



Unaudited results for the three months ended 31 March 2026

30 April 2026

**Reliable energy,
limitless potential**

(Expressed in Nigerian Naira
and US Dollars)



Overview

Lagos and London, 30 Apr 2026: Seplat Energy PLC (“Seplat Energy” or “the Company”), a leading Nigerian independent energy company listed on both the Nigerian Exchange and the London Stock Exchange, announces its unaudited results for the three months ended 31 March 2026.

Summary

Crude and condensate liftings benefitting from our put-option hedge strategy that exposes Seplat to 100% of price upside. Strong free cash flows and further deleveraging supports an increase in dividend for 1Q 2026 to USD 9.0 cents/share, 96% higher than 1Q 2025 payout.

Operational highlights

- Group production averaged 129,841 boepd down 1% from 1Q 2025 (131,745 boepd), but up 9% since 4Q 2025 (119,200 boepd).
 - Production during the first 26 days of April has averaged approximately 153 kboepd, bringing group average daily working interest production for the year to 26 April to approximately 135 kboepd, within FY 2026 guidance.
- Onshore production contribution of 50,700 boepd, down 10% YoY (1Q 2025: 56,267 boepd).
 - YoY decline principally due to 38 days unplanned downtime on third-party operated Trans Forcados Pipeline, impacting Western Assets. Pipeline operations resumed on 24 March and Western Assets production has normalised.
 - First gas at ANOH in January 2026, contributed working interest volumes of 17.0 mmscfd, planned increase 2Q 2026 onwards.
- Offshore production contribution of 79,141 boepd, up 5% vs. 1Q 2025: 75,478 boepd.
 - Idle well restoration programme continued its strong performance, adding 10 kbopd gross JV production capacity from 8 wells.
 - NGLs delivered strong growth, WI production of 9,802 bopd (1Q 2025: 3,376 bopd), as EAP continued to perform at high levels.
 - Yoho restart on track for 2Q 2026, Oso-BRT 1 gas expansion project on track for 3Q 2026 start up.
- Carbon emissions intensity for Seplat group assets: 41.6 kg CO₂/boe improved by 13% YoY (1Q 2025: 47.9 kg CO₂/boe), within this onshore operated emissions intensity reduced 24% on 1Q 2025, reflecting the positive impact of our End of Routine flaring programme.
- 1Q 2026 Lost Time Injury (‘LTI’) free. Group delivered more than 9.1 million man-hours without LTI. 3.0 million hours onshore-operated assets and 6.1 million hours offshore.

Financial highlights

- Gross revenue \$840.7 million up 4% on prior year (1Q 2025: \$809.3 million). Realised oil price of \$86.16/bbl.
- Onshore operated assets now reporting under PIA, group blended unit royalty rate 14.7% of revenue (1Q 2025 16.2%).
- Unit production operating cost of \$17.1/boe (1Q 2025: \$12.6/boe), above our \$13.5-14.5/boe guidance due to acceleration of planned maintenance activities at Yoho and lower volumes in the quarter, also impacting EBITDA, expected to normalise in subsequent quarters.
- Adjusted EBITDA of \$371.3 million (44% margin), down 7% vs prior year (1Q 2025: \$400.6 million).
- Cash generated from operations of \$337.9 million up 10% from \$306.5 million in 1Q 2025.
- Cash capital expenditure of \$42.6 million up 6% YoY (1Q 2025: \$ 40.2 million). Capex run rate expected to increase 2Q 2026 onwards.
- Balance sheet remains robust, end-March cash at bank \$461.7 million (YE 2025: \$332.3 million).
- Net Debt at end-March of \$531.6 million down 21% on prior quarter (YE 2025: \$673 million). ND/EBITDA improves to 0.43x (YE: 0.53x).
- Completed refinancing of our undrawn revolving credit facility (‘RCF’) and upsized to \$400 million, cost of borrowing reduced to SOFR plus 4.5% (down from SOFR plus 5% plus CAS), an overall saving of 76 bps.

Dividend

- 1Q 2026 declared dividend of USD 9.0 cents per share, consisting of USD 5.0 c/share base and USD 4.0 c/share special dividend, for a total cost of approximately \$54 million. The declared dividend is up 8% QoQ and up 96% YoY.

2026 Outlook

- 2026 guidance reiterated
 - Production guidance of 135-155 kboepd (Crude & Condensate: flat, NGL: +85% YoY & Gas: +30% YoY)
 - Capex guidance remains \$360-440 million, unit operating cost guidance reiterated at \$13.5-\$14.5/boe

Roger Brown, Chief Executive Officer, said:

“The conflict in the Middle East has dramatically changed the outlook for the oil and gas industry in 2026, and quite possibly beyond. Nigeria’s favourable geographic positioning, combined with our oil rich portfolio, which is fully exposed to higher oil prices, and our strong balance sheet, means we are well placed to deliver strong cash flows in 2026. As a result, we have increased our 1Q 2026 dividend to 9.0 cents per share (core: 5.0 cents and special: 4.0 cents).

Production in 1Q 2026, improved QoQ but modestly missed our internal expectations, largely due to unplanned downtime on third-party infrastructure onshore. That said, April to date production has averaged c.153 kboepd, illustrating the potential of our asset base. Notably, this is before the return of Yoho, scheduled to come back onstream before end 2Q 2026, and full ramp-up of ANOH, as such we remain comfortable with our 2026 guidance.

While the firmer oil price outlook should enhance cash flows its duration is uncertain, as such, we expect to retain our current growth-focused 2026 work programme, which will deliver enhanced asset reliability and overall portfolio growth on route to our 2030 targets. Overall, we have delivered a solid start to 2026, with expectations that 2Q 2026 will see a step forward in performance”.

Summary of performance

	\$ million			₦ billion	
	1Q 2026	1Q 2025	% change	1Q 2026	1Q 2025
Revenue **	840.7	809.3	3.9 %	1,163.4	1,227.5
Gross profit	370.5	353.0	4.9 %	512.7	535.4
EBITDA ***	371.3	400.6	(7.3)%	513.8	607.6
Operating profit	213.5	238.2	(10.4)%	295.4	361.3
Profit before tax	165.6	207.4	(20.2)%	229.1	314.6
Profit after tax	37.9	23.3	62.7 %	52.5	35.4
Cash generated from operations (post-tax)	243.4	219.9	10.7 %	336.9	333.5
Working interest production (boepd)	129,841	131,745	(1.4)%		
Volumes lifted (MMbbls)	8.7	9.9	(12.6)%		
Average realised oil price (\$/bbl)	86.2	76.4	12.8 %		
Average realised gas price (\$/Mscf)	3.1	3.0	3.0 %		
Average realised NGL price (\$/bbl)	44.4	44.8	(0.8)%		
LTIF	0	0			
CO ₂ emissions intensity from operated assets, kg/boe	41.6	47.9	(13.2)%		

** 1Q 2026 reported revenue includes an overlift of \$92.0 million, 1Q 2025 includes an overlift of \$53.5 million

*** Adjusted for non-cash items

Responsibility for publication

This announcement has been authorised for publication on behalf of Seplat Energy by Eleanor Adaralegbe, Chief Financial Officer, Seplat Energy PLC.

Signed:



Eleanor Adaralegbe

Chief Financial Officer

Important notice

The information contained within this announcement is unaudited and deemed by the Company to constitute inside information. Upon the publication of this announcement, this inside information is now considered to be in the public domain.

Certain statements included in these results contain forward-looking information concerning Seplat Energy's strategy, operations, financial performance or condition, outlook, growth opportunities or circumstances in the countries, sectors, or markets in which Seplat Energy operates. By their nature, forward-looking statements involve uncertainty because they depend on future circumstances and relate to events of which not all are within Seplat Energy's control or can be predicted by Seplat Energy. Although Seplat Energy believes that the expectations and opinions reflected in such forward-looking statements are reasonable, no assurance can be given that such expectations and opinions will prove to have been correct. Actual results and market conditions could differ materially from those set out in the forward-looking statements. No part of these results constitutes, or shall be taken to constitute, an invitation or inducement to invest in Seplat Energy or any other entity and must not be relied upon in any way in connection with any investment decision. Seplat Energy undertakes no obligation to update any forward-looking statements, whether because of new information, future events or otherwise, except to the extent legally required.



Enquiries:

Seplat Energy Plc

Eleanor Adaralegbe, Chief Financial Officer	+23412770400
James Thompson, GM, Investor Relations	ir@seplatenergy.com
Chioma Afe, Director, External Affairs & Social Performance	

FTI Consulting

Ben Brewerton / Christopher Laing	+44 203 727 1000
	seplatenergy@fticonsulting.com

Citigroup Global Markets Limited

Peter Brown / Peter Catterall	+44 207 986 4000
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Canaccord Genuity Limited

Henry Fitzgerald-O'Connor / George Grainger / Rory Blundell	+44 207 523 8000
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Peel Hunt LLP

Richard Crichton / David McKeown / Georgia Langoulant	+44 207 418 8900
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About Seplat Energy

Seplat Energy Plc is Nigeria's leading indigenous energy company. It is listed on the Premium Board of the Nigerian Exchange Limited (NGX: SEPLAT) and the Main Market of the London Stock Exchange (LSE: SEPL). Through our strategy to build a sustainable business and deliver energy transition, we are transforming lives by delivering affordable, reliable and sustainable energy that drives social and economic prosperity.

Seplat Energy's portfolio consists of 11 PMLs, 17 PPLs and 5 OMLs in onshore and shallow water locations in the prolific Niger Delta region of Nigeria, which we operate with partners including the Nigerian Government and other producers. Furthermore, we have an operated interest in three export terminals including: the Qua Iboe export terminal, Yoho FSO, and Bonny River Terminal (BRT), and operate two large offshore NGL recovery plants at Oso and EAP.

We operate three gas processing plants onshore, at Oben and Sapele on our Western Assets and the 300 MMscfd ANOH Gas Processing Plant on our Eastern Assets, an integrated joint venture with NGIC. Combined, these gas facilities augment Seplat Energy's position as a leading supplier of natural gas to the domestic power generation market.

For further information please refer to our website, <https://www.seplatenergy.com/>

Operating review

Group Production

Working interest production for the three months ended 31 March 2026

Asset	Seplat WI %	1Q 2026				1Q 2025			
		Crude & Condensate bopd	Gas MMscfd	NGLs bpd	Total kboepd	Crude & Condensate bopd	Gas MMscfd	NGLs bpd	Total kboepd
Western Assets *	45 %	12,366	104.5	—	30,388	16,291	132.0	—	39,050
Elcrest **	45 %	12,635	—	—	12,635	12,676	—	—	12,676
Eastern Assets ***	40 %	3,374	17.0	—	6,302	2,935	—	—	2,935
Newton ****	40 %	1,375	—	—	1,375	1,607	—	—	1,607
Seplat Onshore		29,751	121.5	—	50,700	33,508	132	—	56,267
OMLs 67, 68, 70, 104	40 %	61,903	29.1	9,802	76,725	65,385	20	3,376	72,239
OML 99 (A/K Field)	9.6 %	533	10.9	—	2,416	816	14	—	3,239
Seplat Offshore		62,436	40.0	9,802	79,141	66,201	34	3,376	75,478
Total		92,187	161.5	9,802	129,841	99,710	166	3,376	131,745

Liquid production volumes as measured at the LACT (Lease Automatic Custody Transfer) unit for Seplat Onshore flow stations.

Gas conversion factor of 5.8 boe per scf.

Volumes stated are subject to reconciliation and may differ from sales volumes within the period.

* Western Assets are the former blocks OMLs 4,38,41 now comprising of 7 PMLs and 12 PPLs following conversion to PIA

** Elcrest is the Seplat entity operating block OML 40 & Abiala marginal field, now named OML 40 & PPL 209

*** Eastern Assets is the former block OML 53 now comprising of 3 PMLs and 4 PPLs following conversion to PIA

**** Newton is the Seplat entity operating block OPL 283 and now designated PML 17

In 1Q 2026, average daily working interest production for the group declined marginally YoY by 1% to 129,841 boepd (1Q 2025: 131,745 boepd). On a QoQ basis, production grew 9% QoQ (4Q 2025: 119,200 boepd). We expect higher production in subsequent quarters, given improvements in evacuation route stability in the Western Assets and planned restoration of production offshore at Yoho.

Average daily working interest production on our onshore assets declined 10% YoY to 50,700 boepd (1Q 2025: 56,267 boepd). The decline was primarily caused by a 38-day unplanned third-party downtime experienced on the Trans Forcados Pipeline ('TFP'), discussed in more detail in the Seplat Onshore section.

On our offshore assets, average daily working interest production grew 5% YoY to 79,141 boepd (1Q 2025: 75,478 boepd), this was driven by the strong improvement in NGL production (up 190% YoY), benefitting from good availability and performance of EAP, and gas production growing 17% YoY in the quarter. Crude and condensate volumes were 6% lower than same period last year due to the ongoing maintenance of the Yoho platform, and further declines at A/K due to low well head pressure.

HSE Performance

Across the Group, we continue to prioritise safe and responsible operations as part of delivering our strategy and growing our business. In 1Q 2026, staff and contractors across our operated onshore and offshore assets recorded a total of 9.1 million man hours worked without LTI.

LTI-Free hours worked	1Q 2026	FY 2025*	Days since last LTI
Onshore Operated Assets	3,053,616	3,556,678	197
Offshore Operated Assets	6,084,828	7,865,778	474
Total Operated Assets	9,138,444	11,422,456	
Elcrest	811,539	3,123,151	2,092
AGPC	442,259	3,045,939	3,357 (since inception)
Total Non-Operated Assets	1,253,798	6,169,090	

* FY 2025 data for operated assets is from 13th September, when we recorded an LTI at Oben.

In the quarter, we reported three Tier-1 Loss of Primary Containment ('LOPC') incidents, which were one fire incident, one gas release and one oil spill. Additionally, we recorded two Tier-2 LOPC incidents related to minor gas releases. We continue to strengthen our spill response, regulatory engagement, and remediation oversight, while maintaining our oil spill contingency plan to support effective management of spill scenarios across our operations.

In our FY 2025 result, we noted that we completed stage one audit for ISO 14001 certificate. We are pleased to announce that stage two audit for ISO 14001 is in line to be completed in 2Q 2026 across our onshore assets. Achieving ISO 14001 will evidence that our Environmental Management Systems ('EMS') are in line with global best practices. Post period end we successfully completed the 2026 ISO 55001 Asset management System ('AMS') surveillance audit.

Seplat Offshore

Crude & Condensate	Seplat WI - %	1Q 2026 bopd	1Q 2025 bopd	y/y change	4Q 2025 bopd	q/q change
OMLs 67, 68, 70, 104	40 %	61,903	65,385	(5) %	49,940	24 %
OML 99 (A/K Field)	9.6 %	533	816	(35) %	528	1 %
Total Crude & Condensate		62,436	66,201	(6) %	50,468	24 %
NGLs						
OMLs 67, 68, 70, 104	51 %	9,802	3,376	190 %	5,085	93 %
Total NGLs		9,802	3,376	190 %	5,085	93 %

Crude, Condensate & NGL Production

In OMLs 67, 68, 70, and 104, average daily working interest crude and condensate production for 1Q 2026 was 62,436 bopd down 6% YoY (1Q 2025: 66,201 bopd) but a strong 24% improvement QoQ (4Q 2025: 50,468 bopd). Improved uptime and the idle well restoration programme supported the strong recovery versus 4Q 2025, while the decline versus 1Q 2025 reflects the impact of Yoho production platform which remained offline during the quarter.

Natural gas liquids average daily working interest production for 1Q 2026 grew 190% YoY to 9,802 bpd (1Q 2025: 3,376 bpd) and 93% on a QoQ basis (4Q 2025: 5,085 bpd). The increase was due to the positive impact of the Inlet Gas Exchanger ('IGE') unit replacement at EAP as reported in 4Q 2025. We continued our delivery of Liquefied Petroleum Gas ('LPG') to the domestic market from the Bonny River Terminal ('BRT'), with two Butane cargos (12,600 MT each) lifted in February and March 2026.

The non-operated Amenam-Kpono ('A/K') field contributed 533 bopd of crude and condensate to average daily working interest production in 1Q 2026, flat on the prior quarter, but down 35% on 1Q 2025.

Idle well restoration

We continued with our Idle well restoration programme in 1Q 2026 after the strong performance recorded in 2025. In 1Q 2026, we have restored an additional nine idle wells of which eight resumed production successfully. These wells have added an incremental gross production capacity of 10.0 kbopd (4.0 kbopd net working interest), above plan and reinforcing the role of the idle well restoration programme as a key production growth lever. Since inception, the idle well restoration programme has delivered a cumulative production capacity increase of 58.6 kbopd (gross JV) from 58 wells (of which 50 successfully produced) at a total cost of \$83 million, delivering strongly accretive value to the JV partnership.

Following an increase in the availability of well-work barges, the rate of well restoration activities is expected to increase in subsequent quarters.

Yoho production platform

As previously communicated, the Yoho production platform was offline throughout 1Q 2026. During the quarter we took delivery of key materials and continued to replace damaged systems, including over 60 km of cabling and almost 400 piping spool replacements. In parallel the JV has accelerated maintenance activities previously planned for 2H 2026, including valve replacements and riser repairs alongside the broader asset integrity scope which will enhance long-term safety and reliability. The facility remains on track for restart in 2Q 2026.

Offshore drilling activities

The Jack-Up unit, Shelf Drilling Victory ('SDV') rig, is in country and on track to mobilise to Seplat and commence operations during 3Q 2026. During the quarter, key milestones achieved included equipment inspections, receipt of regulatory permits, and engagement workshops with service partners. The 2026 plan targets drilling of two new wells at Oso.

Asset integrity

We continue prioritising investment in strategic maintenance and asset integrity activities. Our offshore infrastructure is vast and interconnected; delivery of long-term value to shareholders through growth will be significantly enhanced with improved reliability and uptime. During the quarter we executed; eight riser repairs, 192 pipeline wraps and 8,400m² of coatings. On top of this we proactively addressed the outcomes of our single point of failure analysis, delivering preventative maintenance and equipment change-outs that will further enhance operating performance, reducing risk of unplanned outages and protecting future production volumes.

Industrial Action

Collective bargaining discussions with PENGASSAN commenced late in 2025 as part of the regular triennial collective bargaining agreement ('CBA') process, covering certain elements of our offshore workforce. These negotiations extended into early 2026, reflecting a deliberate effort to ensure appropriate benchmarking against industry peers and alignment on sustainable pay and conditions. This followed earlier collaborative engagements with the union post-CIC, including agreed adjustments to salary and retention structures.

As discussions remained ongoing, notice of withdrawal was received from the Union, which ultimately led to a structured shutdown of offshore operations. While this was an unfortunate event in the process, the matter was resolved swiftly and amicably through continued collaboration between the Company, PENGASSAN, and our JV partner, NNPC.

Operational impact was minimal, with production offline for approximately a day and a return to normal output achieved thereafter. There has been no impact on lifting commitments due to the shutdown.

Seplat Onshore

Crude & Condensate	Seplat WI - %	1Q 2026 bopd	1Q 2025 bopd	y/y change	4Q 2025 bopd	q/q change
Western Assets	45 %	12,366	16,291	(24) %	16,921	(27) %
Elcrest	45 %	12,635	12,676	— %	13,879	(9) %
Eastern Assets	40 %	3,374	2,935	15 %	2,934	15 %
Newton	40 %	1,375	1,607	(14) %	1,665	(17) %
Seplat Onshore		29,751	33,508	(11)%	35,399	(16)%

Western Assets (previously OML 4, 38, 41)

Average daily working interest crude and condensate production on our Western Assets (previously OMLs 4, 38 & 41) was 12,366 bopd down 24% YoY (1Q 2025: 16,921 bopd), and down 27% sequentially. The decline was caused by unplanned downtime on the TFP pipeline totalling 38 days, this was caused by an underwater leak requiring sectional replacement. The TFP resumed operations on 24 March 2026, restoring integrity and supporting improved reliability and production assurance going forward. However, the extended outage prompted multiple operators to divert volumes into the Amukpe–Escravos Pipeline ('AEP'), constraining our ability to deliver our full allocation and amplifying deferrals already arising from the TFP outage. Encouragingly, additional storage capacity is being developed by Seplat and other operators in the area that will help to mitigate this evacuation risk.

Elcrest (OML 40)

in 1Q 2026, average daily working interest crude and condensate production on Elcrest was 12,635 bopd, flat YoY (1Q 2025: 12,676 bopd). The planned production for the period was impacted by a 10-day downtime on the Trans Escravos pipeline ('TEP') in January 2026 resulting in decline in production QoQ by 9% (4Q 2025: 13,879 bopd). Production has since resumed, furthermore, production from Abiala has increased more materially following the commencement of access to a third party custody transfer unit.

Eastern Assets (previously OML 53)

Average daily working interest crude and condensate production on our Eastern Assets (previously OML 53) was 3,374 bopd growing 15% YoY (1Q 2025: 2,935 bopd) and 15% QoQ (4Q 2025: 2,934 bopd). The improvement is due to the availability of recently completed buffer tanks, which have reduced risk of third-party deferrals, and due to the contribution of ANOH, which added net production of 419 bopd of condensate, reflecting the field start-up during the quarter, albeit at a constrained rate transiting the Trans Niger Pipeline ('TNP'). Work by the TNP pipeline operator is ongoing in 2Q 2026 to upgrade the line, which will support a normalisation of production from ANOH.

Newton (previously OPL 283)

The non-operated Newton assets field contributed 1,375 bopd of crude and condensate production to average daily working interest production in 1Q 2026 (1Q 2025: 1,607 bopd). This decline was caused by the unplanned downtime on the third-party operated TFP as earlier explained.

Drilling

The 2026 drilling plan comprises 15 onshore wells. During the quarter, work was ongoing on seven wells: three completions related to the 2025 drilling campaign and four new wells commenced from the 2026 programme. Of the 2026 wells, one was completed in 1Q 2026 (Oben 59 - ILIW 02), with the remaining three expected to be completed as part of the 2Q 2026 plan.

Overall, the drilling programme remains on track to deliver the balance of the planned wells by year-end, with a continued focus on arresting production decline and supporting organic growth objectives.

PIA conversion, updated license area and effects on assets

On 23 December 2025, we announced the completion of the conversion of our operated onshore assets to the Petroleum Industry Act (PIA) fiscal regime, replacing the Petroleum Profit Tax (PPT) regime. This change relates to the assets; OMLs 4, 38 & 41, now called Western Assets and OML 53, now called Eastern Assets.

In compliance with the Petroleum Industry Act (PIA) requirement to relinquish undeveloped acreage, we carried out a review exercise of the asset. Following this exercise, for the Western Assets, we retained 73% of the original licensed area held under the PPT, equivalent to 1,861 sq km of 2,571 sq km. For the Eastern Assets, we retained 40% of the original licensed area under PPT, equivalent to 529 sq km of 1,322 sq km.

This relinquishment has no impact on production, nor does it impact on our reported 2P reserves and 2C resources.

The Western Assets portfolio now comprises seven Petroleum Mining Licenses (PMLs)—PMLs 68, 69, 70, 71, 72, 73, and 74—and twelve Petroleum Prospecting Licenses (PPLs), namely PPLs 2A13, 2A14, 2A15, 2A16, 2A17, 2A18, 2A19, 2A20, 2A21, 2A22, 2A23, and 2A24.

The Eastern Assets portfolio now comprises three PMLs - PMLs 75, 76 & 77 and four PPLs namely PPLs 2A25, 2A26, 2A27 & 2A28.

Midstream gas business performance

Gas	Seplat WI - %	1Q 2026 MMscfd	1Q 2025 MMscfd	y/y change	4Q 2025 MMscfd	q/q change
Western Assets	45 %	104.5	132.0	(21) %	119.7	(13) %
Elcrest	45 %	—	—	— %	—	— %
Eastern Assets	40 %	17.0	—	— %	—	— %
Newton	40 %	—	—	— %	—	— %
Seplat Onshore		121.5	132.0	(8)%	119.7	2 %
OMLs 67, 68, 70, 104	40 %	29.1	20.2	44 %	35.6	(18) %
OML 99 (A/K Field)	9.6 %	10.9	14.1	(23) %	8.5	28 %
Seplat Offshore		40.0	34.2	17 %	44.1	(9)%
Total		161.5	166.2	(3)%	163.8	(1)%

In 1Q 2026, the Group produced 14.5 Bscf of gas (161.5 MMscfd), a 3% decline YoY (1Q 2025: 15.0 Bscf (166.2 MMscfd)). Average daily working interest gas production on our onshore assets was 121.5 MMscfd down 8% YoY (1Q 2025: 132.0 MMscfd) with the decline driven primarily by the unplanned downtime experienced on TFP, described in the onshore section, which affected associated and non-associated gas production, partially offset by first gas production from ANOH.

On the offshore assets, average daily working interest gas production was 40.0 MMscfd in 1Q 2026, growing 17% YoY (1Q 2025: 34.2 MMscfd), largely benefitting from improved efficiency at the EAP facility, and stronger throughput at Oso. However, QoQ, average daily working interest gas production declined 9% (4Q 2025: 44.1 MMscfd) due to third-party pipeline unavailability in the period. We continue to progress on our OSO-BRT projects, described below, to mitigate third-party dependences on the offshore gas evacuation.

Sapele Integrated Gas Plant ('SIGP')

SIGP continues to deliver value to the Group through strong operating performance. Although it was also impacted during the quarter due to restrictions on condensate exports due to the TFP downtime, it is providing strong gas lift support for low pressure wells at both Ovhor and Sapele, aiding liquids production, as well as supporting gas monetization, and reductions in scope 1 emissions.

The Sapele LPG module successfully completed the commissioning of the fractionation system during the quarter and is currently proceeding to completion of product certification process. We are pleased to report that the first LPG and propane loadout completed in April. This milestone will further support our emissions reduction objectives and our revenue diversification efforts.

ANOH Gas Processing Company ('AGPC')

As previously announced, first gas was achieved in January 2026. During 1Q 2026, the ANOH gas plant delivered steady gross processed dry gas volumes of around 50-55 MMscfd to Indorama. All necessary agreements are in place to increase production and sustain sales to Nigeria LNG ('NLNG'), however a constraint related to evacuation of condensates via the TNP restricted our ability to ramp up gas production during the quarter. The pipeline operator plans to carry out necessary repairs to the pipeline connecting ANOH gas plant to TNP during a three week shutdown in 2Q 2026, after which we will be able to increase condensate evacuation via the pipeline.

To support the temporary restriction through TNP, AGPC will shortly commence condensate evacuation by truck to a local refinery, this will support an increase of gas processing at the ANOH gas plant and an increase in gas flows to NLNG. Despite the condensate evacuation constraints, we are pleased to report that at end April 2026, the ANOH gas plant is processing gas at around 50% of nameplate capacity, achieving a peak processing rate to date of approximately 193 MMscfd.

OSO - BRT phase 1

Oso-BRT pipeline upgrade project, designed to enable ramp up of gas supply to NLNG from 120 MMscfd to 240 MMscfd, is on track to be completed in 3Q 2026. As at the end of 1Q 2026 the engineering design phase has been completed, with the majority of long-lead items procured and delivered, while onshore fabrication activities are progressing as planned.

End of Routine Flaring

During the period, the carbon emissions intensity for our operated onshore assets was 23.8 kgCO₂/boe, 24% lower than 1Q 2025's 31.2 kgCO₂/boe, reflecting the impact of the End of Routine Flaring projects, particularly on our Western Assets. On our operated offshore assets, carbon emissions intensity was 47.3 kgCO₂/boe, 15% lower than 1Q 2025's emissions intensity of 55.5 kgCO₂/boe.

