



Unaudited results for the nine months ended 30 September 2026

29 October 2026

Reliable energy,
limitless potential

A large, stylized green outline of the letter 'S' that curves around the bottom and right sides of the page, framing the text.

Interim Management Report

Lagos and London, 29 October 2026: Seplat Energy Plc (“Seplat Energy” or “the Company”), a leading Nigerian independent energy company listed on both the Nigerian Exchange Group and the London Stock Exchange, announces its unaudited results for the nine months ended 30 September 2026.

Summary

Strong production and price realisations delivered 9M 2026 free cash flow of \$749 million, further improving net leverage to c.0.14x TTM Net Debt/EBITDA, and underpinning increased distributions. 3Q 2026 dividend raised by 58% sequentially to USD 19.0 cents/share, reflects the strong operational and financial performance.

Operational highlights

- 9M 2026 working interest production averaged 144,999 boepd up 7% from 9M 2025 (135,636 boepd) with Onshore up 22%.
- 3Q 2026 working interest production averaged 155,801 boepd, up 13% YoY from 3Q 2025 (137,888 boepd) and up 5% sequentially.
- ANOH initial debt principal repayments completed during 3Q. First commercial gas sold via OB3 pipeline in September.
- Offshore, idle well restoration programme continued its strong performance, adding 33.7 kbopd and 176 MMscf/d gross JV production capacity YTD from 41 wells. Of the 41 wells restored YTD, 4 are gas wells.
- Post period end, discovery of oil and gas across five reservoir intervals in the Aku-01 exploration well, in PPL 2A25. Discovery de-risks four prospects on the license, one of which will be tested in a second exploration well that is now being planned for 2027.
- Carbon emissions intensity for the group: 37.4 kg CO₂/boe 14% lower YoY (9M 2025: 43.6 kg CO₂/boe). Onshore operated emissions intensity reduced 34% YoY, reflecting the continued positive impact of our End of Routine Flaring programme.

Financial highlights

- Revenue \$2,764 million up 27% on prior year (9M 2025: \$2,177 million). 9M 2026 average realised oil price \$96.19/bbl, an \$8.12/bbl premium to average Brent price, 3Q 2026 average realised oil price of \$100.44/bbl, a \$10.21/bbl premium to average Brent price.
- Adjusted EBITDA of \$1,530 million, up 38% on prior year (9M 2025: \$1,111.9 million).
- Net income increased to \$260.2 million, up 174% YoY. Earnings per share USD 42 cents, up 172% YoY (9M 2025: USD 16 cents).
- Cash generated from operations of \$1,478.7 million, up 6% on prior year (9M 2025: \$1,395.4 million).
- Balance sheet remains strong, end-Sept cash at bank \$556.9 million (FY 2025: \$332.3 million).
- Net Debt at end-Sept of \$234.9 million down 65% since YE 2025 (\$673.3 million). Net Debt/EBITDA improves to 0.14x from 0.53x at YE 2025.
- On 27 October, the Company repaid the \$100 million balance on the APF. As such, all debt raised to acquire MPNU in 2024 has been repaid.

Corporate Update & 2026 Outlook

- Sale of a 10% interest in NNPC-SEPNU JV to NNPC Ltd expected to complete during 4Q 2026. As previously disclosed, following completion, the Company intends to pay a Transaction dividend of approximately half the consideration (USD 23.3 cents/share, \$140 million).
- 3Q 2026 declared dividend of USD 19.0 cents/share (\$114 million), consisting of USD 5.0 c/shr core and USD 14.0 c/shr special dividend. Total dividend declared YTD USD 40.0 cents/share. FY 2026 dividend guidance of \$270 million (USD 45.0 cents/share), is retained.
- 2026 guidance updated to reflect progress year to date:
 - Production guidance narrowed to the upper end at 145-155 kboepd (from 135-155 kboepd), reflecting strong YTD performance.
 - Capex guidance lowered to \$280-\$340 million (from \$360-\$440 million), primarily due to phasing, given the late arrival of the offshore rig.
 - Unit operating cost guidance increased to \$15.5-\$16.5/boe (from \$14.5-\$15.5/boe), due to ongoing costs related to Yoho.

Effiong Okon, Chief Executive Officer, said:

“In my first update as CEO, I am delighted to report another quarter of robust production growth, averaging over 155 kboepd in 3Q 2026, which puts us firmly on track to meet the upper half of our full year guidance. This was delivered in a period of continued high crude prices, we realised \$100.4/bbl in the quarter, a full \$10.2/bbl higher than the average Brent price in the period, further enhancing our results.

Operationally, in our Onshore business, we achieved record gas production levels in the quarter, supported by continued solid ANOH ramp-up alongside strong performance on our Western assets, and we have clear line of sight to continued growth that will be underpinned by operational excellence as offshore gas production comes back online. Yoho restoration project was completed during the quarter, although start-up has been delayed due to pipeline damage that was identified and is being repaired, production is expected online in 4Q 2026. I’m pleased to announce exploration success at Aku-01, a strong reminder of our rich portfolio of prospects and the quality of the subsurface in Nigeria.

Our strong financial performance supports the interim dividend payment of USD 19.0 cents per share. When paid, the 3Q 2026 dividend will lift cumulative dividends declared since our IPO to over \$1.0 billion, and we are firmly on track to return our second \$1.0 billion to shareholders as we deliver on our 5 year plan. A clear demonstration of the financial robustness of our business.

As I take on the responsibilities of leading Seplat into its next phase of growth, based on my engagements in the first three months on the job, I am inspired by the quality of our people, excited with the depth of portfolio growth opportunities and encouraged by the strength of our balance sheet. We are making significant progress on integration, and multiple initiatives are underway to further enhance our operational capabilities. With these foundations in place, I believe that we are well positioned to deliver substantial growth, further reinforcing our position as a leading energy provider in Nigeria, a region of increasing strategic importance to global energy markets.”

Summary of performance

	\$ million			₦ billion	
	9M 2026	9M 2025	% change	9M 2026	9M 2025
Revenue	2,763.5	2,176.6	27 %	3,776.1	3,356.2
Gross profit	1,188.3	879.5	35 %	1,623.8	1,356.0
Adjusted EBITDA *	1,529.9	1,111.9	38 %	2,090.5	1,714.5
Operating profit	1,067.4	711.0	50 %	1,458.5	1,096.2
Profit after tax	260.2	95.1	174 %	355.6	146.6
Cash generated from operations	1,478.7	1,395.4	6 %	2,020.5	2,151.5
Working interest production (boepd)	144,999	135,636	7 %		
Volumes lifted (MMbbls)	25.7	27.9	(8)%		
Average realised oil price (\$/bbl)	96.19	71.93	34 %		
Average realised gas price (\$/Mscf)	3.18	2.95	8 %		
Average realised NGL price (\$/bbl)	48.48	46.64	4 %		
LTIF - Operated assets	—	0.04	(100)%		
CO ₂ emissions intensity from operated assets, kg/boe	37.4	43.6	(14)%		

* 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 as stipulated under Market Abuse Regulations. Upon the publication of this announcement via Regulatory Information Services, 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
Edith Onwuchekwa, Director, Legal/Company Secretary	
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
-------------------------------	------------------

Canaccord Genuity Limited

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

Peel Hunt LLP

Richard Crichton / David McKeown / Georgia Langoulant	+44 207 418 8900
---	------------------

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, the majority of 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 nine months ended 30 Sept 2026

Asset	Seplat WI %	9 months ended 30 Sept 2026				9 months ended 30 Sept 2025			
		Crude & Condensate bopd	Gas MMscfd	NGLs bopd	Total boepd	Crude & Condensate bopd	Gas MMscfd	NGLs bopd	Total boepd
Western Assets	45 %	16,811	126.2	33	38,606	16,921	132.5	—	39,763
Elcrest	45 %	14,440	—	—	14,440	11,142	—	—	11,142
Eastern Assets	40 %	3,352	—	—	3,352	2,828	—	—	2,828
ANOH	40 %	2,422	41.0	15	9,499	—	—	—	—
Newton	40 %	1,547	—	—	1,547	1,566	—	—	1,566
Seplat Onshore		38,572	167.2	48	67,445	32,457	132.5	—	55,298
OMLs 67, 68, 70, 104	40 %	63,879	17.1	8,175	75,009	68,623	30.3	3,719	77,562
OML 99 (A/K Field)	9.6 %	721	10.6	—	2,545	712	12.0	—	2,775
Seplat Offshore		64,600	27.7	8,175	77,554	69,335	42	3,719	80,337
Total		103,173	194.9	8,222	144,999	101,793	174.7	3,719	135,636

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

Gas conversion factor of 5.8 Mscf per boe

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

A/K Field refers to Amenam-Kpono field

ANOH production contribution represents Seplat's upstream equity interest production. This sold product mix is used to calculate upstream wet gas revenue due to Seplat from AGPC.

In 9M 2026, average daily working interest production for the group increased by 7% to 144,999 boepd (9M 2025: 135,636 boepd), in-line with the midpoint of the guidance range.

Our Onshore assets delivered strong production growth, up 22% YoY to 67,445 boepd (9M 2025: 55,298 boepd) driven by steadily improving production output from ANOH, contributions from new wells brought onstream through the 2025 drilling programme in Elcrest, and reduced production deferrals across the Western assets during 2Q and 3Q 2026. Offshore assets average daily working interest production in the first 9 months of the year declined by 3% to 77,554 boepd (9M 2025: 80,337 boepd). While technical completion of the Yoho restoration project has been achieved, restart has been deferred to 4Q 2026, details discussed below. In addition, commercial gas sales offshore were suspended during 3Q pending completion of the planned sectional replacement of the accidentally damaged Oso-BRT pipeline, which is planned for end 2026.

Production deferrals on the Onshore assets were 22% in 9M 2026 (9M 2025: 21%), reflecting the elevated deferrals recorded in 1Q 2026 following the unplanned TFP outage. Operational performance improved significantly thereafter, with deferrals reducing to 15% in 2Q and further to 14% in 3Q 2026. Offshore deferrals also improved to 16% in 9M 2026, from 20% in 9M 2025, benefiting from continuous investment in asset integrity and reliability.

Working interest production for the three months ended 30 September 2026

Asset	Seplat WI %	3Q 2026				2Q 2026				1Q 2026			
		Crude & Cond kbopd	Gas MMscfd	NGLs kbopd	Total kboepd	Crude & Cond kbopd	Gas MMscfd	NGLs kbopd	Total kboepd	Crude & Cond kbopd	Gas MMscfd	NGLs kbopd	Total kboepd
Western Assets	45 %	19.0	142	0.1	43.6	19.0	132	—	41.7	12.4	105	—	30.4
Elcrest	45 %	16.3	—	—	16.3	14.3	—	—	14.3	12.6	—	—	12.6
Eastern Assets	40 %	3.9	—	—	3.9	3.2	—	—	3.2	3.0	—	—	3.0
ANOH	40 %	4.0	66	—	15.3	2.8	40	—	9.7	0.4	17	—	3.3
Newton	40 %	1.6	—	—	1.6	1.7	—	—	1.7	1.4	—	—	1.4
Seplat Onshore		44.8	208	0.1	80.7	41.0	171	—	70.6	29.8	122	—	50.7
OMLs 67, 68, 70, 104	40 %	64.7	—	7.6	72.3	65.0	23	7.1	76.1	61.9	29	9.8	76.7
OML 99 (A/K Field)	9.6 %	0.9	11	—	2.8	0.7	10	—	2.4	0.5	11	—	2.4
Seplat Offshore		65.6	11	7.6	75.1	65.7	33	7.1	78.5	62.4	40	9.8	79.1
Total		110.4	219	7.8	155.8	106.8	204	7.1	149.1	92.2	162	9.8	129.8

Group average daily working interest production in 3Q 2026 grew by 5% QoQ to 155,801 boepd (2Q 2026: 149,070 boepd), reflecting strong operational performance, particularly on the Onshore Assets. Onshore production grew by 14% compared to the prior quarter, driven by improved performance on our Western Assets and Elcrest, and the continued ramp up at ANOH. Offshore production decreased by 4% QoQ reflecting the impact of the Oso-BRT pipeline leakage due to accidental third party damage, which curtailed NGL and gas production, and the delayed restart of Yoho production, which continued to impact crude production.

HSE Performance

While our operated assets delivered another LTI-free quarter, tragically, a marine-related fatality occurred on 27 September 2026 at Gbetiokun, a non-operated asset within the Elcrest joint venture. An investigation is underway, and further information will be provided upon its conclusion. The incident serves as a stark reminder of the risks associated with our operations and reinforces our continued focus on safety leadership, risk management and the protection of our workforce and contractors across both operated and non-operated assets.

Across our operated assets, we recorded 10.68 million LTI-free man-hours during the quarter and 29.44 million year-to-date.

LTI-Free hours worked	3Q 2026	2Q 2026	1Q 2026	9M 2026	Days since last LTI
Onshore Operated Assets	3,931,844	3,203,659	3,053,616	10,189,119	380
Offshore Operated Assets	6,746,713	6,424,057	6,084,828	19,255,598	657
Total Operated Assets	10,678,557	9,627,716	9,138,444	29,444,717	
Elcrest*	27,402	798,217	811,539	27,402	3
AGPC	606,032	514,196	442,259	1,562,487	3,540 (from inception)
Total Non-Operated Assets	633,434	1,312,413	1,253,798	1,589,889	

* 3Q 2026 and 9M 2026 data for Elcrest is from 27 September 2026 post the fatality at Gbetiokun

In 3Q 2026, we reported zero Tier-1 and Tier-2 Loss of Primary Containment (LOPC). 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.

During the quarter, the Group achieved ISO 14001 Environmental Management System certification and successfully completed ISO 45001 surveillance audits, reinforcing its commitment to environmental stewardship, regulatory compliance, and international best practice in occupational health and safety. The Group also completed its annual regulatory led Oil Spill Contingency Plan activation exercise and asset HSE inspections, resulting in a year-on-year improvement in HSE compliance from 75% to 85%, with a target of achieving full compliance in subsequent periods.

Emissions

Carbon emissions intensity across our operated onshore assets declined by 34% to 17.0 kgCO₂/boe in 9M 2026 (9M 2025: 25.9 kgCO₂/boe), despite higher gas production. The improvement reflects continued benefits from the End of Routine Flaring programme, increased utilisation at ANOH and initiatives to increase gas sales and reduce flaring. Offshore carbon emissions intensity declined by 10% to 46.1 kgCO₂/boe (9M 2025: 51.2 kgCO₂/boe), reflecting production optimisation and operational efficiency initiatives, alongside lower associated gas production following the Oso-BRT pipeline outage.

Overall carbon emissions intensity across our operated assets reduced by 14% to 37.4 kgCO₂/boe in 9M 2026, from 43.6 kgCO₂/boe in 9M 2025.

Emissions Intensity by operated assets	Unit	3Q 2026	2Q 2026	1Q 2026	QoQ change	9M 2026	9M 2025	YoY change
Onshore operated	kgCO ₂ /boe	14.1	16.4	23.8	(14)%	17.0	25.9	(34)%
Offshore operated	kgCO ₂ /boe	45.9	45.9	47.3	— %	46.1	51.2	(10)%
Group	kgCO₂/boe	34.7	36.5	41.6	(5)%	37.4	43.6	(14)%

Seplat Offshore

Crude & Condensate	Seplat WI - %	3Q 2026 bopd	2Q 2026 bopd	1Q 2026 bopd	QoQ change	9M 2026 bopd	9M 2025 bopd	YoY change
OMLs 67, 68, 70, 104	40 %	64,677	65,028	61,903	(1)%	63,879	68,623	(5)%
OML 99 (A/K Field)	9.6 %	931	694	533	34 %	721	712	(3)%
Total Crude & Condensate		65,608	65,722	62,436	— %	64,600	69,335	(5)%
NGLs								
OMLs 67, 68, 70, 104	51 %	7,615	7,131	9,802	7 %	8,175	3,719	92 %
Total NGLs		7,615	7,131	9,802	7 %	8,175	3,719	92 %

Crude, Condensate & NGL Production

Working interest crude & condensate production from OMLs 67, 68, 70, and 104 averaged 64,677 bopd in 3Q 2026, marginally down 1% QoQ (2Q 2026: 65,028 bopd) with contributions from idle well restoration and ongoing asset optimisation activities across the offshore portfolio minimising the impact of the delayed restart of the Yoho production platform. 9M 2026 production remained below 9M 2025 levels by 5% at 63,879 bopd (9M 2025: 68,623 bopd), reflecting the continued impact of the Yoho outage.

Average daily working interest NGL production increased by 7% QoQ to 7,615 boepd in 3Q 2026 (2Q 2026: 7,131 boepd) after the decline experienced in 2Q 2026 due to the remedial repairs undertaken during the quarter on the accidentally damaged Oso-BRT pipeline enabling restoration of NGL processing at BRT in August. In spite of this, NGL production in 9M 2026 grew by 92% YoY to 8,175 bopd (9M 2025: 3,719 boepd) driven by the strong production of NGLs from the EAP complex after the reported Inlet Gas Exchanger (IGE) replacement project in 2025.

The non-operated Amenam-Kpono (A/K) field contributed 931 bopd of crude and condensate production during the quarter, up 34% compared with 2Q 2026 (694 bopd of crude and condensate).

Idle well restoration

During the quarter, interventions and investigations were progressed on a further 17 idle wells, bringing the total number of wells worked on under the programme to 41 wells in 9M 2026, against FY 2026 guidance of 50 wells. Of the 17 wells worked on in 3Q 2026, four previously were shut-in gas wells restored ahead of Oso-BRT phase 1 completion. These four wells added gross production capacity of 176 MMscf/d. The remaining 13 oil wells added 7.7 kbopd gross oil production capacity. Total incremental gross production capacity added year to date from 41 wells stands at 64.0 kbopd. Given year to date progress and the 4Q 2026 idle well programme plan, we are on track to exceed 2026 guidance of 50 wells.

The continued progress of the programme highlights the production potential within the existing asset portfolio and supports our strategy of maximising production through targeted, capital-efficient well interventions.

Yoho production platform

Technical completion of the Yoho production platform restoration project was achieved during the quarter, with approximately 3.7 million man-hours worked and zero lost-time injuries (LTIs) recorded. Key activities completed included major fabrication, piping, cable installation, riser repairs, installation, alignment of the Gas Turbine Generator alternator, and restoration of power to the platform.

Production restart has however been deferred to 4Q 2026 following the identification of a leak on the 14-inch pipeline connecting the Yoho platform to the FSO during restart activities. It has been determined that a section of the pipeline requires replacement, this work is underway and targeting completion this quarter.

In parallel, we are progressing a temporary shuttle-tanker solution as an alternative evacuation route. Technical and commercial evaluations are ongoing alongside engagement with the relevant regulatory authorities. The initiative provides an additional pathway to accelerate production restoration while permanent repairs to the pipeline are completed.

Drilling activities

The offshore drilling programme was impacted by the delays to the mobilisation of the Shelf Drilling Victory (SDV) jack-up rig, which was unable to mobilise to Seplat and commence operations in 3Q 2026 as planned. The rig is currently operating in Nigeria, and we continue to work closely with the contractor to secure mobilisation and minimise the impact on the drilling schedule.

In response, the Company is advancing multiple alternative rig options, targeting an additional unit to arrive in 1Q 2027. This is in addition to the Shelf Drilling Odyssey, which is due to arrive in early 2027.

Asset integrity

Offshore production deferrals improved to 16% in 9M 2026, compared with 20% in 9M 2025, supported by continued execution of the asset integrity and reliability programme targeting maintenance, rehabilitation and equipment upgrade across the portfolio.

