,681	84,100
Balance at the end of the year	(230,126)	(176,278)
Net book value		
Balance at the beginning of the year	699,000	662,177
Balance at the end of the year	699,669	699,000

1 Additions in 2016 were stated net of a $19.2 million decommissioning remeasurement.

2 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 $424m based on management's estimate of value in use. The discount rate used was 22% (pre-tax).
The 2016 Impairment reversal was due to increased reserves related to the Bualuang oil field in Thailand which had a recoverable amount of $410.7m based on management's estimate of value in use. The discount rate used was 15% (pre-tax).

6. Net debt

	As at 31 Dec 2017 $'000	As at 31 Dec 2016 $'000
Amounts due on maturity:		
Interest bearing bank loans	–	(93,656)
Bonds payable	(106,651)	(106,651)
Total gross debt	(106,651)	(200,307)
Less cash and cash equivalents	223,779	360,424
Total net cash	117,128	160,117

At the balance sheet date, the bank borrowings are calculated to be repayable as follows:

	As at 31 Dec 2017 $'000	As at 31 Dec 2016 $'000
On demand or due within one year	–	9,741
In the second year	–	43,831
In the third to fifth year inclusive	106,651	146,735
After five years	–	–
Total principal payable on maturity	106,651	200,307