Across our Western Assets, we delivered a structurally lower level of flaring to ~7 MMscfd in 1Q 2026 (1Q 2025: ~22 MMscfd); this represents just 3% of total gas produced demonstrating the positive impact of our end of routine flaring projects. On our Eastern Assets commencement of gas transfer to AGPC in January 2026 drove a material reduction of 30% in flared gas relative to total gas volumes produced with ~8 MMscfd flared in 1Q 2026 (1Q 2025: ~9 MMscfd). With continued optimization and improved evacuation availability expected from 2Q 2026, we anticipate further reduction in flaring volumes, associated fees and incremental revenues.

Emissions Intensity by operated assets	Unit	1Q 2026	1Q 2025	y/y change	4Q 2025	q/q change
Onshore operated	kgCO ₂ /boe	23.8	31.2	(24) %	22.1	8 %
Offshore operated	kgCO ₂ /boe	47.3	55.5	(15) %	54.3	(13) %
Group	kgCO₂/boe	41.6	47.9	(13)%	43.6	(5)%

Financial review

The oil price environment was favourable in 1Q 2026 as tensions in the Middle East led to a surge in prices. While Brent crude averaged \$77.6/bbl, 4% higher than \$74.9/bbl in 1Q 2025, our oil price realisations saw greater uplift due to timing and weighting of liftings (38% of crude and condensate liftings occurred in March and achieved realised pricing of \$110.3/bbl). As such, we report premium of \$8.55/bbl to Brent (1Q 2025: \$1.55/bbl) and an average realised price of \$86.16/bbl. NGL price realisation of \$44.4/bbl was equivalent to approximately 52% of Brent compared to 59% in 1Q 2025, due to mix and timing with 48% of liftings consisting of lower-priced Propane, lifted in February. Gas price realisations were positive, up 3% to \$3.10/Mscf (1Q 2025: \$3.01/Mscf). Overall, the positive price environment in 1Q 2026 offset the impact of lower sales volumes.

Revenue

Description	Units	1Q 2026	1Q 2025	y/y change	4Q 2025	q/q change
Crude & condensate volumes lifted	mmbbl	8.7	9.9	(13) %	7.4	17 %
NGLs volumes lifted	mmbbl	1.1	0.1	730 %	0.5	150 %
Gas sales volume	Bscf	12.8	14.6	(12) %	16.8	(24) %
Average realised oil price	US\$/bbl	86.16	76.42	13 %	65.57	31 %
Average Brent crude oil price	US\$/bbl	77.61	74.87	4 %	63.04	23 %
Premium (discount) to Brent	US\$/bbl	8.55	1.55	452 %	2.53	237 %
Average realised NGL price	US\$/bbl	44.44	44.79	(1) %	45.43	(2) %
Average realised gas price	US\$/mscf	3.10	3.01	3 %	2.68	16 %
Crude & condensate revenue	US\$m	745.7	759.8	(2) %	483.4	54 %
Gas revenue	US\$m	44.2	44.5	(1) %	45.0	(2) %
NGLs revenue	US\$m	50.9	5.0	927 %	20.8	144 %
Total revenue	US\$m	840.7	809.3	4 %	549.2	53 %
(Overlift)/underlift	US\$m	(92.0)	(53.5)	72 %	23.0	(499) %
Total revenue adjusted for (overlift)/underlift	US\$m	748.7	755.7	(1) %	572.3	31 %

Group revenue in 1Q 2026, rose 4% to \$840.7 million versus the prior year (1Q 2025: \$809.3 million), as higher NGLs liftings and better realised prices during the quarter offset lower volumes. The Group recorded a \$92.0 million overlift in 1Q 2026 (1Q 2025: \$53.5 million overlift), as such overlift adjusted total revenue of \$748.7 million was marginally lower than 1Q 2025.

Across product segments, 1Q 2026 crude and condensate revenue declined by 2% YoY to \$745.7 million (1Q 2025: \$759.8 million), due to lower crude oil liftings, which declined 13% to 8.7 MMbbls (1Q 2025: 9.9 MMbbls) and offset the positive impact of improved price realisations in the quarter, average realised oil price rose 13% year-on-year to \$86.2/bbl (1Q 2025: \$76.4/bbl). In the period, crude and condensate sales accounted for 89% of group revenues, down from 94% in 1Q 2025, due to higher NGLs sales.

Reported gas revenue for 1Q 2026 declined by 1% to \$44.2 million (1Q 2025: \$44.5 million), due to lower gas sales volume on our onshore assets during the quarter. Gas sales volume declined 12% to 12.8 Bscf (1Q 2025: 14.6 Bscf), netting off the 3% increase in average realised price to \$3.1/Mscf (1Q 2025: \$3.0/Mscf). Revenue from gas sales accounted for 5% of group revenues, unchanged from 1Q 2025.

NGLs revenue rose 927% to \$50.9 million in 1Q 2026, from \$5.0 million in 1Q 2025. The increase in NGLs revenue reflects the success of the replacement of the Inlet Gas Exchanger ('IGE') unit at the East Area Project ('EAP') facility which has seen NGLs production grow and lifting frequency increase. In the quarter, NGLs volumes lifted rose 730% to 1.1 MMbbls, compared to 0.1 MMbbls in 1Q 2025. NGLs contribution to group revenue rose to 6% (1Q 2025: 1%).

Cost of sales

Description	Units	1Q 2026	1Q 2025	y/y change	4Q 2025	q/q change
Non-Production Cost:		270.6	307.2	(12) %	292.4	(7) %
Royalties	US\$m	116.5	130.2	(11) %	94.1	24 %
Depletion, Depreciation, & Amortisation	US\$m	141.2	164.0	(14) %	190.9	(26) %
Regulatory fees/levies	US\$m	13.0	12.9	— %	7.4	76 %
Production Cost:		199.7	149.1	34 %	231.83	(14) %
Crude Handling Fees	US\$m	17.1	18.8	(9) %	18.6	(8) %
Barging & Trucking	US\$m	6.5	5.7	14 %	5.5	18 %
Operational & Maintenance Expenses	US\$m	176.1	124.6	41 %	207.7	(15) %
Production Opex per boe	US\$/boe	17.1	12.6	36 %	21.1	(19) %
Cost of Sales	US\$m	470.3	456.3	3 %	524.2	(10) %
Gross Profit	US\$m	370.5	353.0	5 %	25.1	1379 %

In 1Q 2026, group production costs which encompass expenses related to crude-handling charges ('CHC'), barging/trucking, operations & maintenance, rose 34% to \$199.7 million, compared to \$149.1 million in 1Q 2025. The increase in production costs is due to expenses incurred in the restoration of Yoho production platform, alongside higher activity levels offshore. On a cost per barrel basis, production cost rose 36% to \$17.1/boe, from \$12.6/boe in 1Q 2025, we expect this unit cost to normalise to our guidance range over subsequent quarters in 2026.

The business continued to benefit from the conclusion of the End of Routine Flaring ('EORF') projects. Gas flare fees (included in Operational and Maintenance Expenses) declined 52% to \$7.0 million (1Q 2025: \$14.7 million).

Non-production costs declined 12% to \$270.6 million (1Q 2025: \$307.2 million). The lower non-production costs for the period were underpinned by lower royalties and lower depletion, depreciation & amortisation ('DD&A') charge. The decline in royalties reflects the positive impact the transition to the Petroleum Industry Act (PIA) for our onshore operated assets, where the blended (oil and gas) royalty rate on our operated onshore assets was 6% in 1Q 2026 (1Q 2025: 15%). The decline in DD&A charge reflects the update to the reserve base following the updated competence person report (CPR) completed in 4Q 2025.

Overall, gross profit for the Group rose 5% in 1Q 2026 to \$370.5 million (1Q 2025: \$353.0 million).

Operating profit and Adjusted EBITDA

Description	Units	1Q 2026	1Q 2025	y/y change	4Q 2025	q/q change
Other Income/(Loss)	US\$m	(91.3)	(44.4)	106 %	30.9	(395)%
General and Administrative Expenses	US\$m	(46.4)	(64.9)	(29) %	(79.7)	(42) %
Impairment (Loss)/Reversal on Financial Assets	US\$m	(5.4)	(0.5)	920 %	(6.9)	(21) %
Fair Value Loss	US\$m	(13.8)	(5.0)	174 %	(5.2)	165 %
Operating Profit	US\$m	213.5	238.2	(10)%	(35.8)	(697)%
Adjusted EBITDA	US\$m	371.3	400.6	(7)%	163.5	127 %

General and Administrative ('G&A') expenses amounted to \$46.4 million, 29% lower than 1Q 2025's \$64.9 million. Lower G&A expenses during the period was due to a reallocation of field related cost to cost of sales as well as the benefits of cost optimisation efforts across the Group. G&A cost per boe for the Group was \$4.0/boe (1Q 2025: \$5.5/boe), lower than 2026 guidance of \$4.5/boe - \$5.0/boe.

The other income/(loss) line is primarily made up of the overlift of \$92.0 million, translating to 501 kbbls, compared to overlift of \$53.5 million translating to 672 kbbls recorded in 1Q 2025.

Overall, we reported operating profit of \$213.5 million (operating margin: 25%) in 1Q 2026, 10% lower than the \$238.2 million (operating margin: 29%) reported in 1Q 2025.

After adjusting for non-cash items such as impairment, fair value, and exchange gains or losses, the adjusted EBITDA for the quarter was \$371.3 million (1Q 2025: \$400.6 million), resulting in a margin of 44% (1Q 2025: 50%).

Taxation

The income tax expense of \$127.6 million (1Q 2025: \$184.1 million) includes a current tax charge of \$127.4 million (1Q 2025: \$215.0 million) and a deferred tax charge of \$0.2 million (1Q 2025: \$30.9 million credit). This reflects an effective tax rate ('ETR') of 77%, lower than the 89% reported in 1Q 2025. The reduction in ETR is largely driven by the conversion of our onshore assets (excluding Elcrest) to the fiscal terms of the Petroleum Industry Act (PIA), under which the applicable tax rate is 60%, compared to 85% under the Petroleum Profits Tax (PPT). In addition, deferred tax recoverability has been recognised at this lower 60% rate, further contributing to the reduction in ETR.

The 1Q 2026 tax numbers were computed based on the 2026 full-year ETR estimate in line with IAS 34. Cash taxes paid year-to-date totalled \$92.7 million, representing 28% of pre-tax cash flows from operations, and an increasing contribution from NGLs.

Net result

Description	Units	1Q 2026	1Q 2025	y/y change	4Q 2025	q/q change
Profit before Tax	US\$m	165.6	207.4	(20)%	(72.2)	(329)%
Total Income tax expense	US\$m	(127.6)	(184.1)	(31) %	136.2	(194) %
Net Income/(Loss)	US\$m	37.9	23.3	63 %	64.0	(41)%
Profit Attributable to Holders of Equity	US\$m	33.8	20.2	67 %	68.1	(50) %
Earnings per Share	US\$c'shr	0.06	0.03	64 %	0.11	(51)%

Profit before tax declined 20%, amounting to \$165.6 million, compared to \$207.4 million in 1Q 2025, primarily due to lower production in the onshore business, following third-party downtime outlined above, alongside higher finance costs, overlift movement, and impairments. Profit after tax for the quarter was \$37.9 million, 63% higher than the \$23.3 million recorded in 1Q 2025.

The profit attributable to equity holders of the parent Company, representing shareholders, was \$33.8 million in 1Q 2026, which resulted in basic earnings per share of \$0.06 for the period (1Q 2025: \$0.03/share).

Cash flows from operating activities

Description	Units	1Q 2026	1Q 2025	y/y change	4Q 2025	q/q change
Profit before tax	US\$m	165.6	207.4	(20) %	(72.2)	(329) %
Non Cash Adjustments	US\$m	221.6	213.3	4 %	253.7	(13) %
Working Capital Changes	US\$m	(49.2)	(114.2)	(57) %	95.4	(152) %
Pre-tax Cashflow from Operating Activities	US\$m	337.9	306.5	10%	276.8	22%
Cash Taxes	US\$m	(92.7)	(36.2)	156 %	(118.2)	(22) %
Others	US\$m	(1.8)	(50.4)	(96) %	(3.9)	(54) %
Post-tax Cashflow from Operating Activities	US\$m	243.4	219.9	11 %	154.8	57 %

In 1Q 2026, the Company generated pre-tax cashflow from operating activities of \$337.9 million (1Q 2025: \$306.5 million). The improvement reflects favourable working capital movements relative to 1Q 2025 on payables and JV receivables.

Net cash flow from operating activities amounted to \$243.4 million in 1Q 2026, compared to \$219.9 million in 1Q 2025. This figure includes cash tax payments of \$92.7 million and restricted cash movement of \$1.8 million during the current period, while in the previous year, cash tax payments were \$36.2 million, while hedging premium of \$1.7 million was paid.

Cash call collection continued to remain strong in the period. During the quarter, on the NEPL/Seplat JV for Western Assets and Elcrest, we received \$101.7 million in cash calls from our JV partner, bringing the receivables balance on the JV to \$51.1 million (FY 2025: \$88.2 million). On our NUIMS/Seplat JV for Eastern Assets, we received \$15.0 million in cash call settlement in 1Q 2026 with cash call obligations fully paid up.

For our SEPNU/NNPC JV, we received \$292.0 million for cash call settlements in 1Q 2026, with the balance on the JV receivables declining to \$152.8 million (FY 2025: \$201.7 million). On the legacy cash call receivable balance, we have achieved full reconciliation for \$188.0 million (of \$325 million outstanding) which will be settled via 18 monthly instalments starting from 2Q 2026. We continue to engage our JV partner in the audit and reconciliation process for the balance of the legacy receivables.

Cash flows from investing activities

Description	Units	1Q 2026	1Q 2025	y/y change	4Q 2025	q/q change
Post-tax Cashflow from Operating Activities (A)	US\$m	241.9	219.9	10 %	154.8	56 %
Capital Expenditure (B)	US\$m	(42.6)	(40.2)	6 %	(86.8)	(51) %
Additional Investment in Joint Venture	US\$m	—	(10.0)	(100) %	—	nm
Additional payment to ExxonMobil	US\$m	—	—	nm	(262.0)	(100) %
Deposit for asset held for sale	US\$m	—	1.0	(100) %	—	nm
Interest received	US\$m	2.9	2.6	12 %	4.4	nm
Net cash outflows used in investing activities	US\$m	(39.7)	(46.6)	(15)%	(344.4)	(88)%
Free Cashflow (A-B)	US\$m	199.2	179.6	11 %	68.0	193 %

In 1Q 2026, the cash capital expenditure on oil & gas assets during the period was \$41.8 million (1Q 2025: \$39.9 million), up 5% from prior year as drilling activities started on a strong note. Aggregate capital expenditure (including non-oil & gas capex) for the period was \$42.6 million. The total net cash outflow from investing activities was \$39.7 million, a 15% decrease relative to 1Q 2025's \$46.6 million due to the additional investment of \$10m in JV in 1Q 2025.

As a result of the operating performance in 1Q 2026, the business generated \$199.2 million of free cashflow, 11% higher than 1Q 2025's \$179.6 million.

Cash flows from financing activities

Description	Units	1Q 2026	1Q 2025	y/y change	4Q 2025	q/q change
Repayments of Loans and Borrowings	US\$m	—	(919.3)	(100) %	—	nm
Proceeds from Loans and Borrowings	US\$m	—	650.0	(100) %	25.0	(100) %
Interest paid on Loans and Borrowings	US\$m	(36.9)	(36.4)	1 %	(9.4)	292 %
Shares purchased for employees	US\$m	(25.0)	—	nm	(20.9)	19 %
Interest paid on lease liabilities	US\$m	(1.4)	(2.5)	(45) %	(1.3)	4 %
Lease payments - principal portion	US\$m	(3.1)	(2.3)	36 %	(3.5)	(12) %
Payment for other financing charges	US\$m	(11.0)	(0.3)	3485 %	(5.6)	97 %
Dividends paid	US\$m	—	—	nm	(44.9)	(100) %
Net cash outflows used in financing activities	US\$m	(77.4)	(310.7)	(75)%	(60.7)	27 %

Net cash outflow from financing activities was \$77.4 million, compared to an outflow of \$310.7 million in 1Q 2025. The lower cash outflow from financing activities relative to 1Q 2025 reflects the bond refinancing and RCF repayment activities completed in 1Q 2025, and which did not repeat this year.



The main components of financing cash outflow were interest payment on loans and borrowings of \$36.9 million, purchase of shares for the employee long term incentive plan costing \$25.0 million, and \$11.0 million fees associated with the refinancing of the Company's undrawn \$400.0 million revolving credit facility, see below.

Debt Movements

Revolving credit facility ('RCF')

As we disclosed in our FY 2025 results, on 31 January, 2026, the Company refinanced and upscaled its existing facility to a new \$400 million revolving credit facility (up from \$350 million previously), while at the same time lowering the borrowing cost with the new facility interest rate set at SOFR plus 4.5% (down from SOFR plus 5% plus CAS of 0.26%), achieving a saving of 76bps. The facility matures in October 2029 and is currently undrawn.

Liquidity

The balance sheet continues to remain healthy with a solid liquidity position.

Description	Units	1Q 2026	FY 2025
Senior loan notes (Eurobonds)*	US\$m	635.8	649.7
Westport Senior Reserve Based Lending (RBL) facility*	US\$m	55.1	53.5
\$400 million Revolving credit facility*	US\$m	0.0	0.0
\$300 million Advanced payment facility*	US\$m	302.3	302.4
Total borrowings*	US\$m	993.3	1,005.6
Cash and cash equivalents (exclusive of restricted cash)	US\$m	461.7	332.3
Net Debt	US\$m	531.6	673.3
Adjusted EBITDA**	US\$m	1,246.1	1,275.4
Net Debt-to-TTM adjusted EBITDA	x	0.43	0.53

* Including amortised interest and accrual for the RCF (undrawn) commitment fee

** data shows the trailing 12-month ('TTM') adjusted EBITDA

Seplat Energy ended the period with gross debt of \$993.3 million (YE 2025: \$1,005.6 million) and cash at bank of \$461.7 million (YE 2025: \$332.3 million), leaving net debt at \$531.6 million (YE 2025: \$673.3 million). Net debt declined by 21% due to strong cash generation during the quarter.

We continue to monitor the Net Debt-to-EBITDA ratio of the Company with a policy to maintain leverage below 1.5x (Debt covenant - 3.0x). At the end of March 2026, the balance sheet remained strong, and our Net Debt-to-EBITDA ratio improved to 0.43x, from 0.53x at end 2025.

Dividend

The Board has approved a quarterly dividend of USD 9.0 cents per share for 1Q 2026 (subject to appropriate WHT) comprised of the minimum quarterly base dividend (USD 5.0 cents per share), and a special dividend of USD 4.0 cents per share. This represents a 96% increase in core dividend paid relative to 1Q 2025 and a 9% increase in total dividend paid relative to 4Q 2025. The decision to pay a special dividend in 1Q 2026 was underpinned by the Company's strong financial position, favourable commodity price impact, and solid outlook for the rest of the year.

Reporting Period	Proposed Dividend (USD cents per share)	Announcement Date	Qualification Date (LSE)	Qualification Date (NGX)	Payment Date
Q4 2025	8.3	26. February 2026	15. May 2026	15. May 2026	29. May 2026
Total 2025	25.0				
Q1 2026	9.0	30. April 2026	5. June 2026	5. June 2026	19. June 2026
Total 2026 YTD	9.0				

Hedging

Seplat Energy's hedging policy aims to guarantee appropriate levels of cash flow assurance in times of oil price weakness and volatility.

Total volumes hedged for 2026 to date is 20.0 MMbbls at a weighted average cost of \$1.19/bbl. We will continue to monitor developments in the oil market and make our hedging decisions accordingly. Our simple put option hedge strategy remains unchanged.

2026 Oil Hedges (Brent Deferred Premium Put Options)	Unit	1Q 2026	2Q 2026	3Q 2026	4Q 2026
Volumes hedged	MMbbls	6.0	6.0	6.0	2.0
Average price floor protected	US\$/bbl	52.5	50	51.7	52.5
Puts unit cost	US\$/bbl	1.21	1.18	1.36	0.65

Credit ratings

Seplat maintains corporate credit ratings with Moody's Investor Services (Moody's), Standard & Poor's Rating Services (S&P) and Fitch Ratings (Fitch). The current corporate ratings are as follows: (i) Moody's B2 (stable); (ii) S&P B (positive); (iii) Fitch B (stable). There were no changes in the period.

Interim sustainability report for 3 months ended 31 March 2026

Governance

During 1Q 2026, the Sustainability Management Committee ("SMC") convened three times to deliberate on a range of sustainability-related matters, including the Group's Biodiversity Action Plan, progress on the End of Routine Flaring Project, carbon credit development and monetisation initiatives, the 2025 Integrated Annual Report, the 2025 Social Performance Report, and performance across key sustainability metrics. In addition, two Conflict-of-Interest awareness sessions were held during the quarter.

The Board Sustainability Committee, Risk Management and HSE Committee, Energy Transition Committee, and the Board Finance and Audit Committee each met once in 1Q 2026 to consider sustainability-related topics within their respective mandates.

Strategy

The Group's disclosures on strategy are presented in the Sustainability section of the recently released 2025 Annual Report which can be accessed [here](#)

Risk Management

The Group's risk disclosures are presented in the 2025 Annual Report which can be accessed [here](#)

Metrics and Target

Description of performance measure		1Q 2026	1Q 2025	Commentary
Our Commitments/Targets are set for only our operated assets (excluding SEPNU)				
GHG Intensity	Onshore	23.8	31.2	Achieved 13% reduction YoY at group level with Onshore reducing by 24% and Offshore reducing by 15%. Onshore improvement is due to the completion of routine flares-out project on the Western Assets in 4Q 2025, followed by the commencement of gas transfer to AGPC in January 2026.
	Offshore	47.3	55.5	
	Group	41.6	47.9	
Gross Scope 1 emissions- reduction (ktCO ₂ e)	Onshore	154	279	Offshore improvement is driven by improved asset reliability in the period.
	Offshore	946	1,092	
	Group	1,099	1,371	
Methane emissions-reduction (tCO ₂ e)	Onshore	45,282	71,850	Currently reporting on six categories: 5; Waste generated in operations, 6; Business travel, 6 7; Employee commuting, 11; Use of sold product, 15; Investments, 1; Purchased goods and services (partly).
	Offshore	65,250	81,698	
	Group	110,532	153,548	
Scope 3 emissions- reporting (number of categories reported)	Report eight Scope 3 emissions categories by 2026 report	6		
Biodiversity	Complete Biodiversity Assessment of Seplat Offshore Operational areas and develop a consolidated BAP for Seplat Group.	Biodiversity actions advanced with consolidation of the Seplat Biodiversity Action Plan, commencement of internal awareness sessions and conclusion of contracting for offshore assessment studies. The assessment kick-off is planned to run between 2Q 2026 and 4Q 2026.		
Water & Wastewater management	Drive water consumption accuracy and commence measurement in offshore operations	Approximately 30% of reporting gaps identified from the onshore audit were closed, while offshore water footprint audits commenced and are scheduled for completion in 2Q 2026 to inform targeted measurement and reporting improvements.		

*Emissions data are based on gross production numbers

Outlook

The key activities for 2026 remain on track for delivery, and support a reiteration of our FY 2026 guidance. The prevailing price environment has deviated positively from our base case planning assumption for the year, however, as our plans already include a significant step up in activity and are agreed with our partners we do not expect to make meaningful changes to our activity plans during the year. We remain focused on driving cost efficiencies and other tangible benefits from the integration of offshore into the Group.

Production guidance

2026 production guidance reiterated at 135-155 kboepd.

Seplat Energy's production operations were below full year guidance in 1Q 2026, due to items described above. In 2Q 2026 we expect an increase in the contribution of ANOH to the Group, while we also expect a restart of the Yoho platform during the period. Further growth is expected in subsequent quarters with the completion of Oso-BRT phase 1 (3Q 2026), new well stock onshore (ongoing) and offshore (drilling to commence in 3Q 2026).

Capex guidance

Working interest capital expenditure guidance is reiterated in the range of \$360 million - \$440 million.

1Q 2026 cash capital investment was lower than planned, largely due to timing. Cash capex run rate is expected to increase over the remaining quarters of 2026, and FY 2026 guidance is maintained.

Opex guidance

Unit operating cost guidance for the Company is maintained in the range of \$13.5-14.5/boe.

1Q 2026 unit operating cost was above plan primarily due to the acceleration of maintenance activities at Yoho, the inclusion of some production personnel expenses in opex and lower production levels in the quarter. Full year forecast for cash production operating costs remains inline with prior expectations, and hence guidance is reiterated.

Other Financial and Strategic guidance

G&A: Unit G&A costs in 1Q 2026 were \$4.0/boe, below 2026 guidance of \$4.5-5.0/boe, due to certain items being reallocated to production opex. 2026 guidance is reiterated.

Tax: Cash tax guide of \$400-500 million was based off our business plan assumption of an oil price of \$65/bbl for 2026. Following the emergence of the conflict in the Middle East, the near term price outlook is both higher and more volatile. We'd note that a \$5/bbl change in average oil price in 2026 will equate to approximately a \$40-70 million change in cash taxes due in the year.

Dividend: With respect to the dividend, our quarterly base dividend of USD 5.0 c/shr will be implemented for the year. Given the significant deviation in realised oil price, we elected to pay a USD 4.0 c/shr special dividend in 1Q 2026 on top of the regular base dividend. 2026 marks the start of the five year period where the Company has committed to return at least \$1.0 billion to shareholders via dividends. The plan targets distributions of 40-50% of free cash flow over the five year cycle (2026-2030).

Potential divestment: As previously announced we are in discussions with our JV partner regarding a potential sale of a 10% working interest in the SEPNU-NNPC JV. Discussions continue, but no agreement has been reached. We will update on developments as they occur.



Interim Condensed Consolidated Financial Statements (Unaudited)

For the three months ended 31 March 2026

(Expressed in Nigerian Naira and US Dollars)

Interim condensed consolidated statement of profit or loss and other comprehensive income

For the three months ended 31 March 2026

	Notes	3 Months ended 31 March 2026 Unaudited ¥ million	3 Months ended 31 March 2025 Unaudited ¥ million	3 Months ended 31 March 2026 Unaudited \$'000	3 Months ended 31 March 2025 Unaudited \$'000
Revenue from contracts with customers	7	1,163,445	1,227,512	840,745	809,267
Cost of sales	8	(650,794)	(692,079)	(470,289)	(456,273)
Gross profit		512,651	535,433	370,456	352,994
Other loss-net	9	(126,407)	(67,293)	(91,346)	(44,365)
General and administrative expenses	10	(64,165)	(98,415)	(46,368)	(64,884)
Impairment loss on financial assets - net	11.1	(7,536)	(810)	(5,446)	(534)
Fair value loss	12	(19,137)	(7,653)	(13,829)	(5,045)
Operating profit		295,406	361,262	213,467	238,166
Finance income	13	4,047	3,968	2,924	2,616
Finance costs	13	(64,507)	(49,524)	(46,615)	(32,650)
Finance cost - net	13	(60,460)	(45,556)	(43,691)	(30,034)
Share of loss from joint venture accounted for using the equity method		(5,842)	(1,060)	(4,222)	(699)
Profit before taxation		229,104	314,646	165,554	207,433
Income tax expense	14	(176,595)	(279,262)	(127,613)	(184,110)
Profit for the period		52,509	35,384	37,941	23,323
Attributable to:					
Equity holders of the parent		46,763	30,679	33,789	20,221
Non-controlling interests		5,746	4,705	4,152	3,102
		52,509	35,384	37,941	23,323
Earnings per share for the period					
Basic earnings per share ¥/\$	25	77.95	52.14	0.06	0.03
Diluted earnings per share ¥/\$	25	77.95	52.14	0.06	0.03
Profit for the period		52,509	35,384	37,941	23,323
Other comprehensive (loss)/income:					
Foreign currency translation difference		(90,272)	2,380	-	-
Other comprehensive (loss)/income for the period		(90,272)	2,380	-	-
Total comprehensive (loss)/income for the period (net of tax)		(37,763)	37,764	37,941	23,323
Attributable to:					
Equity holders of the parent		(30,130)	33,059	33,789	20,221
Non-controlling interests		(7,633)	4,705	4,152	3,102
		(37,763)	37,764	37,941	23,323

The above interim condensed consolidated statement of profit or loss and other comprehensive income should be read in conjunction with the accompanying notes.