Looking ahead, ongoing reliability initiatives include the Mobiltherm Heater project revamp at QIT to address identified equipment integrity risks and the repairs of the settling tank to support production continuity.

PIA Conversion

Following further regulatory engagement, NUPRC has indicated that the original conversion window has elapsed. The Group continues to engage with NUPRC and other relevant stakeholders to assess available options for the offshore assets and determine the optimal long-term licence framework.

Seplat Onshore

Crude & Condensate	Seplat WI - %	3Q 2026 bopd	2Q 2026 bopd	1Q 2026 bopd	QoQ change	9M 2026 bopd	9M 2025 bopd	YoY change
Western Assets	45 %	18,986	19,008	12,366	— %	16,811	16,921	(1) %
Elcrest	45 %	16,331	14,313	12,635	14 %	14,440	11,142	30 %
Eastern Assets	40 %	3,887	3,205	2,956	21 %	3,352	2,828	19 %
ANOH	40 %	3,959	2,849	419	39 %	2,422	—	— %
Newton	40 %	1,593	1,671	1,375	(5) %	1,547	1,566	(1) %
Total Crude & Condensate		44,756	41,045	29,751	9 %	38,572	32,457	19 %
NGLs								
Western Assets	45 %	98	—	—	— %	33	—	— %
ANOH	40 %	43	—	—	— %	15	—	— %
Total NGLs		142	—	—	— %	48	—	— %

Western Assets

Average daily working interest crude and condensate production on our Western Assets was 18,986 in 3Q 2026, broadly flat QoQ following the strong recovery achieved in 2Q 2026 after the resumption of operations on the Trans Forcados Pipeline (TFP), which experienced a 38-day unplanned third-party outage in 1Q 2026. The recovery recorded in 2Q was sustained throughout 3Q, supported by lower downtime across the assets.

On a 9M 2026 basis, average daily working interest production declined marginally by 1% YoY at 16,811 bopd (9M 2025: 16,921 bopd). New wells and the use of buffer tank facilities, which help to reduce production deferrals associated with third-party infrastructure downtime, offset the unplanned downtime on TFP.

Elcrest

Elcrest delivered a strong performance in 3Q 2026, with daily working interest crude and condensate production averaging 16,331 bopd, up 14% QoQ (2Q 2026: 14,313 bopd). The improvement was driven by enhanced pipeline availability and the successful execution of evacuation route debottlenecking initiatives. As a result of these initiatives asset deferrals improved progressively during the year, declining from 34% in 1Q 2026 to 23% in 2Q and 19% in 3Q 2026.

Average daily working interest production in 9M 2026 improved by 30% YoY to 14,440 bopd (9M 2025: 11,142 bopd) due to strong contribution from wells delivered under the 2025 and 2026 Elcrest drilling programme and improved production at Abiala driven by the commencement of access to a third party custody transfer unit in 1Q 2026.

Eastern Assets

Eastern Assets delivered average daily working interest crude and condensate production of 3,887 bopd in 3Q 2026, a 21% increase from 2Q 2026 (3,205 bopd). The improvement was supported by stronger well performance and reduced third-party interruptions following the deployment of buffer tanks. As a result, total deferment fell to 3.5% compared with 15.7% in 1Q 2026 and 8.1% in 2Q 2026, while third-party deferment reduced to 1.4% from 6.0% in 1Q 2026 and 2.5% in 2Q 2026. This represents the lowest deferment level recorded during the year and reflects the success of ongoing evacuation and infrastructure reliability initiatives.

Average daily working interest grew YoY by 19% to 3,352 bopd in 9M 2026 (9M 2025: 2,828 bopd) supported by factors already highlighted above.

Post period end, the Company successfully discovered oil and gas in the Aku-01 exploration well. Preliminary internal estimates indicate a mid-case gas in-place resource of 157 Bcf and oil in-place resource of 19 MMbbls. Encouragingly, an oil discovery was not part of the original well plan. The well is currently being completed as a potential future production well, that will be tied-back to existing infrastructure, supporting early monetization of the hydrocarbon resources. The discovery also de-risks four adjacent prospects. Seplat is now planning for a second exploration in the Aku area in 2027. Seplat has a 40% operated interest in license PPL 2A25.

Newton

The non-operated Newton assets field contributed 1,593 bopd of crude and condensate production to average daily working interest production in 3Q 2026 (2Q 2026: 1,671 bopd), a decline of 5% QoQ while average daily working interest production in 9M 2026 was 1,547 bopd, marginal decline of 1% YoY compared to 9M 2025: 1,566 bopd.

Drilling activities

In 3Q 2026 we completed four additional wells, Sibiri-3, Sibiri-4, OHS 1PAS-01 and Oben-60, bringing the total number of wells completed under the 2026 onshore drilling programme to eight. As noted above, the Company successfully discovered hydrocarbons in the Aku-01 well.

We continue to actively manage well-specific execution challenges, with six rigs currently operating across our onshore portfolio to support delivery of the remaining planned wells by year-end and sustain production growth.

Midstream Gas business performance

Midstream	Seplat WI - %	3Q 2026 MMscfd	2Q 2026 MMscfd	1Q 2026 MMscfd	QoQ change	9M 2026 MMscfd	9M 2025 MMscfd	YoY change
Western Assets	45 %	142.2	131.5	104.5	8 %	126.2	132.5	(5)%
Elcrest	45 %	—	—	—	-	—	—	-
Eastern Assets	40 %	—	—	—	-	—	—	-
ANOH	40 %	65.7	39.7	17.0	65 %	41.0	—	-
Newton	40 %	—	—	—	-	—	—	-
Seplat Onshore		207.9	171.2	121.5	21 %	167.2	132.5	26 %
OMLs 67, 68, 70, 104	40 %	—	22.6	29.1	(100)%	17.1	30.3	(44)%
OML 99 (A/K Field)	9.6 %	10.7	10.1	10.9	6 %	10.6	12.0	(12)%
Seplat Offshore		10.7	32.7	40.0	(67)%	27.7	42.2	(34)%
Total		218.5	204.0	161.5	7 %	194.9	174.7	12 %

In 3Q 2026 group average daily working interest gas production increased 7% QoQ to 219 MMscfd (2Q 2026: 204 MMscfd), as onshore production growth fully offset the effects of the temporary suspension of gas production offshore. Average daily working interest gas production from the Group's onshore assets increased by 21% to 208 MMscfd QoQ (2Q 2026: 171 MMscfd) driven by continued improvements in production from the Western Assets and the ongoing ramp-up of ANOH, where production increased by 65% QoQ. On the offshore assets, average daily working interest gas production was 11 MMscfd in 3Q 2026, down 67% QoQ (2Q 2026: 33 MMscfd), primarily as a result of the temporary suspension of commercial gas sales during the quarter, due to accidental third-party damage to the Oso-BRT subsea gas pipeline. As a result gas sales offshore were limited to contributions from OML 99, with gas production via Oso limited to volumes sufficient to power the NGL plant.

In 9M 2026, the Group produced 53.2 Bscf of gas, equivalent to average daily working interest production of 194.9 MMscfd, a YoY growth of 12% compared with 9M 2025 (47.7 Bscf, equivalent to average daily working interest production of 174.7 MMscfd). The growth reflects the contribution of ANOH following its first gas in January 2026.

Oben Gas Plant

Following the gas supply and revenue-sharing agreement signed with Gwato Energy LLP in 2Q 2026, activities progressed during the quarter to advance the project towards delivery. Front-End Engineering Design (FEED) for the pipeline connection to the Oben Gas Plant reached 45% completion. Activities within Gwato Energy's scope continue to progress against its current project schedule, with Seplat providing technical support where required.

ANOH Gas Processing Company (AGPC)

The ANOH gas plant continued to increase processing throughput, achieving a gross daily average output of 164 MMscfd in 3Q 2026, and is currently operating at 70-80% of nameplate capacity. Of note, a successful test of plant nameplate throughput was achieved during the quarter, supporting continued growth in the future. The majority of processed gas was sold to NLNG and Indorama. In addition, NGIC completed and commissioned the OB3 pipeline during the quarter and we are pleased to report that commercial flow of gas from ANOH via OB3 commenced on 1 September, with approximately 10% of 3Q 2026 gas sales via the OB3 pipeline.

Following the commencement of condensate exports through the Trans Niger Pipeline (TNP) to Bonny Terminal, on 14 July, AGPC completed its maiden condensate lifting (641 kbbls). A second condensate lifting was completed at the end of August (551 kbbls) and a third is planned for early 4Q (1,190 kbbls). In addition, smaller condensate volumes continue to be loaded directly from the plant for the domestic market. As previously disclosed, ANOH currently has 12.5 kbopd reserved production capacity (RPC) in the TNP, and a further ~1 kbopd of contracted offtake off-the-fence.

During the quarter, AGPC made its first principal repayments on its debt facilities, a total of \$68million paid to lenders during the period.

Oso - BRT Phase 1

The Oso-BRT pipeline upgrade project, designed to increase gas supply capacity to NLNG from 120 MMscfd to 240 MMscfd, remains on track for completion in 4Q 2026. Key engineering and construction activities progressed during the quarter, including mobilisation for the BRT scope and preparatory works ahead of final execution. Production contribution is expected in early 2027 once the sectional replacement of the Oso-BRT pipeline has been completed.

There were no gas sales from Oso during the period with gas production limited to rates sufficient only to power the Bonny River Terminal, given the damage previously incurred. Remediation of the previously reported Oso-BRT pipeline damage is progressing in parallel with the upgrade project. As an interim measure, we have engaged a CNG power provider to support operations at BRT while the sectional replacement for the damaged 12" gas pipeline is underway. This temporary solution enables continued NGL production and helps mitigate the operational impact of the pipeline outage.

Financial review

The global crude oil market remained relatively tight during the period, with supply disruptions and geopolitical tensions across the Middle East and Europe supporting oil prices. Brent crude averaged \$88.07/bbl in the first nine months of the year, up 26% from \$69.73/bbl the equivalent period in 2025. Nigerian crude continued to attract strong demand, benefiting from its high quality and lower exposure to key global shipping and supply chain bottlenecks, on top of which our simple hedge strategy and lifting timing meant that our average realised crude oil price increased by 34% to \$96.19/bbl (9M 2025: \$71.93/bbl), an average premium of \$8.12/bbl to Brent (\$2.20/bbl in 9M 2025), representing an 11% premium to the average Brent price year to date. We also benefited from positive pricing momentum across our gas business, with average realised NGL prices increasing by 4% to \$48.48/bbl supported by a more favourable product mix and a higher contribution from pentane, while average realised dry gas prices increased by 8% to \$3.18/mscf.

Overall, the combination of higher realised prices, increased production, and continued cost discipline provided a strong foundation for financial performance during the period. Together with a more favourable fiscal profile, these factors supported robust growth in earnings and cash generation.

Revenue

Description	Units	3Q 2026	2Q 2026	1Q 2026	QoQ change	9M 2026	9M 2025	YoY change
Crude & condensate volumes lifted	mmbbl	8.4	8.7	8.7	(3)%	25.7	27.9	(8)%
NGLs volumes lifted	mmbbl	0.6	0.9	1.1	(30)%	2.6	0.7	250 %
Dry gas sales volume	Bscf	10.7	14.9	12.8	(28)%	38.4	46.3	(17)%
Average realised oil price	US\$/bbl	100.44	102.59	86.16	(2)%	96.19	71.93	34 %
Average Brent crude oil price	US\$/bbl	90.23	96.00	77.61	(6)%	88.07	69.73	26 %
Premium to Brent	US\$/bbl	10.21	6.59	8.55	55 %	8.12	2.20	269 %
Average realised NGL price	US\$/bbl	67.08	37.60	44.44	78 %	48.48	46.64	4 %
Average realised dry gas price	US\$/mscf	3.33	3.10	3.10	7 %	3.18	2.95	8 %
Crude & condensate revenue	US\$m	839.7	888.8	745.7	(6)%	2,474.3	2,004.4	23 %
Gas revenue	US\$m	63.0	57.9	44.2	9 %	165.1	139.2	19 %
NGLs revenue	US\$m	40.7	32.6	50.9	25 %	124.1	33.0	276 %
Total revenue	US\$m	943.5	979.3	840.7	(4)%	2,763.5	2,176.6	27 %
(Overlift)/underlift	US\$m	107.1	25.0	(92.0)	329 %	40.1	3.8	947 %
Total revenue adjusted for (overlift)/underlift	US\$m	1,050.5	1,004.3	748.7	5 %	2,803.6	2,180.5	29 %
Crude oil revenue adjusted for (overlift)/underlift	US\$m	946.8	913.8	653.7	4 %	2,514.3	2,008.2	25 %

* Across this section there may be minor differences between the sum of individual numbers and the totals presented in the tables, due to rounding

Revenue performance benefited from stronger realised prices, which more than offset lower crude and condensate lifting and gas sales volumes. Gas revenues were further supported by contributions from ANOH following continued production ramp-up contributing additional \$35 million of wet gas sales.

NGL performance improved significantly following the successful replacement of the Inlet Gas Exchanger (IGE) at EAP, which enhanced NGL recovery, improved product yields and supported more frequent cargo liftings.

Cost of Sales

Description	Units	3Q 2026	2Q 2026	1Q 2026	QoQ change	9M 2026	9M 2025	YoY change
Non-Production Cost:	US\$m	333.8	335.5	270.6	(1)%	940.0	776.3	21 %
Royalties	US\$m	161.1	169.7	116.5	(5)%	447.2	381.2	17 %
Depletion, Depreciation, & Amortisation	US\$m	162.2	153.2	141.2	6 %	456.6	358.3	27 %
Regulatory fees/levies*	US\$m	10.6	12.6	13.0	(16)%	36.2	36.8	(2)%
Production Cost:	US\$m	237.2	198.3	199.7	20 %	635.2	520.8	22 %
Crude Handling Fees	US\$m	23.7	26.2	17.1	(10)%	67.0	59.2	13 %
Barging & Trucking	US\$m	6.7	7.5	6.5	(11)%	20.6	20.6	— %
Operational & Maintenance Expenses	US\$m	206.8	164.6	176.1	26 %	547.5	441.0	24 %
Production Opex per boe	US\$/boe	16.5	14.6	17.1	13 %	16.0	14.1	14 %
Cost of Sales	US\$m	571.0	533.8	470.3	7 %	1,575.2	1,297.2	21 %
Gross Profit	US\$m	372.4	445.5	370.5	(16)%	1,188.3	879.5	35 %

*Regulatory fees & levies include NDDC and NESS levies

Higher production costs primarily reflected expenditure associated with the Yoho restoration programme (contributing \$1.8/boe to unit cost in the period), alongside continued investment in offshore asset integrity and reliability. As a result, unit production costs increased to \$16.0/boe in 9M

2026 from \$14.1/boe in 9M 2025 and above the Group's guidance range. The business continued to benefit from the completion of the End of Routine Flaring (EORF) projects, with gas flare fees declining 40% to \$21.7 million (9M 2025: \$36.0 million).

Non-production costs increased primarily due to higher royalty expenses and DD&A charges. Royalty expense increased 17% YOY reflecting the stronger commodity price environment with unit royalty increasing to \$11.3/boe (9M 2025: \$10.3/boe), partially offset by the fiscal benefits arising from the PIA conversion of the Group's onshore assets. Higher DD&A also reflected the unusually low 9M 2025 comparator following the adoption of a revised unit-of-production depreciation rate after completion of the Offshore Asset Competent Person's Report (CPR).

Operating profit and Adjusted EBITDA

Description	Units	3Q 2026	2Q 2026	1Q 2026	QoQ change	9M 2026	9M 2025	YoY change
Other Income	US\$m	128.7	62.2	(91.3)	107 %	99.6	26.6	275 %
General and Administrative Expenses	US\$m	(77.7)	(74.6)	(46.4)	4 %	(198.7)	(169.8)	17 %
Impairment Loss	US\$m	(3.1)	10.8	(5.4)	(129)%	2.3	(8.9)	(126)%
Fair Value Loss	US\$m	(8.9)	(1.5)	(13.8)	499 %	(24.2)	(16.3)	48 %
Operating Profit	US\$m	411.5	442.4	213.5	(7)%	1,067.4	711.0	50 %
Adjusted EBITDA	US\$m	591.3	567.3	371.3	4 %	1,529.9	1,111.9	38 %

General and Administrative ('G&A') expenses increased 17% primarily driven by higher share-based payment charges, reflecting the Group's stronger share price performance during the period and the requirement to satisfy associated long-term incentive awards. As a result, G&A expenses on a unit basis were \$5.0/boe in 9M 2026 (9M 2025: \$4.6/boe), at the upper end of the 2026 guidance range of \$4.5/boe to \$5.0/boe.

The other income/(loss) line is primarily made up of Underlift of \$40.1 million, unrealized and realized FX gains of \$11.3 million and \$1.0 million respectively, and other tariffs from the usage of the group's pipeline by other entities and crude marketing income.

After adjusting the reported EBITDA of \$1,533.9 million for non-cash items, the adjusted EBITDA for the period was \$1,529.9 million (9M 2025: \$1,111.9 million), resulting in a margin of 55% (9M 2025: 51%).

Taxation

The income tax expense of \$722.4 million (9M 2025: \$475.0 million) includes a current tax charge of \$729.2 million (9M 2025: \$474.3 million) partly offset by a deferred tax credit of \$6.8 million (9M 2025: \$0.6 million). This reflects an effective tax rate ('ETR') of 74%, lower than the 83% reported in 9M 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 9M 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 \$501.9 million, representing 34% of pre-tax cash flows from operations.

Net result

Description	Units	3Q 2026	2Q 2026	1Q 2026	QoQ change	9M 2026	9M 2025	YoY change
Profit before Tax	US\$m	407.7	409.4	165.6	— %	982.6	570.1	72 %
Total Income tax expense	US\$m	311.5	283.3	127.6	10 %	722.4	475.0	52 %
Net Income	US\$m	96.2	126.1	37.9	(24)%	260.2	95.1	174 %
Profit Attributable to Holders of Equity	US\$m	95.5	125.7	33.8	(24)%	255.0	92.1	177 %
Earnings per Share	US\$/c/shr	0.16	0.21	0.06	(24)%	0.42	0.16	172 %

The 174% growth in profit after tax benefitted from better price realisations across our product mix.

Cash flows from operating activities

Description	Units	3Q 2026	2Q 2026	1Q 2026	QoQ change	9M 2026	9M 2025	YoY change
Profit before tax	US\$m	407.7	409.4	165.6	— %	982.6	570.1	72 %
Non Cash Adjustments	US\$m	221.7	192.6	221.6	15 %	635.9	579.5	10 %
Working Capital Changes	US\$m	(136.6)	45.9	(49.2)	(398)%	(139.8)	245.7	(157)%
Pre-tax Cashflow from Operating Activities	US\$m	492.9	647.9	337.9	(24)%	1,478.7	1,395.4	6%
Cash Taxes	US\$m	(161.1)	(248.1)	(92.7)	(35)%	(501.9)	(304.4)	65 %
Others*	US\$m	(45.9)	(7.0)	(1.8)	559 %	(54.7)	(80.2)	(32)%
Post-tax Cashflow from Operating Activities	US\$m	285.9	392.8	243.4	(27)%	922.1	1,010.8	(9)%

*Others include hedge premium, PAYE on vested shares, restricted cash movement and contribution to defined pensions benefit obligations

The improvement in pre-tax cashflows reflects the impact of better price realisation during the period. Net cash flow from operating activities includes cash tax payments of \$501.9 million, hedge premium payment of \$15.9 million, PAYE tax paid on vested shares of \$35.9 million; and restricted cash movement of \$2.9 million during the current period, while in the previous year, cash tax payments were \$304.4 million, hedge premium of \$25.0 million was paid, contribution to defined pensions benefit obligation of \$52.0 million and restricted cash movement was \$3.2 million.

