Tight financial controls and discipline are vital to ensure we are funded to execute our strategy.

Financial **flexibility** and access to capital

The Group continued to invest in new wells and surface facilities during the year to increase oil and, in particular, gas production and processing capacity.

In 2016 we will appropriately scale our investment programme taking account of the prevailing oil price environment and its influence on free cash generation within the underlying business, and will maintain our strict discipline of only allocating capital to the opportunities that offer the greatest returns to deliver shareholder value.

Seplat's competitive advantages:

- Discretion of magnitude and timing of expenditures
- Well positioned in both local and international capital markets

Investing in our future

Our financial strategy continues to be driven by preservation of the financial capability, and also flexibility, that is required to realise the value of our enlarged asset base. We are focused on cash generation and will prioritise capital investments to projects that provide the highest return per dollar invested.

Roger Brown
Chief Financial Officer

Revenue

Despite reporting a 41% overall increase in production year on year (with liquids production up 20% and gas production up 119%), the full effect has not been reflected in revenues primarily due to the continued decline in oil prices throughout the year. Revenues were further impacted by third party operated infrastructure being shut-in for significant periods of time, giving a production uptime level of 79% for the full year. The majority of shut-ins were experienced in the first half when production uptime was 65%, after which we saw a marked improvement in the second half when uptime was restored to a more normalised level of 94%. The increase in gas production and sales in the year did provide a partial offset to the impact of oil price decline, with gas pricing in Nigeria being de-linked to oil price. Consequently, revenue in 2015 was US$570 million, a decrease of 26% from 2014 (2014: US$775 million).

Oil revenues (after stock movements) of US$494 million continued to account for the majority of revenues in 2015 (2014: US$748 million). The global oil price decline has negatively impacted the Group's realised oil price with an achieved average price of US$51.2/bbl (2014: US$97.2/bbl) before royalties. The average premium to Brent achieved in 2015 was US$1.02/bbl (2014: US$2.4/bbl). Working interest liquids production in 2015 increased to 29,003 bopd from 24,252 bopd in 2014. The total volume of crude lifted in the year was 8.129 MMbbls compared to 7.999 MMbbls in 2014. Also in 2015, revenues from OML 53 and OML 55 were recognised from February onwards.

In April, the Group put in place deferred premium put options covering a volume of 4.4 MMbbls to year end at a strike price of US$52.0/bbl. The net amount paid out during the year was US$15.6 million. We will continue to closely monitor prevailing oil market dynamics and will consider further measures to provide appropriate levels of cash flow assurance in times of oil price weakness and volatility. In line with this tactic, we have rolled the hedging programme into 2016 and put in place dated Brent put options covering a volume of 3.3 MMbbls over H1 2016 at a strike price of US$45.0/bbl and have post year end covered an additional 2.2 MMbbls over H2 2016 at a strike price of US$40/bbl.

The shut-in of third party operated infrastructure that we rely on to evacuate produced liquids, together with the associated time required to re-establish full production levels, resulted in deferred liquids production of approximately 2.2 MMbbls assuming all other factors constant. To assist in minimising the impact of future pipeline shut downs, the Group continued efforts to optimise the use of its alternative export route to the Warri Refinery which was commissioned in 2014. A total of 388,000 barrels was sent through this route in 2015.

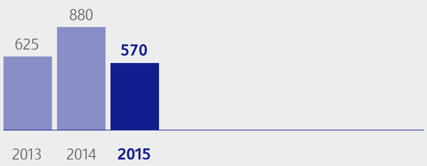
Gas revenues increased significantly year on year to US$76.9 million (2014: US$27.4 million). This trend was driven by a 34% increase in the average realised gas price to US$2.55/Mscf (2014: 1.90/Mscf) and a 119% increase in volumes. Working interest production for the year was 86 MMscfd (31.3 Bscf) compared to 39 MMscfd (14.4 Bscf) in 2014. The increase in volume is a direct result of the successful installation and commissioning of the new 150 MMscfd Oben gas processing facility mid-year that doubled overall gross processing capacity to 300 MMscfd and allowed for a sharp increase in gas sales throughout the second half of the year.