Interim condensed consolidated statement of financial position

For the three months ended 31 March 2026

	Notes	31 March 2026 Unaudited ₹ million	31 Dec 2025 Audited ₹ million	31 March 2026 Unaudited \$'000	31 Dec 2025 Audited \$'000
Assets					
Non-current assets					
Oil & gas properties	16	4,242,603	4,477,741	3,060,565	3,119,818
Other property, plant and equipment		487,122	517,515	351,404	360,573
Right-of-use assets		145,842	163,697	105,209	114,054
Intangible assets		750,880	812,866	541,677	566,355
Other assets		125,890	130,343	90,815	90,815
Investment accounted for using equity method		354,244	372,835	255,547	259,769
Long-term prepayments		20,874	22,462	15,059	15,650
Deferred tax assets	14.1	228,457	289,581	164,806	201,762
Total non-current assets		6,355,912	6,787,040	4,585,082	4,728,796
Current assets					
Inventory		465,694	489,087	335,947	340,766
Trade and other receivables	17	831,547	683,086	599,868	475,932
Short-term prepayments		37,754	47,729	27,235	33,254
Contract assets	18	11,176	29,159	8,062	20,315
Derivative financial assets	19.1	6,668	17,352	4,810	12,090
Restricted cash	20.2	177,609	181,347	128,125	126,351
Cash and cash equivalents	20	639,988	476,970	461,682	332,326
Total current assets		2,170,436	1,924,730	1,565,729	1,341,034
Asset held for sale		17,009	17,611	12,270	12,270
Total assets		8,543,357	8,729,381	6,163,081	6,082,100
Equity and liabilities					
Equity attributable to shareholders					
Issued share capital	21	300	300	1,868	1,868
Share premium	21	150,802	150,802	560,371	560,371
Share based payment reserve	21	30,334	24,985	46,827	42,961
Treasury shares	21	(134,866)	(100,270)	(94,350)	(69,350)
Capital contribution		5,932	5,932	40,000	40,000
Retained earnings		389,172	342,409	1,282,082	1,248,293
Foreign currency translation reserve		2,121,189	2,198,082	2,887	2,887
Non-controlling interest		13,363	20,996	18,777	14,625
Total shareholder's equity		2,576,226	2,643,236	1,858,462	1,841,655
Non-current liabilities					
Interest bearing loans and borrowings	22	1,276,361	1,339,135	920,752	933,028
Lease liabilities		66,102	67,027	47,685	46,700
Provision for decommissioning obligation		1,142,098	1,168,622	823,897	814,225
Deferred tax liability	14.1	1,631,706	1,742,201	1,177,094	1,213,860
Defined benefit plan	23.1	3,738	3,904	2,697	2,720
Total non-current liabilities		4,120,005	4,320,889	2,972,125	3,010,533
Current liabilities					
Interest bearing loans and borrowings	22	100,500	104,154	72,500	72,568
Lease liabilities		25,092	29,162	18,101	20,318
Derivative financial liability	19	17,811	9,041	12,848	6,299
Trade and other payables	24	1,348,344	1,310,242	972,678	912,886
Other provisions		4,799	4,901	3,462	3,415
Current tax liabilities		350,580	307,756	252,905	214,426
Total current liabilities		1,847,126	1,765,256	1,332,494	1,229,912
Total liabilities		5,967,131	6,086,145	4,304,619	4,240,445
Total shareholders' equity and liabilities		8,543,357	8,729,381	6,163,081	6,082,100

The above interim condensed consolidated statement of financial position should be read in conjunction with the accompanying notes.

The financial statements of Seplat Energy Plc and its subsidiaries (The Group) for the three months ended 31 March 2026 were authorised for issue on 30 April 2026 in accordance with a resolution of the Directors signed on its behalf by:



U. U. Udoma

FRC/2013/NBA/00000001796

Chairman

30 April 2026



R.T Brown

FRC/2014/PRO/DIR/00000017939

Chief Executive Officer

30 April 2026



E. Adaralegbe

FRC/2017/ICAN/006/00000017591

Chief Financial Officer

30 April 2026

Interim condensed consolidated statement of changes in equity

For the three months ended 31 March 2026

	Issued share capital ₤ million	Share premium ₤ million	Share based payment reserve ₤ million	Treasury shares ₤ million	Capital contribution ₤ million	Retained earnings ₤ million	Foreign currency translation reserve ₤ million	Non-controlling interest ₤ million	Total equity ₤ million
At 1 January 2025	297	87,375	15,558	(3,570)	5,932	319,013	2,393,251	11,127	2,828,983
Profit for the period	-	-	-	-	-	30,679	-	4,705	35,384
Other comprehensive income	-	-	-	-	-	-	2,380	-	2,380
Total comprehensive income for the period	-	-	-	-	-	30,679	2,380	4,705	37,764
Transactions with owners in their capacity as owners:									
Share based payments	-	-	8,812	-	-	-	-	-	8,812
Total	-	-	8,812	-	-	-	-	-	8,812
At 31 March 2025 (unaudited)	297	87,375	24,370	(3,570)	5,932	349,692	2,395,631	15,832	2,875,559
At 1 January 2026	300	150,802	24,985	(100,270)	5,932	342,409	2,198,082	20,996	2,643,236
Profit for the period	-	-	-	-	-	46,763	-	5,746	52,509
Other comprehensive loss *	-	-	-	-	-	-	(76,893)	(13,379)	(90,272)
Total comprehensive income/(loss) for the period	-	-	-	-	-	46,763	(76,893)	(7,633)	(37,763)
Transactions with owners in their capacity as owners:									
Share based payments	-	-	5,349	-	-	-	-	-	5,349
Share re-purchased	-	-	-	(34,596)	-	-	-	-	(34,596)
Total	-	-	5,349	(34,596)	-	-	-	-	(29,247)
At 31 March 2026 (unaudited)	300	150,802	30,334	(134,866)	5,932	389,172	2,121,189	13,363	2,576,226

*Other comprehensive loss comprises the foreign currency translation difference. The loss for the period is driven by weakening USD (~3% decline to ₤1,386.22/\$ as of 31 March 2026 from ₤1,435.26/\$ as of 31 December 2025).

The above interim condensed consolidated statement of changes in equity should be read in conjunction with the accompanying notes.

	Issued share capital \$'000	Share premium \$'000	Share based payment reserve \$'000	Treasury shares \$'000	Capital contribution \$'000	Retained earnings \$'000	Foreign currency translation reserve \$'000	Non- controlling interest \$'000	Total \$'000
At 1 January 2025	1,864	518,564	36,747	(5,609)	40,000	1,233,128	2,233	15,679	1,842,606
Profit for the period	-	-	-	-	-	20,221	-	3,102	23,323
Total comprehensive income for the period	-	-	-	-	-	20,221	-	3,102	23,323
Transactions with owners in their capacity as owners:									
Share based payments	-	-	5,810	-	-	-	-	-	5,810
Total	-	-	5,810	-	-	-	-	-	5,810
At 31 March 2025 (unaudited)	1,864	518,564	42,557	(5,609)	40,000	1,253,349	2,233	18,781	1,871,739
At 1 January 2026	1,868	560,371	42,961	(69,350)	40,000	1,248,293	2,887	14,625	1,841,655
Profit for the period	-	-	-	-	-	33,789	-	4,152	37,941
Other Comprehensive income	-	-	-	-	-	-	-	-	-
Total comprehensive income for the period	-	-	-	-	-	33,789	-	4,152	37,941
Transactions with owners in their capacity as owners:									
Share based payments	-	-	3,866	-	-	-	-	-	3,866
Share repurchased	-	-	-	(25,000)	-	-	-	-	(25,000)
Total	-	-	3,866	(25,000)	-	-	-	-	(21,134)
At 31 March 2026 (unaudited)	1,868	560,371	46,827	(94,350)	40,000	1,282,082	2,887	18,777	1,858,462

The above interim condensed consolidated statement of changes in equity should be read in conjunction with the accompanying notes.

Interim condensed consolidated statement of cash flows

For the three months ended 31 March 2026

	Notes	3 Months ended 31 March 2026 Unaudited ₦ million	3 Months ended 31 March 2025 Unaudited ₦ million	3 Months ended 31 March 2026 Unaudited \$'000	3 Months ended 31 March 2025 Unaudited \$'000
Cash flows from operating activities					
Cash generated from operations	15	467,665	464,919	337,946	306,504
Tax paid		(128,336)	(54,903)	(92,740)	(36,196)
Contribution to plan assets		–	(78,884)	–	(52,006)
Restricted cash	20.3	(2,455)	5,034	(1,774)	3,319
Hedge premium paid		–	(2,644)	–	(1,743)
Net cash inflows from operating activities		336,874	333,522	243,432	219,878
Cash flows from investing activities					
Payment for acquisition of oil and gas properties		(57,875)	(60,459)	(41,822)	(39,859)
Additional investment in Joint venture		–	(15,168)	–	(10,000)
Payment for acquisition of other property, plant and equipment		(1,138)	(575)	(822)	(379)
Deposit for asset held for Sale		–	1,517	–	1,000
Interest received		4,046	3,968	2,924	2,616
Net cash outflows used in investing activities		(54,967)	(70,717)	(39,720)	(46,622)
Cash flows from financing activities					
Repayments of loans and borrowings		–	(1,394,337)	–	(919,250)
Proceeds from loans & borrowings		–	985,933	–	650,000
Shares purchased for employees *		(34,596)	–	(25,000)	–
Interest paid on lease liability		(1,889)	(3,766)	(1,365)	(2,483)
Lease payment - principal portion		(4,269)	(3,451)	(3,085)	(2,275)
Payments of other financing charges **		(15,280)	(467)	(11,042)	(308)
Interest paid on loans and borrowings		(51,037)	(55,238)	(36,881)	(36,417)
Net cash outflows used in financing activities		(107,071)	(471,326)	(77,373)	(310,733)
Net increase/(decrease) in cash and cash equivalents		174,836	(208,521)	126,339	(137,477)
Cash and cash equivalents at beginning of the period		476,970	721,385	332,326	469,862
Effects of exchange rate changes on cash and cash equivalents		(11,818)	1,233	3,017	2,249
Cash and cash equivalents at end of the period	20	639,988	514,097	461,682	334,634

*Shares purchased for employees of \$25 million, ₦34.6 billion represent shares purchased for the company's LTIP scheme.

**Other financing charges of \$11.0 million, ₦15.3 billion (Q1 2025: \$0.3 million, ₦ 0.5 billion) relate to commitment fees and other transaction costs incurred in refinancing of the \$400 million Revolving Credit Facility.

The above interim condensed consolidated statement of cash flows should be read in conjunction with the accompanying notes.

Notes to the interim condensed consolidated financial statements

For the three months ended 31 March 2026

1. Corporate structure and business

Seplat Energy Plc (formerly called Seplat Petroleum Development Company Plc, hereinafter referred to as 'Seplat' or the 'Company'), the parent of the Group, was incorporated on 17 June 2009 as a private limited liability company and re-registered as a public company on 3 October 2014, under the Companies and Allied Matters Act, CAP C20, Laws of the Federation of Nigeria 2004. The Company commenced operations on 1 August 2010. The Company is principally engaged in oil and gas exploration and production and gas processing activities. The Company's registered address is: Seplat House, No. 1, Lekki Expressway, Victoria Island, Lagos, Nigeria.

The Company acquired, pursuant to an agreement for assignment dated 31 January 2010 between the Company, SPDC, TOTAL and AGIP, a 45% participating interest in OML 4, OML 38 and OML 41 located in Nigeria.

On 7 November 2010, Newton Energy Limited ('Newton Energy'), an entity previously beneficially owned by the same shareholders as Seplat, became a subsidiary of the Company. On 1 June 2013, Newton Energy acquired from Pillar Oil Limited ('Pillar Oil') a 40% Participating interest in producing assets: the Umuseti/Igbuku marginal field area located within OPL 283 (the 'Umuseti/Igbuku Fields').

On 11 December 2013, the Group incorporated a new subsidiary, Seplat East Swamp Company Limited with the principal activity of oil and gas exploration and production.

On 11 December 2013, Seplat Gas Company Limited ('Seplat Gas') was incorporated as a private limited liability company to engage in oil and gas exploration and production and gas processing.

On 21 August 2014, the Group incorporated a new subsidiary, Seplat Energy UK Limited (formerly called Seplat Petroleum Development UK Limited). The subsidiary provides technical, liaison and administrative support services relating to oil and gas exploration activities.

In 2015, the Group purchased a 40% participating interest in OML 53, onshore northeastern Niger Delta (Seplat East Onshore Limited), from Chevron Nigeria Ltd for \$259.4 million.

In 2017, the Group incorporated a new subsidiary, ANOH Gas Processing Company Limited. The principal activity of the Company is the processing of gas from OML 53 using the ANOH gas processing plant. The Group divested some of its ownership interest in this Company to Nigerian Gas Processing and Transportation Company (NGPTC) which was effective from 18 April 2019, hence this investment qualifies as a joint arrangement and has continued to be recognised as investment in joint venture.

On 16 January 2018, the Group incorporated a subsidiary, Seplat West Limited ('Seplat West'). Seplat West was incorporated to manage the producing assets of Seplat Plc.

On 31 December 2019, Seplat Energy Plc, acquired 100% of Eland Oil and Gas Plc's issued and yet to be issued ordinary shares. Eland is an independent oil and gas company that holds interest in subsidiaries and joint ventures that are into production, development and exploration in West Africa, particularly the Niger Delta region of Nigeria.

On acquisition of Eland Oil and Gas Plc (Eland), the Group acquired indirect interest in existing subsidiaries of Eland.

Eland Oil & Gas (Nigeria) Limited, is a subsidiary acquired through the purchase of Eland and is into exploration and production of oil and gas.

Westport Oil Limited, which was also acquired through purchase of Eland is a financing company.

Elcrest Exploration and Production Company Limited (Elcrest) who became an indirect subsidiary of the Group purchased a 45 percent interest in OML 40 in 2012. Elcrest is a Joint Venture between Eland Oil and Gas (Nigeria) Limited (45%) and Starcrest Nigeria Energy Limited (55%). It has been consolidated because Eland is deemed to have power over the relevant activities of Elcrest to affect variable returns from Elcrest at the date of acquisition by the Group. (See details in Note 4.1.v) The principal activity of Elcrest is exploration and production of oil and gas.

Wester Ord Oil & Gas (Nigeria) Limited, who also became an indirect subsidiary of the Group acquired a 40% stake in a licence, Ubima, in 2014 via a joint operations agreement. The principal activity of Wester Ord Oil & Gas (Nigeria) Limited is exploration and production of oil and gas. In 2022, Wester Ord Oil and Gas (Nigeria) divested its interest in Ubima.

Other entities acquired through the purchase of Eland are Tarland Oil Holdings Limited (a holding company), Brineland Petroleum Limited (dormant company) and Destination Natural Resources Limited (dormant company).

On 1 January 2020, Seplat Energy Plc transferred its 45% participating interest in OML 4, OML 38 and OML 41 ("transferred assets") to Seplat West Limited. As a result, Seplat ceased to be a party to the Joint Operating Agreement in respect of the transferred assets and became a holding company. Seplat West Limited became a party to the Joint Operating Agreement in respect of the transferred assets and assumed its rights and obligations.

On 20 May 2021, following a special resolution by the Board in view of the Company's strategy of transitioning into an energy Company promoting renewable energy, sustainability, and new energy, the name of the Company was changed from Seplat Petroleum Development Company Plc to Seplat Energy Plc under the Companies and Allied Matters Act 2020.

On 7 February 2022, the Group incorporated a subsidiary, Seplat Energy Offshore Limited. The Company was incorporated for oil and gas exploration and production.

On 26 April 2023, Seplat Gas Company Limited was changed to Seplat Midstream Company Limited. This subsidiary was incorporated to engage in oil and gas exploration and production and gas processing. The company is yet commence operations.

On 14 June 2023, the Group entered into a joint venture agreement with Pol Gas Limited which birthed Pine Gas Processing Limited. Both parties subscribed to equal proportion of ordinary shares. The Company was incorporated for processing natural gas, storage, marketing, transportation, trading, supply and distribution of natural gas and petroleum products derived from natural gas. The company is yet to commence operations.

On 7 August 2024, the Group incorporated a subsidiary, Seplat Energy Investment Limited. The Company was incorporated for oil and gas exploration and production.

On 12 December 2024, the Group acquired 100% of Mobil Producing Nigeria Unlimited and later changed the name on 19 December 2024 to Seplat Energy Producing Nigeria Unlimited. The Company was acquired for the purpose of oil and gas exploration and production.

The Company together with its subsidiaries as shown below are collectively referred to as the Group.

Subsidiary	Date of incorporation	Country of incorporation and place of business	Percentage holding	Principal activities	Nature of holding
Eland Oil & Gas Limited	28 August 2009	United Kingdom	100%	Holding company	Direct
Eland Oil & Gas (Nigeria) Limited	11 August 2010	Nigeria	100%	Oil and Gas Exploration and Production	Indirect
Elcrest Exploration and Production Nigeria Limited	6 January 2011	Nigeria	45%	Oil and Gas Exploration and Production	Indirect
Westport Oil Limited	8 August 2011	Jersey	100%	Financing	Indirect
Brineland Petroleum Limited	18 February 2013	Nigeria	49%	Dormant	Indirect
Newton Energy Limited	1 June 2013	Nigeria	99.9%	Oil & gas exploration and production	Direct
Seplat East Swamp Company Limited	11 December 2013	Nigeria	99.9%	Oil & gas exploration and production	Direct
Seplat Midstream Company Limited	11 December 2013	Nigeria	99.9%	Oil and Gas exploration and production and gas processing	Direct
Tarland Oil Holdings Limited	16 July 2014	Jersey	100%	Holding Company	Indirect
Wester Ord Oil and Gas Limited	16 July 2014	Jersey	100%	Holding Company	Indirect
Wester Ord Oil & Gas (Nigeria) Limited	18 July 2014	Nigeria	100%	Oil and Gas Exploration and Production	Indirect
Seplat Energy UK Limited	21 August 2014	United Kingdom	100%	Technical, liaison and administrative support services relating to oil & gas exploration and production	Direct
Seplat East Onshore Limited	12 December 2014	Nigeria	99.9%	Oil & gas exploration and production	Direct
Seplat West Limited	16 January 2018	Nigeria	99.9%	Oil & gas exploration and production	Direct
Seplat Energy Offshore Limited	7 February 2022	Nigeria	100%	Oil and Gas exploration and production	Direct
Seplat Energy Investment Limited	07 August , 2024	Nigeria	100%	Oil and Gas exploration and production	Direct
Seplat Energy Producing Nigeria Unlimited (formerly Mobil Producing Nigeria Unlimited)	16 June , 1969	Nigeria	100%	Oil and Gas exploration and production	Direct

2. Significant changes in the current accounting period

During the period, a major shareholder, Maurel & Prom S.A. (M&P), disposed of its entire shareholding in the Seplat Energy Plc to Heirs Energies Limited and Heirs Holdings Limited. Consequently, Heirs Energies Limited and Heirs Holdings Limited together now own 120.4 million Seplat Plc shares, representing a 20.07% equity stake in the Seplat Energy Plc.

3. Summary of significant accounting policies

3.1 Introduction to summary of significant accounting policies

This note provides a list of the significant accounting policies adopted in the preparation of these consolidated financial statements. These accounting policies have been applied to all the periods presented, unless otherwise stated. The Consolidated financial statements are for the Group consisting of Seplat Energy Plc and its subsidiaries.

3.2 Basis of preparation

The interim condensed consolidated financial statements of the Group for the three months ended 31 March 2026 have been prepared in accordance with International Financial Reporting Standards ("IFRS Accounting Standards") and interpretations issued by the IFRS Interpretations Committee (IFRS IC). The interim condensed financial statements comply with IFRS Accounting Standards as issued by the International Accounting Standards Board (IASB). Additional information required by National regulations is included where appropriate.

The financial statements comprise the statement of profit or loss and other comprehensive income, the statement of financial position, the statement of changes in equity, the statement of cash flows and the notes to the financial statements.

The financial statements have been prepared under the going concern and historical cost convention, except for financial instruments measured at fair value on initial recognition, derivative financial instruments, underlift and defined benefit plans – plan assets measured at fair value. The financial statements are presented in Nigerian Naira and United States Dollars, and all values are rounded to the nearest million (₦ million) and thousand (\$'000) respectively, except when otherwise indicated.

Nothing has come to the attention of the directors to indicate that the Group will not remain a going concern for at least twelve months from the date of these financial statements.

The interim condensed consolidated financial statements do not include all the information and disclosures required in the annual financial statements, and should be read in conjunction with the Group's annual consolidated financial statements as at 31 December 2025.

The accounting policies adopted are consistent with those of the previous financial year end, except for the adoption of new and amended standard which are set out below.

3.3 New and amended standards adopted by the Group

The Group applied for the first-time certain standards and amendments, which are effective for annual periods beginning on or after 1 January 2026. The Group has not early adopted any other standard, interpretation or amendment that has been issued but is not yet effective.

a) Classification and Measurement of Financial Instruments - Amendments to IFRS 9 and IFRS 7

In May 2024, the IASB issued Amendments to IFRS 9 and IFRS 7, Amendments to the Classification and Measurement of Financial Instruments (the Amendments). The Amendments include:

- Clarifications of the requirements for recognition and derecognition of financial assets and financial liabilities. In particular, a financial liability is derecognised on the 'settlement date' and an accounting policy choice is introduced (if specific conditions are met) to derecognise financial liabilities settled using an electronic payment system before the settlement date
- Additional guidance on how the contractual cash flows for financial assets with environmental, social and corporate governance (ESG) and similar features should be assessed
- Clarifications on what constitute 'non-recourse features' and what are the characteristics of contractually linked instruments
- The introduction of disclosures for financial instruments with contingent features and additional disclosure requirements for equity instruments classified at fair value through other comprehensive income (OCI)

The amendments had no impact on the Group's interim condensed financial statements.

b) Annual Improvements to IFRS Accounting Standards— Volume 11

In July 2024, the IASB issued nine narrow scope amendments as part of its periodic maintenance of IFRS accounting standards. The amendments include clarifications, simplifications, corrections or changes to improve consistency in IFRS 1 First-time Adoption of International Financial Reporting Standards, IFRS 7 Financial Instruments: Disclosure and its accompanying Guidance on implementing IFRS 7, IFRS 9 Financial Instruments, IFRS 10 Consolidated Financial Statements and IAS 7 Statements of Cash Flows.

The amendments had no impact on the Group's interim condensed financial statements.

c) Contracts Referencing Nature-dependent Electricity – Amendments to IFRS 9 and IFRS 7

In December 2024, the IASB issued Amendments to IFRS 9 and IFRS 7 - Contracts Referencing Nature dependent Electricity. The amendments apply only to contracts that reference nature-dependent electricity, and they:

- Clarify the application of the 'own-use' requirements for in-scope contracts
- Amend the designation requirements for a hedged item in a cash flow hedging relationship for in-scope contracts
- Add new disclosure requirements to enable investors to understand the effect of these contracts on a company's financial performance and cash flows

The amendments had no impact on Group's interim condensed financial statements.

3.4 Standards issued but not yet effective

The new and amended standards and interpretations that are issued, but not yet effective, up to the date of issuance of the Group's financial statements are disclosed below. The Group intends to adopt these new and amended standards and interpretations, if applicable, when they become effective. Details of these new standards and interpretations are set out below:

a) IFRS 18 - Presentation and Disclosure in Financial Statements

In April 2024, the IASB issued IFRS 18, which replaces IAS 1 Presentation of Financial Statements. IFRS 18 introduces new requirements for presentation within the statement of profit or loss, including specified totals and subtotals. Furthermore, entities are required to classify all income and expenses within the statement of profit or loss into one of five categories: operating, investing, financing, income taxes and discontinued operations, whereof the first three are new.

It also requires disclosure of newly defined management-defined performance measures, subtotals of income and expenses, and includes new requirements for aggregation and disaggregation of financial information based on the identified 'roles' of the primary financial statements (PFS) and the notes.

IFRS 18, and the amendments to the other standards, is effective for reporting periods beginning on or after 1 January 2027, but earlier application is permitted and must be disclosed. IFRS 18 will apply retrospectively.

b) IFRS 19 - Subsidiaries without Public Accountability: Disclosures

In May 2024, the IASB issued IFRS 19, which allows eligible entities to elect to apply its reduced disclosure requirements while still applying the recognition, measurement and presentation requirements in other IFRS accounting standards. To be eligible, at the end of the reporting period, an entity must be a subsidiary as defined in IFRS 10, cannot have public accountability and must have a parent (ultimate or intermediate) that prepares consolidated financial statements, available for public use, which comply with IFRS accounting standards.

IFRS 19 will become effective for reporting periods beginning on or after 1 January 2027, with early application permitted.

c) Sale or Contribution of Assets between an Investor and its Associate or Joint Venture - Amendments to IFRS 10 and IAS 28

The IASB has made limited scope amendments to IFRS 10 Consolidated Financial Statements and IAS 28 Investments in Associates and Joint Ventures.

The amendments clarify the accounting treatment for sales or contribution of assets between an investor and their associates or joint ventures. They confirm that the accounting treatment depends on whether the non-monetary assets sold or contributed to an associate or joint venture constitute a "business" (as defined in IFRS 3 Business Combinations).

Where the non-monetary assets constitute a business, the investor will recognise the full gain or loss on the sale or contribution of assets. If the assets do not meet the definition of a business, the gain or loss is recognised by the investor only to the extent of the other investor's interests in the associate or joint venture. The amendments apply prospectively. There is currently no effective date for this amendment.

3.5 Basis of consolidation

i. Subsidiaries

Subsidiaries are all entities (including structured entities) over which the Group has control.

The consolidated financial information comprises the financial statements of the Company and its subsidiaries as at 31 March 2026. Control is achieved when the Group is exposed, or has rights, to variable returns from its involvement with the investee and has the ability to affect those returns through its power over the investee. Specifically, the Group controls an investee if and only if the Group has:

- Power over the investee (i.e., existing rights that give it the current ability to direct the relevant activities of the investee);
- Exposure, or rights, to variable returns from its involvement with the investee; and
- The ability to use its power over the investee to affect its returns.

Subsidiaries are consolidated from the date on which control is obtained by the Group and are deconsolidated from the date control ceases.