Cash call collection from our JV partners remained positive in the period. In 9M 2026, on the NEPL/Seplat JV for Western Assets and Elcrest, we received \$244 million in cash calls from our JV partner, lowering the receivables balance on the JV to \$61.6 million (FY 2025: \$84.5 million).

For our NUIMS/Seplat JV and SEPNU/NNPC JV for our Eastern Assets and SEPNU, we received \$921 million in cash call settlement in 9M 2026, bringing outstanding cash call receivables on both JVs to \$105.6 million (FY 2025: \$201.7 million). Payment under the previously agreed 18-month settlement arrangement with NUIMS for \$188 million of \$325 million outstanding legacy cash call receivables commenced in September with a further payment received post period-end in October. We continue to audit and seek reconciliation of the remaining balance with our JV partner.

Cash flows from investing activities

Description	Units	3Q 2026	2Q 2026	1Q 2026	QoQ change	9M 2026	9M 2025	YoY change
Post-tax Cashflow from Operating Activities	US\$m	285.9	392.8	243.4	(27)%	922.1	1,010.8	(9)%
Capital Expenditure	US\$m	(63.3)	(67.2)	(42.6)	(6)%	(173.1)	(180.1)	(4)%
Free Cashflow	US\$m	222.6	325.6	200.8	(32)%	749.0	830.7	(10)%
Additional Investment in Joint Venture	US\$m	—	—	—	— %	—	(20.0)	nm
Others*	US\$m	37.0	3.5	2.9	951 %	43.4	(55.0)	(179)%
Net cash outflows used in investing activities	US\$m	(26.3)	(63.7)	(39.7)	(59)%	(129.7)	(255.1)	(49)%

*Others include Interest received, and deposit for asset held for sale.

Cash capital expenditure on oil and gas assets was \$168.7 million in 9M 2026 (9M 2025: \$178.8 million), with total capital expenditure of \$173.1 million. Net investing cash outflows reduced to \$129.7 million from \$255.1 million in 9M 2025. This reflects, receipts from Belemaoil of \$40 million, of which net proceeds of \$32.6 million are reported in cash from investing, after recovery of prior advances for evacuation cost, and lower than planned cash capital expenditure reflecting primarily the delayed start of the offshore drilling programme, but also timing of onshore drilling and delays with engineering projects.

Cash flows from financing activities

Description	Units	3Q 2026	2Q 2026	1Q 2026	QoQ change	9M 2026	9M 2025	YoY change
Repayments of Loans and Borrowings	US\$m	—	(200.0)	—	(100)%	(200.0)	(1,030.3)	(81)%
Proceeds from Loans and Borrowings	US\$m	—	—	—	nm	—	650.0	(100)%
Interest paid on Loans and Borrowings	US\$m	(32.0)	(12.6)	(36.9)	155 %	(81.4)	(91.2)	(11)%
Other Finance Costs	US\$m	(19.9)	(8.2)	(15.5)	144 %	(43.6)	(70.0)	(38)%
Dividends paid	US\$m	(72.1)	(103.7)	—	(30)%	(175.8)	(95.3)	85 %
Shares purchased for employees	US\$m	(13.3)	(31.2)	(25.0)	(57)%	(69.5)	(10.0)	595 %
Net cash outflows used in financing activities	US\$m	(137.3)	(355.6)	(77.4)	(61)%	(570.3)	(646.7)	(12)%

Debt Movements

Advanced payment facility ('APF')

As previously reported, during 2Q 2026 the Company repaid and cancelled \$200 million of the advance payment facility (APF) used to support the MPNU acquisition, reducing the outstanding drawn balance to \$100 million at the end of 3Q 2026.

Subsequent to the period end, on 27 October, the outstanding \$100 million balance was repaid and the facility fully cancelled. As a result, the Company has fully repaid all acquisition debt associated with the acquisition of MPNU in December 2024.

Credit ratings

Seplat maintains corporate credit ratings with Moody's Ratings, Standard & Poor's Rating Services (S&P) and Fitch Ratings (Fitch). The current corporate ratings are as follows: (i) Moody's B2 (positive); (ii) S&P B+ (stable); (iii) Fitch B (stable).

In September 2026, Moody's revised Seplat's outlook to Positive from Stable, while affirming its B2 long-term corporate family rating, following a similar revision to positive from stable for the outlook on the Government of Nigeria, while affirming Nigeria's B3 local- and foreign-currency issuer ratings. This followed S&P's upgrade of Seplat's long-term issuer credit rating to B+ (Stable) from B (Positive) in May 2026, following its upgrade of Nigeria's sovereign rating. In March 2026, Fitch affirmed Seplat's Long-Term Issuer Default Rating at B with a Stable outlook.

Liquidity

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

Description	Units	9M 2026	9M 2025	FY2025
Senior loan notes (Eurobonds)*	US\$m	637.5	634.3	649.7
Westport Reserve Based Lending (RBL) facility*	US\$m	55.2	28.5	53.5
\$400 million Revolving credit facility*	US\$m	0.0	0.0	—
\$300 million Advance payment facility*	US\$m	99.1	302.8	302.4
Offtake facilities*	US\$m	0.0	0.0	—
Total borrowings*	US\$m	791.7	965.7	1,005.6
Cash and cash equivalents (exclusive of restricted cash)	US\$m	556.9	579.8	332.3
Net Debt	US\$m	234.9	385.9	673.3
Adjusted EBITDA **	US\$m	1,693.4	1,420.7	1,275.4
Net Debt-to-Trailing Twelve Months EBITDA	x	0.14	0.27	0.53

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

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

The Group remains focused on maintaining a prudent capital structure, with a corporate policy of keeping Net Debt-to-EBITDA below 1.5x, compared with a debt covenant of 3.0x. At the end of September 2026, Net Debt-to-EBITDA improved to 0.14x, from 0.53x at year-end 2025, remaining comfortably within the Group's leverage policy and covenant threshold.

Dividend

The Board has approved a 3Q 2026 dividend of USD 19.0 cents per share, subject to applicable withholding tax, comprising a USD 5.0 cents per share base dividend and a USD 14.0 cents per share special dividend. This represents a 153% increase compared with the total dividend declared for 3Q 2025 (USD 7.5 cents per share) and reflects the Group's strong financial position and supportive commodity price environment.

The Company remains on track with its previously communicated plan to distribute USD 45.0 cents per share, approximately \$270 million, for the 2026 financial year, with USD 40.0 cents per share declared year to date. This amount excludes any potential additional transaction-related dividend associated with the proposed 10% working interest sale in the NNPC/SEPNU joint venture to NNPC Limited.

Reporting Period	Proposed Dividend (US\$ cents per share)	Announcement Date	Qualification Date (LSE)	Qualification Date (NGX)	Payment Date
Q1 2026	9.0	30 April 2026	5 June 2026	5 June 2026	19 June 2026
Q2 2026	12.0	30 July 2026	13 August 2026	13 August 2026	28 August 2026
Q3 2026	19.0	29 October 2026	12 November 2026	12 November 2026	27 November 2026
Total 2026 YTD	40.0				

Hedging

Seplat Energy's hedging policy is designed to provide a degree of cash flow protection during periods of oil price weakness and volatility.

During 3Q 2026, we commenced our 2027 hedging programme, purchasing put options covering 6.0 MMbbls at a weighted average strike price of \$55.00/bbl and a weighted average premium of \$0.77/bbl. We will continue to monitor oil market conditions and evaluate further hedging opportunities in line with our policy. Our strategy of using simple put options, which provides downside price protection while retaining exposure to higher oil prices, remains unchanged.

Post period end, we purchased additional put options covering 2.0 MMbbls at a strike price of \$60.00/bbl and a premium of \$0.96/bbl.

Oil Hedges (Brent Put Options)	Unit	1Q 2026	2Q 2026	3Q 2026	4Q 2026	FY 2026
Volumes hedged	MMbbls	6.00	6.00	6.00	6.00	24.00
Price hedged	US\$/bbl	52.50	50.00	51.67	55.00	52.29
Puts cost	US\$/bbl	1.21	1.18	1.36	0.88	1.16

Oil Hedges (Brent Put Options)	Unit	1Q 2027	2Q 2027
Volumes hedged	MMbbls	6.00	2.00
Price hedged	US\$/bbl	55.00	60.00
Puts cost	US\$/bbl	0.77	0.96

Interim sustainability disclosure for 9 months ended 30 September 2026

Introduction

This interim report provides an update on Seplat Energy's sustainability-related programmes and activities for the nine months ended 30 September 2026. It provides additional context, refreshed metrics and recent developments since the publication of the 2025 Integrated Annual Report.

The disclosures highlight material developments and changes during the third quarter of 2026. They should be read together with the sustainability-related financial disclosures in the 2025 Integrated Annual Report, and the interim sustainability-related disclosures for the six months ended 30 June 2026.

Previously reported disclosures on governance, strategy, risk management, reporting policies and methodologies have not been repeated where there have been no material changes. Unless otherwise stated, the reporting boundary and measurement approaches remain consistent with those applied in the 2025 Integrated Annual Report, and comparative information is prepared on a consistent basis and presented where available and useful to users of general purpose financial reports.

Governance

The Group's governance structure for sustainability-related risks and opportunities remain as described in the 2025 Integrated Annual Report, pages 112–113, which can be accessed [here](#), Key activities are detailed below.

3Q 2026 developments

Oversight body	3Q 2026 activity	Material matters considered
Sustainability Management Committee (SMC)	Two meetings held during 3Q 2026.	- Offshore flare management - GHG management and reporting 2026 Integrated Reporting readiness and assurance - ESG performance and disclosure - Human Capital reporting - CSI and afforestation activities
Sustainability Committee (SusCo)	SMC's 3Q 2026 performance and sustainability developments were reported to SusCo in October 2026.	- Environmental performance, social initiatives, governance 2026 Integrated Annual Report readiness - ESG performance and disclosure assessment

Strategy

The Group's sustainability strategy, material sustainability and climate-related risks and opportunities, business model, value chain, climate scenario analysis and climate strategy, climate resilience remain as described in the 2025 Integrated Annual Report, pp. 137–152, which can be accessed [here](#) except for the updates described below outlined below.

Material sustainability-related current financial effects – 9M 2026

Material sustainability-related matter	Nature of financial effect	9 Month 2026 amount	Financial statement connection
Climate change and energy transition	This relates to revenue from gas, and natural gas liquids (NGL), reflecting a 12% and 121% increase in production compared with 9M 2025.	\$289.2 million	Revenue from contracts with customers. Refer to note 7
	This represents gas flare penalties incurred as a direct regulatory cost of operational flaring, in 9M 2026 there was a reduction of 40% YoY, reflecting progress on flare-reduction projects in the offshore business.	\$21.7 million	
	This captures environmental management costs, including environmental sustainability activities, environmental impact assessments and environmental sensitivity mapping.	\$0.48 million	
Asset integrity management	This comprises costs incurred in maintaining asset integrity, including corrosion control, detailed inspections and integrity checks, maintenance services, and maintenance of oil facilities, pipelines, flowlines, platforms and flow stations.	\$252.25 million	Cost of sales represented under operation and maintenance cost. Refer to note 8

Material sustainability-related matter	Nature of financial effect	9 Month 2026 amount	Financial statement connection
Human rights and community relations	This covers financial commitments towards host communities and social investment, including healthcare, education, electrification, agricultural and livelihood initiatives, community engagement and Host Communities Development Trust contributions.	\$17.57 million	Cost of sales and General and administrative expenses represented under operation and maintenance cost, and other general expenses. Refer to note 8 and note 10 respectively.
Health, safety and security	This encompasses costs associated with health, safety and security measures, including protective equipment, emergency medical services, security services and other activities supporting the management of related risks.	\$23.07 million	
Water and waste management	Waste-management expenditure relating to the handling and disposal of operational waste.	\$0.18 million	Cost of sales represented under operation and maintenance cost. Refer to note 8
Ecological impact	This pertains to spill response and clean-up costs incurred in managing and remediating environmental impacts arising from operational incidents.	\$0.06 million	Cost of sales represented under operation and maintenance cost. Refer to note 8

Material sustainability-related anticipated financial effects - 9M 2026

As at 30 September 2026, there were no material changes to the anticipated financial effects previously disclosed.

Risk Management

The Group's Enterprise Risk Management and Internal Control Framework and process for identifying, assessing, prioritising and monitoring sustainability-related risks and opportunities remain as described in the 2025 Integrated Annual Report (pages 135-146), which can be accessed [here](#). During 3Q 2026, no new material sustainability-related risks or opportunities were identified, and the previously disclosed assessments remained unchanged.

Metrics and Target

Quantitative

Description of performance measure		9M 2026	9M 2025	3Q 2026	2Q 2026	1Q 2026	Commentary
GHG Intensity ($\text{kgCO}_2\text{e}/\text{boe}$)	Onshore	17.0	25.9	14.1	16.4	23.8	Onshore: Emissions YoY declined despite increased gas production. Completed EORF projects continue to deliver reductions in flare volumes and associated penalties, initiatives to increase gas sales are being progressed to further reduce flaring.
	Offshore	46.1	51.2	45.9	45.9	47.3	
	Group	37.4	43.6	34.7	36.5	41.6	
Gross Scope 1 emissions (ktCO_2e)	Onshore	432.3	707.8	137.7	141.3	153.3	Offshore: Reduction in 3Q flare, partly reflecting lower associated gas production following the Oso-BRT outage, alongside improvements from product optimisation and operational efficiency initiatives.
	Offshore	2,760.5	3,277.1	880.8	934.2	945.5	
	Group	3,192.8	3,984.9	1,018.5	1,075.5	1,098.8	
Methane emissions (tCO_2e)	Onshore	156.9	207.9	56.3	51.0	41.8	Group QoQ increase in emission of 5.5% reflects a higher contribution of grid-supplied electricity.
	Offshore	186.2	241.7	62.2	62.2	65.3	
	Group	343.1	449.5	118.5	113.2	107.0	
Scope 2 emissions (tCO_2e)	Onshore	295.0	880.0	101.0	115.0	78.0	Scope 3 reporting currently covers six categories, with work underway to increase coverage to eight. The categories currently covered are:
	Offshore	1,318.0	556.0	512.0	466.0	340.0	
	Group	1,613.0	1,436.0	613.0	581.0	418.0	
Scope 3 emissions - reporting (number of categories reported)	Onshore	6	6	6	6	6	- Category 1: Purchased Goods and Services (currently reported as Drilling Operations) - Category 5: Waste Generated in Operations - Category 6: Business Travel - Category 7: Employee Commuting - Category 11: Use of Sold Products - Category 15: Investments

Description of performance measure		9M 2026	9M 2025	3Q 2026	2Q 2026	1Q 2026	Commentary
Critical Incident Risk Management - Tier 1 Process Safety Events Rate	Operated Assets	4	9	0	1	3	No Tier 1 or Tier 2 Process Safety Events were recorded during the quarter. We continue to maintain a strong focus on process safety, asset integrity and the proactive management of operational risks.
	Non-Operated Assets	0	0	0	0	0	
Critical Incident Risk Management - Tier 2 Process Safety Events Rate	Operated Assets	4	4	0	3	1	
	Non-Operated Assets	0	0	0	0	0	
Health, safety and security - LTI/LTIF rate	Operated Assets	0.0	0.0	0.0	0.0	0.0	3Q 2026 performance was impacted by a fatal incident at a non-operated asset. An investigation is underway, and further information will be provided upon its conclusion. We continue to reinforce focus on safety leadership, risk management and the protection of our workforce and contractors across both operated and non-operated assets
	Non-Operated Assets	0.2	0.0	0.7	0.0	0.0	
Health, safety and security - TRIR	Operated Assets	0.2	0.2	0.2	0.1	0.2	TRIR increased following two recordable injuries across our Onshore and Offshore operations. Hand-safety and Line-of-Fire controls reinforced in response to strengthen preventive measures.
	Non-Operated Assets	0.7	0.2	1.3	0.8	0.0	
Health, safety and security - Fatality rate	Operated Assets	0.0	0.0	0.0	0.0	0.0	The fatality rate reflects one fatal incident at a non-operated asset.
	Non-Operated Assets	0.2	0.0	0.7	0.0	0.0	
Health, safety and security - NMFR	Operated Assets	0.8	1.5	0.9	1.1	0.4	NMFR improved during the quarter, reflecting fewer near-miss incidents, this is despite higher man-hours for operated assets.
	Non-Operated Assets	0.2	0.0	0.7	0.0	0.8	

*Emissions data are based on gross production numbers.

*Scope 3 emissions data are provisional and subject to reconciliation, with final figures to be confirmed following year-end review and assurance.

*All qualitative metrics remain the same as described in the 2025 annual report on pages 110-152.

*No calculation and basis of measurement changed during 3Q reviews.

*GHG emissions are calculated using AR5 for Onshore operations and AR6 for Offshore operations with a target to consolidation by full year 2026.

*Operated Assets include (Onshore + Offshore).

*Non-Operated Assets include (AGPC + Elcrest).

Qualitative

Metric	Boundary	3Q 2026 Updates
Health, Safety and Security	Onshore	During 3Q 2026, Seplat sustained its ISO 45001:2018 Occupational Health & Safety Management System certification through the surveillance audit programme.
Water & Wastewater management	Group	Water management progressed during 3Q 2026, with closure of identified onshore reporting gaps increasing from 35% to 45% from Onshore water audit. The Offshore Water Footprint Audit was completed, with corrective actions progressing to address identified gaps and strengthen reporting accuracy.
Ecological Impact	Group	Management systems In 3Q 2026, Seplat onshore continued strengthening its ISO 14001 Environmental Management System through certification close-out activities, management system improvements, internal audits, management reviews and readiness initiatives supporting ongoing certification objectives. Preparatory activities also commenced for the future transition to the revised ISO 14001 standard for offshore.
	Group	Tree4life Afforestation A total of 155,484 additional trees were planted during the period, bringing the cumulative number of trees planted in 2026 to 205,484 and the overall total since programme inception to 436,512 trees. Furthermore, 20,000 seedlings were distributed to host communities, increasing cumulative seedling distribution to 43,000 seedlings between 2024 and 2026.
	Offshore	Biodiversity Assessment of Offshore Operational areas and development of a consolidated BAP for Seplat Group. During 3Q 2026, the gap analysis and field data gathering for the Offshore Biodiversity Assessment were completed, marking progress towards development of the consolidated Biodiversity Action Plan (BAP). Report development is underway, with completion expected by the end of 4Q 2026.

Assurance

External assurance has not been performed on the interim sustainability disclosure for 9 months ended 30 September 2026. The disclosures have, however, been subject to the Group's established managements review.

As part of its year-end reporting process, Seplat intends to obtain independent limited assurance over relevant FY2026 sustainability-related disclosures, in accordance with ISSA 5000 (International Standard on Sustainability Assurance) and the FRC Nigeria sustainability reporting requirements. The final assurance scope, criteria and related details will be communicated in the 2026 Annual Report.



E. Adaralegbe

FRC/2017/ICAN/006/00000017591

Chief Financial Officer

29 October 2026

Outlook

Production guidance

2026 production guidance narrowed to the upper half of guidance, 145-155 kboepd.

Seplat Energy's production operations improved materially in 3Q 2026, bringing overall production to the mid-point of our prior guidance range. In 4Q 2026 we expect continued growth, driven by contribution from the ongoing idle well restoration programme, the onshore drilling programme and continued ANOH ramp-up. This supports narrowing guidance to the upper half of the original guidance range (previously: 135-155 kboepd). Our guidance excludes the effects of the sale of 10% in the offshore assets to our JV partner, further updates will be provided at completion.