Gross profit

Gross profit for the year was US$249 million, a decrease of 46% on the prior year (2014: US$459 million). This principally reflects the decline in revenue, primarily attributed to the oil price, the additional field costs related to OML 53 and 55 together with the increase in the rate of DD&A. Direct operating costs, being crude handling fees, rig-related costs and other field expenses, decreased to US$3.30/boe in 2015 (2014: US$3.52/boe), principally reflecting the decrease in work-over costs and higher production, offset by increased levels of field expenditures and crude handling charges (including a balancing one-off crude handling charge of US$25 million recognised in 2015 for the period 2010 to 2014).

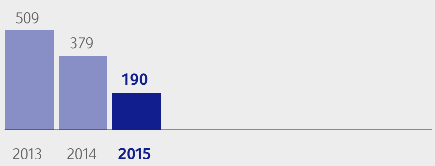
Revenue

US$570m



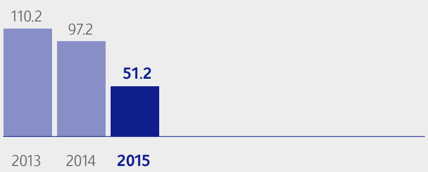
Cash from operations before working capital

US$190m



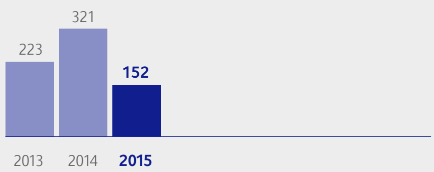
Realised oil price

US$51.2/bbl



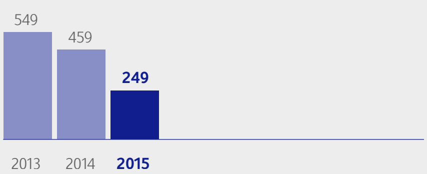
Capital expenditure

US$152m



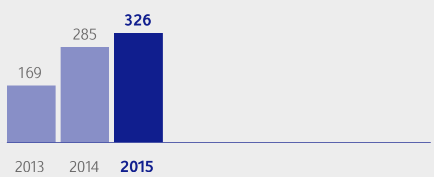
Gross profit

US$249m



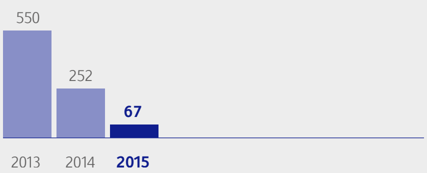
Cash position

US$326m



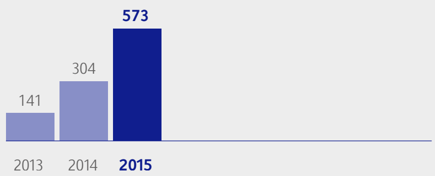
Net profit

US$67m



Net debt

US$573m



Management is aware of the need to operate as efficiently as possible in the current low oil price environment whilst maximising the production and cash flows from existing assets. The DD&A charge for oil and gas assets has increased during 2015 to US$68 million (2014: US$41 million) reflecting field investments made in the year, acquisition costs associated with OML 53 and OML 55, forecast levels of production and estimates of future capital commitments. These increases were partly offset by the reduction in the level of royalties in 2015, which despite the higher production year on year stood at US$102.5 million compared to US$149.7 million in 2014. The reduction in well work-over activities also translated into a decrease in rig related expenses to US$8.64 million in 2015 compared to US$29.9 million in 2014.

Operating profit

Operating profit for the year was US$157 million, a decrease of 46% on the prior year (2014: US$290 million).

Partially offsetting the impact of lower gross revenues was a 21% decrease in G&A expenses to US$121 million. Included within the reported G&A figure are finance costs of US$24.2 million, depreciation of US$5.5 million and other costs in relation to business development activities and advisory fees totalling US$7.4 million. Additionally, the Group has also taken steps to reduce recurring G&A expenses and in the full year has realised a decrease of US$5 million through reductions in contract labour, travel costs, facilities costs and IT costs.