Generally, there is a presumption that a majority of voting rights results in control. To support this presumption and when the Group has less than a majority of the voting or similar rights of an investee, the Group considers all relevant facts and circumstances in assessing whether it has power over an investee, including:

- The contractual arrangement(s) with the other vote holders of the investee
- Rights arising from other contractual arrangements
- The Group's voting rights and potential voting rights

ii. Change in the ownership interest of subsidiary

The acquisition method of accounting is used to account for business combinations by the Group.

Non-controlling interests in the results and equity of subsidiaries are shown separately in the consolidated statement of profit or loss and other comprehensive income, statement of changes in equity and statement of financial position respectively.

Intercompany transaction balances and unrealized gains on transactions between group companies are eliminated. Unrealised losses are also eliminated unless the transaction provides evidence of an impairment of the transferred asset. Accounting policies of subsidiaries have been changed where necessary to ensure consistency with the policies adopted by the Group.

iii. Disposal of subsidiary

Where the Group disposes a subsidiary, it:

- Derecognises the assets (including goodwill) and liabilities of the subsidiary;
- Derecognises the carrying amount of any non-controlling interests;
- Derecognises the cumulative translation differences recorded in equity;
- Recognises the fair value of the consideration received;
- Recognises the fair value of any investment retained;
- Recognises any surplus or deficit in profit or loss; and
- Reclassifies the parent's share of components previously recognised in OCI to profit or loss or retained earnings, as appropriate, as would be required if the Group had directly disposed of the related assets or liabilities.

iv. Joint arrangements

Under IFRS 11 Joint Arrangements, investments in joint arrangements are classified as either joint operations or joint ventures. The classification depends on the contractual rights and obligations of each investor, rather than the legal structure of the joint arrangement.

Interest in the joint venture is accounted for using the equity method, after initially being recognised at cost in the consolidated statement of financial position. All other joint arrangements of the Group are joint operations.

v. Associates

Associates are all entities over which the Group has significant influence but not control or joint control. This is generally the case where the group holds between 20% and 50% of the voting rights. Investment in associates is accounted for using the equity method of accounting (see (vi) below) after initially being recognised at cost.

vi. Equity method

Under the equity method of accounting, the Group's investments are initially recognised at cost and adjusted thereafter to recognise the Group's share of the post-acquisition profits or losses of the investee in profit or loss, and the Group's share of movements in other comprehensive income of the investee in other comprehensive income. Dividends received or receivable from associates and joint ventures are recognised as a reduction in the carrying amount of the investment.

Where the Group's share of loss in an equity accounting investment equals or exceeds its interest in the entity, including any other unsecured long-term receivables, the Group does not recognise further losses, unless it has incurred obligations or made payments on behalf of the other party.

Unrealised gains on transactions between the Group and its associate and joint venture are eliminated to the extent of the Group's interest in the entities. Unrealised losses are also eliminated unless the transaction provides evidence of an impairment of the asset transferred.

Accounting policies of equity accounted investees are changed where necessary to ensure consistency with the policies adopted by the Group.

The carrying amount of equity accounted investments is tested for impairment in accordance with the policy described in Note 3.14.

vii. Changes in ownership interest

The Group treats transactions with non-controlling interests that do not result in a loss of control as transactions with equity owners of the Group. A change in ownership interest results in an adjustment between the carrying amounts of the controlling and non-controlling interests to reflect their relative interests in the subsidiary. Any difference between the amount of the adjustment to non-controlling interests and any consideration paid or received is recognised in a separate reserve within equity attributable to owners of the group.

When the Group ceases to consolidate or equity account for an investment because of a loss of control, joint control or significant influence, any retained interest in the entity is remeasured to its fair value, with the change in carrying amount recognised in profit or loss. This fair value becomes the initial carrying amount for the purposes of subsequently accounting for the retained interest as an associate, joint venture or financial asset. In addition, any amounts previously recognised in other comprehensive income in respect of that entity are accounted for as if the group had directly disposed of the related assets or liabilities. This may mean that amounts previously recognised in other comprehensive income are reclassified to profit or loss.

viii. Accounting for loss of control

When the Group ceases to consolidate a subsidiary because of a joint control, it does the following:

- deconsolidates the assets (including goodwill), liabilities and non-controlling interest (including attributable other comprehensive income) of the former subsidiary from the consolidated financial position;
- any retained interest (including amounts owed by and to the former subsidiary) in the entity is remeasured to its fair value, with the change in carrying amount recognised in profit or loss. This fair value becomes the initial carrying amount for the purposes of subsequently accounting for the retained interest as an associate or a joint venture;

- any amounts previously recognised in other comprehensive income in respect of that entity are accounted for as if the Group had directly disposed of the related assets or liabilities. This may mean that amounts previously recognised in other comprehensive income are reclassified to profit or loss or transferred directly to retained earnings if required by other IFRSs;
- the resulting gain or loss, on loss of control, is recognised together with the profit or loss from the discontinued operation for the period before the loss of control; and
- the gain or loss on disposal will comprise of the gain or loss attributable to the portion disposed of and the gain or loss on remeasurement of the portion retained. The latter is disclosed separately in the notes to the financial statements. If the ownership interest in a joint venture is reduced but joint control or significant influence is retained, only a proportionate share of the amounts previously recognised in other comprehensive income is reclassified to profit or loss where appropriate.

ix. Non-controlling interest

The Group recognises non-controlling interests in an acquired entity either at fair value or at the non-controlling interest's proportionate share of the acquired entity's net identifiable assets. This decision is made on an acquisition-by-acquisition basis.

x. Gain on bargain purchase

A gain on bargain purchase arises when the fair value of the identifiable net assets acquired in a business combination exceeds the aggregate of the consideration transferred, the amount of any non-controlling interest in the acquiree, and the fair value of the acquirer's previously held equity interest in the acquiree, if any.

The Group recognises, any gain on a bargain purchase immediately in profit or loss. The gain is measured as the excess of the fair value of the identifiable net assets acquired over the aggregate of the consideration transferred, the amount of any non-controlling interest in the acquiree, and the fair value of the acquirer's previously held equity interest in the acquiree, if any.

3.6 Functional and presentation currency

Items included in the financial statements are measured using the currency of the primary economic environment in which the Company operates ('the functional currency'), which is the US dollar. The financial statements are presented in Nigerian Naira and the US Dollars.

The Company has chosen to show both presentation currencies and this is allowable by the regulator.

i. Transaction and balances

Foreign currency transactions are translated into the functional currency using the exchange rates at the dates of the transactions. Foreign exchange gains and losses resulting from the settlement of such transactions and from the translation of monetary assets and liabilities denominated in foreign currencies at year end are generally recognised in profit or loss. They are deferred in equity if attributable to net investment in foreign operations.

Foreign exchange gains and losses that relate to borrowings are presented in the statement of profit or loss, within finance costs. All other foreign exchange gains and losses are presented in the statement of profit or loss on a net basis within other income or other expenses.

Non-monetary items that are measured at fair value in a foreign currency are translated using the exchange rates at the date when the fair value was determined. Translation differences on assets and liabilities carried at fair value are reported as part of the fair value gain or loss or other comprehensive income depending on where fair value gain or loss is reported.

ii. Group companies

The results and financial position of foreign operations that have a functional currency different from the presentation currency are translated into the presentation currency as follows:

- assets and liabilities for each statement of financial position presented are translated at the closing rate at the date of the reporting date.
- income and expenses for statement of profit or loss and other comprehensive income are translated at average exchange rates (unless this is not - a reasonable approximation of the cumulative effect of the rates prevailing on the transaction dates, in which case income and expenses are translated at the dates of the transactions), and all resulting exchange differences are recognised in other comprehensive income.
- Equity items for each statement of financial position presented are translated at the historical rates.

On disposal of a foreign operation, the component of other comprehensive income relating to that particular foreign operation is recognised in profit or loss. Goodwill and fair value adjustments arising on the acquisition of a foreign operation are treated as assets and liabilities of the foreign operation and translated at the closing rate.

3.7 Oil and gas accounting

i. Pre-licensing costs

Pre-license costs are expensed in the period in which they are incurred.

ii. Exploration license cost

Exploration license costs are capitalised within intangible assets. License costs paid in connection with a right to explore in an existing exploration area are capitalised and amortised on a straight-line basis over the life of the license.

License costs are reviewed at each reporting date to confirm that there is no indication that the carrying amount exceeds the recoverable amount. This review includes confirming that exploration drilling is still under way or firmly planned, or that it has been

determined, or work is under way to determine that the discovery is economically viable based on a range of technical and commercial considerations and sufficient progress is being made to establish development plans and timing. If no future activity is planned or the license has been relinquished or has expired, the carrying value of the license is written off through profit or loss. The exploration license costs are initially recognised at cost and subsequently amortised on a straight line based on the economic life. They are subsequently carried at cost less accumulated amortisation and impairment losses. The amortization rate for the intangible asset is 5% with useful life of 20 years.

iii. Acquisition of producing assets

Upon acquisition of producing assets which do not constitute a business combination, the Group identifies and recognises the individual identifiable assets acquired (including those assets that meet the definition of, and recognition criteria for, intangible assets in IAS 38 Intangible Assets) and liabilities assumed. The purchase price paid for the group of assets is allocated to the individual identifiable assets and liabilities on the basis of their relative fair values at the date of purchase.

iv. Exploration and evaluation expenditures

Geological and geophysical exploration costs are charged to profit or loss as incurred.

Exploration and evaluation expenditures incurred by the entity are accumulated separately for each area of interest. Such expenditures comprise net direct costs and an appropriate portion of related overhead expenditure, but do not include general overheads or administrative expenditure that is not directly related to a particular area of interest. Each area of interest is limited to a size related to a known or probable hydrocarbon resource capable of supporting an oil operation.

Costs directly associated with an exploration well, exploratory stratigraphic test well and delineation wells are temporarily suspended (capitalised) until the drilling of the well is complete and the results have been evaluated. These costs include employee remuneration, materials and fuel used, rig costs, delay rentals and payments made to contractors. If hydrocarbons ('proved reserves') are not found, the exploration expenditure is written off as a dry hole and charged to profit or loss. If hydrocarbons are found, the costs continue to be capitalised.

Suspended exploration and evaluation expenditure in relation to each area of interest is carried forward as an asset provided that one of the following conditions is met:

- the costs are expected to be recouped through successful development and exploitation of the area of interest or alternatively, by its sale;
- exploration and/or evaluation activities in the area of interest have not, at the reporting date, reached a stage which permits a reasonable assessment of the existence or otherwise of economically recoverable reserves; and
- active and significant operations in, or in relation to, the area of interest.

Exploration and/or evaluation expenditures which fail to meet at least one of the conditions outlined above are written off. In the event that an area is subsequently abandoned or exploration activities do not lead to the discovery of proved or probable reserves, or if the Directors consider the expenditure to be of no value, any accumulated costs carried forward relating to the specified areas of interest are written off in the year in which the decision is made. While an area of interest is in the development phase, amortisation of development costs is not charged pending the commencement of production. Exploration and evaluation costs are transferred from the exploration and/or evaluation phase to the development phase upon commitment to a commercial development.

v. Development expenditures

Development expenditure incurred by the Group is accumulated separately for each area of interest in which economically recoverable reserves have been identified to the satisfaction of the Directors. Such expenditure comprises net direct costs and, in the same manner as for exploration and evaluation expenditure, an appropriate portion of related overhead expenditure directly related to the development property. All expenditure incurred prior to the commencement of commercial levels of production from each development property is carried forward to the extent to which recoupment is expected to be derived from the sale of production from the relevant development property.

3.8 Revenue recognition (IFRS 15)

IFRS 15 uses a five-step model for recognising revenue to depict transfer of goods or services. The model distinguishes between promises to a customer that are satisfied at a point in time and those that are satisfied over time.

It is the Group's policy to recognise revenue from a contract when it has been approved by both parties, rights have been clearly identified, payment terms have been defined, the contract has commercial substance, and collectability has been ascertained as probable. Collectability of customer's payments is ascertained based on the customer's historical records, guarantees provided, the customer's industry and advance payments made if any.

Revenue is recognised when control of goods sold has been transferred. Control of an asset refers to the ability to direct the use of and obtain substantially all of the remaining benefits (potential cash inflows or savings in cash outflows) associated with the asset. For crude oil, this occurs when the crude products are lifted by the customer (buyer) Free on Board at the Group's loading facility. Revenue from the sale of oil is recognised at a point in time when performance obligation is satisfied. For gas sales, revenue is recognised when the product passes through the custody transfer point to the customer. Revenue from the sale of gas is recognised over time using the practical expedient of the right to invoice.

The surplus or deficit of the product sold during the period over the Group's share of production is termed as an overlift or underlift. With regard to underlifts, if the over-lifter does not meet the definition of a customer or the settlement of the transaction is non-monetary, a receivable and other income is recognised. Initially, when an overlift occurs, cost of sale is debited, and a corresponding liability is accrued. Overlifts and underlifts are initially measured at the market price of oil at the date of lifting, consistent with the measurement of the sale and purchase. Subsequently, they are remeasured at the current market value. The change arising from this remeasurement is included in the profit or loss as other income/expenses-net. In instances, where Seplat controls the storage of crude and petroleum products at a terminal, surplus or deficit of the product sold over the Group's share of production is termed an overlift or inventory.

Definition of a customer

A customer is a party that has contracted with the Group to obtain crude oil or gas products in exchange for a consideration, rather than to share in the risks and benefits that result from sale. The Group has entered into collaborative arrangements with its Joint arrangement partners to share in the production of oil. Collaborative arrangements with its Joint arrangement partners to share in the production of oil are accounted for differently from arrangements with customers as collaborators share in the risks and benefits of the transaction, and therefore, do not meet the definition of customers. Revenue arising from these arrangements are recognised separately in other income.

Contract enforceability and termination clauses

It is the Group's policy to assess that the defined criteria for establishing contracts that entail enforceable rights and obligations are met. The criteria provide that the contract has been approved by both parties, rights have been clearly identified, payment terms have

been defined, the contract has commercial substance, and collectability has been ascertained as probable. Revenue is not recognised for contracts that do not create enforceable rights and obligations to parties in a contract. The Group also does not recognise revenue for contracts that do not meet the revenue recognition criteria. In such cases where consideration is received it recognises a contract liability and only recognises revenue when the contract is terminated.

The Group may also have the unilateral rights to terminate an unperformed contract without compensating the other party. This could occur where the Group has not yet transferred any promised goods or services to the customer and the Group has not yet received, and is not yet entitled to receive, any consideration in exchange for promised goods or services.

Identification of performance obligation

At inception, the Group assesses the goods or services promised in the contract with a customer to identify as a performance obligation, each promise to transfer to the customer either a distinct good or series of distinct goods. The number of identified performance obligations in a contract will depend on the number of promises made to the customer. The delivery of barrels of crude oil or units of gas are usually the only performance obligation included in oil and gas contract with no additional contractual promises. Additional performance obligations may arise from future contracts with the Group and its customers.

The identification of performance obligations is a crucial part in determining the amount of consideration recognised as revenue. This is due to the fact that revenue is only recognised at the point where the performance obligation is fulfilled, Management has therefore developed adequate measures to ensure that all contractual promises are appropriately considered and accounted for accordingly.

Transaction price is the amount allocated to the performance obligations identified in the contract. It represents the amount of revenue recognised as those performance obligations are satisfied. Complexities may arise where a contract includes variable consideration, significant financing component or consideration payable to a customer.

Variable consideration not within the Group's control is estimated at the point of revenue recognition and reassessed periodically. The estimated amount is included in the transaction price to the extent that it is highly probable that a significant reversal of the amount of cumulative revenue recognised will not occur when the uncertainty associated with the variable consideration is subsequently resolved. As a practical expedient, where the Group has a right to consideration from a customer in an amount that corresponds directly with the value to the customer of the Group's performance completed to date, the Group may recognise revenue in the amount to which it has a right to invoice.

Significant financing component (SFC) assessment is carried out (using a discount rate that reflects the amount charged in a separate financing transaction with the customer and also considering the Group's incremental borrowing rate) on contracts that have a repayment period of more than 12 months.

As a practical expedient, the Group does not adjust the promised amount of consideration for the effects of a significant financing component if it expects, at contract inception, that the period between when it transfers a promised good or service to a customer and when the customer pays for that good or service will be one year or less.

Instances when SFC assessment may be carried out include where the Group receives advance payment for agreed volumes of crude oil or receives take or pay deficiency payment on gas sales. Take or pay gas sales contract ideally provides that the customer must sometimes pay for gas even when not delivered to the customer. The

customer, in future contract years, takes delivery of the product without further payment. The portion of advance payments that represents significant financing component will be recognised as interest expense.

Consideration payable to a customer is accounted for as a reduction of the transaction price unless the payment to the customer is in exchange for a distinct goods or services that the customer transfers to the Group.

Breakage

The Group enters into take or pay contracts for sale of gas where the buyer may not ultimately exercise all of their rights to the gas. The take or pay quantity not taken is paid for by buyer called take or pay deficiency payment. The Group assesses if there is a reasonable assurance that it will be entitled to a breakage amount. Where it establishes that a reasonable assurance exists, it recognises the expected breakage amount as revenue in proportion to the pattern of rights exercised by the customer. However, where the Group is not reasonably assured of a breakage amount, it would only recognise the expected breakage amount as revenue when the likelihood of the customer exercising its remaining rights becomes remote.

Contract modification and contract combination

Contract modifications relate to a change in the price and/or scope of an approved contract. Where there is a contract modification, the Group assesses if the modification will create a new contract or change the existing enforceable rights and obligations of the parties to the original contract. Contract modifications are treated as new contracts when the performance obligations are separately identifiable and transaction price reflects the standalone selling price of the crude oil or the gas to be sold. Revenue is adjusted prospectively when the crude oil or gas transferred is separately identifiable and the price does not reflect the standalone selling price. Conversely, if there are remaining performance obligations which are not separately identifiable, revenue will be recognised on a cumulative catch-up basis when crude oil or gas is transferred.

The Group combines contracts entered into at near the same time (less than 12 months) as one contract if they are entered into with the same or related party customer, the performance obligations are the same for the contracts and the price of one contract depends on the other contract.

Portfolio expedients

As a practical expedient, the Group may apply the requirements of IFRS 15 to a portfolio of contracts (or performance obligations) with similar characteristics if it expects that the effect on the financial statements would not be materially different from applying IFRS to individual contracts within that portfolio.

Contract assets and liabilities

The Group recognises contract assets for unbilled revenue from crude oil and gas sales. The Group recognises contract liability for consideration received for which performance obligation has not been met.

Disaggregation of revenue from contract with customers

The Group derives revenue from three types of products, oil, gas and natural gas liquids. The Group has determined that the disaggregation of revenue based on the criteria of type of products meets the disaggregation of revenue disclosure requirement of IFRS 15. It depicts how the nature, amount, timing and uncertainty of revenue and cash flows are affected by economic factors. See further details in note 6.1.1.

3.9 Property, plant and equipment

Oil and gas properties and other plant and equipment are stated at cost, less accumulated depreciation, and accumulated impairment losses.

The initial cost of an asset comprises its purchase price or construction cost, any costs directly attributable to bringing the asset into operation, the initial estimate of any decommissioning obligation and, for qualifying assets, borrowing costs. The purchase price or construction cost is the aggregate amount paid and the fair value of any other consideration given to acquire the asset. Where parts of an item of property, plant and equipment have different useful lives, they are accounted for as separate items of property, plant and equipment.

Expenditure on major maintenance refits or repairs comprises the cost of replacement assets or parts of assets, inspection costs and overhaul costs. Where an asset or part of an asset that was separately depreciated and is now written off is replaced and it is probable that future economic benefits associated with the item will flow to the entity, the expenditure is capitalised. Inspection costs associated with major maintenance programmes are capitalised and amortised over the period to the next inspection. Overhaul costs for major maintenance programmes are capitalised as incurred as long as these costs increase the efficiency of the unit or extend the useful life of the asset. All other maintenance costs are expensed as incurred.

Depreciation

Oil and Gas Production Assets are depreciated on a unit-of-production basis over estimated proved reserves. Specifically, well assets are depreciated over proved developed reserves while production facilities are depreciated over proved reserves.

Gas plants and other property, plant and equipment are depreciated on a straight line basis over their estimated useful lives. Depreciation commences when an asset is available for use.

Assets under construction are not depreciated. The depreciation rate for each class is as follows:

Plant and machinery	10%-20%
Motor vehicles	25%-30%
Office furniture and IT equipment	10%-33.33%
Building	4%
Land	-
Intangible assets	5%
Leasehold improvements	Over the unexpired portion of the lease

The expected useful lives and residual values of property, plant and equipment are reviewed on an annual basis and, if necessary, changes in useful lives are accounted for prospectively.

Gains or losses on disposal of property, plant and equipment are determined as the difference between disposal proceeds and carrying amount of the disposed assets. These gains or losses are included in the statement of profit or loss.

An item of property, plant and equipment and any significant part initially recognised is derecognised upon disposal (i.e., at the date the recipient obtains control) or when no future economic benefits are expected from its use or disposal. Any gain or loss arising on derecognition of the asset (calculated as the difference between the net disposal proceeds and the carrying amount of the asset) is included in the statement of profit or loss when the asset is derecognised.

3.10 Right-of-use assets

The Group recognises right-of-use assets at the commencement date of a lease (i.e. the date the underlying asset is available for use). Right-of-use assets are measured at cost, less any accumulated depreciation and impairment losses, and adjusted for any remeasurement of lease liabilities. The cost of right-of-use assets include the amount of lease liabilities recognised, initial direct costs

incurred, decommissioning costs (if any), and lease payments made at or before the commencement date less any lease incentives received. Unless the Group is reasonably certain to obtain ownership of the leased asset at the end of the lease term, the recognised right-of-use assets are depreciated on a straight-line basis over the shorter of its estimated useful life and the lease term. Right-of-use assets are subject to impairment.

Short-term leases and leases of low value

The Group applies the short-term lease recognition exemption to its short-term leases (i.e., those leases that have a lease term of 12 months or less from the commencement date and do not contain a purchase option). It also applies the lease of low-value assets recognition exemption to leases that are considered of low value (i.e. low value assets). Low-value assets are assets with lease amount of less than \$5,000 when new. Lease payments on short-term leases and leases of low-value assets are recognised as an expense on a straight-line basis over the lease term.

3.11 Lease liabilities

At the commencement date of a lease, the Group recognises lease liabilities measured at the present value of lease payments to be made over the lease term. The lease payments include the exercise price of a purchase option reasonably certain to be exercised by the Group and payments of penalties for terminating a lease, if the lease term reflects the Group exercising the option to terminate. Variable lease payments that do not depend on an index or a rate are recognised as an expense in the period in which the event or condition that triggers the payment occurs.

In calculating the present value of lease payments, the Group uses the incremental borrowing rate at the lease commencement date if the interest rate implicit in the lease is not readily determinable. The weighted average incremental borrowing rate for the Group is 10.5%. After the commencement date, the amount of lease liabilities is increased to reflect the accretion of interest and reduced for the lease payments made. In addition, the carrying amount of lease liabilities is remeasured if there is a modification, a change in the lease term, a change in the in-substance fixed lease payments or a change in the assessment to purchase the underlying asset. The lease term refers to the contractual period of a lease.

The Group has elected to exclude non-lease components in calculating lease liabilities and instead treat the related costs as an expense in the statement of profit or loss.

3.12 Borrowing costs

Borrowing costs directly attributable to the acquisition, construction or production of qualifying assets, which are assets that necessarily take a substantial period of time to get ready for their intended use or sale, are added to the cost of those assets, until such time as the assets are substantially ready for their intended use or sale.

Borrowing costs consist of interest and other costs incurred in connection with the borrowing of funds. These costs may arise from: specific borrowings used for the purpose of financing the construction of a qualifying asset, and those that arise from general borrowings that would have been avoided if the expenditure on the qualifying asset had not been made. The general borrowing costs attributable to an asset's construction is calculated by reference to the weighted average cost of general borrowings that are outstanding during the period.

Investment income earned on the temporary investment of specific borrowings pending their expenditure on the qualifying assets is deducted from the borrowing costs eligible for capitalisation. All other borrowing costs are recognised in the statement of profit or loss in the period in which they are incurred.

3.13 Finance income and costs

Finance income

Finance income is recognised in the statement of profit or loss as it accrues using the effective interest rate (EIR), which is the rate that exactly discounts estimated future cash payments or receipts through the expected life of the financial instrument or a shorter period, where appropriate, to the amortised cost of the financial instrument. The determination of finance income takes into account all contractual terms of the financial instrument as well as any fees or incremental costs that are directly attributable to the instrument and are an integral part of the effective interest rate (EIR), but not future credit losses.

Finance costs

Finance costs includes borrowing costs, interest expense calculated using the effective interest rate method, finance charges in respect of lease liabilities, the unwinding of the effect of discounting provisions, and the amortisation of discounts and premiums on debt instruments that are liabilities.

The Group applies the IBOR reform Phase 2 amendments which allows as a practical expedient for changes to the basis for determining contractual cash flows to be treated as changes to a floating rate of interest, provided certain conditions are met. The conditions include that the change is necessary as a direct consequence of IBOR reform and that the transition takes place on an economically equivalent basis.

3.14 Impairment of non-financial assets

Goodwill and intangible assets that have an indefinite useful life are not subject to amortisation and are tested annually for impairment, or more frequently. Other non-financial assets are tested for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. Individual assets are grouped for impairment assessment purposes at the lowest level at which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets. This should be at a level not higher than an operating segment.

If any such indication of impairment exists or when annual impairment testing for an asset group is required, the entity makes an estimate of its recoverable amount. Such indicators include changes in the Group's business plans, changes in commodity prices, evidence of physical damage and, for oil and gas properties, significant downward revisions of estimated recoverable volumes or increases in estimated future development expenditure.

The recoverable amount is the higher of an asset's fair value less costs of disposal ('FVLCD') and value in use ('VIU'). The recoverable amount is determined for an individual asset, unless the asset does not generate cash inflows that are largely independent of those from other assets or group of assets, in which case, the asset is tested as part of a larger cash generating unit to which it belongs. Where the carrying amount of an asset group exceeds its recoverable amount, the asset group is considered impaired and is written down to its recoverable amount.

Non-financial assets other than goodwill that suffered an impairment are reviewed for possible reversal of the impairment at the end of each reporting period.

In calculating VIU, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset/CGU. In determining FVLCD, recent market transactions are taken into account. If no such transactions can be identified, an appropriate valuation model is used. These calculations are corroborated by valuation multiples, quoted share prices for publicly traded companies or other available fair value indicators.

Impairment – exploration and evaluation assets

Exploration and evaluation assets are tested for impairment once commercial reserves are found before they are transferred to oil and gas assets, or whenever facts and circumstances indicate

impairment. An impairment loss is recognised for the amount by which the exploration and evaluation assets' carrying amount exceeds their recoverable amount. The recoverable amount is the higher of the exploration and evaluation assets' fair value less costs to sell and their value in use.

Impairment – proved oil and gas production properties

Proved oil and gas properties are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. An impairment loss is recognised for the amount by which the asset's carrying amount exceeds its recoverable amount. The recoverable amount is the higher of an asset's fair value less costs of disposal and value in use. For the purposes of assessing impairment, assets are grouped at the lowest levels for which there are separately identifiable cash flows.