Capex guidance

Working interest capital expenditure guidance is reduced to \$280 million - \$340 million.

9M 2026 cash capital investment was lower than planned, largely due to timing on certain projects costs and particularly due to the delayed start of the offshore drilling programme. While cash capex is expected to increase in 4Q 2026, overall investment for 2026 is expected to be lower than previous expectations (previously: \$360-\$440 million). Onshore drilling is expected to continue at a high tempo for the remainder of the year and plans are underway for an active 2027 offshore drilling campaign.

Opex guidance

Unit operating cost guidance for the Company raised into the range of \$15.5-16.5/boe.

9M 2026 unit operating cost was above plan primarily due to the additional costs incurred at Yoho (equivalent to approximately \$1.8/boe in 9M 2026). Without this additional cost, unit production opex would be within the original guidance range. Full year additional net costs on Yoho are now expected to impact production opex by approximately \$2.0/boe, as such we increase FY26 unit production opex guidance to \$15.5-16.5/boe.

We note that we are targeting recovery of a portion of Yoho costs through our insurance. Guidance on this potential recovery will be provided when the outcome of the process is clear.

Other Financial and Strategic guidance

G&A: Unit G&A costs in 9M 2026 were \$5.0/boe, within 2026 guidance of \$4.5-5.0/boe, 2026 guidance is reiterated.

Tax: Given the continued elevated price environment, we update our FY2026 cash tax guidance. Assuming 2026 average realised oil price of \$95/bbl, we expect FY 2026 cash taxes in the range of \$650-700 million (previously \$600-650 million at \$85/bbl).

Dividend: Our previously communicated guidance for the 2026 underlying business performance dividend of \$270 million, equivalent to USD 45.0 cents/share, is retained. Of this USD 40.0 cents/share has been declared for 1Q, 2Q and 3Q combined.

In addition, the Company intends to distribute \$140 million (USD 23.3 cents/share) as a Transaction dividend following the completion of the sale of a 10% interest in the NNPC/SEPNU Joint Venture to our JV partner. As a result, planned 2026 dividends to shareholders are expected to total \$410.0 million (or USD 68.3 c/shr).

Over the 2026-2030 5 year period 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).

SEPNU Divestment

The previously announced sale of a 10% working interest in the assets held within the NNPC/SEPNU Joint Venture to our joint venture partner is progressing, and is expected to complete in 4Q 2026.

Note: Our 2026 guidance listed above exclude any adjustments that may be required due to the sale of the 10% interest in the NNPC/SEPNU JV. Any changes will be communicated post-completion of the transaction.

Responsibility Statement

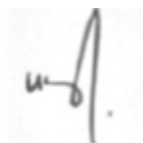
For the nine months ended 30 September 2026

The directors confirm to the best of their knowledge that:

- 1) The condensed set of financial statements have been prepared in accordance with IAS 34 'Interim Financial Report';
- 2) The interim management report includes a fair review of the information required by UK DTR 4.2.7R (indication of important events during the nine months and description of principal risks and uncertainties for the remaining three months of the year); and
- 3) The interim management report includes a fair review of the information required by UK DTR 4.2.8R disclosure of related parties' transactions and changes therein.

A list of current Directors is included on the company website: www.seplatenergy.com.

By order of the Board,



U.U. Udoma
Chairman

FRC/2013/NBA/00000001796
29 Oct 2026



E. Okon
Chief Executive Officer

FRC/2024/PRO/COREN/004/460715
29 Oct 2026



E. Adaralegbe
Chief Financial Officer

FRC/2017/ICAN/00000017591
29 Oct 2026

Unaudited condensed consolidated interim financial statements for the nine months ended 30 September 2026 (NGN)

29 October 2026

Reliable energy,
limitless potential

Condensed consolidated interim statement of profit or loss and other comprehensive income

For the nine months ended 30 September 2026

		9 months ended 30 Sept 2026	9 months ended 30 Sept 2025	3 Months ended 30 Sept 2026	3 Months ended 30 Sept 2025
		Unaudited ₦ million	Unaudited ₦ million	Unaudited ₦ million	Unaudited ₦ million
	Notes				
Revenue from contracts with customers	7	3,776,108	3,356,187	1,273,927	1,189,470
Cost of sales	8	(2,152,321)	(2,000,184)	(771,852)	(584,711)
Gross profit		1,623,787	1,356,003	502,075	604,759
Other income/(loss) -net	9	136,100	40,944	176,087	(38,126)
General and administrative expenses	10	(271,471)	(261,880)	(105,111)	(52,438)
Impairment reversal/(loss) on financial assets	11	3,122	(13,654)	(4,254)	(8,936)
Fair value loss	12	(33,003)	(25,207)	(11,994)	(10,241)
Operating profit		1,458,535	1,096,206	556,803	495,018
Finance income	13	14,214	12,123	5,081	3,848
Finance costs	13	(163,422)	(223,485)	(47,290)	(72,936)
Finance cost - net	13	(149,208)	(211,362)	(42,209)	(69,088)
Share of profit/(loss) from joint venture accounted for using the equity method		33,372	(5,855)	37,690	(1,052)
Profit before taxation		1,342,699	878,989	552,284	424,878
Income tax expense	14	(987,146)	(732,350)	(422,209)	(320,758)
Profit for the period		355,553	146,639	130,075	104,120
Attributable to:					
Equity holders of the parent		348,400	141,944	129,165	105,347
Non-controlling interests		7,153	4,695	910	(1,227)
		355,553	146,639	130,075	104,120
Earnings per share for the period					
Basic earnings per share ₦	26	580.72	240.18	215.29	178.25
Diluted earnings per share ₦	26	580.72	240.18	215.29	178.25
Profit for the period		355,553	146,639	130,075	104,120
Other comprehensive loss:					
Items that may be reclassified to profit or loss (net of tax):					
Foreign currency translation difference		(203,540)	(129,587)	(100,372)	(118,950)
Total comprehensive income/(loss) for the period (net of tax)		152,013	17,052	29,703	(14,830)
Attributable to:					
Equity holders of the parent		159,656	83,630	29,753	51,819
Non-controlling interests		(7,643)	(66,578)	(50)	(66,649)
		152,013	17,052	29,703	(14,830)

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

Condensed consolidated interim statement of financial position

As at 30 September 2026

	Notes	30 Sept 2026 Unaudited ₦ million	31 Dec 2025 Audited ₦ million
Assets			
Non-current assets			
Oil & gas properties	16	3,917,320	4,477,741
Other property, plant and equipment		445,609	517,515
Right-of-use assets		114,662	163,697
Intangible assets		658,295	812,866
Other assets		77,315	130,343
Investment accounted for using equity method		377,595	372,835
Long-term prepayments		19,033	22,462
Deferred tax assets	14.1	205,238	289,581
Other financial assets at amortised cost	21	2,872	—
Total non-current assets		5,817,939	6,787,040
Current assets			
Inventory		487,239	489,087
Trade and other receivables	17	849,222	683,086
Short-term prepayments		30,535	47,729
Contract assets	18	51,735	29,159
Derivative financial assets	19	13,140	17,352
Other financial assets at amortised cost	21	980	—
Restricted cash	20.2	171,674	181,347
Cash and cash equivalents	20	739,867	476,970
Total current assets		2,344,392	1,924,730
Asset held for sale		16,303	17,611
Total assets		8,178,634	8,729,381
Equity and liabilities			
Equity attributable to shareholders			
Issued share capital	22.2	300	300
Share premium	22.2	81,813	150,802
Share-based payment reserve	22.2	5,591	24,985
Treasury shares	22.2	(147,372)	(100,270)
Capital contribution	22.2	5,932	5,932
Retained earnings	22.2	450,532	342,409
Foreign currency translation reserve	22.2	2,009,338	2,198,082
Non-controlling interest		13,361	20,996
Total shareholder's equity		2,419,495	2,643,236
Non-current liabilities			
Interest-bearing loans and borrowings	23	960,269	1,339,135
Lease liabilities		30,810	67,027
Provision for decommissioning obligation		1,120,379	1,168,622
Deferred tax liability	14.1	1,540,944	1,742,201
Defined benefit plan	24.1	1,241	3,904
Other payables	25	61,714	—
Total non-current liabilities		3,715,357	4,320,889
Current liabilities			
Interest-bearing loans and borrowings	23	91,693	104,154
Lease liabilities		34,170	29,162
Derivative financial liability	19	16,388	9,041
Trade and other payables	25	1,304,685	1,310,242
Other provisions		4,678	4,901
Current tax liabilities		592,168	307,756
Total current liabilities		2,043,782	1,765,256
Total liabilities		5,759,139	6,086,145
Total shareholders' equity and liabilities		8,178,634	8,729,381

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 nine months ended 30 September 2026 were authorised for issue on 29 October 2026 in accordance with a resolution of the Directors signed on its behalf by:

A handwritten signature in black ink, appearing to be "U. U. Udoma".

U. U. Udoma

FRC/2013/NBA/00000001796

Chairman

29 October 2026

A handwritten signature in black ink, appearing to be "E. Okon".

E. Okon

FRC/2024/PRO/COREN/004/460715

Chief Executive Officer

29 October 2026

A handwritten signature in purple ink, appearing to be "E. Adaralegbe".

E. Adaralegbe

FRC/2017/ICAN/006/00000017591

Chief Financial Officer

29 October 2026

Condensed consolidated interim statement of changes in equity

For the period ended 30 September 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- restated	297	87,375	15,558	(3,570)	5,932	312,635	2,393,009	11,127	2,822,363
Profit for the period	–	–	–	–	–	141,944	–	4,695	146,639
Other comprehensive loss	–	–	–	–	–	–	(58,314)	(71,273)	(129,587)
Total comprehensive income/(loss) for the period	–	–	–	–	–	141,944	(58,314)	(66,578)	17,052
Transactions with owners in their capacity as owners:									
Dividend paid	–	–	–	–	–	(146,903)	–	–	(146,903)
Share-based payments	–	–	18,874	–	–	–	–	–	18,874
Vested shares	–	–	(25,728)	25,728	–	–	–	–	–
Transfer to share-based payment liability	–	–	(4,888)	–	–	–	–	–	(4,888)
Shares re-purchased	–	–	–	(15,419)	–	–	–	–	(15,419)
Shares issued	6	63,024	–	(63,030)	–	–	–	–	–
Total	6	63,024	(11,742)	(52,721)	–	(146,903)	–	–	(148,336)
At 30 Sept 2025 (unaudited)	303	150,399	3,816	(56,291)	5,932	307,676	2,334,695	(55,451)	2,691,079
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	–	–	–	–	–	348,400	–	7,153	355,553
Other comprehensive loss	–	–	–	–	–	–	(188,744)	(14,796)	(203,540)
Total comprehensive income/(loss) for the period	–	–	–	–	–	348,400	(188,744)	(7,643)	152,013
Transactions with owners in their capacity as owners:									
Dividend paid	–	–	–	–	–	(240,277)	–	–	(240,277)
Share-based payments	–	–	14,442	–	–	–	–	–	14,442
Vested Shares	–	(68,989)	(27,897)	96,886	–	–	–	–	–
PAYE tax remitted on vested shares	–	–	–	(49,063)	–	–	–	–	(49,063)
Contribution by non-controlling interest *	–	–	–	–	–	–	–	8	8
Transfer to share-based payment liability	–	–	(5,939)	–	–	–	–	–	(5,939)
Shares repurchased	–	–	–	(94,925)	–	–	–	–	(94,925)
Total	–	(68,989)	(19,394)	(47,102)	–	(240,277)	–	8	(375,754)
At 30 Sept 2026 (unaudited)	300	81,813	5,591	(147,372)	5,932	450,532	2,009,338	13,361	2,419,495

*Represents Starcrest additional contribution following the increase in the nominal share capital of Elcrest.

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

Condensed consolidated interim statement of cash flows

For the nine months ended 30 September 2026

		9 months ended 30 Sept 2026	9 months ended 30 Sept 2025
	Notes	₦ million	₦ million
Cash flows from operating activities			
Cash generated from operations	15	2,020,537	2,151,512
Tax paid		(685,762)	(469,325)
Contribution to plan assets *		–	(80,189)
Hedge premium paid		(21,767)	(38,523)
Restricted cash	20.3	(3,905)	(4,948)
PAYE tax remitted on vested shares **		(49,063)	–
Net cash inflows from operating activities		1,260,040	1,558,527
Cash flows from investing activities			
Payment for acquisition of oil and gas properties	16	(230,557)	(275,723)
Additional investment in Joint venture		–	(30,838)
Payment for acquisition of other property, plant and equipment		(6,007)	(1,920)
Deposit for asset held for sale		–	2,159
Receipts from other asset ***		44,579	–
Receipt from investments held at amortised cost	21	491	–
Payment for acquisition of subsidiary ****		–	(99,070)
Interest received		14,214	12,123
Net cash outflows used in investing activities		(177,280)	(393,269)
Cash flows from financing activities			
Repayment of loans and borrowings		(273,284)	(1,588,563)
Proceeds from loans and borrowings		–	1,002,248
Dividend paid		(240,277)	(146,903)
Shares purchased for LTIP scheme		(94,925)	(15,419)
Interest paid on lease liability		(5,128)	(9,623)
Lease payment – principal portion		(28,117)	(34,534)
Payment of financing charges from the issue of shares		–	(176)
Payments of other financing charges *****		(26,297)	(63,629)
Interest paid on loans and borrowings		(111,265)	(140,578)
Net cash outflows used in financing activities		(779,293)	(997,177)
Net increase in cash and cash equivalents		303,467	168,081
Cash and cash equivalents at beginning of the period		476,970	721,385
Effects of exchange rate changes on cash and cash equivalents		(40,570)	(39,964)
Cash and cash equivalents at end of the period	20	739,867	849,502

* Prior year contribution relates to the funding of the deficit of SEPNU's defined benefit obligation.

** PAYE tax for the current period relates to payments made in 2026. In the comparative period, the PAYE tax payment was made in Q4 2025 and, therefore, was not reflected in the 9M 2025 results.

*** Receipt from Other asset relates to proceeds from the financial interest in OML 55. During the period ₦54.7 billion was received, comprising ₦10.1 billion applied to receivables arising from advances to support crude evacuation at OML 55 and ₦44.6 billion recognised against other assets.

**** This relates to the reconciliation settlement paid to Exxon for the acquisition of SEPNU (formerly MPNU).

***** Other financing charges of ₦26.3 billion (2025: ₦63.6 billion) largely 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 condensed consolidated interim financial statements

For the nine months ended 30 September 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% Participant 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.

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.III) 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 to 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.

On 23 December 2025, the Group 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, the Group 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, the Group 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.

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	7 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, the Board of Seplat Energy Plc announced the appointment of Mr. Tony O. Elumelu, CFR, as a Non-Executive Director, effective 22 January 2026, following the resignation of Mr. Olivier De Langavant from the Board on the same date. The change followed the sale of Maurel & Prom S.A.'s 20.07% shareholding in Seplat Energy Plc to Heirs Holdings Limited and Heirs Energies Limited.

On 9 June 2026, the Board further announced a planned leadership succession. Mr. Roger Brown retired as Chief Executive Officer and Executive Director on 31 July 2026, and Engr. Effiong Okon was appointed Chief Executive Officer and Executive Director with effect from 1 August 2026. In addition, the Chairman of the Board, Senator Udoma Udo Udoma, CON, notified the Board of his intention to retire on 31 December 2026, and the Board elected Mr. Tony O. Elumelu, CFR, as the next Chairman of Seplat Energy Plc, effective 1 January 2027.

On 29 July 2026, the Group entered into an agreement to divest 25% of its participating interest in the NNPC/SEPNU JV, subject to regulatory approvals and other customary completion conditions. The agreed purchase price is ₦384.78 billion (\$281.6 million) and is subject to lockbox adjustment. The financial effect of the transaction will be determined on completion.

On 15 September 2026, APEX Global Energy Limited notified the Company that its shareholding had increased to 14.16% of the Company's issued share capital and voting rights.

On 30 September 2026, Mr. Tony O. Elumelu, through Heirs Energies Limited, increased his interest in the Company. Following the transaction, entities controlled by Mr. Tony O. Elumelu held an aggregate interest representing 21.07% of the Company's issued share capital.

3. Summary of material accounting policies

3.1 Introduction to summary of material accounting policies

This note provides a list of the material 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 Interim condensed 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 nine months ended 30 September 2026 have been prepared in accordance with IAS 34 (Interim Financial Reporting) 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, and defined benefit plans – plan assets measured at fair value. The financial statements are presented in

Nigerian Naira, and all values are rounded to the nearest million (₦ million), 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 in the preparation of the interim condensed consolidated financial statements are consistent with those followed in the preparation of the Group's annual IFRS compliant consolidated financial statements for the year ended 31 December 2025, except for the adoption of new and amended standards 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 be applied retrospectively.

Seplat Energy Plc engaged consultants to support its implementation of IFRS 18. Based on the gap assessment performed, the implementation of IFRS 18 is not expected to affect the recognition or measurement of the Group's assets, liabilities, income or expenses. However, it is expected to affect the presentation of the statement of profit or loss, related note disclosures and certain comparative information. The Group continues to assess the detailed presentation and disclosure implications.

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.

d) IFRS 20-Regulatory Assets and Regulatory Liabilities

On 27 May 2026, the International Accounting Standards Board issued IFRS 20 Regulatory Assets and Regulatory Liabilities. IFRS 20 sets out the requirements for the recognition, measurement, presentation and disclosure of regulatory assets, regulatory liabilities, regulatory income and regulatory expense.

IFRS 20 introduces requirements that will result in information that supplements the information an entity already provides by applying IFRS accounting standards, including IFRS 15 Revenue from Contracts with Customers. Such information enables users of financial statements to understand the total allowed compensation for regulatory goods or services supplied in each reporting period and the related rights and obligations. The income, expenses, assets and liabilities an entity reports by applying IFRS 20 supplement, but do not replace, the information the entity provides by applying IFRS 15 and other IFRS accounting standards.

IFRS 20 is effective for reporting periods beginning on or after 1 January 2029, with earlier application permitted.

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 30 Sept 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 it loses control and the retained interest becomes subject to 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 these financial statements are measured using the presentation currency which is Nigerian Naira.

The financial statements are presented in Nigerian Naira as required by the regulator.

a) 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.

b) 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 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.

Overlifts and underlifts represent differences between crude oil lifted and the Group's entitlement based on its share of production. 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. When an overlift occurs, other income is debited, and a corresponding liability is accrued. Overlifts are measured by reference to the observable lifted price at the date of lifting. Underlifts are measured at current market value at each reporting date. Changes in the underlift position are recognised in profit or loss as other (loss)/income. Instances, where Seplat controls the storage of crude and petroleum products at a terminal, differences between product sold and the Group's entitlement are 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 include 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 comprise of 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 comprise crude oil and natural gas liquids, and materials and supplies, including tubulars, casings, spares and well materials used in production and operational activities.

Inventories are measured at the lower of cost and net realisable value. Cost is determined using the weighted average method and includes purchase price and other directly attributable costs incurred in bringing inventories to their present location and condition.

For crude oil and natural gas liquids, net realisable value is based on estimated selling prices in the ordinary course of business, less estimated costs to sell. For materials and supplies, which are consumed in operations rather than held for resale, net realisable value is assessed based on expected recoverability through use, taking into account obsolescence, excess quantities and expected future utilisation.

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 amortised cost less impairment.

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 consists 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 30 September 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 and bonds. 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 financial assets at amortised cost 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, cash and bank balances and bonds.