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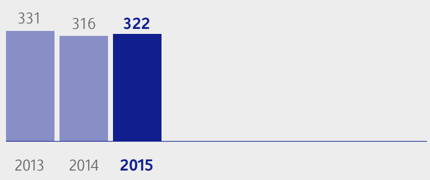
Tax
The Group continued to benefit from pioneer tax status in 2015 which resulted in the effective tax rate remaining consistent with 2014 (2014: nil%). The Group has completed the first three years of the tax incentive and has applied for the final two years under the provisions of the Industrial Development ('Income tax Relief') Act. The Group considers that it has met or exceeded the requirements of the scheme, as evidenced by the investments it has made to develop its blocks and in particular accelerate the expansion of its gas business to supply the domestic market. In 2015, a deferred tax charge of US$21 million has been recognised in the accounts representing the tax of a timing difference which will reverse in the future.

Profit attributable to parent
Profit for the period was US$67 million, a decrease of 73% on the prior year (2014: US$252 million). The resultant EPS for 2015 was US$0.12 (2014: US$0.5). In 2015, adjustments have been made in respect of a balancing crude handling charge reconciling actual capacity usage with reserves capacity for the past five years of US$25 million, payments made in association with the Group's successful US$1 billion refinancing of its debt facilities of US$24 million and other costs of US$7 million which mainly include business development costs.

Dividends
The Board has decided to recommend a final dividend of US$0.04 per share (2014: US$0.09 per share) bringing total dividends for the year to US$0.08 per share (2014: US$0.15 per share).

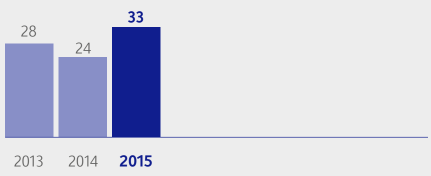
Cost of sales

US$322m



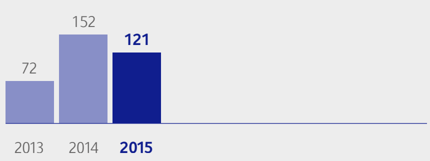
Gearing (total debt/total assets)

33%

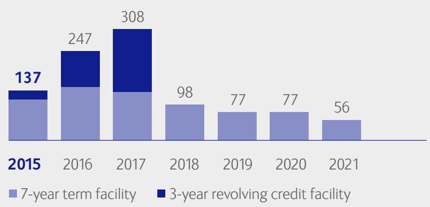


G&A

US$121m



Debt maturity profile (US$m)



Reconciliation of net NPDC receivables balance

	US$ million
Opening balance at 31 December 2014	463
Receipts in 2015	(163)
Payments in 2015	246
NPDC gas revenues withheld in 2015	(55)
Headline receivable at 31 December 2015	491
Crude handling charges withheld in 2015	(56)
Net receivable at 31 December 2015	435

Net debt at 31 December 2015

	US$ million	Coupon	Maturity
7-year secured term facility	588	L+8.75%	January 2022
3-year secured RCF	275	L+6.00%	January 2018
Gross debt at parent	863		
Net Belemaoil subsidiary debt[1]	36	L+10.5%	
Total gross debt	899		
Cash and cash equivalents	326		
Net debt	573		
Accordion facility (undrawn)	700	L+8.75%	

1. Net of capitalised interest of US$16 million.

“The low oil price has impacted financial performance but we remained profitable, dividend paying and preserved a strong balance sheet.

Cash flows and liquidity

Cash flows from operating activities

Operating cash flow before movements in working capital was US$190 million (2014: US$379 million). The outstanding net NPDC receivable at year end, after offsetting NPDC's share of gas revenue and further adjusting for crude handling charges that have also been withheld, stood at US$435 million (2014: US$463 million). In July the Group entered into a signed agreement with NPDC on terms for the payment of receivables due to Seplat and also for the future structure of joint venture funding to mitigate the risk of the receivable. Pursuant to the agreement outstanding sums owed to Seplat in relation to expenditures up to 31 December 2014 will be settled by offsetting gas revenues attributable to NPDC's 55% share of contracted gas sales.