3.15 Cash and cash equivalents

Cash and cash equivalents in the statement of cash flows comprise cash at banks and at hand and short-term deposits with an original maturity of three months or less that are readily convertible to known amounts of cash and which are subject to an insignificant risk of change in value.

3.16 Restricted cash

Restricted cash represents deposits with banks set aside for the settlement of the abandonment and decommissioning liabilities, host community development fund, unclaimed dividends, bank guarantee on garnishees against court judgements and for the purpose of covering the costs payable on the stamping and registering the security documents on loans and borrowings. These amounts are subject to legal restrictions and are therefore not available for general use by the Group.

3.17 Inventories

Inventories represent the value of tubulars, casings, spares, wellheads and crude stocks. These are stated at the lower of cost and net realisable value. Cost is determined using the invoice value and all other directly attributable costs to bringing the inventory to the point of use determined on a weighted average pricing basis. Net realisable value is the estimated selling price in the ordinary course of business, less estimated costs of completion and the estimated cost necessary to make the sale.

3.18 Prepayments

Prepayments are non-financial assets which result when payments are made in advance of the receipt of goods and services. They are recognised when the Group expects to receive future economic benefits equivalent to the value of the prepayments. The receipt or consumption of the services results in a reduction in the prepayment and a corresponding increase in expenses or assets for that reporting period.

3.19 Contract asset

Contract asset is the entity's right to consideration in exchange for goods or services that the entity has transferred to the customer. A contract asset becomes a receivable when the entity's right to consideration is unconditional, which is the case when only the passage of time is required before payment of the consideration is due. The impairment of contract assets is measured, presented and disclosed on the same basis as financial assets that are within the scope of IFRS 9.

3.20 Other asset

The Group's interest in the oil and gas reserves of OML 55 has been classified as other asset. On initial recognition, it is measured at the fair value of future recoverable oil and gas reserves. Subsequently, the other asset is recognised at fair value through profit or loss.

3.21 Segment reporting

Operating segments are reported in a manner consistent with the internal reporting provided to the chief operating decision maker.

The Board of directors has appointed a Senior leadership team to assess the financial performance and position of the Group and makes strategic decisions. The Senior leadership team consist of Chief Executive Officer; Chief Financial Officer; Chief Operating Officer; Managing Director Offshore; Managing Director Onshore; Technical Director; Gas and New Energy Director; Director, Legal and Company Secretariat; Director, Strategy, Planning & Business Development; Director, External Affairs and Social Performance; Director, Corporate Services. See further details in note 6.

3.22 Financial instruments

IFRS 9 provides guidance on the recognition, classification and measurement of financial assets and financial liabilities; derecognition of financial instruments; impairment of financial assets and hedge accounting. IFRS 9 also significantly amends other standards dealing with financial instruments such as IFRS 7 Financial Instruments: Disclosures.

a) Classification and measurement

Financial assets - Initial recognition and measurement

It is the Group's policy to initially recognise financial asset at fair value plus transaction costs, except in the case of financial assets recorded at fair value through profit or loss which are expensed in profit or loss.

Classification and subsequent measurement are dependent on the Group's business model for managing the asset and the cash flow characteristics of the asset.

Subsequent measurement

For purposes of subsequent measurement, financial assets are classified in four categories:

- Financial assets at amortised cost (debt instruments)
- Financial assets at fair value through OCI with recycling of cumulative gains and losses (debt instruments)
- Financial assets designated at fair value through OCI with no recycling of cumulative gains and losses upon derecognition (equity instruments)
- Financial assets at fair value through profit or loss

On this basis, the Group may classify its financial instruments at amortised cost, fair value through profit or loss and at fair value through other comprehensive income.

All the Group's financial assets as at 31 March 2026 satisfy the conditions for classification at amortised cost under IFRS 9 except for derivatives which are classified at fair value through profit or loss.

Financial assets at amortised cost

Financial assets at amortised cost are subsequently measured using the effective interest (EIR) method and are subject to impairment. Gains and losses are recognised in profit or loss when the asset is derecognised, modified or impaired.

The Group's financial assets at amortised cost include trade receivables, NEPL receivables, NUIIMS receivables, other receivables, cash and bank balances. They are included in current assets, except for maturities greater than 12 months after the reporting date. Interest income from these assets is included in finance income using the effective interest rate method. Any gain or loss arising on derecognition is recognised directly in profit or loss and presented in finance income/cost.

Financial assets at fair value through OCI

For debt instruments at fair value through OCI, interest income, foreign exchange revaluation and impairment losses or reversals are recognised in the statement of profit or loss and computed in the

same manner as for financial assets measured at amortised cost. The remaining fair value changes are recognised in OCI. Upon derecognition, the cumulative fair value change recognised in OCI is recycled to profit or loss.

The Group does not have financial assets measured at fair value through OCI.

Financial assets at fair value through profit or loss

Financial assets at fair value through profit or loss are carried in the statement of financial position at fair value with net changes in fair value recognised in the statement of profit or loss.

The Group has derivative instruments under this category.

Financial liabilities - Initial recognition, measurement and presentation

Financial liabilities of the Group are classified and measured at fair value on initial recognition and subsequently at amortised cost net of directly attributable transaction costs, except for derivatives which are classified and subsequently recognised at fair value through profit or loss

Fair value gains or losses for financial liabilities designated at fair value through profit or loss are accounted for in profit or loss except for the amount of change that is attributable to changes in the Group's own credit risk which is presented in other comprehensive income. The remaining amount of change in the fair value of the liability is presented in profit or loss.

Subsequent measurement

For purposes of subsequent measurement, financial liabilities are classified in two categories:

- Financial liabilities at fair value through profit or loss
- Financial liabilities at amortised cost

Financial liabilities at fair value through profit or loss

Financial liabilities at fair value through profit or loss include financial liabilities held for trading and financial liabilities designated upon initial recognition as at fair value through profit or loss. The Group currently holds derivative financial liability at fair value through profit or loss.

Financial liabilities at amortised cost

This is the category most relevant to the Group. After initial recognition, interest bearing loans and borrowings are subsequently measured at amortised cost using the EIR method. Gains and losses are recognised in profit or loss when the liabilities are derecognised as well as through the EIR amortisation process.

Amortised cost is calculated by taking into account any discount or premium on acquisition and fees or costs that are an integral part of the EIR. The EIR amortisation is included as finance costs in the statement of profit or loss. The Group's financial liabilities at amortised cost include trade and other payables and interest-bearing loans and borrowings

b) Impairment of financial assets

Recognition of impairment provisions under IFRS 9 is based on the expected credit loss (ECL) model. The ECL model is applicable to financial assets classified at amortised cost and contract assets under IFRS 15: Revenue from Contracts with Customers. The measurement of ECL reflects an unbiased and probability-weighted amount that is determined by evaluating a range of possible outcomes, time value of money and reasonable and supportable information that is available without undue cost or effort at the reporting date, about past events, current conditions and forecasts of future economic conditions.

The Group applies the simplified approach or the three-stage general approach to determine impairment of receivables depending on their respective nature. The simplified approach is applied for trade

receivables and contract assets while the general approach is applied to NEPL receivables, NUIMS receivables, other receivables and cash and bank balances.

The simplified approach requires expected lifetime losses to be recognised from initial recognition of the receivables. This involves determining the expected loss rates using a provision matrix that is based on the Group's historical default rates observed over the expected life of the receivable and adjusted forward-looking estimates. This is then applied to the gross carrying amount of the receivable to arrive at the loss allowance for the period.

The three-stage approach assesses impairment based on changes in credit risk since initial recognition using the past due criterion and other qualitative indicators such as increase in political concerns or other macroeconomic factors and the risk of legal action, sanction or other regulatory penalties that may impair future financial performance.

Financial assets classified as stage 1 have their ECL measured as a proportion of their lifetime ECL that results from possible default events that can occur within one year, while assets in stage 2 or 3 have their ECL measured on a lifetime basis.

Under the three-stage approach, the ECL is determined by projecting the probability of default (PD), loss given default (LGD) and exposure at default (EAD) for each ageing bucket and for each individual exposure. The PD is based on default rates determined by external rating agencies for the counterparties. The LGD is determined based on management's estimate of expected cash recoveries after considering the historical pattern of the receivable, and it assesses the portion of the outstanding receivable that is deemed to be irrecoverable at the reporting period. The EAD is the total amount of outstanding receivable at the reporting period. These three components are multiplied together and adjusted for forward looking information, such as the gross domestic product (GDP) in Nigeria and crude oil prices, to arrive at an ECL which is then discounted back to the reporting date and summed. The discount rate used in the ECL calculation is the original effective interest rate or an approximation thereof.

Loss allowances for financial assets measured at amortised cost are deducted from the gross carrying amount of the related financial assets and the amount of the loss is recognised in profit or loss.

c) Significant increase in credit risk and default definition

The Group assesses the credit risk of its financial assets based on the information obtained during periodic review of publicly available information, industry trends and payment records. Based on the analysis of the information provided, the Group identifies the assets that require close monitoring.

Furthermore, financial assets that have been identified to be more than 30 days past due on contractual payments are assessed to have experienced significant increase in credit risk. These assets are grouped as part of Stage 2 financial assets where the three-stage approach is applied.

In line with the Group's credit risk management practices, a financial asset is defined to be in default when contractual payments have not been received at least 90 days after the contractual payment period. Subsequent to default, the Group carries out active recovery strategies to recover all outstanding payments due on receivables. Where the Group determines that there are no realistic prospects of recovery, the financial asset and any related loss allowance is written off either partially or in full.

d) Write off policy

The Group writes off financial assets, in whole or in part, when it has exhausted all practical recovery efforts and has concluded that there is no reasonable expectation of recovery. Indicators that there is no reasonable expectation of recovery include;

- ceasing enforcement activity and;
- where the Group's recovery method is foreclosing on collateral and the value of the collateral is such that there is no reasonable expectation of recovering in full.

The Group may write - off financial assets that are still subject to enforcement activity. The outstanding contractual amounts of such assets written off during the period ended 31 March 2026 was Nil (2025: Nil).

The Group seeks to recover amounts it legally owed in full, but which have been partially written off due to no reasonable expectation of full recovery.

e) Derecognition

Financial assets

The Group derecognises a financial asset when the contractual rights to the cash flows from the financial asset expire or when it transfers the financial asset and the transfer qualifies for derecognition. Gains or losses on derecognition of financial assets are recognised as finance income/cost.

Financial liabilities

The Group derecognises a financial liability when it is extinguished i.e. when the obligation specified in the contract is discharged or cancelled or expires. When an existing financial liability is replaced by another from the same lender on substantially different terms, or the terms of an existing liability are substantially modified, such an exchange or modification is treated as a derecognition of the original liability and the recognition of a new liability. The difference in the respective carrying amounts is recognised immediately in the statement of profit or loss.

In the context of IBOR reform, the Group's assessment of whether a change to an amortised cost financial instrument is substantial, is made after applying the practical expedient introduced by IBOR reform Phase 2. This requires the transition from an IBOR to an RFR to be treated as a change to a floating interest rate, as described in Note 3.13 above.

f) Modification

When the contractual cash flows of a financial instrument are renegotiated or otherwise modified and the renegotiation or modification does not result in the derecognition of that financial instrument, the Group recalculates the gross carrying amount of the financial instrument and recognises a modification gain or loss immediately within finance income/(cost)-net at the date of the modification. The gross carrying amount of the financial instrument is recalculated as the present value of the renegotiated or modified contractual cash flows that are discounted at the financial instrument's original effective interest rate.

g) Offsetting of financial assets and financial liabilities

Financial assets and liabilities are offset and the net amount reported in the statement of financial position when and only when there is legally enforceable right to offset the recognised amount, and there is an intention to settle on a net basis or realise the asset and settle the liability simultaneously.

The legally enforceable right is not contingent on future events and is enforceable in the normal course of business, and in the event of default, insolvency or bankruptcy of the Company or the counterparty.

h) Derivatives

The Group uses derivative financial instruments such as forward exchange contracts to hedge its foreign exchange risks as well as put options to hedge against its oil price risk. However, such contracts are not accounted for as designated hedges. Derivatives are initially recognised at fair value on the date a derivative contract is entered and subsequently remeasured to their fair value at the end of each reporting period. Any gains or losses arising from changes in the fair value of derivatives are recognised within operating profit in the

statement of profit or loss for the period. An analysis of the fair value of derivatives is provided in Note 5, Financial risk Management.

The Group accounts for financial assets with embedded derivatives (hybrid instruments) in their entirety on the basis of its contractual cash flow features and the business model within which they are held, thereby eliminating the complexity of bifurcation for financial assets. For financial liabilities, hybrid instruments are bifurcated into hosts and embedded features. In these cases, the Group measures the host contract at amortised cost and the embedded features is measured at fair value through profit or loss.

For the purpose of the maturity analysis, embedded derivatives included in hybrid financial instruments are not separated. The hybrid instrument, in its entirety, is included in the maturity analysis for non-derivative financial liabilities.

i) Fair value of financial instruments

The Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. When available, the Group measures the fair value of an instrument using quoted prices in an active market for that instrument. A market is regarded as active if quoted prices are readily available and represent actual and regularly occurring market transactions on an arm's length basis.

If a market for a financial instrument is not active, the Group establishes fair value using valuation techniques. Valuation techniques include using recent arm's length transactions between knowledgeable, willing parties (if available), reference to the current fair value of other instruments that are substantially the same, and discounted cash flow analysis. The chosen valuation technique makes maximum use of market inputs, relies as little as possible on estimates specific to the Group, incorporates all factors that market participants would consider in setting a price, and is consistent with accepted economic methodologies for pricing financial instruments.

Inputs to valuation techniques reasonably represent market expectations and measure the risk-return factors inherent in the financial instrument. The Group calibrates valuation techniques and tests them for validity using prices from observable current market transactions in the same instrument or based on other available observable market data.

The best evidence of the fair value of a financial instrument at initial recognition is the transaction price – i.e., the fair value of the consideration given or received. However, in some cases, the fair value of a financial instrument on initial recognition may be different to its transaction price. If such fair value is evidenced by comparison with other observable current market transactions in the same instrument (without modification or repackaging) or based on a valuation technique whose variables include only data from observable markets, then the difference is recognised in the income statement on initial recognition of the instrument. In other cases, the difference is not recognised in the income statement immediately but is recognised over the life of the instrument on an appropriate basis or when the instrument is redeemed, transferred, or sold, or the fair value becomes observable.

3.23 Share capital

On issue of ordinary shares, any consideration received net of any directly attributable transaction costs is included in equity. Issued share capital has been translated at the exchange rate prevailing at the date of the transaction and is not retranslated after initial recognition.

3.24 Treasury shares

Own equity instruments that are reacquired (treasury shares) are recognised at cost and deducted from equity. No gain or loss is recognised in profit or loss on the purchase, sale, issue or cancellation

of the Group's own equity instruments. Any difference between the carrying amount and the consideration, if reissued, is recognised in the share premium.

3.25 Earnings per share and dividends

Basic EPS

Basic earnings per share is calculated on the Company's profit or loss after taxation and based on the weighted average of issued and fully paid ordinary shares at the end of the period.

Diluted EPS

Diluted EPS is calculated by dividing the profit or loss after taxation by the weighted average number of ordinary shares outstanding during the year plus the weighted average number of ordinary shares that would be issued on conversion of all the dilutive potential ordinary shares (after adjusting for outstanding share options arising from the share-based payment scheme) into ordinary shares.

Dividend

Dividends on ordinary shares are recognised as a liability in the period in which they are approved.

3.26 Post-employment benefits

Defined contribution scheme

The Group contributes to a defined contribution scheme for its employees in compliance with the provisions of the Pension Reform Act 2014. The scheme is fully funded and is managed by licensed Pension Fund Administrators. Membership of the scheme is automatic upon commencement of duties at the Group. The Group's contributions to the defined contribution scheme are charged to the statement of profit and loss account in the year to which they relate.

The employer contributes 17% while the employee contributes 3% of the qualifying employee's salary.

Employee benefits are all forms of consideration given by an entity in exchange for service rendered by employees or for the termination of employment. The Group operates a defined contribution plan and it is accounted for based on IAS 19 Employee benefits.

Defined contribution plans are post-employment benefit plans under which an entity pays fixed contributions into a separate entity (a fund) and will have no legal or constructive obligation to pay further contributions if the fund does not hold sufficient assets to pay all employee benefits relating to employee service in the current and prior periods. Under defined contribution plans the entity's legal or constructive obligation is limited to the amount that it agrees to contribute to the fund.

Thus, the amount of the post-employment benefits received by the employee is determined by the amount of contributions paid by an entity (and perhaps also the employee) to a post-employment benefit plan or to an insurance company, together with investment returns arising from the contributions. In consequence, actuarial risk (that benefits will be less than expected) and investment risk (that assets invested will be insufficient to meet expected benefits) fall, in substance, on the employee.

Defined benefit scheme

The Group operated a defined benefit plan covering gratuity, which was discontinued in 2025. The plan required contributions to be made to a separately administered fund. The Group also provided certain additional post-employment benefits to employees; these benefits were unfunded.

The cost of providing benefits under the defined benefit plan was determined using the projected unit credit method and was calculated annually by independent actuaries. The liability or asset recognised in the statement of financial position in respect of the defined benefit plan represents the present value of the defined benefit obligation at the end of the reporting period, less the fair value of any plan assets.(if any).

The present value of the defined benefit obligation was determined by discounting the estimated future cash outflows using government bonds.

Remeasurement gains and losses, arising from changes in financial and demographic assumptions and from experience adjustments, were recognised immediately in the statement of financial position, with a corresponding debit or credit to retained earnings through other comprehensive income in the period in which they occurred. Remeasurements were not reclassified to profit or loss in subsequent periods.

Past service costs were recognised in profit or loss at the earlier of:

- The date of the plan amendment or curtailment; and
- The date that the Group recognised related restructuring costs.

Net interest was calculated by applying the discount rate to the net defined benefit obligation and the fair value of the plan assets.

The Group recognised the following changes in the net defined benefit obligation under employee benefit expenses in general and administrative expenses:

- Service costs comprises current service costs, past-service costs, gains and losses on curtailments and non-routine settlements.
- Net interest cost

Termination benefits

Termination benefits are expensed at the earlier of when the Group can no longer withdraw the offer of those benefits and when the Group recognises costs for a restructuring. If benefits are not expected to be settled wholly within 12 months of the reporting date; then they are discounted.

3.27 Provisions

Provisions are recognised when

- i) the Group has a present legal or constructive obligation as a result of past events;
- ii) it is probable that an outflow of economic resources will be required to settle the obligation as a whole; and
- iii) the amount can be reliably estimated.

Provisions are not recognised for future operating losses.

In measuring the provision:

- risks and uncertainties are taken into account;
- the provisions are discounted (where the effects of the time value of money is considered to be material) using a pre-tax rate that is reflective of current market assessments of the time value of money and the risk specific to the liability;
- when discounting is used, the increase of the provision over time is recognised as interest expense;
- future events such as changes in law and technology, are taken into account where there is subjective audit evidence that they will occur; and
- gains from expected disposal of assets are not taken into account, even if the expected disposal is closely linked to the event giving rise to the provision.

Decommissioning

Liabilities for decommissioning costs are recognised as a result of the constructive obligation of past practice in the oil and gas industry, when it is probable that an outflow of economic resources will be required to settle the liability and a reliable estimate can be made. The estimated costs, based on current requirements, technology and price levels, prevailing at the reporting date, are computed based on the latest assumptions as to the scope and method of abandonment.

Provisions are measured at the present value of management's best estimates of the expenditure required to settle the present obligation at the end of the reporting period. The discount rate used to determine the present value is a pre-tax rate that reflects current

market assessments of the time value of money and the risks specific to the liability. The increase in the provision due to the passage of time is recognised as a finance cost. The corresponding amount is capitalised as part of the oil and gas properties and is amortised on a unit-of-production basis as part of the depreciation, depletion and amortisation charge. Any adjustment arising from the estimated cost of the restoration and abandonment cost is capitalised, while the charge arising from the accretion of the discount applied to the expected expenditure is treated as a component of finance costs.

If the change in estimate results in an increase in the decommissioning provision and, therefore, an addition to the carrying value of the asset, the Company considers whether this is an indication of impairment of the asset as a whole, and if so, tests for impairment in accordance with IAS 36. If, for mature fields, the revised oil and gas assets net of decommissioning provisions exceed the recoverable value, that portion of the increase is charged directly to expense.

3.28 Contingencies

A contingent asset or contingent liability is a possible asset or obligation that arises from past events and whose existence will be confirmed by the occurrence or non-occurrence of uncertain future events. The assessment of the existence of the contingencies will involve management judgement regarding the outcome of future events.

3.29 Income taxation

i. Current income tax

The income tax expense or credit for the period is the tax payable on the current period's taxable income, based on the applicable income tax rate for each jurisdiction, adjusted by changes in deferred tax assets and liabilities attributable to temporary differences and to unused tax losses. The current income tax charge is calculated on the basis of the tax laws enacted or substantively enacted at the end of the reporting period in the countries where the company and its subsidiaries and associates operate and generate taxable income. Management periodically evaluates positions taken in tax returns with respect to situations in which applicable tax regulation is subject to interpretation. It establishes provisions, where appropriate, on the basis of amounts expected to be paid to the tax authorities.

ii. Deferred tax

Deferred income tax is provided in full, using the liability method, on temporary differences arising between the tax bases of assets and liabilities and their carrying amounts in the consolidated financial statements. However, deferred tax liabilities are not recognised if they arise from the initial recognition of goodwill. Deferred income tax is also not accounted for if it arises from initial recognition of an asset or liability in a transaction other than a business combination that, at the time of the transaction, affects neither accounting nor taxable profit or loss.

Deferred income tax is determined using tax rates (and laws) that have been enacted or substantially enacted by the end of the reporting period and are expected to apply when the related deferred income tax asset is realised or the deferred income tax liability is settled.

Deferred tax assets are recognised only if it is probable that future taxable amounts will be available to utilise those temporary differences and losses.

Deferred tax liabilities and assets are not recognised for temporary differences between the carrying amount and tax bases of investments in foreign operations where the company is able to control the timing of the reversal of the temporary differences and it is probable that the differences will not reverse in the foreseeable future.

Current tax assets and tax liabilities are offset where the entity has a legally enforceable right to offset and intends either to settle on a net basis, or to realise the asset and settle the liability simultaneously.

Current and deferred tax is recognised in profit or loss, except to the extent that it relates to items recognised in other comprehensive income or directly in equity. In this case, the tax is also recognised in other comprehensive income or directly in equity, respectively.

iii. Uncertainty over income tax treatments

The Group examines where there is an uncertainty regarding the treatment of an item, including taxable profit or loss, the tax bases of assets and liabilities, tax losses and credits and tax rates. It considers each uncertain tax treatment separately or together as a group, depending on which approach better predicts the resolution of the uncertainty. The factors it considers include:

- how it prepares and supports the tax treatment; and
- the approach that it expects the tax authority to take during an examination.

If the Group concludes that it is probable that the tax authority will accept an uncertain tax treatment that has been taken or is expected to be taken on a tax return, it determines the accounting for income taxes consistently with that tax treatment. If it concludes that it is not probable that the treatment will be accepted, it reflects the effect of the uncertainty in its income tax accounting in the period in which that determination is made (for example, by recognising an additional tax liability or applying a higher tax rate).

The Group measures the impact of the uncertainty using methods that best predicts the resolution of the uncertainty. The Group uses the most likely method where there are two possible outcomes, and the expected value method when there are a range of possible outcomes.

The Group assumes that the tax authority with the right to examine and challenge tax treatments will examine those treatments and have full knowledge of all related information. As a result, it does not consider detection risk in the recognition and measurement of uncertain tax treatments. The Group applies consistent judgements and estimates on current and deferred taxes. Changes in tax laws or the presence of new tax information by the tax authority is treated as a change in estimate in line with IAS 8 - Accounting policies, changes in accounting estimates and errors.

Judgements and estimates made to recognise and measure the effect of uncertain tax treatments are reassessed whenever circumstances change or when there is new information that affects those judgements. New information might include actions by the tax authority, evidence that the tax authority has taken a particular position in connection with a similar item, or the expiry of the tax authority's right to examine a particular tax treatment. The absence of any comment from the tax authority is unlikely to be, in isolation, a change in circumstances or new information that would lead to a change in estimate.

3.30 Business combinations

The acquisition method of accounting is used to account for all business combinations, regardless of whether equity instruments or other assets are acquired. The consideration transferred for the acquisition of a subsidiary comprises the:

- fair values of the assets transferred
- liabilities incurred to the former owners of the acquired business
- equity interests issued by the group
- fair value of any asset or liability resulting from a contingent consideration arrangement, and
- fair value of any pre-existing equity interest in the subsidiary.

Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are, with limited exceptions, measured initially at their fair values at the acquisition date. The group recognises any non-controlling interest in the acquired entity on an acquisition-by-acquisition basis either at fair value or at the non-controlling interest's proportionate share of the acquired entity's net identifiable assets. Acquisition-related costs are expensed as incurred.

The excess of the:

- consideration transferred,
- amount of any non-controlling interest in the acquired entity, and
- acquisition-date fair value of any previous equity interest in the acquired entity

over the fair value of the net identifiable assets acquired is recorded as goodwill. If those amounts are less than the fair value of the net identifiable assets of the business acquired, the difference is recognised directly in profit or loss as a bargain purchase.

3.31 Share based payments

Employees (including senior executives) of the Group receive remuneration in the form of share-based payments, whereby employees render services as consideration for equity instruments (equity-settled transactions).

a) Equity-settled transactions

The cost of equity-settled transactions is determined by the fair value at the date when the grant is made using an appropriate valuation model.

That cost is recognised in employee benefits expense together with a corresponding increase in equity (share-based payment reserve), over the period in which the service and, where applicable, the performance conditions are fulfilled (the vesting period). The cumulative expense recognised for equity-settled transactions at each reporting date until the vesting date reflects the extent to which the vesting period has expired and the Group's best estimate of the number of equity instruments that will ultimately vest. The expense or credit in profit or loss for a period represents the movement in cumulative expense recognised as at the beginning and end of that period.

Service and non-market performance conditions are not taken into account when determining the grant date and for fair value of awards, but the likelihood of the conditions being met is assessed as part of the Group's best estimate of the number of equity instruments that will ultimately vest. Market performance conditions are reflected within the grant date fair value. Any other conditions attached to an award, but without an associated service requirement, are considered to be non-vesting conditions. Non-vesting conditions are reflected in the fair value of an award and lead to an immediate expensing of an award unless there are also service and/or performance conditions.

No expense is recognised for awards that do not ultimately vest because non-market performance and/or service conditions have not been met. Where awards include a market or non-vesting condition, the transactions are treated as vested irrespective of whether the market or non-vesting condition is satisfied, provided that all other performance and/or service conditions are satisfied. When the terms of an equity-settled award are modified, the minimum expense recognised is the grant date fair value of the unmodified award provided the original terms of the award are met. An additional expense, measured as at the date of modification, is recognised for any modification that increases the total fair value of the share-based payment transaction, or is otherwise beneficial to the employee. Where an award is cancelled by the entity or by the counterparty, any remaining element of the fair value of the award is expensed immediately through profit or loss. The dilutive effect of outstanding awards is reflected as additional share dilution in the computation of diluted earnings per share.

b) Cash-settled transactions

A liability is recognised for the fair value of cash-settled transactions. The fair value is measured initially and at each reporting date up to and including the settlement date, with changes in fair value recognised in employee benefits expense. The fair value is expensed over the period until the vesting date with recognition of a corresponding liability. The fair value is determined using a binomial model. The approach used to account for vesting conditions when

measuring equity-settled transactions also applies to cash-settled transactions.