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 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 30 September 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. Reasonable expectation of recovery include;

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 a 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 Group 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 are 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 held by the Group 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 Group's profit or loss after taxation and based on the weighted average of issued and fully paid ordinary shares outstanding during 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 operates a defined benefit pension plan. The Group previously operated a gratuity plan, which was discontinued in 2025. The defined benefit pension plan requires contributions to be made to a separately administered fund. The Group also provides certain additional post-employment benefits to employees. These benefits are unfunded.

The cost of providing benefits under the defined benefit plan is determined using the projected unit credit method and is calculated annually by independent actuaries. The liability or asset recognised in the statement of financial position represents the present value of the defined benefit obligation at the reporting date, less the fair value of plan assets (if any). The defined benefit obligation is determined using market yields at the reporting date on Nigerian government bonds with maturities that approximate the expected timing of the benefit payments.

Remeasurement gains and losses, arising from changes in financial and demographic assumptions and experience adjustments, are recognised immediately in other comprehensive income and

accumulated in retained earnings. Remeasurements are not reclassified to profit or loss in subsequent periods.

Past service costs are recognised in profit or loss on the earlier of:

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

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

The Group recognises 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 sufficient objective 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 Group 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 Group 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) or cash amounts based on the value of the Group's equity instruments (cash-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.

c) Modification of equity-settled awards to cash-settled awards

Where the terms of an equity-settled share-based payment awards are modified such that the Group becomes obligated to settle the awards in cash, the award is accounted for as cash-settled from the modification date. The cumulative amount recognised in the share-based payment reserve in respect of services received up to the modification date is reclassified from equity to a share-based payment liability.

Thereafter, the liability is measured at fair value at each reporting date and at settlement, with changes in fair value recognised in profit or loss over the remaining vesting period as services are rendered.

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) 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.

II) Foreign currency translation reserve

The Group has used the CBN rate to translate its US 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 ₦377.6 billion (2025: ₦40.4 billion). See Note 31 for the applicable translation rates.

III) Consolidation of Elcrest

On acquisition of 100% shares of Eland Oil and Gas Limited, 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 Limited 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 Limited is exposed to variable returns from the activities of Elcrest through dividends and interests.
- Eland Oil and Gas Limited 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.

IV) 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.

V) 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 steering committee which assesses the financial performance and position of the Group and makes strategic decisions. The steering committee, which has been identified as being the 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.

VI) 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 5.1.1.

IX. Intangible assets

The contract based intangible assets (licence) 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 basis 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. The management of financial risks is carried out by the corporate finance team 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, investments 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 investments, cash and bank balances as well as credit exposures to customers (i.e. MSN Energy, Transcorp, Shell western, Pillar, Azura, Geregu Power, Sapele Power, ExxonMobil and Nigerian Gas Marketing Company (NGMC) receivables), and other parties (i.e., NUIMS JV receivables, NEPL JV 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.

b) Estimation uncertainty in measuring impairment loss

The table below shows information on the sensitivity of the carrying amounts of the Group'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.

i. 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 30 Sept 2026	Effect on other components of equity before tax 30 Sept 2026
	₦ million	₦ million
Increase/decrease in loss given default		
+10%	(146)	—
-10%	146	—

	Effect on profit before tax 31 Dec 2025	Effect on other components of equity before tax 31 Dec 2025
	₦ million	₦ million
Increase/decrease in loss given default		
+10%	(3,846)	—
-10%	3,846	—

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 30 Sept 2026	Effect on other components of equity before tax 30 Sept 2026
	₦ million	₦ million
Increase/decrease in probability of default		
+10%	(146)	—
-10%	146	—

	Effect on profit before tax 31 Dec 2025	Effect on other components of equity before tax 31 Dec 2025
	₦ million	₦ million
Increase/decrease in probability of default		
+10%	(1,068)	—
-10%	1,068	—

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:

	Effect on profit before tax 30 Sept 2026 ₦ million	Effect on other components of equity before tax 30 Sept 2026 ₦ million
Increase/decrease in forward looking macroeconomic indicators		
+10%	(143)	—
-10%	143	—

	Effect on profit before tax 31 Dec 2025 ₦ million	Effect on other components of equity before tax 31 Dec 2025 ₦ million
Increase/decrease in forward looking macroeconomic indicators		
+10%	(613)	—
-10%	613	—

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 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.

30 Sept 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%	78,807	78,807	78,807	903,032	1,139,453
Variable interest rate borrowings						
The Mauritius Commercial Bank Ltd	6.5% + SOFR	2,348	5,780	10,900	11,205	30,233
Stanbic IBTC Bank Plc	6.5% + SOFR	2,114	5,202	9,809	10,083	27,208
Standard Bank of South Africa	6.5% + SOFR	1,175	2,890	5,450	5,602	15,117
First City Monument Ltd (FCMB)	6.5% + SOFR	1,127	2,774	5,232	5,378	14,511
Zenith Bank Plc	6.5% + SOFR	753	1,849	3,488	3,585	9,675
\$300 million Advance Payment Facility (APF)						
ExxonMobil Financing	5% + SOFR+CAS	11,865	135,832	—	—	147,697
Total variable interest borrowings		19,382	154,327	34,879	35,853	244,441
Other non-derivatives						
Trade and other payables**		1,149,035	—	—	—	1,149,035
Lease liability		19,688	28,024	17,158	4,321	69,191
		1,168,723	28,024	17,158	4,321	1,218,226
Total		1,266,912	261,158	130,844	943,206	2,602,120

** Trade and other payables (exclude non-financial liabilities such as provisions, taxes, pension and other non-contractual payables)

31 December 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%	85,129	85,129	85,129	1,060,611	1,315,998
Variable interest rate borrowings						
The Mauritius Commercial Bank Ltd	6.5% + SOFR	2,582	2,583	11,224	17,888	34,277
Stanbic IBTC Bank Plc	6.5% + SOFR	2,324	2,323	10,101	16,098	30,846
Standard Bank of South Africa	6.5% + SOFR	1,292	1,292	5,612	8,943	17,139
First City Monument Ltd (FCMB)	6.5% + SOFR	1,240	1,240	5,387	8,586	16,453
Zenith Bank Plc	6.5% + SOFR	827	827	3,591	5,724	10,969
\$300 million Advance Payment Facility (APF)						
ExxonMobil Financing	5%+SOFR+CAS	41,309	451,231	—	—	492,540
Total variable interest borrowings		49,574	459,496	35,915	57,239	602,224
Other non-derivatives						
Trade and other payables**		1,203,071	—	—	—	1,203,071
Lease liability		52,800	27,726	23,436	—	103,962
		1,255,871	27,726	23,436	—	1,307,033
Total		1,390,574	572,351	144,480	1,117,850	3,225,255

** Trade and other payables (exclude non-financial liabilities such as provisions, taxes, pension and other non-contractual payables)

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	
	30 Sept 2026 ₦ million	31 Dec 2025 ₦ million	30 Sept 2026 ₦ million	31 Dec 2025 ₦ million
Financial assets measured at amortised cost				
Trade and other receivables*	752,133	663,315	752,133	663,315
Cash and cash equivalents	739,867	476,970	739,867	476,970
Restricted cash	171,674	181,347	171,674	181,347
Other financial assets at amortised cost	3,852	—	3,794	—
	1,667,526	1,321,632	1,667,468	1,321,632
Financial assets measured at fair value				
Derivative financial assets	13,140	17,352	13,140	17,352
	13,140	17,352	13,140	17,352
Financial liabilities				
Interest-bearing loans borrowings**	1,051,962	1,443,289	1,060,889	1,462,032
Trade and other payables***	1,149,035	1,203,071	1,149,035	1,203,071
	2,200,997	2,646,360	2,209,924	2,665,103
Financial liabilities at fair value				
Derivative financial liabilities	16,388	9,041	16,388	9,041
	16,388	9,041	16,388	9,041

* Trade and other receivables exclude underlift, Gereg 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 exclude non-financial liabilities such as provisions, taxes, overlift, pension and other non-contractual payables.

Derivative liability of ₦16.39 billion (2025: ₦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.

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 period.

- 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 other financial assets at amortised cost is determined by reference to quoted prices in an active market, i.e. FMDQ. Accordingly, these other financial assets at amortised cost are classified within Level 1 of the fair value hierarchy.

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 nine months ended 30 September 2026, revenue from the gas segment of the business constituted 10% (9M 2025: 8%) of the Group's revenue and about 62% (9M 2025: 45%) of the Group's profit – mostly due to positive fiscal regime associated with the gas business. Management is committed to continued growth of the gas segment and will procure the required infrastructure for this segment of the business. The gas business is positioned separately within the Group and reports directly to the Director New Energy and Gas (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 and other gas facilities).

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

6.1 Segment profit disclosure

	9 months ended 30 Sept 2026	9 months ended 30 Sept 2025	3 Months ended 30 Sept 2026	3 Months ended 30 Sept 2025
	₦ million	₦ million	₦ million	₦ million
Oil	135,467	80,319	21,577	64,804
Gas	220,086	66,320	108,498	39,316
Total profit for the period	355,553	146,639	130,075	104,120

	9 months ended 30 Sept 2026	9 months ended 30 Sept 2025	3 Months ended 30 Sept 2026	3 Months ended 30 Sept 2025
	₦ million	₦ million	₦ million	₦ million
Oil				
Revenue from contracts with customers				
Crude oil sales (Note 7)	3,380,880	3,090,596	1,133,767	1,085,876
Cost of sales and general and administrative expenses	(2,251,843)	(2,109,204)	(826,355)	(557,453)
Other income/(loss)	116,959	30,097	166,616	(43,790)
Operating profit before impairment	1,245,996	1,011,489	474,028	484,633
Impairment reversal/(loss)	2,059	1,320	(1,903)	1,891
Fair value loss	(33,003)	(25,207)	(11,994)	(10,241)
Operating profit	1,215,052	987,602	460,131	476,283
Finance income (Note 13)	13,742	12,123	4,919	3,848
Finance expenses (Note 13)	(163,422)	(223,485)	(47,290)	(72,936)
Profit before taxation	1,065,372	776,240	417,760	407,195
Income tax expense (Note 14)	(929,905)	(695,921)	(396,183)	(342,391)
Profit for the period	135,467	80,319	21,577	64,804

*Other income/(loss) in the Oil business includes foreign exchange gain and majorly changes in underlift. Note 9 provides details for the combined business.

*Impairment on trade receivables relates to oil customers (Waltersmith and Pillar).

Gas	9 months ended 30 Sept 2026 ₦ million	9 months ended 30 Sept 2025 ₦ million	3 Months ended 30 Sept 2026 ₦ million	3 Months ended 30 Sept 2025 ₦ million
Revenue from contracts with customers				
Gas sales	225,619	214,636	85,271	67,977
Natural gas liquid sales	169,609	50,955	54,889	35,617
Cost of sales and general and administrative expenses	(171,949)	(152,860)	(50,608)	(79,696)
Other income	19,141	10,847	9,471	5,664
Operating profit before impairment	242,420	123,578	99,023	29,562
Impairment reversal/(loss)	1,063	(14,974)	(2,351)	(10,827)
Operating profit	243,483	108,604	96,672	18,735
Finance income (Note 13)	472	–	162	–
Share of profit/(loss) from joint venture accounted for using the equity method	33,372	(5,855)	37,690	(1,052)
Profit before taxation	277,327	102,749	134,524	17,683
Income tax (expense)/credit (Note 14)	(57,241)	(36,429)	(26,026)	21,633
Profit/(loss) for the period	220,086	66,320	108,498	39,316

Impairment reversal/loss recognised in the gas segment relate to MSN, Azura, Transcorp, Geregu 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.

	9 months ended 30 Sept 2026	9 months ended 30 Sept 2026	9 months ended 30 Sept 2026	9 months ended 30 Sept 2026	9 months ended 30 Sept 2025	9 months ended 30 Sept 2025	9 months ended 30 Sept 2025	9 months ended 30 Sept 2025
	Oil ₦ million	Gas ₦ million	Natural Gas Liquid ₦ million	Total ₦ million	Oil ₦ million	Gas ₦ million	Natural gas liquid ₦ million	Total ₦ million
Geographical markets								
Canada	—	—	—	—	112,460	—	—	112,460
Cote D'Ivoire	40,996	—	34,278	75,274	124,377	—	—	124,377
France	215,838	—	—	215,838	101,918	—	—	101,918
Germany	—	—	—	—	111,123	—	—	111,123
Ghana	—	—	—	—	—	—	36,096	36,096
India	146,231	—	—	146,231	639,581	—	—	639,581
Indonesia	388,214	—	—	388,214	317,814	—	—	317,814
Italy	97,783	—	—	97,783	203,017	—	—	203,017
Japan	—	—	19,109	19,109	—	—	—	—
Kenya	—	—	—	—	—	—	7,622	7,622
Malaysia	92,458	—	—	92,458	98,852	—	—	98,852
Namibia	—	—	23,491	23,491	—	—	—	—
Netherlands	317,400	—	—	317,400	259,608	—	—	259,608
Nigeria	604,632	225,619	54,192	884,443	24,301	214,636	7,237	246,174
Portugal	84,319	—	—	84,319	192,808	—	—	192,808
Singapore	439,588	—	38,539	478,127	—	—	—	—
South Africa	61,207	—	—	61,207	179,641	—	—	179,641
Spain	423,663	—	—	423,663	223,887	—	—	223,887
Turkey	—	—	—	—	132,425	—	—	132,425
Thailand	380,703	—	—	380,703	—	—	—	—
UK	—	—	—	—	95,485	—	—	95,485
Uruguay	77,704	—	—	77,704	62,901	—	—	62,901
USA	10,144	—	—	10,144	206,984	—	—	206,984
Vietnam	—	—	—	—	3,414	—	—	3,414
Revenue from contracts with customers	3,380,880	225,619	169,609	3,776,108	3,090,596	214,636	50,955	3,356,187
Geographical region								
Africa	706,836	225,619	111,962	1,044,417	328,319	214,636	50,955	593,910
Asia	1,447,193	—	57,647	1,504,840	1,059,661	—	—	1,059,661
Europe	1,139,003	—	—	1,139,003	1,320,271	—	—	1,320,271
Americas	87,848	—	—	87,848	382,345	—	—	382,345
Revenue from contracts with customers	3,380,880	225,619	169,609	3,776,108	3,090,596	214,636	50,955	3,356,187

	9 months ended 30 Sept 2026	9 months ended 30 Sept 2026	9 months ended 30 Sept 2026	9 months ended 30 Sept 2026	9 months ended 30 Sept 2025	9 months ended 30 Sept 2025	9 months ended 30 Sept 2025	9 months ended 30 Sept 2025
	Oil	Gas	Natural Gas Liquid	Total	Oil	Gas	Natural Gas Liquid	Total
	₦ million	₦ million	₦ million	₦ million	₦ million	₦ million	₦ million	₦ million
Timing of revenue recognition								
At a point in time	3,380,880	—	169,609	3,550,489	3,090,596	—	50,955	3,141,551
Over time	—	225,619	—	225,619	—	214,636	—	214,636
Revenue from contracts with customers	3,380,880	225,619	169,609	3,776,108	3,090,596	214,636	50,955	3,356,187
	3 Months ended 30 Sept 2026	3 Months ended 30 Sept 2026	3 Months ended 30 Sept 2026	3 Months ended 30 Sept 2026	3 Months ended 30 Sept 2025	3 Months ended 30 Sept 2025	3 Months ended 30 Sept 2025	3 Months ended 30 Sept 2025
	Oil	Gas	Natural gas liquid	Total	Oil	Gas	Natural Gas Liquid	Total
	₦ million	₦ million	₦ million	₦ million	₦ million	₦ million	₦ million	₦ million
Geographical markets								
Canada	—	—	—	—	16,727	—	—	16,727
Cote D'Ivoire	—	—	34,278	34,278	47,224	—	—	47,224
France	111,637	—	—	111,637	(546)	—	—	(546)
Germany	—	—	—	—	(595)	—	—	(595)
Ghana	—	—	—	—	—	—	28,420	28,420
India	115,525	—	—	115,525	185,303	—	—	185,303
Indonesia	—	—	—	—	123,337	—	—	123,337
Italy	(2,761)	—	—	(2,761)	2,653	—	—	2,653
Kenya	—	—	—	—	—	—	(40)	(40)
Malaysia	—	—	—	—	(530)	—	—	(530)
Namibia	—	—	(104)	(104)	—	—	—	—
Netherlands	238,883	—	—	238,883	103,911	—	—	103,911
Nigeria	318,835	85,271	21,068	425,174	5,436	67,977	7,237	80,650
Portugal	—	—	—	—	110,886	—	—	110,886
Singapore	(3,016)	—	—	(3,016)	—	—	—	—
South Africa	(140)	—	—	(140)	107,225	—	—	107,225
Spain	361,386	—	—	361,386	63,700	—	—	63,700
Turkey	—	—	—	—	128,978	—	—	128,978
UK	—	—	—	—	93,279	—	—	93,279
Uruguay	—	—	—	—	(337)	—	—	(337)
USA	—	—	—	—	99,243	—	—	99,243
Vietnam	—	—	—	—	(18)	—	—	(18)
Impact of exchange rate changes	(6,582)	—	(353)	(6,935)	—	—	—	—
Revenue from contracts with customers	1,133,767	85,271	54,889	1,273,927	1,085,876	67,977	35,617	1,189,470
Geographical region								
Africa	318,695	85,271	55,242	459,208	159,885	67,977	35,617	263,479
Asia	112,509	—	—	112,509	308,092	—	—	308,092
Europe	709,145	—	—	709,145	502,266	—	—	502,266
Americas	—	—	—	—	115,633	—	—	115,633
Impact of exchange rate changes	(6,582)	—	(353)	(6,935)	—	—	—	—
Revenue from contracts with customers	1,133,767	85,271	54,889	1,273,927	1,085,876	67,977	35,617	1,189,470

	3 Months ended 30 Sept 2026	3 Months ended 30 Sept 2026	3 Months ended 30 Sept 2026	3 Months ended 30 Sept 2026	3 Months ended 30 Sept 2025	3 Months ended 30 Sept 2025	3 Months ended 30 Sept 2025	3 Months ended 30 Sept 2025
	Oil ₦ million	Gas ₦ million	Natural gas liquid ₦ million	Total ₦ million	Oil ₦ million	Gas ₦ million	Natural Gas Liquid ₦ million	Total ₦ million
Timing of revenue recognition								
At a point in time	1,133,767	—	54,889	1,188,656	1,085,876	—	35,617	1,121,493
Over time	—	85,271	—	85,271	—	67,977	—	67,977
Revenue from contracts with customers	1,133,767	85,271	54,889	1,273,927	1,085,876	67,977	35,617	1,189,470

The Group's transactions with its major customers, Shell Western, Chevron, and ExxonMobil, constitute about 91% (₦3.07 trillion) (9M 2025: 92%, ₦2.9 trillion) of the total revenue from oil segment. Also, the Group's transactions with NGML, MSN, Egbin Power and Azura constitute about 65% (₦146.31 billion) (9M 2025: 72%, ₦155.6 billion) of the total revenue from gas segment.

The current period data reflects location of the final buyers based on information extracted from bill of lading.

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

	9 months ended 30 Sept 2026			9 months ended 30 Sept 2025		
	Oil ₦ million	Gas ₦ million	Total ₦ million	Oil ₦ million	Gas ₦ million	Total ₦ million
Impairment reversal/(loss) recognised during the period	2,059	1,063	3,122	1,320	(14,974)	(13,654)

	3 Months ended 30 Sept 2026			3 Months ended 30 Sept 2025		
	Oil ₦ million	Gas ₦ million	Total ₦ million	Oil ₦ million	Gas ₦ million	Total ₦ million
Impairment (loss)/reversal recognised during the period	(1,903)	(2,351)	(4,254)	1,891	(10,827)	(8,936)

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.