Furthermore, NPDC and Seplat have agreed to jointly source loan facilities, up to an envisaged limit of US$300 million, to fund joint venture cash calls. Under the agreed structure, once such facilities are in place, NPDC and Seplat will each contribute crude oil production commensurate with their respective obligations.

Cash flows from investing activities

Net cash flows from investing activities were US$79 million (2014: US$780 million). In February, the Group closed the acquisition of a direct 40.0% interest in OML 53 and effective 22.5% interest in OML 55 (through the purchase of 56.25% of the share capital of Belemaoil Producing Limited ('Belemaoil') from Chevron Nigeria Limited. Payments made by the Group at completion amounted to US$190.4 million for OML 53 (for which a deposit of US$69.0 million had previously been paid in 2013) and US$132.2 million for OML 55. Both transactions also carry an element of deferred consideration (US$18.8 million for OML 53 and US$11.6 million for OML 55) that is contingent on oil price averaging US$90/bbl or above for 12 consecutive months within the next five years.

In respect of OML 55, the Group also advanced certain loans amounting to US$80.0 million to the other shareholders of Belemaoil to meet their share of investments and costs associated with Belemaoil.

Under the agreed terms the Group will recover the loaned amounts, together with an uplift premium of up to US$20.6 million and annual interest of LIBOR plus 10.00%, from 80.00% of the other shareholders' oil lifting entitlements.

Capital expenditure ('Capex') attributed to oil and gas assets in the year amounted to US$152million (2014: US$321 million). These expenditures include drilling costs in relation to seven development and appraisal wells, facility costs in relation to the new Oben gas processing facility, flow lines and additional crude oil and condensate storage tanks installed at the Amukpe field. Other non-drilling and facility related capex of US$4.9 million (2014: US$10 million) includes expenditures for crude oil pumps, generators, motor vehicles, office and IT equipment and other leasehold improvements.

In July, the Group reached agreement for release of the sums from escrow that had previously been allocated as a refundable deposit against a potential investment by a consortium. The net funds returned to the Group, and reinstated as unrestricted cash at bank, were US$368 million. A sum of US$45 million remains in escrow as a deposit with the potential vendors whilst negotiations with the consortium continue, and US$29 million was placed into a new escrow account in London pending outcome of the ongoing negotiations. The Company also agreed to pay a portion of previously incurred consortium costs, amounting to US$11 million, US$3.5 million of which has been paid and US$7.5 million of which is payable on a deferred basis and is presently also held in the escrow account (total amount in escrow US$36.5 million).

Cash flows from financing activities

Net debt at the year-end was US$573 million, compared to US$304 million at December 2014. Net cash inflows from financing activities were US$82 million (2014: US$671 million). These principally reflect the refinancing of the business during the year through the debt markets.

In January 2015, the Group successfully refinanced its pre-existing debt facilities with a new US$700 million seven-year secured term facility and US$300 million three-year secured revolving credit facility. The seven-year facility also includes an option for the Group to upsize the facility by up to an additional US$700 million for qualifying acquisition opportunities.

Outlook

Our financial strategy continues to be driven by preservation of the financial capability and also flexibility that is required to realise the value of our enlarged asset base. We will continue to closely monitor the oil price, performance of our strongly productive asset base and the implications these factors have on cash generation over the near, medium and long term allowing us to scale and phase our future investments appropriately. Our enlarged asset base provides greater optionality and will allow us to more rigorously benchmark and high grade the extensive inventory of drilling and development opportunities we have, making sure that each dollar invested goes to the highest cash return projects.

We will continue to prioritise expansion of our domestic natural gas business which provides a revenue stream that is de-linked from the oil price, and underpinned by the strong fundamentals of high demand and increasing pricing. Continuing to reduce the outstanding NPDC receivables balance remains an absolute priority, and we have measures in place that will achieve this and allow us to further strengthen and improve our balance sheet. The combination of all these factors will ensure we have a sound financial platform from which we can build and grow further, both through organic means and also capitalising on inorganic opportunities as and when they may arise.

Roger Brown
Chief Financial Officer