4. Significant accounting judgements, estimates and assumptions

The preparation of the Group's consolidated historical financial information requires management to make judgements, estimates and assumptions that affect the reported amounts of revenues, expenses, assets and liabilities, and the accompanying disclosures, and the disclosure of contingent liabilities. Uncertainty about these assumptions and estimates could result in outcomes that require a material adjustment to the carrying amount of assets or liabilities affected in future periods.

4.1 Judgements

In the process of applying the Group's accounting policies, management has made the following judgements, which have the most significant effect on the amounts recognised in the consolidated historical financial information:

i. OMLs 4, 38 and 41

OMLs 4, 38, 41 are grouped together as a cash generating unit for the purpose of impairment testing. These three OMLs are grouped together because they each cannot independently generate cash flows. They currently operate as a single block sharing resources for generating cash flows. Crude oil and gas sold to third parties from these OMLs are invoiced when the Group has an unconditional right to receive payment.

ii. Deferred tax asset

Deferred income tax assets are recognised for tax losses carried forward to the extent that the realisation of the related tax benefit through future taxable profits is probable.

iii. Foreign currency translation reserve

The Group has used the CBN rate to translate its Dollar currency to its Naira presentation currency. Management has determined that this rate is available for immediate delivery. If the rate was 10% higher or lower, revenue in Naira would have increased/decreased by ₦5.25 billion (2025: ₦24.16 billion). See Note 30 for the applicable translation rates.

iv. Consolidation of Elcrest

On acquisition of 100% shares of Eland Oil and Gas Plc, the Group acquired indirect holdings in Elcrest Exploration and Production (Nigeria) Limited. Although the Group has an indirect holding of 45% in Elcrest, Elcrest has been consolidated as a subsidiary for the following basis:

- Eland Oil and Gas Plc has controlling power over Elcrest due to its representation on the board of Elcrest, and clauses contained in the Share Charge agreement and loan agreement which gives Eland the right to control 100% of the voting rights of shareholders.
- Eland Oil and Gas Plc is exposed to variable returns from the activities of Elcrest through dividends and interests.
- Eland Oil and Gas Plc has the power to affect the amount of returns from Elcrest through its right to direct the activities of Elcrest and its exposure to returns.

v. Revenue recognition

Performance obligations

The judgments applied in determining what constitutes a performance obligation will impact when control is likely to pass and therefore when revenue is recognised i.e. over time or at a point in time. The Group has determined that only one performance obligation exists in oil contracts which is the delivery of crude oil to specified ports. Revenue is therefore recognised at a point in time.

For gas contracts, the performance obligation is satisfied through the delivery of a series of distinct goods. Revenue is recognised over time in this situation as gas customers simultaneously receive and consume the benefits provided by the Group's performance. The Group has elected to apply the 'right to invoice' practical expedient in determining revenue from its gas contracts. The right to invoice is a measure of progress that allows the Group to recognise revenue based on amounts invoiced to the customer. Judgement has been applied in evaluating that the Group's right to consideration corresponds directly with the value transferred to the customer and is therefore eligible to apply this practical expedient.

Transactions with Joint Operating arrangement (JOA) partners

The treatment of underlift and overlift transactions is judgmental and requires a consideration of all the facts and circumstances including the purpose of the arrangement and transaction. The transaction between the Group and its JOA partners involves sharing in the production of crude oil, and for which the settlement of the transaction is non-monetary. The JOA partners have been assessed to be partners not customers. Therefore, shortfalls or excesses below or above the Group's share of production are recognised in other income/ (expenses) - net.

vi. Segment reporting

Operating segments are reported in a manner consistent with the internal reporting provided to the chief operating decision maker.

The Board of directors assesses the financial performance and position of the Group and makes strategic decisions. The board has delegated the day to day implementation of the Group's strategic framework to the Chief Executive Officer who is supported by the senior leadership team. See further details in note 6.

vii. Leases

Critical judgements in determining the lease term

In determining the lease term, management considers all facts and circumstances that create an economic incentive to exercise an extension option, or not exercise a termination option. Extension options (or periods after termination options) are only included in the lease term if the lease is reasonably certain to be extended (or not terminated). For leases of warehouses, retail stores and equipment, the following factors are normally the most relevant

- If there are significant penalty payments to terminate (or not extend), the group is typically reasonably certain to extend (or not terminate).
- If any leasehold improvements are expected to have a significant remaining value, the group is typically reasonably certain to extend (or not terminate).
- Otherwise, the group considers other factors including historical lease durations and the costs and business disruption required to replace the leased asset.

Most extension options in offices and vehicles leases have not been included in the lease liability, because the group could replace the assets without significant cost or business disruption.

4.2 Estimates and assumptions

The key assumptions concerning the future and the other key source of estimation uncertainty at the reporting date that have a significant risk of causing a material adjustment to the carrying amounts of assets and liabilities within the next financial year are described below. The Group based its assumptions and estimates on parameters available when the consolidated financial statements were prepared. Existing circumstances and assumptions about future developments may change due to market changes or circumstances arising that are beyond the control of the Group. Such changes are reflected in the assumptions when they occur.

The following are some of the estimates and assumptions made:

i. Defined benefit plans

The cost of the defined benefit retirement plan and the present value of the retirement obligation are determined using actuarial valuations. An actuarial valuation involves making various assumptions that may differ from actual developments in the future. These include the determination of the discount rate, future salary increases, mortality rates and changes in inflation rates.

Due to the complexities involved in the valuation and its long-term nature, a defined benefit obligation is highly sensitive to changes in these assumptions. The parameter most subject to change is the discount rate. In determining the appropriate discount rate, management considers market yield on federal government bonds in

currencies consistent with the currencies of the post-employment benefit obligation and extrapolated as needed along the yield curve to correspond with the expected term of the defined benefit obligation.

The rates of mortality assumed for employees are the rates published in 67/70 ultimate tables, published jointly by the Institute and Faculty of Actuaries in the UK.

ii. Oil and gas reserves

Proved oil and gas reserves are used in the units of production calculation for depletion as well as the determination of the timing of well closure for estimating decommissioning liabilities and impairment analysis. There are numerous uncertainties inherent in estimating oil and gas reserves. Assumptions that are valid at the time of estimation may change significantly when new information becomes available. Changes in the forecast prices of commodities, exchange rates, production costs or recovery rates may change the economic status of reserves and may ultimately result in the reserves being restated.

iii. Share-based payment reserve

Estimating fair value for share-based payment transactions requires determination of the most appropriate valuation model, which depends on the terms and conditions of the grant. This estimate also requires determination of the most appropriate inputs to the valuation model including the expected life of the share award or appreciation right, volatility and dividend yield and making assumptions about them. The Group measures the fair value of equity-settled transactions with employees at the grant date.

The Group makes estimates and assumptions concerning the future. The resulting accounting estimates will, by definition, seldom equal the related actual results. Such estimates and assumptions are continually evaluated and are based on historical experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances.

iv. Provision for decommissioning obligations

Provisions for environmental clean-up and remediation costs associated with the Group's drilling operations are based on current constructions, technology, price levels and expected plans for remediation. Actual costs and cash outflows can differ from estimates because of changes in public expectations, prices, discovery and analysis of site conditions and changes in clean-up technology.

v. Property, plant and equipment

The Group assesses its property, plant and equipment, including exploration and evaluation assets, for possible impairment if there are events or changes in circumstances that indicate that carrying values of the assets may not be recoverable, or at least at every reporting date.

If there are low oil prices or natural gas prices during an extended period, the Group may need to recognise significant impairment charges. The assessment for impairment entails comparing the carrying value of the cash-generating unit with its recoverable amount, that is, higher of fair value less cost to dispose and value in use. Value in use is usually determined on the basis of discounted estimated future net cash flows. Determination as to whether and how much an asset is impaired involves management estimates on highly uncertain matters such as future commodity prices, the effects of inflation on operating expenses, discount rates, production profiles and the outlook for regional market supply-and-demand conditions for crude oil and natural gas.

During the year, the Group carries out an impairment assessment on OML 4,38 and 41, OML 56, OML 53, OML 40, OML 67, OML 68, OML 70 and OML 104. The Group uses the higher of the fair value less cost to dispose and the value in use in determining the recoverable amount of the cash-generating unit. In determining the value, the Group uses a forecast of the annual net cash flows over the life of proved plus probable reserves, production rates, oil and gas prices, future costs (excluding (a) future restructurings to which the entity is

not yet committed; or (b) improving or enhancing the asset's performance) and other relevant assumptions based on the year-end Competent Persons Report (CPR). The pre-tax future cash flows are adjusted for risks specific to the forecast and discounted using a pre-tax discount rate which reflects both current market assessment of the time value of money and risks specific to the asset.

Management considers whether a reasonable possible change in one of the main assumptions will cause an impairment and believes otherwise.

vi. Useful life of other property, plant and equipment

The Group recognises depreciation on other property, plant and equipment on a straight-line basis in order to write-off the cost of the asset over its expected useful life. The economic life of an asset is determined based on existing wear and tear, economic and technical ageing, legal and other limits on the use of the asset, and obsolescence. If some of these factors were to deteriorate materially, impairing the ability of the asset to generate future cash flow, the Group may accelerate depreciation charges to reflect the remaining useful life of the asset or record an impairment loss.

vii. Income taxes

The Group is subject to income taxes by the Nigerian tax authority, which does not require significant judgement in terms of provision for income taxes, but a certain level of judgement is required for recognition of deferred tax assets. Management is required to assess the ability of the Group to generate future taxable economic earnings that will be used to recover all deferred tax assets. Assumptions about the generation of future taxable profits depend on management's estimates of future cash flows. The estimates are based on the future cash flow from operations taking into consideration the oil and gas prices, volumes produced, operational and capital expenditure.

viii. Impairment of financial assets

The loss allowances for financial assets are based on assumptions about risk of default, expected loss rates and maximum contractual period. The Group uses judgement in making these assumptions and selecting the inputs to the impairment calculation, based on the Group's past history, existing market conditions as well as forward looking estimates at the end of each reporting period. Details of the key assumptions and inputs used are disclosed in note 5.1.3.

ix. Intangible assets

The contract based intangible assets (license) were acquired as part of a business combination. They are recognised at their fair value at the date of acquisition and are subsequently amortised on a straight-line bases over their estimated remaining useful lives of the asset. The fair value of contract based intangible assets is estimated using the multi period excess earnings method. This requires a forecast of revenue and all cost projections throughout the useful life of the intangible assets. A contributory asset charge that reflects the return on assets is also determined and applied to the revenue but subtracted from the operating cash flows to derive the pre-tax cash flow. The post-tax cashflows are then obtained by deducting out the tax using the effective tax rate.

Discount rates represent the current market assessment of the risks specific to each CGU, taking into consideration the time value of money. The discount rate calculation is based on the specific circumstances of the Group and its operating segments and is derived from its weighted average cost of capital (WACC). The WACC takes into account both debt and equity. The cost of equity is derived from the expected return on investment by the Group's investors. The cost of debt is based on the interest-bearing borrowings the Group is obliged to service.

x. Inventories - Operational Spares

The Group holds inventories comprising spare parts and consumables used in production and operational activities. These items are not held for resale but are consumed in the maintenance and operation of assets and are accounted for in accordance with IAS 2.

Inventories are measured at the lower of cost and net realisable value.

For operational spares, net realisable value is assessed with reference to their expected future use in operations and replacement cost.

The determination of whether spares are recoverables requires management judgement, particularly in assessing:

- Expected future utilisation of the related assets
- Forecast production profiles
- Technological obsolescence risk
- Physical condition and shelf life
- Current replacement cost Where spare parts are slow-moving, obsolete or no longer expected to be utilised in operations, a write-down is recognised.

Due to the judgement involved in assessing future usage and recoverability, there is estimation uncertainty associated with the carrying amount of operational spares. Changes in operational plans or asset life assumptions could result in a material adjustment to inventory values in future reporting periods.

5. Financial risk management

5.1 Financial risk factors

The Group's activities expose it to a variety of financial risks such as market risk (including foreign exchange risk, interest rate risk and commodity price risk), credit risk and liquidity risk. The Group's risk management programme focuses on the unpredictability of financial markets and seeks to minimise potential adverse effects on the Group's financial performance. Risk management is carried out by the treasury department under policies approved by the Board of Directors. The Board provides written principles for overall risk management, as well as written policies covering specific areas, such as foreign exchange risk, interest rate risk, credit risk and investment of excess liquidity

Risk	Exposure arising from	Measurement	Management
Market risk – foreign exchange	Future commercial transactions Recognised financial assets and liabilities not denominated in US dollars.	Cash flow forecasting Sensitivity analysis	Match and settle foreign denominated cash inflows with the relevant cash outflows to mitigate any potential foreign exchange risk.
Market risk – interest rate	Long term borrowings at variable rate	Sensitivity analysis	None
Market risk – commodity prices	Derivative financial instruments	Sensitivity analysis	Oil price hedges
Credit risk	Cash and bank balances, trade receivables and derivative financial instruments.	Ageing analysis Credit ratings	Diversification of bank deposits
Liquidity risk	Borrowings and other liabilities	Rolling cash flow forecasts	Availability of committed credit lines and borrowing facilities

5.1.1 Credit risk

Credit risk refers to the risk of a counterparty defaulting on its contractual obligations resulting in financial loss to the Group. Credit risk arises from cash and bank balances as well as credit exposures to customers (i.e., Shell western, Pillar, Azura, Geregu Power, Sapele Power, ExxonMobil and Nigerian Gas Marketing Company (NGMC) receivables), and other parties (i.e., NUIMS receivables, NEPL receivables and other receivables)

a) Risk management

The Group is exposed to credit risk from its sale of crude oil to Exxonmobil, Waltersmith, Chevron, Vitol S.A and Shell western. The Group has in place a 30-day payment term bill of lading date in the offtake agreement with Shell Western Supply and Trading Limited. The Group is exposed to further credit risk from outstanding cash calls from NEPL and NUIMS.

In addition, the Group is exposed to credit risk in relation to the sale of gas to its customers.

The credit risk on cash and bank balances is managed through the diversification of banks in which the balances are held. The risk is limited because the majority of deposits are with banks that have an acceptable credit rating assigned by an international credit agency. The Group's maximum exposure to credit risk due to default of the counterparty is equal to the carrying value of its financial assets.

Estimation uncertainty in measuring impairment loss

The table below shows information on the sensitivity of the carrying amounts of the Company's financial assets to the methods, assumptions and estimates used in calculating impairment losses on those financial assets at the end of the reporting period. These methods, assumptions and estimates have a significant risk of causing material adjustments to the carrying amounts of the Group's financial assets.

Significant unobservable inputs

The table below demonstrates the sensitivity of the Company's profit before tax to movements in the probability of default (PD) and loss given default (LGD) for financial assets, with all other variables held constant:

	Effect on profit before tax 31 March 2026 ₦ million	Effect on other components of equity before tax 31 March 2026 ₦ million	Effect on profit before tax 31 March 2026 \$'000	Effect on other components of equity before tax 31 March 2026 \$'000
Increase/decrease in loss given default				
+10%	(395)	—	(285)	—
-10%	395	—	285	—

	Effect on profit before tax 31 March 2025 ₦ million	Effect on other components of equity before tax 31 March 2025 ₦ million	Effect on profit before tax 31 March 2025 \$'000	Effect on other components of equity before tax 31 March 2025 \$'000
Increase/decrease in loss given default				
+10%	(208)	—	(141)	—
-10%	208	—	141	—

The table below demonstrates the sensitivity of the Group's profit before tax to movements in probabilities of default, with all other variables held constant:

	Effect on profit before tax 31 March 2026 ₦ million	Effect on other components of equity before tax 31 March 2026 ₦ million	Effect on profit before tax 31 March 2026 \$'000	Effect on other components of equity before tax 31 March 2026 \$'000
Increase/decrease in probability of default				
+10%	(385)	—	(279)	—
-10%	385	—	279	—

	Effect on profit before tax 31 March 2025 ₦ million	Effect on other components of equity before tax 31 March 2025 ₦ million	Effect on profit before tax 31 March 2025 \$'000	Effect on other components of equity before tax 31 March 2025 \$'000
Increase/decrease in probability of default				
+10%	(218)	—	(147)	—
-10%	218	—	147	—

The table below demonstrates the sensitivity of the Company's profit before tax to movements in the forward-looking macroeconomic indicators, with all other variables held constant:

Increase/decrease in forward looking macroeconomic indicators	Effect on profit before tax	Effect on other components of equity before tax	Effect on profit before tax	Effect on other components of equity before tax
	31 March 2026	31 March 2026	31 March 2026	31 March 2026
	₹ million	₹ million	\$'000	\$'000
+10%	(398)	—	(287)	—
-10%	398	—	287	—

Increase/decrease in forward looking macroeconomic indicators	Effect on profit before tax	Effect on other components of equity before tax	Effect on profit before tax	Effect on other components of equity before tax
	31 March 2025	31 March 2025	31 March 2025	31 March 2025
	₹ million	₹ million	\$'000	\$'000
+10%	(63)	—	(42)	—
-10%	63	—	42	—

5.1.2 Liquidity risk

Liquidity risk is the risk that the Group will not be able to meet its financial obligations as they fall due. The Group manages liquidity risk by ensuring that sufficient funds are available to meet its commitments as they fall due.

The Group uses both long-term and short-term cash flow projections to monitor funding requirements for activities and to ensure there are sufficient cash resources to meet operational needs. Cash flow projections take into consideration the Group's debt financing plans and covenant compliance. Surplus cash held is transferred to the treasury department which invests in interest bearing current accounts and time deposits.

The following table details the Group's remaining contractual maturity for its non-derivative financial liabilities with agreed maturity periods. The table has been drawn based on the undiscounted cash flows of the financial liabilities based on the earliest date on which the Group can be required to pay.

31 March 2026	Effective interest rate %	Less than 1 year ₦ million	1 – 2 year ₦ million	2 – 3 years ₦ million	3 – 5 years ₦ million	Total ₦ million
Non-derivatives						
Fixed interest rate borrowings						
\$650 million Senior notes	9.125%	82,221	82,221	82,221	983,261	1,229,924
Variable interest rate borrowings						
The Mauritius Commercial Bank Ltd	6.5% + SOFR	2,494	2,494	10,652	17,276	32,916
Stanbic IBTC Bank Plc	6.5% + SOFR	2,244	2,244	9,587	15,548	29,623
Standard Bank of South Africa	6.5% + SOFR	1,248	1,248	5,326	8,638	16,460
First City Monument Ltd (FCMB)	6.5% + SOFR	1,198	1,198	5,112	8,292	15,800
Zenith Bank plc	6.5% + SOFR	798	798	3,409	5,528	10,533
\$300 million Advance Payment Facility (APF)						
ExxonMobil Financing	5% + SOFR+CAS	37,137	429,791	—	—	466,928
Total variable interest borrowings		45,119	437,773	34,086	55,282	572,260
Other non-derivatives						
Trade and other payables		1,117,270	—	—	—	1,117,270
Lease liability		50,324	26,359	15,623	8,428	100,734
		1,167,594	26,359	15,623	8,428	1,218,004
Total		1,294,934	546,353	131,930	1,046,971	3,020,188

31 March 2025	Effective interest rate %	Less than 1 year ₹ million	1 – 2 year ₹ million	2 – 3 years ₹ million	3 – 5 years ₹ million	Total ₹ million
Non-derivatives						
Fixed interest rate borrowings						
\$650 million Senior notes	9.125%	91,123	91,123	91,123	1,180,851	1,454,220
Variable interest rate borrowings						
The Mauritius Commercial Bank Ltd	8% + SOFR	17,646	—	—	—	17,646
Stanbic IBTC Bank Plc	8% + SOFR	18,015	—	—	—	18,015
Standard Bank of South Africa	8% + SOFR	10,293	—	—	—	10,293
First City Monument Ltd (FCMB)	8% + SOFR	4,595	—	—	—	4,595
Shell Western Supply & Trading Limited	10.5% + SOFR	2,600	19,499	—	—	22,099
\$350 million RCF						
Citibank N.A London	5% + SOFR+CAS	428	4,711	—	—	5,139
Nedbank Limited, London Branch	5% + SOFR+CAS	1,922	21,201	—	—	23,123
Stanbic Ibtc Bank Plc	5% + SOFR+CAS	2,136	23,556	—	—	25,692
RMB International (Mauritius) Limited	5% + SOFR+CAS	2,776	30,623	—	—	33,399
The Mauritius Commercial Bank, N.A Ltd	5% + SOFR+CAS	1,922	21,201	—	—	23,123
JP Morgan Chase Bank, N.A London	5% + SOFR+CAS	1,282	14,134	—	—	15,416
Standard Chartered Bank	5% + SOFR+CAS	1,282	14,134	—	—	15,416
Zenith Bank Plc	5% + SOFR+CAS	641	7,067	—	—	7,708
Zenith Bank (UK) Limited	5% + SOFR+CAS	855	9,422	—	—	10,277
United Bank for Africa Plc	5% + SOFR+CAS	641	7,067	—	—	7,708
First City Monument Bank Limited	5% + SOFR+CAS	855	9,422	—	—	10,277
BP	5% + SOFR+CAS	214	2,356	—	—	2,570
\$300 million Advance Payment Facility (APF)						
ExxonMobil Financing	5% + SOFR+CAS	44,789	44,789	505,684	—	595,262
Total variable interest borrowings		112,892	229,182	505,684	—	847,758
Other non-derivatives						
Trade and other payables		1,731,588	—	—	—	1,731,588
Lease Liability		23,981	—	—	—	23,981
		1,755,569	—	—	—	1,755,569
Total		1,959,584	320,305	596,807	1,180,851	4,057,547

31 March 2026	Effective interest rate	Less than 1 year	1 – 2 year	2 – 3 years	3 – 5 years	Total
	%	\$'000	\$'000	\$'000	\$'000	\$'000
Non-derivatives						
Fixed interest rate borrowings						
\$650 million Senior notes	9.125%	59,313	59,313	59,313	709,313	887,252
Variable interest rate borrowings						
The Mauritius Commercial Bank Ltd	6.5% + SOFR	1,799	1,799	7,684	12,463	23,745
Stanbic IBTC Bank Plc	6.5% + SOFR	1,619	1,619	6,916	11,216	21,370
Standard Bank of South Africa	6.5% + SOFR	900	900	3,842	6,231	11,873
First City Monument Ltd (FCMB)	6.5% + SOFR	864	864	3,688	5,982	11,398
Zenith Bank plc	6.5% + SOFR	576	576	2,459	3,988	7,599
\$300 million Advance Payment Facility (ADF)						
ExxonMobil Financing	5% + SOFR + CAS	26,790	310,046	—	—	336,836
Total variable interest borrowings		32,548	315,804	24,589	39,880	412,821
Other non-derivatives						
Trade and other payables		805,983	—	—	—	805,983
Lease liability		36,303	19,015	11,270	6,080	72,668
		842,286	19,015	11,270	6,080	878,651
Total		934,147	394,132	95,172	755,273	2,178,724

Derivative liability of \$12.8 million, ₦17.8 billion (2025: \$6.299 million, ₦9.04 billion) are expected to be settled within the next 12 months. Hence, it would be classified under less than one year for the purpose of liquidity and maturity analysis.

31 March 2025	Effective interest rate %	Less than 1 year \$'000	1 – 2 year \$'000	2 – 3 years \$'000	3 – 5 years \$'000	Total \$'000
Non-derivatives						
Fixed interest rate borrowings						
\$650 million Senior notes	9.125%	59,313	59,313	59,313	768,625	946,564
Variable interest rate borrowings						
The Mauritius Commercial Bank Ltd	8% + SOFR	11,486	—	—	—	11,486
Stanbic IBTC Bank Plc	8% + SOFR	11,726	—	—	—	11,726
Standard Bank of South Africa	8% + SOFR	6,700	—	—	—	6,700
First City Monument Ltd (FCMB)	8% + SOFR	2,991	—	—	—	2,991
Shell Western Supply & Trading Limited	10.5% + SOFR	1,692	12,692	—	—	14,384
\$350 million Seplat RCF						
Citibank N.A London	5% + SOFR+CAS	278	3,067	—	—	3,345
Nedbank Limited, London Branch	5% + SOFR+CAS	1,251	13,800	—	—	15,051
Stanbic Ibtc Bank Plc	5% + SOFR+CAS	1,390	15,333	—	—	16,723
RMB International (Mauritius) Limited	5% + SOFR+CAS	1,807	19,933	—	—	21,740
The Mauritius Commercial Bank, N.A Ltd	5% + SOFR+CAS	1,251	13,800	—	—	15,051
JP Morgan Chase Bank, N.A London	5% + SOFR+CAS	834	9,200	—	—	10,034
Standard Chartered Bank	5% + SOFR+CAS	834	9,200	—	—	10,034
Zenith Bank Plc	5% + SOFR+CAS	417	4,600	—	—	5,017
Zenith Bank (UK) Limited	5% + SOFR+CAS	556	6,133	—	—	6,689
United Bank for Africa Plc	5% + SOFR+CAS	417	4,600	—	—	5,017
First City Monument Bank Limited	5% + SOFR+CAS	556	6,133	—	—	6,689
BP	5% + SOFR+CAS	139	1,533	—	—	1,672
\$300 million Advance Payment Facility						
ExxonMobil Financing	5% + SOFR+CAS	29,153	29,153	329,153	—	387,459
Total variable interest borrowings		73,478	149,177	329,153	—	551,808
Other non-derivatives						
Trade and other payables		1,127,091	—	—	—	1,127,091
Lease liability		15,610	—	—	—	15,610
		1,142,701	—	—	—	1,142,701
Total		1,275,492	208,490	388,466	768,625	2,641,073

5.1.3 Fair value measurements

Set out below is a comparison by category of carrying amounts and fair value of all financial instruments:

	Carrying amount		Fair value	
	31 March 2026 ₦ million	31 Dec 2025 ₦ million	31 March 2026 ₦ million	31 Dec 2025 ₦ million
Financial assets measured at amortised cost				
Trade and other receivables*	813,622	663,315	813,622	663,315
Cash and cash equivalents	639,988	476,970	639,988	476,970
Restricted cash	177,609	181,347	177,609	181,347
	1,631,219	1,321,632	1,631,219	1,321,632
Financial assets measured at fair value				
Derivative financial assets	6,668	17,352	6,668	17,352
	6,668	17,352	6,668	17,352
Financial liabilities measured at amortised cost				
Interest bearing loans borrowings	1,376,861	1,443,289	1,391,953	1,462,032
Trade and other payables**	1,117,270	1,307,005	1,117,270	1,307,005
Lease Liability	91,194	96,188	91,194	103,962
	2,585,325	2,846,482	2,600,417	2,872,999
Financial liabilities measured at fair value				
Derivative financial liability	(17,811)	(9,041)	(17,811)	(9,041)
	(17,811)	(9,041)	(17,811)	(9,041)

	Carrying amount		Fair value	
	31 March 2026 \$'000	31 Dec 2025 \$'000	31 March 2026 \$'000	31 Dec 2025 \$'000
Financial assets at amortised cost				
Trade and other receivables*	586,937	462,157	586,937	462,157
Cash and cash equivalents	461,682	332,571	461,682	332,571
Restricted cash	128,125	126,351	128,125	126,351
	1,176,744	921,079	1,176,744	921,079
Financial assets at fair value				
Derivative financial assets	4,810	12,090	4,810	12,090
	4,810	12,090	4,810	12,090
Financial liabilities				
Interest bearing loans and borrowings	993,252	1,005,596	1,004,139	1,018,655
Trade and other payables**	805,983	910,637	805,983	910,637
Lease Liability	65,786	67,018	65,786	72,435
	1,865,021	1,983,251	1,875,908	2,001,727
Financial liabilities measured at fair value				
Derivative financial liability	(12,848)	(6,299)	(12,848)	(6,299)
	(12,848)	(6,299)	(12,848)	(6,299)

- Trade and other receivables exclude Geregu Power, Sapele Power and NGMC VAT receivables, cash advances and advance payments. In determining the fair value of the interest-bearing loans and borrowings, non-performance risks of the Group as at period-end were assessed to be insignificant.
- Trade and other payables (excluding non-financial liabilities such as provisions, taxes, pension and other non-contractual payables), trade and other receivables (excluding prepayments), cash and bank balances are financial instruments whose carrying amounts as per the financial statements approximate their fair values. This is mainly due to their short-term nature.