Total segment assets	Oil ₦ million	Gas ₦ million	Total ₦ million
30 September 2026	6,727,567	1,451,067	8,178,634
31 December 2025	7,521,563	1,207,818	8,729,381

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.

Total segment liabilities	Oil ₦ million	Gas ₦ million	Total ₦ million
30 September 2026	4,989,644	769,495	5,759,139
31 December 2025	5,429,717	656,428	6,086,145

7. Revenue from contract with customers

	9 months ended 30 Sept 2026	9 months ended 30 Sept 2025	3 Months ended 30 Sept 2026	3 Months ended 30 Sept 2025
	₦ million	₦ million	₦ million	₦ million
Crude oil sales	3,380,880	3,090,596	1,133,767	1,085,876
Gas sales	225,619	214,636	85,271	67,977
Natural gas liquid sales	169,609	50,955	54,889	35,617
	3,776,108	3,356,187	1,273,927	1,189,470

The major off-takers for crude oil are Chevron, Vitol, Shell Western, and ExxonMobil. The major off-takers for gas are Azura, MSN Energy, Egbin Power, and Nigerian Gas Marketing Company. The major off-taker for natural gas liquid is ExxonMobil.

8. Cost of sales

	9 months ended 30 Sept 2026	9 months ended 30 Sept 2025	3 Months ended 30 Sept 2026	3 Months ended 30 Sept 2025
	₦ million	₦ million	₦ million	₦ million
Royalties	611,079	587,750	217,687	197,087
Depletion, Depreciation and Amortisation	599,813	525,761	211,596	33,659
Depreciation of Right of Use Assets	24,067	26,754	7,513	2,878
Crude handling fees	91,613	91,328	32,047	31,536
Nigeria Export Supervision Scheme (NESS) fee	4,091	3,083	1,708	1,097
Niger Delta Development Commission Levy	45,378	53,692	12,585	19,986
Barging/Trucking	28,212	31,712	9,000	10,725
Operational & Maintenance expenses	748,068	680,104	279,716	287,743
	2,152,321	2,000,184	771,852	584,711

Operational & maintenance expenses relate mainly to maintenance costs, warehouse operations expenses, security expenses, community expenses, clean-up costs, fuel supplies and catering services. The increase in operational and maintenance expense in 9M 2026 is principally driven by Yoho restoration expense of ₦92 billion. Included in operational and maintenance expenses is gas flare penalty of ₦29.7 billion (9M 2025: ₦55.5 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 income/(loss) - net

	9 months ended 30 Sept 2026	9 months ended 30 Sept 2025	3 Months ended 30 Sept 2026	3 Months ended 30 Sept 2025
	₦ million	₦ million	₦ million	₦ million
Underlift/(Overlift)	54,730	5,900	146,877	(60,124)
Realised gain/(loss) on foreign exchange	1,406	25,751	(12,907)	25,751
Unrealised gain/(loss) on foreign exchange	15,498	(8,181)	5,489	(10,843)
Others	64,466	17,474	36,628	7,090
	136,100	40,944	176,087	(38,126)

Underlifts and overlifts represent differences between crude oil lifted and the Group's entitlement based on its share of production. Underlifts are measured at current market value. Overlifts are measured by reference to the observable lifted price at the date of lifting. Movements during the period are recognised within other income/(loss).

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

Others include tariffs from the usage of the Group's pipeline by others.

10. General and administrative expenses

	9 months ended 30 Sept 2026	9 months ended 30 Sept 2025	3 Months ended 30 Sept 2026	3 Months ended 30 Sept 2025
	₦ million	₦ million	₦ million	₦ million
Depreciation and amortisation	4,150	38,617	1,477	11,744
Depreciation of right of use assets	15,736	21,916	5,189	7,387
Professional & Consulting Fees	22,709	31,728	9,901	16,967
Auditor's remuneration	447	408	128	176
Directors Emoluments (Executives)	3,545	3,574	1,965	1,110
Directors Emoluments (Non-Executives)	3,976	4,829	1,317	1,296
Employee benefits	99,554	67,563	34,257	(3,549)
Share-based benefits	72,201	23,546	35,441	7,624
Donation	41	102	4	20
Flights and other travel costs	11,619	11,445	6,360	(1,377)
Other general expenses	37,493	58,152	9,072	11,040
	271,471	261,880	105,111	52,438

Depreciation expenses reflect depreciation on non-field related assets.

The increase in share-based benefits expense primarily reflects the impact of a higher Company share price on the valuation of share-based awards.

Included in the other general expenses are IT\communications consumables of ₦9.61 billion (9M 2025: ₦13.58 billion), contract labour ₦8.39 billion (9M 2025: ₦23.13 billion), repairs and maintenance expenses of ₦9.39 billion (9M 2025: ₦14.75 billion) and software license/maintenance fees of ₦6.68 billion (9M 2025: ₦3.70 billion).

10.1 Below are details of non-audit services provided by the auditors:

Entity	Service	PwC office	Fees (₦'million)	Period
Seplat Energy Plc	Remuneration committee advice	PwC UK	541	2026

11. Impairment reversal/(loss)

	9 months ended 30 Sept 2026	9 months ended 30 Sept 2025	3 Months ended 30 Sept 2026	3 Months ended 30 Sept 2025
	₦ million	₦ million	₦ million	₦ million
Impairment reversal/(loss) on financial assets-net (Note 11.1)	3,122	(13,654)	(4,254)	(8,936)
	3,122	(13,654)	(4,254)	(8,936)

11.1 Impairment reversal/(loss) on financial assets - net

	9 months ended 30 Sept 2026	9 months ended 30 Sept 2025	3 Months ended 30 Sept 2026	3 Months ended 30 Sept 2025
	₦ million	₦ million	₦ million	₦ million
Impairment reversal/(loss) on:				
NUIMS receivables	–	–	–	258
NEPL receivables	1,723	248	(747)	560
Trade receivables (Gas customers)*	413	(13,516)	(2,775)	(9,510)
Contract asset	(1,437)	(128)	(969)	14
Other receivables	2,423	(258)	237	(258)
Total impairment reversal/(loss)	3,122	(13,654)	(4,254)	(8,936)

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

12. Fair value loss

	9 months ended 30 Sept 2026	9 months ended 30 Sept 2025	3 Months ended 30 Sept 2026	3 Months ended 30 Sept 2025
	₦ million	₦ million	₦ million	₦ million
Hedge premium expenses	(24,757)	(16,088)	(6,046)	(4,624)
Fair value loss on derivatives (Note 19)	(8,246)	(9,119)	(5,948)	(5,617)
	(33,003)	(25,207)	(11,994)	(10,241)

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

13. Finance income/(cost)

	9 months ended 30 Sept 2026	9 months ended 30 Sept 2025	3 Months ended 30 Sept 2026	3 Months ended 30 Sept 2025
	₦ million	₦ million	₦ million	₦ million
Finance Income				
Interest income on fixed deposit	13,742	12,123	4,919	3,848
Interest income on other financial assets at amortised cost	472	–	162	–
Finance Income	14,214	12,123	5,081	3,848
Finance Charges				
Interest on loans and borrowings	(118,637)	(170,790)	(32,693)	(55,553)
Interest on lease liabilities	(5,128)	(9,624)	(1,533)	(3,180)
Unwinding of discount on provision for decommissioning	(39,657)	(43,071)	(13,064)	(14,203)
	(163,422)	(223,485)	(47,290)	(72,936)
Finance cost - net	(149,208)	(211,362)	(42,209)	(69,088)

Finance costs decreased due to lower gross debt in the period.

14. Taxation

The major components of income tax expense for the period ended 30 September 2026 and 2025 are:

	9 months ended 30 Sept 2026	9 months ended 30 Sept 2025	3 Months ended 30 Sept 2026	3 Months ended 30 Sept 2025
	₦ million	₦ million	₦ million	₦ million
Current tax:				
Current tax expense on profit for the period	919,011	704,413	307,632	167,579
Education Tax	–	24,546	–	7,089
NASENI Levy	–	2,358	–	1,129
Police Levy	–	51	–	23
Development levy	77,420	–	35,002	–
Total current tax	996,431	731,368	342,634	175,820
Deferred tax:				
Deferred tax (credit)/expense to profit or loss (Note 14.1)	(9,285)	982	79,575	144,938
Total tax expense in statement of profit or loss	987,146	732,350	422,209	320,758
Total tax charged for the period	987,146	732,350	422,209	320,758
Effective tax rate	74 %	83 %	76 %	76 %

In accordance with IAS 34: Interim Financial Reporting, income tax expense for the interim period has been determined using the estimated weighted average annual effective income tax rate expected for the full financial year. This estimate is reviewed at each interim reporting date and adjusted, where necessary, to reflect changes in the expected annual tax rate.

Income tax expense for the Group is analysed by Oil segment – 9 months ended ₦929.9 billion (9M 2025: ₦695.9 billion); 3 months ended ₦396.2 billion (3M 2025: ₦342.4 billion) and Gas Segment – 9 months ended ₦57.2 billion (9M 2025: ₦36.4 billion); 3 months ended ₦26.0 billion (3M 2025: ₦21.6 billion).

The Group has applied the provisions of the Nigeria Tax Act 2025 which became effective in January 2026 and require Education Tax, the NASENI Levy, and the Police Trust Fund Levy to be consolidated into Development Levy.

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	Exchange difference	Balance as at 30 Sept 2026
	₦ million	₦ million	₦ million	₦ million	₦ million
Deferred tax assets	289,581	(64,621)	–	(19,722)	205,238
Deferred tax liabilities	(1,742,201)	73,906	–	127,351	(1,540,944)
	(1,452,620)	9,285	–	107,629	(1,335,706)

	Balance as at 1 January 2025	(Charged) /credited to profit or loss	Credited to other comprehensive income	Exchange difference	Balance as at 30 Sept 2025
	₦ million	₦ million	₦ million	₦ million	₦ million
Deferred tax assets	353,954	(11,617)	–	(15,592)	326,745
Deferred tax liabilities	(1,615,677)	10,635	–	73,281	(1,531,761)
	(1,261,723)	(982)	–	57,689	(1,205,016)

In line with the requirements of IAS 12, the Group offset the deferred tax assets against the deferred tax liabilities arising from similar transactions.

15. Computation of cash generated from operations

	Notes	9 months ended 30 Sept 2026 ₦ million	9 months ended 30 Sept 2025 ₦ million
Profit before tax		1,342,699	878,989
Adjusted for:			
Depletion, depreciation and amortisation		603,963	564,378
Depreciation of right-of-use asset		39,802	48,669
Impairment (reversal)/loss on financial assets	11.1	(3,122)	13,654
Interest income	13	(14,214)	(12,122)
Interest expense on bank loans	13	118,637	170,790
Interest on lease liabilities	13	5,128	9,624
Unwinding of discount on provision for decommissioning	13	39,657	43,072
Fair value loss on derivatives	12	8,246	9,119
Hedge premium expenses	12	24,757	16,089
Unrealised foreign exchange (gain)/loss	9	(15,498)	8,181
Share-based payment expenses	8 & 10	95,163	23,546
Share of (profit)/loss from joint venture		(33,372)	5,855
Defined benefit plan	24.1	(227)	(7,251)
Changes in working capital: (excluding the effects of exchange differences)			
Trade and other receivables		(238,972)	233,053
Inventories		(35,457)	16,150
Prepayments		15,845	48,774
Contract assets		(26,882)	(52,248)
Trade and other payables		94,384	133,190
Cash generated from operations		2,020,537	2,151,512

16. Oil and gas properties

During the nine months ended 30 September 2026, the Group acquired oil and gas properties amounting to ₦230.56 billion (Dec 2025: ₦396 billion)

17. Trade and other receivables

	30 Sept 2026 ₦ million	31 Dec 2025 ₦ million
Financial instruments		
Trade receivables (Note 17.1)	417,389	193,504
NEPL receivables (Note 17.2)	81,863	121,337
NUIMS receivables (Note 17.3)	140,324	289,437
Receivables from ANOH (Note 17.5)	32,524	5,029
Other receivables (Note 17.4)	80,033	54,008
Non-financial instruments		
Other receivables (Note 17.4)	7,955	2,965
Underlift	76,766	7,603
Advances to suppliers-others	12,368	9,203
	849,222	683,086

17.1 Trade receivables

Included in the trade receivables are:

	30 Sept 2026 ₦ million	31 Dec 2025 ₦ million
Geregu	7,516	17,964
Waltersmith	–	3,767
Sapele Power	12,454	12,649
NGMC	2,718	373
MSN ENERGY	28,998	21,701
Pillar	20,896	13,247
Shell Western	55,607	46,839
Azura	19,781	3,619
Transcorp Power	8,219	7,027
Ardova Plc	19,486	–
TotalEnergies	2,908	–
NAOC JV	2,326	–
ExxonMobil	285,109	117,798
Others - crude injectors	2,753	505
Impairment allowance	(51,382)	(51,985)
Total	417,389	193,504

Reconciliation of trade receivables

	30 Sept 2026 ₦ million	31 Dec 2025 ₦ million
Balance as at 1 January	245,492	567,051
Additions during the period	3,404,876	3,598,263
Receipt for the period	(3,160,941)	(4,108,584)
Exchange difference	(20,656)	188,762
Gross carrying amount	468,771	245,492
Less: Impairment allowance	(51,382)	(51,988)
Balance as at	417,389	193,504

Reconciliation of impairment allowance on trade receivables

	30 Sept 2026 ₦ million	31 Dec 2025 ₦ million
Loss allowance as at 1 January	51,988	32,134
(Decrease)/increase in loss allowance	(413)	21,739
Exchange difference	(193)	(1,885)
Loss allowance as at	51,382	51,988

17.2 NEPL receivables

The outstanding cash calls due to Seplat from its JOA partner, NEPL is ₦85.19 billion (Dec 2025 : ₦126.6 billion).

Reconciliation of NEPL receivables

	30 Sept 2026 ₦ million	31 Dec 2025 ₦ million
Balance as at 1 January	126,606	67,954
Addition during the period	309,192	550,220
Receipts during the period	(348,378)	(519,088)
Exchange difference	(2,234)	27,520
Gross carrying amount	85,186	126,606
Less: impairment allowance	(3,323)	(5,269)
Balance as at	81,863	121,337

Reconciliation of impairment allowance on NEPL receivables

	30 Sept 2026 ₦ million	31 Dec 2025 ₦ million
Loss allowance as at 1 January	5,269	4,339
(Decrease)/increase in loss allowance	(1,723)	1,813
Exchange difference	(223)	(883)
Loss allowance as at	3,323	5,269

17.3 NUIMS receivables

The outstanding cash calls due to Seplat from its JOA partner, NUIMS is ₦140.32 billion (Dec 2025: ₦289.4 billion).

Reconciliation of NUIMS receivables

	30 Sept 2026 ₦ million	31 Dec 2025 ₦ million
Balance as at 1 January	289,437	454,571
Addition during the period	1,123,604	1,518,443
Receipts during the period	(1,257,709)	(1,755,049)
Exchange difference	(15,008)	71,472
Balance as at	140,324	289,437

17.4 Other receivables

Reconciliation of other receivables

	30 Sept 2026 ₦ million	31 Dec 2025 ₦ million
Balance as at 1 January	143,037	173,107
Addition during the period	50,298	10,586
Receipts for the period	(19,128)	(41,828)
Exchange difference	(8,994)	1,172
Gross carrying amount	165,213	143,037
Less: impairment allowance	(77,225)	(86,064)
Balance as at	87,988	56,973

Other receivables include receivables from 3rd party injectors (tariff income) of ₦16.4 billion (Dec 2025: ₦17 billion), employee receivables of ₦8.1 billion, receivable from All Grace for Ubima Disposal of ₦22.5 billion (Dec 2025: ₦24.9 billion), receivable from Naptha for Abiala Marginal field of ₦1.7 billion (Dec 2025: ₦4.2 billion).

Reconciliation of impairment allowance on other receivables

	30 Sept 2026 ₦ million	31 Dec 2025 ₦ million
Loss allowance as at 1 January	86,064	79,667
Decrease in loss allowance	(2,423)	(2,048)
Exchange difference	(6,416)	8,445
Loss allowance as at	77,225	86,064

17.5 Receivables from joint venture (ANOH)

	30 Sept 2026 ₦ million	31 Dec 2025 ₦ million
Balance as at 1 January	9,389	7,253
Additions during the period	28,934	2,544
Receipts for the period	(868)	–
Exchange difference	(895)	(408)
Gross carrying amount	36,560	9,389
Less: impairment allowance	(4,036)	(4,360)
Balance as at	32,524	5,029

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

	30 Sept 2026 ₦ million	31 Dec 2025 ₦ million
Loss allowance as at 1 January	4,360	4,664
Increase/(decrease) in loss allowance	–	–
Exchange difference	(324)	(304)
Loss allowance as at	4,036	4,360

18. Contract assets

	30 Sept 2026 ₦ million	31 Dec 2025 ₦ million
Revenue on gas sales	33,557	17,307
Revenue on oil sales	21,898	14,316
Impairment allowance on contract assets	(3,720)	(2,464)
	51,735	29,159

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, Egbin Power, AGPC, Waltersmith, Shell Western and Chevron, 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 payment 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. Upon obtaining gas receipt certificates, bill of lading and other reconciliation documents with the respective customers/offtakers, after which invoices are issued, the respective balances are 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:

	30 Sept 2026 ₦ million	31 Dec 2025 ₦ million
Balance as at 1 January	31,623	24,173
Additions during the period	630,648	642,386
Amount billed during the period	(603,583)	(634,779)
Exchange difference	(3,233)	(157)
Gross contract assets	55,455	31,623
Impairment allowance	(3,720)	(2,464)
Balance as at	51,735	29,159

Reconciliation of impairment allowance on contract assets

	30 Sept 2026 ₦ million	31 Dec 2025 ₦ million
Loss allowance as at 1 January	2,464	255
Increase in loss allowance during the period	1,437	2,353
Exchange difference	(181)	(144)
Loss allowance as at	3,720	2,464

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. Derivative financial assets and liabilities are presented as current to the extent they are expected to be realised or 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

	30 Sept 2026 ₦ million	31 Dec 2025 ₦ million
Opening Balance	17,352	–
Hedge expense	(24,773)	–
Premium paid	21,767	18,342
Exchange difference	(1,206)	(990)
Balance as at	13,140	17,352

19.2 Derivative financial liabilities

	30 Sept 2026 ₦ million	31 Dec 2025 ₦ million
Opening Balance	(9,041)	(6,073)
Unrealized fair value loss	(8,246)	330
Prior year premium paid	–	(3,886)
Exchange difference	899	588
Balance as at	(16,388)	(9,041)

19.3 For cashflow purposes:

	30 Sept 2026 ₦ million	31 Dec 2025 ₦ million
Prior period premium paid	–	330
Hedge premium prepaid	13,514	18,342
Current period hedge expense paid	8,253	28,834
	21,767	47,506

During the period ended 30 September 2026, the Group entered into economic crude oil hedge contracts with an average strike price of ₦70,220/bbl (Dec 2025: ₦75,925/bbl) for 18 million barrels (Dec 2025: 5.25 million barrels) at a cost of ₦30.7 billion (Dec 2025: ₦10.1 billion).

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.