5.1.4 Fair Value Hierarchy

As at the reporting period, the Group had classified its financial instruments into the three levels prescribed under the accounting standards. There were no transfers of financial instruments between fair value hierarchy levels during the year.

- Level 1 – Quoted (unadjusted) market prices in active markets for identical assets or liabilities.
- Level 2 – Valuation techniques for which the lowest level input that is significant to the fair value measurement is directly or indirectly observable.
- Level 3 – Valuation techniques for which the lowest level input that is significant to the fair value measurement is unobservable.

The fair value of the financial instruments is included at the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date.

The fair value of the Group's derivative financial instruments has been determined using a proprietary pricing model that uses marked to market valuation. The valuation represents the mid-market value and the actual close-out costs of trades involved. The market inputs to the model are derived from observable sources. Other inputs are unobservable but are estimated based on the market inputs or by using other pricing models. The derivative financial instruments are in level 2.

The fair value of the Group's interest-bearing loans and borrowings is determined by using discounted cash flow models that use market interest rates as at the end of the period. The interest-bearing loans and borrowings are in level 2.

The fair value of the property, plant and equipment (oil rig) held for sale is determined using the replacement cost of the asset and the actual values market participants are willing to pay for the asset. These assets are of specialised nature and has been recognised under level 2.

The valuation process

The finance & corporate planning teams of the Group perform the valuations of financial and non-financial assets required for financial reporting purposes, including level 3 fair values. The corporate planning team reports to the Director, Strategy, Planning and Business Development who reports directly to the Chief Executive Officer (CEO). Discussions on the valuation process and results are held between the Director and the valuation team at least twice every year.

6. Segment reporting

Business segments are based on the Group's internal organisation and management reporting structure. The Group's business segments are the two core businesses: Oil and Gas. The Oil segment deals with the exploration, development and production of crude oil while the Gas segment deals with the production and processing of gas. These two reportable segments make up the total operations of the Group.

For the 3 months ended 31 March 2026, revenue from the gas segment of the business constituted 11% (2025: 6%) of the Group's revenue. Management is committed to continued growth of the gas segment of the business, including through increased investment to establish additional offices, create a separate gas business operational management team and procure the required infrastructure for this segment of the business. The gas business is positioned separately within the Group and reports directly to the (chief operating decision maker). As the gas business segment's revenues, results and cash flows are largely independent of other business units within the Group, it is regarded as a separate segment. The result is two reporting segments, Oil and Gas. There were no inter segment sales during the reporting periods under consideration, therefore all revenue was from external customers.

Amounts relating to the gas segment are determined using the gas cost centres, with the exception of depreciation. Depreciation relating to the gas segment is determined by applying a percentage which reflects the proportion of the Net Book Value of oil and gas properties that relates to gas investment costs (i.e., cost for the gas processing facilities).

The Group accounting policies are also applied in the segment reports.

6.1 Segment profit disclosure

	3 Months ended 31 March 2026	3 Months ended 31 March 2025	3 Months ended 31 March 2026	3 Months ended 31 March 2025
	₹ million	₹ million	\$'000	\$'000
Oil	684	(4,770)	491	(3,151)
Gas	51,825	40,154	37,450	26,474
Total profit for the period	52,509	35,384	37,941	23,323

	3 Months ended 31 March 2026	3 Months ended 31 March 2025	3 Months ended 31 March 2026	3 Months ended 31 March 2025
Oil	₦ million	₦ million	\$'000	\$'000
Revenue from contracts with customers				
Crude oil sales (Note 7)	1,031,930	1,152,510	745,708	759,821
Cost of sales and general and administrative expenses	(656,700)	(780,052)	(474,557)	(514,276)
Other loss	(133,794)	(68,437)	(96,684)	(45,119)
Operating profit before impairment	241,436	304,021	174,467	200,426
Impairment (loss)/reversal	(359)	426	(260)	281
Fair value loss	(19,137)	(7,652)	(13,829)	(5,045)
Operating profit	221,940	296,795	160,378	195,662
Finance income (Note 13)	4,047	3,968	2,924	2,616
Finance expenses (Note 13)	(64,507)	(49,524)	(46,615)	(32,649)
Profit before taxation	161,480	251,239	116,687	165,629
Income tax expense (Note 14)	(160,796)	(256,009)	(116,196)	(168,780)
Profit/(loss) for the period	684	(4,770)	491	(3,151)

Other loss in the Oil business includes foreign exchange loss and majorly changes in overlift. Note 9 provides details for the combined business.

	3 Months ended 31 March 2026	3 Months ended 31 March 2025	3 Months ended 31 March 2026	3 Months ended 31 March 2025
Gas	₦ million	₦ million	\$'000	\$'000
Revenue from contracts with customers				
Gas sales	61,134	67,492	44,178	44,496
Natural gas liquid	70,381	7,510	50,859	4,951
Cost of sales and general and administrative expenses	(58,259)	(10,443)	(42,100)	(6,884)
Other income	7,387	1,142	5,338	754
Operating profit before impairment	80,643	65,701	58,275	43,317
Impairment loss	(7,177)	(1,236)	(5,186)	(815)
Operating profit	73,466	64,465	53,089	42,502
Share of loss from joint venture accounted for using the equity method	(5,842)	(1,060)	(4,222)	(699)
Profit before taxation	67,624	63,405	48,867	41,803
Income tax expense (Note 14)	(15,799)	(23,251)	(11,417)	(15,329)
Profit for the period	51,825	40,154	37,450	26,474

Impairment losses recognised in the gas segment relate to MSN, Azura, Transcorp, Gereggu Power, Sapele Power and NGMC. See Note 11 for further details.

Other income on the gas segment relates to foreign exchange gains.

The increase in the cost of sales and general and administrative expenses in the gas segment is attributable to Natural gas liquids(NGL) related costs following the increase in NGL production during the period.

6.1.1 Disaggregation of revenue from contracts with customers

The Group derives revenue from the transfer of commodities at a point in time or over time and from different geographical regions.

	3 Months ended 31 March 2026	3 Months ended 31 March 2026	3 Months ended 31 March 2026	3 Months ended 31 March 2026	3 Months ended 31 March 2026	3 Months ended 31 March 2026	3 Months ended 31 March 2026	3 Months ended 31 March 2026
	Oil ₹ million	Gas ₹ million	Natural Gas Liquid ₹ million	Total ₹ million	Oil \$'000	Gas \$'000	Natural Gas Liquid \$'000	Total \$'000
Geographical markets								
France	101,834	—	—	101,834	73,589	—	—	73,589
Indonesia	218,554	—	—	218,554	157,934	—	—	157,934
Japan	—	—	19,353	19,353	—	—	13,985	13,985
Malaysia	93,635	—	—	93,635	67,664	—	—	67,664
Netherlands	77,405	—	—	77,405	55,936	—	—	55,936
Nigeria	44,716	61,134	14,001	119,851	32,313	44,178	10,117	86,608
Portugal	85,394	—	—	85,394	61,708	—	—	61,708
Singapore	305,516	—	37,027	342,543	220,777	—	26,757	247,534
South Africa	26,182	—	—	26,182	18,920	—	—	18,920
Uruguay	78,694	—	—	78,694	56,867	—	—	56,867
Revenue from contracts with customers	1,031,930	61,134	70,381	1,163,445	745,708	44,178	50,859	840,745

Geographical Regions	3 Months ended 31 March 2026	3 Months ended 31 March 2026	3 Months ended 31 March 2026	3 Months ended 31 March 2026	3 Months ended 31 March 2026	3 Months ended 31 March 2026	3 Months ended 31 March 2026	3 Months ended 31 March 2026
	Oil ₹ million	Gas ₹ million	Natural Gas Liquid ₹ million	Total ₹ million	Oil \$'000	Gas \$'000	Natural Gas Liquid \$'000	Total \$'000
Africa	70,898	61,134	14,001	146,033	51,233	44,178	10,117	105,528
Asia	617,705	—	56,380	674,085	446,375	—	40,742	487,117
Europe	264,633	—	—	264,633	191,233	—	—	191,233
Americas	78,694	—	—	78,694	56,867	—	—	56,867
Revenue from contracts with customers	1,031,930	61,134	70,381	1,163,445	745,708	44,178	50,859	840,745

	3 Months ended 31 March 2026	3 Months ended 31 March 2026	3 Months ended 31 March 2026	3 Months ended 31 March 2026	3 Months ended 31 March 2026	3 Months ended 31 March 2026	3 Months ended 31 March 2026	3 Months ended 31 March 2026
	Oil ₹ million	Gas ₹ million	Natural Gas Liquid ₹ million	Total ₹ million	Oil \$'000	Gas \$'000	Natural Gas Liquid \$'000	Total \$'000
Timing of revenue recognition								
At a point in time	1,031,930	—	70,381	1,102,311	745,708	—	50,859	796,567
Over time	—	61,134	—	61,134	—	44,178	—	44,178
Revenue from contracts with customers	1,031,930	61,134	70,381	1,163,445	745,708	44,178	50,859	840,745

	3 Months ended 31 March 2025	3 Months ended 31 March 2025	3 Months ended 31 March 2025	3 Months ended 31 March 2025	3 Months ended 31 March 2025	3 Months ended 31 March 2025	3 Months ended 31 March 2025	3 Months ended 31 March 2025
	Oil ₦ million	Gas ₦ million	Natural Gas Liquid ₦ million	Total ₦ million	Oil \$'000	Gas \$'000	Natural Gas Liquid \$'000	Total \$'000
Geographical markets								
Cote D'Ivoire	75,493	—	—	75,493	49,771	—	—	49,771
France	5,520	—	—	5,520	3,639	—	—	3,639
Germany	109,314	—	—	109,314	72,068	—	—	72,068
Ghana	—	—	7,511	7,511	—	—	4,952	4,952
India	130,219	—	—	130,219	85,850	—	—	85,850
Indonesia	84,885	—	—	84,885	55,962	—	—	55,962
Italy	105,391	—	—	105,391	69,481	—	—	69,481
Malaysia	95,386	—	—	95,386	62,886	—	—	62,886
Netherlands	152,346	—	—	152,346	100,438	—	—	100,438
Nigeria	8,697	67,491	—	76,188	5,732	44,496	—	50,228
Portugal	80,159	—	—	80,159	52,846	—	—	52,846
South Africa	68,230	—	—	68,230	44,983	—	—	44,983
Spain	61,164	—	—	61,164	40,324	—	—	40,324
Turkey	3,372	—	—	3,372	2,223	—	—	2,223
UK	2,158	—	—	2,158	1,423	—	—	1,423
Uruguay	61,877	—	—	61,877	40,794	—	—	40,794
USA	104,941	—	—	104,941	69,185	—	—	69,185
Vietnam	3,358	—	—	3,358	2,214	—	—	2,214
Revenue from contracts with customers	1,152,510	67,491	7,511	1,227,512	759,819	44,496	4,952	809,267
Geographical Regions								
Africa	152,420	67,491	7,511	227,422	100,486	44,496	4,952	149,934
Asia	313,848	—	—	313,848	206,912	—	—	206,912
Europe	519,424	—	—	519,424	342,442	—	—	342,442
Americas	166,818	—	—	166,818	109,979	—	—	109,979
Revenue from contracts with customers	1,152,510	67,491	7,511	1,227,512	759,819	44,496	4,952	809,267
Timing of revenue recognition								
At a point in time	1,152,510	—	7,511	1,160,021	759,819	—	4,952	764,771
Over time	—	67,491	—	67,491	—	44,496	—	44,496
Revenue from contracts with customers	1,152,510	67,491	7,511	1,227,512	759,819	44,496	4,952	809,267

The Group's transactions with its major customers, Shell Western, Vitol S.A, Chevron, and ExxonMobil, constitute about 88% (\$657 million, ₦910 billion) of the total revenue from oil segment and the Group as a whole. Also, the Group's transactions with Egbin Power, Oando, NGMC, MSNE and Azura (\$37 million, ₦50 billion) accounted for most of the revenue from gas segment.

6.1.2 Impairment (losses)/reversal on financial assets by reportable segments

	3 Months ended 31 March 2026			3 Months ended 31 March 2025		
	Oil ₦ million	Gas ₦ million	Total ₦ million	Oil ₦ million	Gas ₦ million	Total ₦ million
Impairment (losses)/reversal recognised during the period	(359)	(7,177)	(7,536)	426	(1,236)	(810)

	3 Months ended 31 March 2026			3 Months ended 31 March 2025		
	Oil \$'000	Gas \$'000	Total \$'000	Oil \$'000	Gas \$'000	Total \$'000
Impairment (losses)/reversal recognised during the period	(260)	(5,186)	(5,446)	281	(815)	(534)

6.2 Segment assets

Segment assets are measured in a manner consistent with that of the financial statements. These assets are allocated based on the operations of the reporting segment and the physical location of the asset. The Group had no non-current assets domiciled outside Nigeria.

	Oil ₦ million	Gas ₦ million	Total ₦ million	Oil \$'000	Gas \$'000	Total \$'000
Total segment assets						
31 March 2026	7,311,578	1,231,779	8,543,357	5,274,490	888,591	6,163,081
31 Dec 2025	7,521,563	1,207,818	8,729,381	5,240,566	841,534	6,082,100

6.3 Segment liabilities

Segment liabilities are measured in a manner consistent with that of the financial statements. These liabilities are allocated based on the operations of the segment.

	Oil ₦ million	Gas ₦ million	Total ₦ million	Oil \$'000	Gas \$'000	Total \$'000
Total segment liabilities						
31 March 2026	5,308,383	658,748	5,967,131	3,829,406	475,213	4,304,619
31 Dec 2025	5,429,717	656,428	6,086,145	3,783,086	457,359	4,240,445

7. Revenue from contract with customers

	3 Months ended 31 March 2026 ₦ million	3 Months ended 31 March 2025 ₦ million	3 Months ended 31 March 2026 \$'000	3 Months ended 31 March 2025 \$'000
Crude oil sales	1,031,930	1,152,510	745,708	759,820
Gas sales	61,134	67,492	44,178	44,496
Natural gas liquids sales	70,381	7,510	50,859	4,951
	1,163,445	1,227,512	840,745	809,267

The major off-takers for crude oil are Shell West, Chevron and ExxonMobil. The major off-takers for gas are Geregu Power, Sapele Power, Nigerian Gas Marketing Company and Azura. The major off-taker for natural gas liquid is ExxonMobil.

8. Cost of Sales

	3 Months ended 31 March 2026	3 Months ended 31 March 2025	3 Months ended 31 March 2026	3 Months ended 31 March 2025
	₦ million	₦ million	\$'000	\$'000
Royalties	161,170	197,531	116,467	130,227
Depletion, Depreciation and Amortisation	186,623	234,338	134,860	154,493
Depreciation of Right of Use Assets	8,782	14,489	6,346	9,552
Crude handling fees	23,658	28,588	17,096	18,847
Nigeria Export Supervision Scheme (NESS) fee	939	–	678	–
Niger Delta Development Commission Levy	16,991	19,565	12,279	12,899
Barging/Trucking	8,965	8,641	6,478	5,697
Operational & Maintenance expenses	243,666	188,927	176,085	124,558
	650,794	692,079	470,289	456,273

Operational & maintenance expenses relate mainly to maintenance costs, including Yoho restoration, personnel costs properly reallocated from G&A, warehouse operations expenses, security expenses, community expenses, clean-up costs, fuel supplies and catering services.

Also included in operational and maintenance expenses is gas flare fees of \$8.7 million, ₦12.0 billion (Q1 2025: \$13.2 million, ₦20 billion) reflecting the early gains on completion of end of routine flaring projects in the onshore business.

Barging and Trucking costs relate to costs on the OML 40 Gbetiokun field.

9. Other loss - net

	3 Months ended 31 March 2026	3 Months ended 31 March 2025	3 Months ended 31 March 2026	3 Months ended 31 March 2025
	₦ million	₦ million	\$'000	\$'000
Overlifts	(127,319)	(81,199)	(92,005)	(53,533)
Realised gain on foreign exchange	4,195	–	3,031	–
Unrealised (loss)/gain on foreign exchange	(4,030)	8,997	(2,912)	5,932
Tariffs	2,213	2,787	1,599	1,837
Others	(1,466)	2,122	(1,059)	1,399
	(126,407)	(67,293)	(91,346)	(44,365)

Overlifts are surplus of crude lifted above the share of production. It may exist when the crude oil lifted by the Group during the period is more than its ownership share of production. The surplus is initially measured at the market price of oil at the date of lifting and recognised as other loss. At each reporting period, the surplus is remeasured at the current market value. The resulting change, as a result of the remeasurement, is also recognised in profit or loss as other loss.

Gain on foreign exchange is principally due to the translation of Naira, Pounds and Euro denominated monetary assets and liabilities.

Tariffs which is a form of crude handling fee, relate to income generated from the use of the Group's pipeline by others.

10. General and administrative expenses

	3 Months ended 31 March 2026	3 Months ended 31 March 2025	3 Months ended 31 March 2026	3 Months ended 31 March 2025
	₹ million	₹ million	\$'000	\$'000
Depreciation and amortisation	1,223	13,267	884	8,747
Depreciation of right of use assets	5,297	2,760	3,828	1,819
Professional & Consulting fees	6,337	5,593	4,579	3,687
Auditor's remuneration	119	59	86	39
Directors Emoluments (Executives)	908	1,133	656	747
Directors Emoluments (Non - Executives)	1,325	1,492	958	984
Employee benefits	24,349	33,881	17,596	22,337
Share-based benefits	6,606	8,812	4,774	5,810
Donation	21	54	15	35
Flights and other travel costs	2,096	5,606	1,514	3,696
Other general expenses	15,884	25,758	11,478	16,983
	64,165	98,415	46,368	64,884

Depreciation expenses now reflect depreciation on non-field related assets.

Employee costs in current period adjust for allocations of production personnel to cost of sales.

Share based benefits includes equity settled share based payment expense of \$3.87 million, ₹5.35 billion (Q1 2025: \$5.81 million, ₹8.81 billion); and cash settled share based payment expense of \$908 thousand, ₹1.26 billion (Q1 2025: Nil)

Included in the other general expenses are repair and maintenance expenses of \$2.09 million ₹2.89 billion (Q1 2025: \$3.58 million, ₹5.43 Billion), dues and subscription of \$2.65 million, ₹3.66 billion (Q1 2025: \$1.58 million, ₹2.4 billion), IT expenses of \$1.33 million, ₹1.84 billion (Q1 2025: \$5.31 million, ₹8,055 million), Contract labor expenses of \$3.43 million, ₹4.75 billion (Q1 2025: \$4.09 million, ₹6 billion) among others.

11. Impairment loss

	3 Months ended 31 March 2026	3 Months ended 31 March 2025	3 Months ended 31 March 2026	3 Months ended 31 March 2025
	₹ million	₹ million	\$'000	\$'000
Impairment losses on financial assets-net (Note 11.1)	(7,536)	(810)	(5,446)	(534)
	(7,536)	(810)	(5,446)	(534)

11.1 Impairment loss on financial assets - net

	3 Months ended 31 March 2026	3 Months ended 31 March 2025	3 Months ended 31 March 2026	3 Months ended 31 March 2025
	₹ million	₹ million	\$'000	\$'000
Impairment (losses)/reversal on:				
NEPL receivables	1,143	426	825	281
Trade receivables (Gas customers) *	(7,238)	(1,236)	(5,230)	(815)
Contract asset	70	-	51	-
Other receivables	(1,511)	-	(1,092)	-
Total impairment loss	(7,536)	(810)	(5,446)	(534)

*Impairment loss on trade receivables relate to Gas customers (Azura, MSN, Transcorp, Sapele Power, NGMC and Geregu Power).

12. Fair value loss

	3 Months ended 31 March 2026	3 Months ended 31 March 2025	3 Months ended 31 March 2026	3 Months ended 31 March 2025
	₦ million	₦ million	\$'000	\$'000
Hedge premium expenses	(10,074)	(3,470)	(7,280)	(2,287)
Fair value loss on derivatives (Note 19)	(9,063)	(4,183)	(6,549)	(2,758)
	(19,137)	(7,653)	(13,829)	(5,045)

Fair value loss on derivatives represents changes in the fair value of hedging receivables charged to profit or loss.

13. Finance income/(cost)

	3 Months ended 31 March 2026	3 Months ended 31 March 2025	3 Months ended 31 March 2026	3 Months ended 31 March 2025
	₦ million	₦ million	\$'000	\$'000
Finance Income				
Interest income	4,047	3,968	2,924	2,616
Finance Charges				
Interest on bank loan	(49,235)	(30,283)	(35,579)	(19,965)
Interest on lease liabilities	(1,888)	(3,766)	(1,365)	(2,483)
Unwinding of discount on provision for decommissioning	(13,384)	(15,475)	(9,671)	(10,202)
	(64,507)	(49,524)	(46,615)	(32,650)
Finance cost - net	(60,460)	(45,556)	(43,691)	(30,034)

Finance income represents interest on short-term fixed deposits.

14. Taxation

The major components of income tax expense for the period ended 31 March 2026 and 2025 are:

	3 Months ended 31 March 2026	3 Months ended 31 March 2025	3 Months ended 31 March 2026	3 Months ended 31 March 2025
	₹ million	₹ million	\$'000	\$'000
Current tax:				
Current tax expense on profit for the period	161,069	313,987	116,394	207,004
Education Tax	–	12,102	–	7,979
Development Levy	15,263	–	11,029	–
Total current tax	176,332	326,089	127,423	214,983
Deferred tax:				
Deferred tax expense in profit or loss (Note 14.1)	263	(46,827)	190	(30,873)
Total tax expense in statement of profit or loss	176,595	279,262	127,613	184,110
Total tax charged for the period	176,595	279,262	127,613	184,110
Effective tax rate	77 %	89 %	77 %	89 %

14.1 Deferred tax

The analysis of deferred tax assets and deferred tax liabilities is as follows:

	Balance as at 1 January 2026	(Charged) / credited to profit or loss	Credited to other comprehensive income	Impact of net off	Exchange difference	Balance as at 31 March 2026
	₹ million	₹ million	₹ million	₹ million	₹ million	₹ million
Deferred tax assets	289,581	(49,233)	–	(1,908)	(9,983)	228,457
Deferred tax liabilities	(1,742,201)	48,970	–	1,908	59,617	(1,631,706)
	(1,452,620)	(263)	–	–	49,634	(1,403,249)

	Balance as at 1 January 2026	(Charged) /credited to profit or loss	Credited to other comprehensive income	Impact of net off	Balance as at 31 March 2026
	\$'000	\$'000	\$'000	\$'000	\$'000
Deferred tax assets	201,762	(35,577)	–	(1,379)	164,806
Deferred tax liabilities	(1,213,860)	35,387	–	1,379	(1,177,094)
	(1,012,098)	(190)	–	–	(1,012,288)

15. Computation of cash generated from operations

		31 March 2026	31 March, 2025	31 March 2026	31 March, 2025
	Notes	₹ million	₹ million	\$'000	\$'000
Profit before tax		229,104	314,646	165,554	207,433
Adjusted for:					
Depletion, depreciation and amortisation		187,847	247,606	135,745	163,241
Depreciation of right-of-use asset		14,079	17,248	10,174	11,371
Impairment loss on financial assets	11.1	7,536	810	5,446	534
Interest income	13	(4,045)	(3,967)	(2,924)	(2,616)
Interest expense on bank loans	13	49,235	30,283	35,579	19,965
Interest on lease liabilities	13	1,890	3,767	1,365	2,483
Unwinding of discount on provision for decommissioning	13	13,383	15,475	9,671	10,202
Fair value loss on derivatives	12	9,063	4,183	6,549	2,758
Hedge premium expenses	12	10,074	3,470	7,280	2,287
Unrealised foreign exchange loss/(gain)	9	4,030	(8,997)	2,912	(5,932)
Share based payment expenses		6,606	8,812	4,774	5,810
Share of loss from joint venture		5,843	1,060	4,222	699
Defined benefit plan		1,064	3,792	770	2,500
Changes in working capital: (excluding the effects of exchange differences)					
Trade and other receivables		(179,042)	(231,125)	(129,382)	(152,374)
Inventories		6,669	13,494	4,819	8,896
Prepayments		9,147	11,851	6,610	7,813
Contract assets		16,956	(11,164)	12,253	(7,360)
Trade and other payables		78,161	43,675	56,482	28,794
Provisions		65	-	47	-
Net cash from operating activities		467,665	464,919	337,946	306,504

16 Oil and gas properties

During the three months ended 31 March 2026, the Group acquired assets amounting to ₦57.9 billion, \$41.8 million (Dec 2025: ₦396 billion, \$261 million)

17. Trade and other receivables

	31 March 2026	31 Dec 2025	31 March 2026	31 Dec 2025
	₦ million	₦ million	\$'000	\$'000
Financial Assets				
Trade receivables (Note 17.1)	472,106	193,504	340,572	134,822
NNPC Exploration Production Limited receivables (Note 17.2)	66,885	121,337	48,250	84,540
NUIMS receivables (Note 17.3)	211,791	289,437	152,783	201,662
Receivables from ANOH(Note 17.5)	5,800	5,029	4,184	3,504
Other receivables (Note 17.4)	57,040	54,008	41,148	37,629
Non-Financial Assets				
Advances to suppliers-others	14,385	9,203	10,377	6,412
Other receivables (Note 17.4)	3,540	2,965	2,554	2,066
Underlift	-	7,603	-	5,297
	831,547	683,086	599,868	475,932

17.1 Trade receivables

Included in the trade receivables are:

	31 March 2026	31 Dec 2025	31 March 2026	31 Dec 2025
	₦ million	₦ million	\$'000	\$'000
Geregu	16,369	17,964	11,808	12,517
Waltersmith	-	3,767	-	2,624
Sapele Power	12,360	12,649	8,917	8,813
NGMC	2,278	373	1,644	260
MSN ENERGY	30,875	21,701	22,273	15,120
Pillar	6,574	13,247	4,742	9,229
Shell Western	52,197	46,839	37,654	32,634
Azura	18,420	3,619	13,288	2,522
Transcorp Power	7,218	7,027	5,207	4,896
Exxon Mobil	365,935	117,798	263,981	82,074
Others - crude injectors	19,044	505	13,738	353
Impairment allowance	(59,164)	(51,985)	(42,680)	(36,220)
Total	472,106	193,504	340,572	134,822

Reconciliation of trade receivables

	31 March 2026 ¥ million	31 Dec 2025 ¥ million	31 March 2026 \$'000	31 Dec 2025 \$'000
Balance as at 1 January	245,492	567,051	171,042	369,337
Additions during the period	1,120,982	3,598,263	810,060	2,506,976
Receipt for the period	(830,081)	(4,108,584)	(599,845)	(2,708,183)
Exchange difference	(5,123)	188,762	1,995	2,912
Gross carrying amount	531,270	245,492	383,252	171,042
Less: Impairment allowance	(59,164)	(51,988)	(42,680)	(36,220)
Balance as at	472,106	193,504	340,572	134,822

Reconciliation of impairment allowance on trade receivables

	31 March 2026 ¥ million	31 Dec 2025 ¥ million	31 March 2026 \$'000	31 Dec 2025 \$'000
Loss allowance as at 1 Jan	51,988	32,134	36,220	20,930
Increase in loss allowance	7,238	21,739	5,230	14,329
Revaluation impact	1,702	–	1,230	961
Exchange difference	(1,764)	(1,885)	–	–
Loss allowance as at	59,164	51,988	42,680	36,220

17.2 NEPL receivables

The outstanding cash calls due to Seplat from its JOA partner, NEPL is \$51.2 million, ¥70.9 billion (Dec 2025: \$88.2 million, ¥126.6 billion).

Reconciliation of NEPL receivables

	31 March 2026 ¥ million	31 Dec 2025 ¥ million	31 March 2026 \$'000	31 Dec 2025 \$'000
Balance as at 1 January	126,606	67,954	88,211	44,260
Addition during the period	84,232	550,220	60,869	383,360
Receipts during the period	(140,795)	(519,088)	(101,743)	(342,160)
Exchange difference	861	27,520	3,812	2,751
Gross carrying amount	70,904	126,606	51,149	88,211
Less: impairment allowance	(4,019)	(5,269)	(2,899)	(3,671)
Balance as at	66,885	121,337	48,250	84,540

Reconciliation of impairment allowance on NEPL receivables

	31 March 2026 ¥ million	31 Dec 2025 ¥ million	31 March 2026 \$'000	31 Dec 2025 \$'000
Loss allowance as at 1 January	5,268	4,339	3,671	2,826
(Decrease)/increase in loss allowance	(1,143)	1,813	(825)	1,195
Foreign exchange revaluation impact	73	–	53	(350)
Exchange difference	(179)	(883)	–	–
Loss allowance as at	4,019	5,269	2,899	3,671

17.3 NUIMS receivables

The outstanding cash calls due to Seplat from its JOA partner, NUIMS is \$152.8 million, ₦211.8 billion (Dec 2025: \$201.7 million, ₦289.4 billion).

Reconciliation of NUIMS receivables

	31 March 2026 ₦ million	31 Dec 2025 ₦ million	31 March 2026 \$'000	31 Dec 2025 \$'000
Balance as at 1 January	289,437	454,571	201,662	296,075
Addition during the period	356,970	1,518,443	257,959	1,057,959
Receipts during the period	(423,707)	(1,755,049)	(306,185)	(1,156,852)
Exchange difference	(10,909)	71,472	(653)	4,480
Gross carrying amount	211,791	289,437	152,783	201,662
Less: impairment allowance	–	–	–	–
Balance as at	211,791	289,437	152,783	201,662

17.4 Other receivables

Reconciliation of other receivables

	31 March 2026 ₦ million	31 Dec 2025 ₦ million	31 March 2026 \$'000	31 Dec 2025 \$'000
Balance as at 1 January	143,037	173,107	99,659	119,118
Addition during the period	34,493	10,586	24,926	6,978
Receipts for the period	(29,325)	(41,828)	(21,191)	(27,571)
Exchange difference	(3,041)	1,172	1,326	1,134
Gross carrying amount	145,164	143,037	104,720	99,659
Less: impairment allowance	(84,584)	(86,064)	(61,018)	(59,964)
Balance as at	60,580	56,973	43,702	39,695

Other receivables includes receivables from 3rd party injectors (tariff income) of \$10.9 million, ₦15.1 billion, employee receivables of \$16.9 million, ₦23.4 billion, advances to Belema for OML 55 crude evacuation of \$3.7 million, ₦5.1 billion, receivable from All Grace for Ubima Disposal of \$16.5 million, ₦22.8 billion, receivable from Naptha for Abiala Marginal field of \$3.2 million, ₦4.4 billion.

Reconciliation of impairment allowance on other receivables

	31 March 2026 ₦ million	31 Dec 2025 ₦ million	31 March 2026 \$'000	31 Dec 2025 \$'000
Loss allowance as at 1 January	86,064	79,667	59,964	58,258
Increase/ (Decrease) in loss allowance during the period	1,511	(2,048)	1,092	(1,349)
Foreign exchange revaluation impact	(53)	–	(38)	3,055
Exchange difference	(2,938)	8,445	–	–
Loss allowance as at	84,584	86,064	61,018	59,964

17.5 Receivables from joint venture (ANOH)

	31 March 2026 ₦ million	31 Dec 2025 ₦ million	31 March 2026 \$'000	31 Dec 2025 \$'000
Balance as at 1 January	9,389	7,253	6,542	4,724
Additions during the period	941	2,544	680	1,677
Exchange difference	(318)	(408)	–	141
Gross carrying amount	10,012	9,389	7,222	6,542
Less: Impairment allowance	(4,212)	(4,360)	(3,038)	(3,038)
Balance as at	5,800	5,029	4,184	3,504

Reconciliation of impairment allowance on receivables from joint venture (ANOH)

	31 March 2026 ₦ million	31 Dec 2025 ₦ million	31 March 2026 \$'000	31 Dec 2025 \$'000
Loss allowance as at 1 January	4,360	4,664	3,038	3,038
Increase in loss allowance during the period	–	–	–	–
Exchange difference	(148)	(304)	–	–
Loss allowance as at	4,212	4,360	3,038	3,038

18. Contract assets

	31 March 2026 ₦ million	31 Dec 2025 ₦ million	31 March 2026 \$'000	31 Dec 2025 \$'000
Revenue on gas sales	8,051	17,307	5,808	12,058
Revenue on oil sales	5,449	14,316	3,931	9,974
Impairment allowance	(2,324)	(2,464)	(1,677)	(1,717)
	11,176	29,159	8,062	20,315

A contract asset is an entity's right to consideration in exchange for goods or services that the entity has transferred to a customer. The Group has recognised an asset in relation to a contract with Sapele Power, Azura, NGMC, Transcorp Power, MSN Energy, Waltersmith and Pillar for the delivery of oil and gas supplies which these customers have received but which has not been invoiced as at the end of the reporting period.

The terms of payments relating to the contract is between 30– 45 days from the invoice date. However, invoices are raised after delivery between 14–21 days when the receivable amount has been established and the right to the receivables crystallises. The right to the unbilled receivables is recognised as a contract asset. At the point where the gas receipt certificates and crude invoices are obtained from the customers (Sapele Power, Azura, NGMC, Transcorp Power, Egbin Power, MSN Energy, Waltersmith and Pillar) upon volumes reconciliation with offtakers authorising the quantities, this will be reclassified from contract assets to trade receivables.

18.1 Reconciliation of contract assets

The movement in the Group's contract assets is as detailed below:

	31 March 2026 ₦ million	31 Dec 2025 ₦ million	31 March 2026 \$'000	31 Dec 2025 \$'000
Balance as at 1 January	31,623	24,173	22,032	15,745
Additions during the period	127,658	642,386	92,250	423,433
Amount billed during the period	(145,120)	(634,779)	(104,869)	(418,419)
Foreign exchange revaluation impact	452	–	326	1,273
Exchange difference	(1,113)	(157)	–	–
Gross contract asset	13,500	31,623	9,739	22,032
Impairment allowance	(2,324)	(2,464)	(1,677)	(1,717)
Balance as at	11,176	29,159	8,062	20,315

19. Derivative financial instruments

The Group uses its derivatives for economic hedging purposes and not as speculative investments. Derivatives are measured at fair value through profit or loss. They are presented as current liability to the extent they are expected to be settled within 12 months after the reporting period.

The fair value has been determined using a proprietary pricing model which generates results from inputs. The market inputs to the model are derived from observable sources. Other inputs are unobservable but are estimated based on the market inputs or by using other pricing models.

19.1 Derivative financial assets

	31 March 2026 ₹ million	31 Dec 2025 ₹ million	31 March 2026 \$'000	31 Dec 2025 \$'000
Opening balance	17,352	–	12,090	–
Movement within the year	(10,074)	18,342	(7,280)	12,090
Exchange difference	(610)	(990)	–	–
Closing balance	6,668	17,352	4,810	12,090

19.2 Derivative financial liabilities

	31 March 2026 ₹ million	31 Dec 2025 ₹ million	31 March 2026 \$'000	31 Dec 2025 \$'000
Opening balance	(9,041)	(6,073)	(6,299)	(3,955)
Realised fair value (Note12)	8,717	(3,886)	6,299	(2,562)
Prior year premium paid	–	330	–	218
Unrealised fair value (Note12)	(17,780)	–	(12,848)	–
Exchange difference	293	588	–	–
Closing balance	(17,811)	(9,041)	(12,848)	(6,299)

20. Cash and cash equivalents

Cash and cash equivalents in the statement of financial position comprise of cash at bank, cash on hand and short-term deposits with a maturity of three months or less.

	31 March 2026	31 Dec 2025	31 March 2026	31 Dec 2025
	₦ million	₦ million	\$'000	\$'000
Short-term fixed deposits	30	69	21	24
Cash at bank	640,298	477,253	461,906	332,547
Gross cash and cash equivalents	640,328	477,322	461,927	332,571
Loss allowance	(340)	(352)	(245)	(245)
Net cash and cash equivalents	639,988	476,970	461,682	332,326

20.1 Reconciliation of impairment allowance on cash and cash equivalents

	31 March 2026	31 Dec 2025	31 March 2026	31 Dec 2025
	₦ million	₦ million	\$'000	\$'000
Loss allowance as at 1 January 2026	352	376	245	245
Increase/ (decrease) in loss allowance during the period	–	–	–	–
Exchange difference	(12)	(24)	–	–
Loss allowance as at	340	352	245	245

20.2 Restricted cash

	31 March 2026	31 Dec 2025	31 March 2026	31 Dec 2025
	₦ million	₦ million	\$'000	\$'000
Restricted cash	177,609	181,347	128,125	126,351
	177,609	181,347	128,125	126,351

20.3 Movement in restricted cash

	31 March 2026	31 Dec 2025	31 March 2026	31 Dec 2025
	₦ million	₦ million	\$'000	\$'000
Opening balance	181,347	202,983	126,351	132,209
Increase/(decrease) in restricted cash	2,455	(8,887)	1,774	(5,858)
Exchange difference	(6,193)	(12,749)	–	–
Closing balance	177,609	181,347	128,125	126,351

Included in the restricted cash is \$119.9 million, ₦166.2 billion (Dec 2025: \$119.5 million, ₦171.5 billion), which relates to SEPNU's decommissioning and abandonment deposit of \$103.4 million, ₦143.5 billion, as well as the host community fund of \$16.5million, ₦22.9 billion.

Also included in the restricted cash balance is \$2.8 million, ₦3.9 billion (Dec 2025: \$2.4 million, ₦3.5 billion) and \$4.3 million, ₦6.0 billion (Dec 2025: \$3.4 million, ₦4.9 billion) set aside in the stamping reserve account and debt service reserve account respectively for the revolving credit facility. The stamping reserve amount is to be used for the settlement of all fees and costs payable for the purposes of stamping and registering the Security Documents at the stamp duties office and at the Corporate Affairs Commission (CAC).

A garnishee order of \$0.6 million, ₦0.8 billion (Dec 2025: \$0.6 million, ₦804.9 million) is included in the restricted cash balance as at the end of the reporting period.

Also included in the restricted cash balance is \$0.5 million, ₦0.7 billion (Dec 2025: \$0.4 million, ₦0.6 billion) for unclaimed dividend.

The movement in the restricted cash during the period is movement due to increase in the debt service reserve accounts.

These amounts are subject to legal restrictions and are therefore not available for general use by the Group.

21. Share capital

21.1 Authorised and issued share capital

	31 March 2026	31 Dec 2025	31 March 2026	31 Dec 2025
	₦ million	₦ million	\$'000	\$'000
Authorised ordinary share capital				–
599,944,561 (Dec. 2025: 599,944,561) issued shares denominated in Naira of 50 kobo per share	300	300	1,868	1,868
Issued and fully paid				
599,944,561 (Dec. 2025: 599,944,561) issued shares denominated in Naira of 50 kobo per share	300	300	1,868	1,868

Fully paid ordinary shares carry one vote per share and the right to dividends. There were no restrictions on the Group's share capital.

21.2 Movement in share capital and other reserves

	Number of shares	Issued share capital	Share premium	Share based payment reserve	Treasury shares	Capital contribution	Retained earnings	Foreign Currency Reserves	Total
	Shares	₦ million	₦ million	₦ million	₦ million	₦ million	₦ million	₦ million	₦ million
Opening balance as at 1 January 2026	599,944,561	300	150,802	24,985	(100,270)	5,932	342,409	2,198,082	2,622,240
Profit for the period	–	–	–	–	–	–	46,763	–	46,763
Other Comprehensive income	–	–	–	–	–	–	–	(76,893)	(76,893)
Share based payments	–	–	–	5,349	–	–	–	–	5,349
Share repurchased	–	–	–	–	(34,596)	–	–	–	(34,596)
Closing balance as at 31 March 2026	599,944,561	300	150,802	30,334	(134,866)	5,932	389,172	2,121,189	2,562,863

	Number of shares	Issued share capital	Share premium	Share based payment reserve	Treasury shares	Capital contribution	Retained Earnings	Foreign Currency Translation Reserve	Total
	Shares	\$'000	\$'000	\$'000	\$'000	\$'000	\$'000	\$'000	\$'000
Opening balance as at 1 January 2026	599,944,561	1,868	560,371	42,961	(69,350)	40,000	1,248,293	2,887	1,827,030
Profit for the period	–	–	–	–	–	–	33,789	–	33,789
Share based payments	–	–	–	3,866	–	–	–	–	3,866
Share repurchased	–	–	–	–	(25,000)	–	–	–	(25,000)
Closing balance as at 31 March 2026	599,944,561	1,868	560,371	46,827	(94,350)	40,000	1,282,082	2,887	1,839,685

21.3 Employee share-based payment scheme

As at 31 March 2026, the Group had 49,999,973 shares (Dec 2025: 49,999,973 shares), which are yet to fully vest. These shares have been assigned to certain employees and senior executives in line with its share-based incentive scheme.

During the three months ended 31 March 2026, no new shares were vested (Dec 2025: 13,342,715 shares).

22. Interest bearing loans and borrowings

22.1 Reconciliation of interest bearings loans and borrowings

Below is the reconciliation on interest bearing loans and borrowings for Q1 2026:

	Borrowings within 1 year ₦ million	Borrowings above 1 year ₦ million	Total ₦ million	Borrowings within 1 year \$'000	Borrowings above 1 year \$'000	Total \$'000
Balance as at 1 January 2026	104,154	1,339,135	1,443,289	72,568	933,028	1,005,596
Interest accrued	49,235	–	49,235	35,579	–	35,579
Interest repayment	(51,037)	–	(51,037)	(36,881)	–	(36,881)
Other financing charges	(15,280)	–	(15,280)	(11,042)	–	(11,042)
Transfers	16,988	(16,988)	–	12,276	(12,276)	–
Exchange differences	(3,560)	(45,786)	(49,346)	–	–	–
Carrying amount as at 31 March 2026	100,500	1,276,361	1,376,861	72,500	920,752	993,252

Other financing charges relate to commitment fees and other transaction costs incurred in refinancing of the \$400 million Revolving Credit Facility.

Below is the reconciliation on interest bearing loans and borrowings for 31 December 2025:

	Borrowings within 1 year ₦ million	Borrowings due above 1 year ₦ million	Total ₦ million	Borrowings within 1 year \$'000	Borrowings above 1 year \$'000	Total \$'000
Balance as at 1 January 2025	690,270	1,409,480	2,099,750	449,593	918,036	1,367,629
Additions	–	953,106	953,106	–	628,246	628,246
Interest accrued	213,239	–	213,239	140,558	–	140,558
Principal paid	(1,562,982)	–	(1,562,982)	(1,030,250)	–	(1,030,250)
Interest repayment	(152,600)	–	(152,600)	(100,587)	–	(100,587)
Transfers	930,362	(930,362)	–	613,254	(613,254)	–
Exchange differences	(14,135)	(93,089)	(107,224)	–	–	–
Carrying amount as at 31 Dec 2025	104,154	1,339,135	1,443,289	72,568	933,028	1,005,596

22.2 Amortised cost of borrowings

	31 March 2026 ₦ million	31 Dec 2025 ₦ million	31 March 2026 \$'000	31 Dec 2025 \$'000
\$650 million Senior notes – April 2021	881,418	932,497	635,845	649,707
\$80 million Senior reserve based lending (RBL) facility	76,371	76,796	55,093	53,507
\$300 million Advance Payment Facility	419,072	433,996	302,314	302,382
	1,376,861	1,443,289	993,252	1,005,596

\$650 million Senior notes

On 21 March 2025, the Group refinanced the \$650m notes due 2026 with a new \$650m issuance maturing in 2030. The newly issued \$650m notes due in 2030 carry a coupon rate of 9.125%, reflecting prevailing global market volatility. The \$650 million bond issuance was used exclusively to redeem the maturing \$650 million note, with transaction costs covered from the Company's cash reserves. The amortised cost for the senior notes as at the reporting period is \$635.8 million, ₺881.4 billion (Dec 2025: \$649.7 million, ₺932.5 billion) although the principal is \$650 million.

\$80 million Senior reserve-based lending (RBL) facility - refinanced facility

On 30 September 2025, the Group, through its subsidiary Westport, successfully completed the refinancing of the Westport RBL Facility. The new facility is an \$80M RBL facility with Standard Bank (USD 35 million), Mauritius Commercial Bank (USD 25 million), First City Monument Bank (USD 12 million), and Zenith Bank (USD 8 million). Zenith Bank represents a new participant in this financing.

The refinancing resulted in improved pricing terms, with the facility now carrying a margin of 6.5% for the first three years, increasing to 7.0% from year four onwards should the facility remain drawn. These margins are more favourable than those under the previous senior (8.0% plus a CAS of 0.25%) and junior (10.5% plus a CAS of 0.25%) facilities. The final maturity date is five years from the effective date, with an 18-month moratorium on principal repayments. The amortised cost for the senior notes as at the reporting period is \$55.1 million, ₺76.4 billion (Dec 2025: \$53.5 million, ₺76.7 billion)

\$50 million Reserved based lending (RBL) facility

The \$50M junior offtake facility was fully repaid and cancelled on 25 August 2025. The facility was only drawn to \$11M and had a headroom of \$26.5M.

\$400 million Revolving credit facility

The RCF was fully drawn for the completion of the MPNU transaction in December 2024, \$250m was prepaid on 31 March 2025, and the remaining \$100m was prepaid on 28 July 2025. The amortised cost for the RCF as at the reporting period is nil (Dec 2025: nil). The RCF was subsequently refinanced to \$400 million on January 31, 2026. Margins were improved to 4.5% from 5.26% (including a credit adjustment spread). The maturity was also extended to 30 September 2029, maturing before the \$650 million senior notes.

\$300 million Advance payment facility

On 6 December 2024, Seplat Energy Offshore Limited entered into an Advance Payment Facility ("APF") of up to \$300 million with ExxonMobil Financial Investment Company Limited ("EMFICL"), a fully owned subsidiary of ExxonMobil. The APF can be used for general corporate purposes and was used to provide financing in the completion of the MPNU acquisition. The APF is currently fully drawn and bears interest at a rate of the aggregate of Term SOFR (including a credit adjustment spread of 0.25% per annum) plus 5% per annum.

Final maturity is three years following the date of the agreement, i.e., December 2027. EMFICL concluded the syndication of the APF on 30 May 2025 when four additional bank lenders entered the financing, namely, First Abu Dhabi Bank (\$100M), Standard Bank (\$75M), Mauritius Commercial Bank (\$50M) and Rand Merchant Bank (\$45M). The amortised cost for the APF as at the reporting period is \$302.3 million, ₺419.1 billion (Dec 2025: \$302.3 million, ₺433.9 billion), although the principal is \$300 million

23. Employee benefit obligation

23.1 Defined benefit plan

During the reporting period, the defined benefit plan was presented as a net defined benefit liability of \$2.69 million, ₺3.7 billion (Dec. 2025: \$2.7 million, ₺3.9 billion).

	31 March 2026	Movement during the period	31 Dec 2025	31 March 2026	Movement during the period	31 Dec 2025
	₺ million	₺ million	₺ million	\$'000	\$'000	\$'000
Net defined benefit (assets)/liabilities recognised in the financial position						
Present value of defined benefit obligation	97,514	(2,719)	100,233	70,345	509	69,836
Fair value of plan assets	(93,776)	2,553	(96,329)	(67,648)	(532)	(67,116)
	3,738	(166)	3,904	2,697	(23)	2,720

	Movement during the period	Movement during the period
	₺ million	\$'000
Movement during the period for the defined benefit (assets)/liabilities:		
Opening balance	3,904	2,720
Current service cost	591	427
Interest income	(308)	(222)
Revaluation	(449)	(228)
Closing balance	3,738	2,697

24. Trade and other payables

	31 March 2026 ₦ million	31 Dec 2025 ₦ million	31 March 2026 \$'000	31 Dec 2025 \$'000
Financial Liabilities				
Trade payable	620,068	740,168	447,310	515,704
Accruals and other payables	497,202	462,903	358,673	322,512
Non-Financial Liabilities				
Share based payment liability	4,377	3,229	3,158	2,250
NDDC levy	37,548	17,917	27,087	12,483
Royalties payable	76,289	86,025	55,034	59,937
Overlift	112,860	–	81,416	–
	1,348,344	1,310,242	972,678	912,886

Included in accruals and other payables are field accruals of \$99.8 million, ₦138.6 billion (Dec. 2025: \$101.8 million, ₦146.1 billion), deposit received for asset held for sale of \$9.5 million, ₦13.2 billion (Dec. 2025: \$9.9 million, ₦14.3 billion) and other vendor payables of \$249.4 million, ₦346.2 billion (Dec. 2025: \$210 million, ₦301.4 billion). Royalties payable include accruals in respect of crude oil and gas production for which payment is outstanding at the end of the period.

Overlifts are excess crude lifted above the share of production. It may exist when the crude oil lifted by the Group during the period is above its ownership share of production. Overlifts are initially measured at the market price of oil at the date of lifting and recognised in profit or loss. At each reporting period, overlifts are remeasured at the current market value. The resulting change, as a result of the remeasurement, is also recognised in profit or loss and any amount unpaid at the end of the year is recognised in overlift payable.

25. Earnings per share (EPS)

Basic

Basic EPS is calculated on the Group's profit after taxation attributable to the parent entity, which is based on the weighted average number of issued and fully paid ordinary shares at the end of the period.

Diluted

Diluted EPS is calculated by dividing the profit after taxation attributable to the parent entity by the weighted average number of ordinary shares outstanding during the period plus all the dilutive potential ordinary shares (arising from outstanding share awards in the share-based payment scheme) into ordinary shares.

	31 March 2026 ₦ million	31 March 2025 ₦ million	31 March 2026 \$'000	31 March 2025 \$'000
Profit attributable to Equity holders of the parent	46,763	30,679	33,789	20,221
Profit attributable to Non-controlling interests	5,746	4,705	4,152	3,102
Profit for the period	52,509	35,384	37,941	23,323

	Shares '000	Shares '000	Shares '000	Shares '000
Weighted average number of ordinary shares in issue	599,945	588,445	599,945	588,445
Weighted average number of ordinary shares adjusted for the effect of dilution	599,945	588,445	599,945	588,445

*There were no shares issued during the period that could potentially dilute the earnings per share

	₦	₦	\$	\$
Basic earnings per share for the period				
Basic earnings per share	77.95	52.14	0.06	0.03
Diluted earnings per share	77.95	52.14	0.06	0.03
Profit used in determining basic/diluted earnings per share	46,763	30,679	33,789	20,221

The weighted average number of issued shares was calculated as a proportion of the number of months in which they were in issue during the reporting period.

26. Proposed dividend

For the three months ended 31 March 2026, the Group's directors proposed an interim dividend of 5.0 cents per share and a special dividend of 4.0 cents share for the reporting period (1Q 2025: 4.6 cents per share).

27. Related party relationships and transactions

The Group is controlled by Seplat Energy Plc (the parent Company).

During the period, Heirs Energies and Heirs Holding Limited acquired 20.07% of the issued share capital of the Seplat Energy PLC. These entities are controlled by Mr Tony O Elumelu CFR. He was appointed to the Board effective 22 January 2026. The remaining shares in the parent Company are widely held.

The following are details of transactions and balances with related parties. The terms of these transactions are at arm's length.

1. Entities controlled by Directors of the Group

United Bank for Africa: Mr. Tony Elumelu is a Director and shareholder of United Bank for Africa Plc ('UBA'). UBA provides the Group with joint venture-related banking services, financing, and direct banking support. The bank is also one of the Group's lenders under the \$400 million, ₦554.5 billion revolving credit facility ('RCF'), which remained undrawn as at the reporting date. At the end of the reporting period, the Group held balances of \$120.5 million, ₦167 billion with UBA, comprising joint venture and corporate balances.

Transcorp Power Limited: During the period, the Group engaged in gas sales transactions with Transcorp Power Limited, an entity controlled by a Director of the Group (Mr. Tony Elumelu), amounting to \$381 thousand, ₦527 million. As at the reporting date, amounts due from Transcorp Power Limited was \$5.2 million, ₦7.2 billion.

Transcorp Hotel Plc: Transcorp Hotels Plc is an entity controlled by a Director of the Group (Mr. Tony Elumelu). During the period, Transcorp Hotels Plc provided hospitality services to the Group, with services rendered amounting to \$116 thousand, ₦160.5 million. The Group had no outstanding balance with Transcorp Hotels Plc as at the reporting date.

28. Commitments and contingencies

28.1 Contingent liabilities

The Group is involved in a number of legal suits as defendant. The estimated value of the contingent liabilities for the period ended 31 March 2026 is \$332.55 million, ₦460.98 billion (Dec 2025: \$275.75 million, ₦395.77 billion). The contingent liability for the period is determined based on possible occurrences, though unlikely to occur. No provision has been made for this potential liability in these financial statements. Management and the Group's solicitors are of the opinion that the Group will suffer no loss from these claims.

29. Events after the reporting period

There was no event after the reporting period which could have a material effect on the disclosures and the financial position of the Group as at 31 March 2026 and on its profit or loss and other comprehensive income for the period ended.

30. Exchange rates used in translating the accounts to Naira

The table below shows the exchange rates used in translating the accounts into Naira

		31 March 2026	31 March 2025	31 Dec. 2025
	Basis	N/\$	N/\$	N/\$
Property, plant & equipment – opening balances	Historical rate	1435.26	1,535.32	899.39
Property, plant & equipment – additions	Average rate	1,383.83	1,516.82	1,517.09
Property, plant & equipment - closing balances	Closing rate	1,386.22	1536.32	1435.26
Current assets	Closing rate	1,386.22	1536.32	1435.26
Current liabilities	Closing rate	1,386.22	1536.32	1435.26
Equity	Historical rate	Historical	Historical	Historical
Income and Expenses:	Overall Average rate	1,383.83	1,516.82	1,517.09