	30 Sept 2026	31 Dec 2025
	₦ million	₦ million
Fixed deposits	35	69
Cash at bank	740,158	477,253
Gross cash and cash equivalents	740,193	477,322
Impairment allowance	(326)	(352)
Net cash and cash equivalents	739,867	476,970

20.1 Reconciliation of impairment allowance on cash and cash equivalents

	30 Sept 2026	31 Dec 2025
	₦ million	₦ million
Loss allowance as at 1 January	352	376
Increase/ (decrease) in loss allowance	—	—
Exchange difference	(26)	(24)
Loss allowance as at	326	352

20.2 Restricted cash

	30 Sept 2026	31 Dec 2025
	₦ million	₦ million
Restricted cash	171,674	181,347
	171,674	181,347

20.3 Movement in restricted cash

	30 Sept 2026	31 Dec 2025
	₦ million	₦ million
Opening balance	181,347	202,983
Increase/(decrease) in restricted cash	3,905	(8,887)
Exchange difference	(13,578)	(12,749)
Closing balance	171,674	181,347

Included in the restricted cash is ₦160.63 billion (Dec 2025: ₦171.5 billion), which relates to SEPNU's decommissioning and abandonment deposit of ₦137.25 billion (Dec 2025: ₦148.26 billion), as well as the host community fund of ₦23.38 billion (Dec 2025: ₦23.3 billion). SEPNU's decommissioning and abandonment deposit has been classified as current because it is held under a one-year letter of credit facility.

Also included in the restricted cash balance is ₦3.7 billion (Dec 2025: ₦3.5 billion) and ₦5.8 billion (Dec 2025: ₦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 ₦0.8 billion (Dec 2025: ₦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 ₦0.7 billion (Dec 2025: ₦0.6 billion) for unclaimed dividend.

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

21. Other financial assets at amortised cost

	30 Sept 2026	31 Dec 2025
	₦ million	₦ million
Opening Balance	–	–
Addition	3,871	–
Interest Income	472	–
Repayment	(491)	–
Gross carrying amount	3,852	–
Impairment allowance	–	–
Net carrying amount	3,852	–

Split into:

	30 Sept 2026	31 Dec 2025
	₦ million	₦ million
Current	980	–
Non-current	2,872	–
	3,852	–

During the period, Seplat West Limited entered into a debt settlement agreement with Geregu Power PLC for outstanding gas sales receivables. As part of the settlement, and in line with the Presidential Power Sector Debt Reduction Programme, the company received NBET Finance Company PLC Series I (Tranche B) Bonds with a face value of ₦3.87 billion, bearing interest at 17.50% per annum and maturing in January 2033. The bonds have been recognised at amortised cost in accordance with the Group's accounting policy in Note 3.22.

22. Share capital

22.1 Authorised and issued share capital

	30 Sept 2026	31 Dec 2025
	₦ million	₦ million
Authorised ordinary share capital		
599,944,561 (Dec 2025: 599,944,561) ordinary shares denominated in Naira of 50 kobo per share	300	300
Issued and fully paid		
599,944,561 (Dec 2025: 599,944,561) issued shares denominated in Naira of 50 kobo per share	300	300

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

22.2 Movement in total equity attributable to owners of the parent

	Number of shares Shares	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	Total ₦ 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	-	-	-	-	-	-	348,400	-	348,400
Other comprehensive loss	-	-	-	-	-	-	-	(188,744)	(188,744)
Dividend paid	-	-	-	-	-	-	(240,277)	-	(240,277)
Vested shares during the period	-	-	(68,989)	(27,897)	96,886	-	-	-	-
PAYE tax remitted on vested shares	-	-	-	-	(49,063)	-	-	-	(49,063)
Transfer to share based liability	-	-	-	(5,939)	-	-	-	-	(5,939)
Share based payments	-	-	-	14,442	-	-	-	-	14,442
Share repurchased	-	-	-	-	(94,925)	-	-	-	(94,925)
Closing balance as at 30 Sept 2026	599,944,561	300	81,813	5,591	(147,372)	5,932	450,532	2,009,338	2,406,134

	Number of shares Shares	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	Total ₦ million
Opening balance as at 1 January 2025	588,444,561	297	87,375	15,558	(3,570)	5,932	312,635	2,393,009	2,811,236
Profit for the period	-	-	-	-	-	-	243,179	-	243,179
Other comprehensive loss	-	-	-	-	-	-	(710)	(194,699)	(195,409)
Dividend paid	-	-	-	-	-	-	(212,695)	-	(212,695)
Reclassification of foreign currency translation reserve	-	-	-	-	-	-	-	(228)	(228)
Share based payments	-	-	-	36,510	-	-	-	-	36,510
Vested shares during the year	-	-	-	(27,083)	27,083	-	-	-	-
PAYE tax remitted on vested shares	-	-	-	-	(13,443)	-	-	-	(13,443)
Share repurchased	-	-	-	-	(46,910)	-	-	-	(46,910)
Shares issued	11,500,000	3	63,427	-	(63,430)	-	-	-	-
Closing balance as at 31 December 2025	599,944,561	300	150,802	24,985	(100,270)	5,932	342,409	2,198,082	2,622,240

22.3 Employee share-based payment scheme

As at 30 Sept 2026, the Group had 29,575,922 shares (Dec 2025: 49,999,973 shares), comprising 6,918,200 equity-settled awards and 22,657,722 cash-settled awards, which were 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 nine months ended 30 Sept 2026, 22,229,727 shares were vested (Dec 2025: 13,342,715 shares).

22.4 Treasury shares

This relates to shares purchased from the market or issued by the company to fund the Group's Long-Term Incentive Plan. The programme commenced from 1 March 2021 and are held by the Trustees under the Trust for the benefit of the Group's employee beneficiaries covered under the Trust.

23. Interest-bearing loans and borrowings

23.1 Reconciliation of interest-bearing loans and borrowings

Below is the reconciliation of interest-bearing loans and borrowings for 30 September 2026:

	Borrowings within 1 year ₦ million	Borrowings above 1 year ₦ million	Total ₦ million
Balance as at 1 January 2026	104,154	1,339,135	1,443,289
Interest accrued	118,637	–	118,637
Principal paid	(273,284)	–	(273,284)
Interest repayment	(111,265)	–	(111,265)
Other financing charges	(26,297)	–	(26,297)
Transfers	287,349	(287,349)	–
Exchange differences	(7,601)	(91,517)	(99,118)
Carrying amount as at 30 Sept 2026	91,693	960,269	1,051,962

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

	Borrowings within 1 year ₦ million	Borrowings due above 1 year ₦ million	Total ₦ million
Balance as at 1 January 2025	690,270	1,409,480	2,099,750
Additions	–	953,106	953,106
Interest accrued	213,239	–	213,239
Principal paid	(1,562,982)	–	(1,562,982)
Interest repayment	(152,600)	–	(152,600)
Transfers	930,362	(930,362)	–
Exchange differences	(14,135)	(93,089)	(107,224)
Carrying amount as at 31 Dec 2025	104,154	1,339,135	1,443,289

*Transfers represent the reclassification from non-current to current as contractual cash flows become due within the next 12 months as a result of the passage of time.

Other financing charges include term loan arrangement and commitment fees, annual bank charges, technical bank fee, agency fee and analytical services in connection with annual service charge. These costs do not form an integral part of the effective interest rate. As a result, they are not included in the measurement of the interest-bearing loan.

23.2 Amortised cost of borrowings

	30 Sept 2026 ₦ million	31 Dec 2025 ₦ million
\$650 million Senior notes – March 2025	847,041	932,497
\$80 million Senior reserve-based lending (RBL) facility	73,313	76,796
\$300 million Advance Payment Facility	131,608	433,996
	1,051,962	1,443,289

\$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 at the time of issuance. The \$650 million bond issuance was used exclusively to redeem the maturing \$650 million note, with transaction costs covered from the Group's cash reserves. The amortised cost for the senior notes as at the reporting period is ₦847.04 billion, \$637.52 million (Dec 2025: ₦932.5 billion, \$649.7 million) 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. Current drawdown under the financing is \$55.25 million, which is below the committed level of \$80 million for the period up to and including 30 June 2027. The amortised cost for the senior notes as at the reporting period is ₦73.31 billion, \$55.18 million (Dec 2025: ₦76.7 billion, \$53.6 million).

\$400 million Revolving credit facility

The RCF was refinanced to \$400 million on January 31, 2026. All in pricing improved to SOFR + 4.5% from SOFR + 5.26% (including a credit adjustment spread). The facility is no longer amortising and includes a bullet repayment at final maturity, with maturity extended to 30 September 2029, i.e., maturing before the \$650 million senior notes. The facility is currently fully undrawn.

\$300 million Advance payment facility

The \$300 million APF was closed in December 2024 to provide financing for the completion of the MPNU acquisition. The facility was fully drawn; however, the Group has repaid and cancelled \$200M under the APF in May and June 2026. The current outstanding drawdown amount is \$100 million.

The APF 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 and matures in December 2027. The amortised cost for the APF as at the reporting period is ₦131.61 billion, \$99.05 million (Dec 2025: ₦433.9 billion, \$302.3 million).

24. Employee benefit obligation

24.1 Defined benefit plan

During the reporting period, the defined benefit plan was presented as a net defined benefit liability of ₦1.24 billion (Dec. 2025: ₦3.9 billion).

	30 Sep 2026	Movement during the period	31 Dec 2025
	₦ million	₦ million	₦ million
Net defined benefit assets/(liabilities) recognised in the financial position			
Present value of defined benefit obligation	91,742	(8,491)	100,233
Fair value of plan assets	(90,501)	5,828	(96,329)
	1,241	(2,663)	3,904

	30 Sep 2026
	₦ million
Movement during the period for the defined benefit assets/(liabilities):	
Income on plan asset (note 15)	227
Charged to receivables	2,214
Exchange differences	(5,104)
	(2,663)

25. Trade and other payables

	30 Sept 2026 ₦ million	31 Dec 2025 ₦ million
Financial Instruments		
Trade payables	653,223	740,168
Accruals and other payables	495,812	462,903
Non-Financial Instruments		
Share-based payment liability (Note 25.1)	95,050	3,229
NDDC levy	34,199	17,917
Royalties payable	88,115	86,025
	1,366,399	1,310,242

Split into:

	30 Sept 2026 ₦ million	31 Dec 2025 ₦ million
Current	1,304,685	1,310,242
Non-current *	61,714	—
	1,366,399	1,310,242

Included in accruals and other payables are field accruals of ₦302.4 billion (Dec 2025: ₦146.1 billion), balance received for asset held for sale of ₦13.2 billion (Dec 2025: ₦14.3 billion) and other vendor payables of ₦180.2 billion (Dec 2025: ₦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.

* Non-current portion relates to share-based payment liability due after 12 months.

25.1. Share-based payment liability

The Group granted share-based awards to employees that will be settled in cash. These awards comprise the 2024 LTIP, 2025 LTIP and 2026 LTIP. Awards granted under these LTIPs to employees below Board level will be settled in cash and have a three year vesting period. Share-based payment liability represents the Group's obligation in respect of these cash-settled LTIP awards granted to employees below Board level.

	30 Sep 2026 ₦ million	31 Dec 2025 ₦ million
Opening balance	3,229	—
Additions	80,723	3,229
Transfer from share-based payment reserve *	5,939	—
Exchange Difference	5,159	—
Closing balance	95,050	3,229

* During the period, the terms of the 2024 LTIP were changed such that awards granted to employees below Board level, which were previously classified as equity-settled, will now be settled in cash. The modification took effect on 1 January 2026 and affected 12.49 million unvested awards. Following the modification, a cash-settled share-based payment liability was recognised in accordance with IFRS 2. The modification resulted in a transfer of ₦5.94 billion from share-based payment reserve to share-based payment liability and an incremental fair value expense of ₦31.29 billion, which has been recognised as share-based payment expense during the reporting period. The fair value of the share-based liability was subsequently remeasured at 30 September 2026 using a binomial valuation model.

26. 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 during 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.

	9 months ended 30 Sept 2026 ₦ million	9 months ended 30 Sept 2025 ₦ million	3 Months ended 30 Sept 2026 ₦ million	3 Months ended 30 Sept 2025 ₦ million
Profit attributable to Equity holders of the parent	348,400	141,944	129,165	105,347
Profit/(loss) attributable to Non-controlling interests	7,153	4,695	910	(1,227)
Profit for the period	355,553	146,639	130,075	104,120

	Shares '000	Shares '000	Shares '000	Shares '000
Weighted average number of ordinary shares in issue	599,945	591,001	599,945	591,001
Weighted average number of ordinary shares adjusted for the effect of dilution	599,945	591,001	599,945	591,001

	₦	₦	₦	₦
Basic earnings per share for the period				
Basic earnings per share	580.72	240.18	215.29	178.25
Diluted earnings per share	580.72	240.18	215.29	178.25
Profit used in determining basic/diluted earnings per share	348,400	141,944	129,165	105,347

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.

27. Proposed dividend

For the third quarter ended 30 September 2026, the Group's directors declared an interim dividend of ₦252.45 per share, consisting of core dividend of ₦66.43 per share and special dividend of ₦186.01 per share. (Dec 2025: final dividend of ₦72.15 and special dividend of ₦47.62).

28. 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 21.07% 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 following are details of transactions and balances with related parties. The terms of these transactions are at arm's length.

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 ₦551.7 billion revolving credit facility ('RCF'), which remained undrawn as at the reporting date. UBA also provides a ₦1.3 billion customs bond for operational cargo clearance for an annual fee of 0.15%. At the end of the reporting period, the Group held balances of ₦119.7 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 ₦3.1 billion. As at the reporting date, amounts due from Transcorp Power Limited was ₦8.2 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 ₦1.1 billion. The Group had an outstanding payable balance of ₦30.1 million with Transcorp Hotels Plc as at the reporting date.

Shareholders of the parent company

Vaaris Resources JVCo Limited: Following the sale of TotalEnergies EP Nigeria Limited's (TEPNG) non-operated interest in the Renaissance JV (formerly SPDC) licences to Vaaris, Seplat consented, through a Deed of Novation, to Vaaris replacing TEPNG under the ANOH Unitization and Unit Operating Agreement (UUA), to which the Renaissance JV is a party. Vaaris is controlled by Platform Petroleum, a shareholder of Seplat. No transactions or outstanding balances arose from the arrangement.

Entities controlled by Directors of the Company

Vaaris Resources JVCo Limited: Mr Kazeem Raimi, a Non-Executive Director of Seplat PLC, is also a director of Vaaris, which replaced TEPNG under the ANOH Unitization and Unit Operating Agreement (UUA) pursuant to a Deed of Novation consented to by Seplat during the period. No transactions or outstanding balances arose from the arrangement.

29. Commitments and contingencies

29.1 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 30 Sept 2026 is ₦450.17 billion, (Dec 2025: ₦395.77 billion). The contingent liability for the year 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.

30. Events after the reporting period

There are no other events which could have had a material effect on the financial position of the Group as at 30 September 2026 and its financial performance for the period then ended that have not been adequately provided for or disclosed in these financial statements.

31. Exchange rates used in translating the accounts to Naira

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

		30 Sept 2026	30 Sept 2025	31 Dec. 2025
	Basis	N/\$	N/\$	N/\$
Property, plant & equipment – opening balances	Historical rate	1435.26	1535.32	1535.32
Property, plant & equipment – additions	Average rate	1,366.42	1,541.92	1,517.09
Property, plant & equipment – closing balances	Closing rate	1,328.66	1465.18	1435.26
Current assets	Closing rate	1,328.66	1465.18	1435.26
Current liabilities	Closing rate	1,328.66	1465.18	1435.26
Equity	Historical rate	Historical	Historical	Historical
Income and Expenses:	Overall Average rate	1,366.42	1,541.92	1,517.09

Unaudited condensed consolidated interim financial statements for the nine months ended 30 September 2026 (USD)

29 October 2026

Reliable energy,
limitless potential

Condensed consolidated interim statement of profit or loss and other comprehensive income

For the nine months ended 30 September 2026

		9 months ended 30 Sept 2026	9 months ended 30 Sept 2025	3 Months ended 30 Sept 2026	3 Months ended 30 Sept 2025
		Unaudited \$'000	Unaudited \$'000	Unaudited \$'000	Unaudited \$'000
	Notes				
Revenue from contracts with customers	7	2,763,504	2,176,629	943,460	778,908
Cost of sales	8	(1,575,156)	(1,297,176)	(571,026)	(384,068)
Gross profit		1,188,348	879,453	372,434	394,840
Other income/(loss) -net	9	99,604	26,553	128,690	(24,454)
General and administrative expenses	10	(198,674)	(169,840)	(77,667)	(34,731)
Impairment reversal/(loss) on financial assets	11	2,285	(8,855)	(3,080)	(5,811)
Fair value loss	12	(24,153)	(16,348)	(8,871)	(6,694)
Operating profit		1,067,410	710,963	411,506	323,150
Finance income	13	10,403	7,862	3,760	2,524
Finance costs	13	(119,599)	(144,939)	(35,127)	(47,822)
Finance cost - net	13	(109,196)	(137,077)	(31,367)	(45,298)
Share of profit/(loss) from joint venture accounted for using the equity method		24,423	(3,797)	27,564	(699)
Profit before taxation		982,637	570,089	407,703	277,153
Income tax expense	14	(722,432)	(474,960)	(311,507)	(209,447)
Profit for the period		260,205	95,129	96,196	67,706
Attributable to:					
Equity holders of the parent		254,970	92,084	95,502	68,481
Non-controlling interests		5,235	3,045	694	(775)
		260,205	95,129	96,196	67,706
Earnings per share for the period					
Basic earnings per share \$	26	0.42	0.16	0.16	0.12
Diluted earnings per share \$	26	0.42	0.16	0.16	0.12
Profit for the period		260,205	95,129	96,196	67,706
Other comprehensive income:					
Total comprehensive income for the period (net of tax)		260,205	95,129	96,196	67,706
Attributable to:					
Equity holders of the parent		254,970	92,084	95,502	68,481
Non-controlling interests		5,235	3,045	694	(775)
		260,205	95,129	96,196	67,706

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

Condensed consolidated interim statement of financial position

As at 30 September 2026

	Notes	30 Sept 2026 Unaudited \$'000	31 Dec 2025 Audited \$'000
Assets			
Non-current assets			
Oil & gas properties	16	2,948,326	3,119,818
Other property, plant and equipment		335,382	360,573
Right-of-use assets		86,298	114,054
Intangible assets		495,458	566,355
Other assets		58,190	90,815
Investment accounted for using equity method		284,192	259,769
Long-term prepayments		14,325	15,650
Deferred tax assets	14.1	154,470	201,762
Other financial assets at amortised cost	21	2,161	—
Total non-current assets		4,378,802	4,728,796
Current assets			
Inventory		366,715	340,766
Trade and other receivables	17	639,155	475,932
Short-term prepayments		22,983	33,254
Contract assets	18	38,937	20,315
Derivative financial assets	19	9,890	12,090
Other financial assets at amortised cost	21	738	—
Restricted cash	20.2	129,209	126,351
Cash and cash equivalents	20	556,855	332,326
Total current assets		1,764,482	1,341,034
Asset held for sale		12,270	12,270
Total assets		6,155,554	6,082,100
Equity and liabilities			
Equity attributable to shareholders			
Issued share capital	22.2	1,868	1,868
Share premium	22.2	511,696	560,371
Share-based payment reserve	22.2	21,088	42,961
Treasury shares	22.2	(103,821)	(69,350)
Capital contribution	22.2	40,000	40,000
Retained earnings	22.2	1,327,419	1,248,293
Foreign currency translation reserve	22.2	2,887	2,887
Non-controlling interest		19,866	14,625
Total shareholder's equity		1,821,003	1,841,655
Non-current liabilities			
Interest-bearing loans and borrowings	23	722,735	933,028
Lease liabilities		23,189	46,700
Provision for decommissioning obligation		843,240	814,225
Deferred tax liability	14.1	1,159,773	1,213,860
Defined benefit plan	24.1	934	2,720
Other payables	25	46,448	—
Total non-current liabilities		2,796,319	3,010,533
Current liabilities			
Interest-bearing loans and borrowings	23	69,011	72,568
Lease liabilities		25,718	20,318
Derivative financial liability	19	12,334	6,299
Trade and other payables	25	981,960	912,886
Other provisions		3,521	3,415
Current tax liabilities		445,688	214,426
Total current liabilities		1,538,232	1,229,912
Total liabilities		4,334,551	4,240,445
Total shareholders' equity and liabilities		6,155,554	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 nine months ended 30 September 2026 were authorised for issue on 29 October 2026 in accordance with a resolution of the Directors signed on its behalf by:



U. U. Udoma

FRC/2013/NBA/00000001796

Chairman

29 October 2026



E. Okon

FRC/2024/PRO/COREN/004/460715

Chief Executive Officer

29 October 2026



E. Adaralegbe

FRC/2017/ICAN/006/00000017591

Chief Financial Officer

29 October 2026

Condensed consolidated interim statement of changes in equity

For the period ended 30 September 2026

	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 equity \$'000
At 1 January 2025- restated	1,864	518,564	36,747	(5,609)	40,000	1,228,817	2,233	15,679	1,838,295
Profit for the period	–	–	–	–	–	92,084	–	3,045	95,129
Total comprehensive income for the period	–	–	–	–	–	92,084	–	3,045	95,129
Transactions with owners in their capacity as owners:									
Dividend paid	–	–	–	–	–	(95,273)	–	–	(95,273)
Share-based payments	–	–	12,082	–	–	–	–	–	12,082
Vested shares	–	–	(16,686)	16,686	–	–	–	–	–
Transfer to share-based payment liability	–	–	(3,336)	–	–	–	–	–	(3,336)
Shares repurchased	–	–	–	(10,000)	–	–	–	–	(10,000)
Shares issued	4	40,874	–	(40,878)	–	–	–	–	–
Total	4	40,874	(7,940)	(34,192)	–	(95,273)	–	–	(96,527)
At 30 Sept 2025 (unaudited)	1,868	559,438	28,807	(39,801)	40,000	1,225,628	2,233	18,724	1,836,897
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	–	–	–	–	–	254,970	–	5,235	260,205
Total comprehensive income for the period	–	–	–	–	–	254,970	–	5,235	260,205
Transactions with owners in their capacity as owners:									
Dividend paid	–	–	–	–	–	(175,844)	–	–	(175,844)
Share-based payments	–	–	10,569	–	–	–	–	–	10,569
Vested Shares	–	(48,675)	(22,230)	70,905	–	–	–	–	–
PAYE tax remitted on vested shares	–	–	–	(35,906)	–	–	–	–	(35,906)
Contribution by non-controlling interest *	–	–	–	–	–	–	–	6	6
Transfer to share-based payment liability	–	–	(10,212)	–	–	–	–	–	(10,212)
Shares repurchased	–	–	–	(69,470)	–	–	–	–	(69,470)
Total	–	(48,675)	(21,873)	(34,471)	–	(175,844)	–	6	(280,857)
At 30 Sept 2026 (unaudited)	1,868	511,696	21,088	(103,821)	40,000	1,327,419	2,887	19,866	1,821,003

*Represents Starcrest additional contribution following the increase in the nominal share capital of Elcrest.

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

Condensed consolidated interim statement of cash flows

For the nine months ended 30 September 2026

		9 months ended 30 Sept 2026	9 months ended 30 Sept 2025
	Notes	\$'000	\$'000
Cash flows from operating activities			
Cash generated from operations	15	1,478,707	1,395,374
Tax paid		(501,868)	(304,377)
Contribution to plan assets *		–	(52,006)
Hedge premium paid		(15,930)	(24,984)
Restricted cash	20.3	(2,858)	(3,209)
PAYE tax remitted on vested shares **		(35,906)	–
Net cash inflows from operating activities		922,145	1,010,798
Cash flows from investing activities			
Payment for acquisition of oil and gas properties	16	(168,731)	(178,818)
Additional investment in Joint venture		–	(20,000)
Payment for acquisition of other property, plant and equipment		(4,396)	(1,245)
Deposit for asset held for sale		–	1,400
Receipts from other asset ***		32,625	–
Receipt from investments held at amortised cost	21	355	–
Payment for acquisition of subsidiary ****		–	(64,251)
Interest received		10,403	7,862
Net cash outflows used in investing activities		(129,744)	(255,052)
Cash flows from financing activities			
Repayment of loans and borrowings		(200,000)	(1,030,250)
Dividend paid		(175,844)	(95,273)
Proceeds from loans & borrowings		–	650,000
Shares purchased for LTIP scheme		(69,470)	(10,000)
Interest paid on lease liability		(3,753)	(6,241)
Lease payment – principal portion		(20,577)	(22,397)
Payments of other financing charges *****		(19,245)	(41,266)
Payment of financing charges from the issue of shares		–	(114)
Interest paid on loans and borrowings		(81,428)	(91,171)
Net cash outflows used in financing activities		(570,317)	(646,712)
Net increase in cash and cash equivalents		222,084	109,034
Cash and cash equivalents at beginning of the period		332,326	469,862
Effects of exchange rate changes on cash and cash equivalents		2,445	898
Cash and cash equivalents at end of the period	20	556,855	579,794

* Prior year contribution relates to the funding of the deficit of SEPNU's defined benefit obligation.

** PAYE tax for the current period relates to payments made in 2026. In the comparative period, the PAYE tax payment was made in Q4 2025 and, therefore, was not reflected in the 9M 2025 results.

*** Receipt from Other asset relates to proceeds from the financial interest in OML 55. During the period \$40 million was received, comprising \$7.4 million applied to receivables arising from advances to support crude evacuation at OML 55 and \$32.6 million recognised against other assets.

**** This relates to the reconciliation settlement paid to Exxon for the acquisition of SEPNU (formerly MPNU).

***** Other financing charges of \$19.2 million, (2025: \$41.3 million) largely 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 condensed consolidated interim financial statements

For the nine months ended 30 September 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% Participant 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.

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.III) 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 to 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.

On 23 December 2025, the Group 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, the Group 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, the Group 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.

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, the Board of Seplat Energy Plc announced the appointment of Mr. Tony O. Elumelu, CFR, as a Non-Executive Director, effective 22 January 2026, following the resignation of Mr. Olivier De Langavant from the Board on the same date. The change followed the sale of Maurel & Prom S.A.'s 20.07% shareholding in Seplat Energy Plc to Heirs Holdings Limited and Heirs Energies Limited.

On 9 June 2026, the Board further announced a planned leadership succession as follows:

- Mr. Roger Brown retired as Chief Executive Officer and Executive Director on 31 July 2026, and Engr. Effiong Okon was appointed Chief Executive Officer and Executive Director with effect from 1 August 2026.
- The Chairman of the Board, Senator Udoma Udo Udoma, CON, notified the Board of his intention to retire on 31 December 2026, and the Board elected Mr. Tony O. Elumelu, CFR, as the next Chairman of Seplat Energy Plc, effective 1 January 2027.

On 29 July 2026, the Group entered into an agreement to divest 25% of its participating interest in the NNPC/SEPNU JV, subject to regulatory approvals and other customary completion conditions. The agreed purchase price is \$281.6 million, and is subject to lockbox adjustment. The financial effect of the transaction will be determined on completion.

On 15 September 2026, APEX Global Energy Limited notified the Company that its shareholding had increased to 14.16% of the Company's issued share capital and voting rights.

On 30 September 2026, Mr. Tony O. Elumelu, CFR, through Heirs Energies Limited, increased his interest in the Company. Following the transaction, entities controlled by Mr. Tony O. Elumelu, CFR, held an aggregate interest representing 21.07% of the Company's issued share capital.

3. Summary of material accounting policies

3.1 Introduction to summary of material accounting policies

This note provides a list of the material 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 interim condensed 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 nine months ended 30 September 2026 have been prepared in accordance with IAS 34 (Interim Financial Reporting) 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, and defined benefit plans – plan assets measured at fair value. The financial statements are presented in United States Dollars, and all values are rounded to the nearest thousand (\$'000), 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 in the preparation of the interim condensed consolidated financial statements are consistent with those followed in the preparation of the Group's annual IFRS compliant consolidated financial statements for the year ended 31 December 2025, except for the adoption of new and amended standards 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 be applied retrospectively.

Seplat Energy Plc engaged consultants to support its implementation of IFRS 18. Based on the gap assessment performed, the implementation of IFRS 18 is not expected to affect the recognition or measurement of the Group's assets, liabilities, income or expenses. However, it is expected to affect the presentation of the statement of profit or loss, related note disclosures and certain comparative information. The Group continues to assess the detailed presentation and disclosure implications.

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.

d) IFRS 20-Regulatory Assets and Regulatory Liabilities

On 27 May 2026, the International Accounting Standards Board issued IFRS 20 Regulatory Assets and Regulatory Liabilities. IFRS 20 sets out the requirements for the recognition, measurement, presentation and disclosure of regulatory assets, regulatory liabilities, regulatory income and regulatory expense.

IFRS 20 introduces requirements that will result in information that supplements the information an entity already provides by applying IFRS accounting standards, including IFRS 15 Revenue from Contracts with Customers. Such information enables users of financial statements to understand the total allowed compensation for regulatory goods or services supplied in each reporting period and the related rights and obligations. The income, expenses, assets and liabilities an entity reports by applying IFRS 20 supplement, but do not replace, the information the entity provides by applying IFRS 15 and other IFRS accounting standards.

IFRS 20 is effective for reporting periods beginning on or after 1 January 2029, with earlier application permitted.

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 30 September 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 because it loses control and the retained interest becomes subject to 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 this financial statements are measured using the currency of the primary economic environment in which the Group operates ('the functional currency'), which is the US dollar.

a) 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.

b) 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 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.

Overlifts and underlifts represent differences between crude oil lifted and the Group's entitlement based on its share of production. 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. When an overlift occurs, other income is debited, and a corresponding liability is accrued. Overlifts are measured by reference to the observable lifted price at the date of lifting. Underlifts are measured at current market value at each reporting date. Changes in the underlift position are recognised in profit or loss as other (loss)/income. Instances, where Seplat controls the storage of crude and petroleum products at a terminal, differences between product sold and the Group's entitlement are 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 include 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 comprise of 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 comprise crude oil and natural gas liquids, and materials and supplies, including tubulars, casings, spares and well materials used in production and operational activities.

Inventories are measured at the lower of cost and net realisable value. Cost is determined using the weighted average method and includes purchase price and other directly attributable costs incurred in bringing inventories to their present location and condition.

For crude oil and natural gas liquids, net realisable value is based on estimated selling prices in the ordinary course of business, less estimated costs to sell. For materials and supplies, which are consumed in operations rather than held for resale, net realisable value is assessed based on expected recoverability through use, taking into account obsolescence, excess quantities and expected future utilisation.

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 amortised cost less impairment.

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 consists 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 30 September 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, NUIMS receivables, other receivables, cash and bank balances and bonds. 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 financial assets at amortised cost 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, cash and bank balances and bonds.

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 year ended 30 Sept 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 Group 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 are 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 held by the Group 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 Group's profit or loss after taxation and based on the weighted average of issued and fully paid ordinary shares outstanding during 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 operates a defined benefit pension plan. The Group previously operated a gratuity plan, which was discontinued in 2025. The defined benefit pension plan requires contributions to be made to a separately administered fund. The Group also provides certain additional post-employment benefits to employees. These benefits are unfunded.

The cost of providing benefits under the defined benefit plan is determined using the projected unit credit method and is calculated annually by independent actuaries. The liability or asset recognised in the statement of financial position represents the present value of the defined benefit obligation at the reporting date, less the fair value of plan assets (if any). The defined benefit obligation is determined using market yields at the reporting date on Nigerian government bonds

with maturities that approximate the expected timing of the benefit payments.

Remeasurement gains and losses, arising from changes in financial and demographic assumptions and experience adjustments, are recognised immediately in other comprehensive income and accumulated in retained earnings. Remeasurements are not reclassified to profit or loss in subsequent periods.

Past service costs are recognised in profit or loss on the earlier of:

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

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

The Group recognises 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 sufficient objective 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 Group 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 Group 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) or cash amounts based on the value of the Group's equity instruments (cash-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.

c) Modification of equity-settled awards to cash-settled awards

Where the terms of an equity-settled share-based payment awards are modified such that the Group becomes obligated to settle the awards in cash, the award is accounted for as cash-settled from the modification date. The cumulative amount recognised in the share-based payment reserve in respect of services received up to the modification date is reclassified from equity to a share-based payment liability.

Thereafter, the liability is measured at fair value at each reporting date and at settlement, with changes in fair value recognised in profit or loss over the remaining vesting period as services are rendered.

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) 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.

II) Foreign currency translation reserve

The Group has used the CBN rate to translate its US 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 ₦377.6 billion (2025: ₦40.4 billion). See Note 31 for the applicable translation rates.

III) Consolidation of Elcrest

On acquisition of 100% shares of Eland Oil and Gas Limited, 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 Limited 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 Limited is exposed to variable returns from the activities of Elcrest through dividends and interests.
- Eland Oil and Gas Limited 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.

IV) 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.

V) 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 steering committee which assesses the financial performance and position of the Group and makes strategic decisions. The steering committee, which has been identified as being the 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.

VI) 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 pretax 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 5.1.1.

IX. Intangible assets

The contract based intangible assets (licence) 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 basis 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. The management of financial risks is carried out by the corporate finance team 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, investments 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 investments, cash and bank balances as well as credit exposures to customers (i.e. MSN Energy, Transcorp, Shell western, Pillar, Azura, Geregu Power, Sapele Power, ExxonMobil and Nigerian Gas Marketing Company (NGMC) receivables), and other parties (i.e., NUIMS JV receivables, NEPL JV 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.

b) Estimation uncertainty in measuring impairment loss

The table below shows information on the sensitivity of the carrying amounts of the Group'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.

i. Significant unobservable inputs

The table below demonstrates the sensitivity of the Group'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 30 Sept 2026	Effect on other components of equity before tax 30 Sept 2026
Increase/decrease in loss given default	\$'000	\$'000
+10%	(107)	—
-10%	107	—

	Effect on profit before tax 31 Dec 2025	Effect on other components of equity before tax 31 Dec 2025
Increase/decrease in loss given default	\$'000	\$'000
+10%	(268)	—
-10%	268	—

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 30 Sept 2026	Effect on other components of equity before tax 30 Sept 2026
Increase/decrease in probability of default	\$'000	\$'000
+10%	(107)	—
-10%	107	—

	Effect on profit before tax 31 Dec 2025	Effect on other components of equity before tax 31 Dec 2025
Increase/decrease in probability of default	\$'000	\$'000
+10%	(744)	—
-10%	744	—

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

	Effect on profit before tax 30 Sept 2026	Effect on other components of equity before tax 30 Sept 2026
Increase/decrease in forward looking macroeconomic indicators	\$'000	\$'000
+10%	(105)	—
-10%	105	—

	Effect on profit before tax 31 Dec 2025	Effect on other components of equity before tax 31 Dec 2025
Increase/decrease in forward looking macroeconomic indicators	\$'000	\$'000
+10%	(427)	—
-10%	427	—

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.

	Effective interest rate	Less than 1 year	1 – 2 year	2 – 3 years	3 – 5 years	Total
30 Sept 2026	%	\$'000	\$'000	\$'000	\$'000	\$'000
Non-derivatives						
Fixed interest rate borrowings						
\$650 million Senior notes	9.125%	59,313	59,313	59,313	679,656	857,595
Variable interest rate borrowings						
The Mauritius Commercial Bank Ltd	6.5% + SOFR	1,767	4,350	8,204	8,433	22,754
Stanbic IBTC Bank Plc	6.5% + SOFR	1,591	3,915	7,383	7,589	20,478
Standard Bank of South Africa	6.5% + SOFR	884	2,175	4,102	4,216	11,377
First City Monument Ltd (FCMB)	6.5% + SOFR	848	2,088	3,938	4,048	10,922
Zenith Bank Plc	6.5% + SOFR	566	1,392	2,625	2,698	7,281
\$300 million Advance Payment Facility (APF)						
ExxonMobil Financing	5% + SOFR + CAS	8,930	102,233	—	—	111,163
Total variable interest borrowings		14,586	116,153	26,252	26,984	183,975
Other non-derivatives						
Trade and other payables**		864,812	—	—	—	864,812
Lease liability		14,818	21,092	12,914	3,252	52,076
		879,630	21,092	12,914	3,252	916,888
Total		953,529	196,558	98,479	709,892	1,958,458

** Trade and other payables (exclude non-financial liabilities such as provisions, taxes, pension and other non-contractual payables)

31 December 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	738,969	916,908
Variable interest rate borrowings						
The Mauritius Commercial Bank Ltd	6.5% + SOFR	1,799	1,799	7,820	12,463	23,881
Stanbic IBTC Bank Plc	6.5% + SOFR	1,619	1,619	7,038	11,216	21,492
Standard Bank of South Africa	6.5% + SOFR	900	900	3,910	6,231	11,941
First City Monument Ltd (FCMB)	6.5% + SOFR	864	864	3,753	5,982	11,463
Zenith Bank Plc	6.5% + SOFR	576	576	2,502	3,988	7,642
\$300 million Advance Payment Facility (APF)						
ExxonMobil Financing	5% + SOFR + CAS	28,781	314,391	—	—	343,172
Total variable interest borrowings		34,539	320,149	25,023	39,880	419,591
Other non-derivatives						
Trade and other payables**		838,216	—	—	—	838,216
Lease liability		36,788	19,318	16,329	—	72,435
		875,004	19,318	16,329	—	910,651
Total		968,856	398,780	100,665	778,849	2,247,150

** Trade and other payables (exclude non-financial liabilities such as provisions, taxes, pension and other non-contractual payables)

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	
	30 Sept 2026 \$'000	31 Dec 2025 \$'000	30 Sept 2026 \$'000	31 Dec 2025 \$'000
Financial assets at amortised cost				
Trade and other receivables*	566,083	462,157	566,083	462,157
Cash and cash equivalents	556,855	332,326	556,855	332,326
Restricted cash	129,209	126,351	129,209	126,351
Other financial assets at amortised cost	2,899	—	2,855	—
	1,255,046	920,834	1,255,002	920,834
Financial assets at fair value				
Derivative financial assets	9,890	12,090	9,890	12,090
	9,890	12,090	9,890	12,090
Financial liabilities				
Interest-bearing loans and borrowings**	791,746	1,005,596	798,465	1,018,655
Trade and other payables***	864,812	838,216	864,812	838,216
	1,656,558	1,843,812	1,663,277	1,856,871
Financial liabilities at fair value				
Derivative financial liability	12,334	6,299	12,334	6,299
	12,334	6,299	12,334	6,299

* Trade and other receivables exclude underlift, 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 exclude non-financial liabilities such as taxes, overlift, pension and other non-contractual payables.

Trade and other receivables (excluding prepayments), contract assets and 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.

Derivative liability of \$12.33 million (2025: \$6.299 million) 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.

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 period.

- 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 other financial assets at amortised cost is determined by reference to quoted prices in an active market, i.e FMDQ. Accordingly, these other financial assets at amortised cost are classified within Level 1 of the fair value hierarchy.

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 nine months ended 30 September 2026, revenue from the gas segment of the business constituted 10% (2025: 8%) of the Group's revenue and about 61.9% of the Group's profit - mostly due to positive fiscal regime associated with the gas business. Management is committed to continued growth of the gas segment and will procure the required infrastructure for this segment of the business. The gas business is positioned separately within the Group and reports directly to the Director New Energy and Gas (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 and other gas facilities).

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

6.1 Segment profit disclosure

	9 months ended 30 Sept 2026	9 months ended 30 Sept 2025	3 Months ended 30 Sept 2026	3 Months ended 30 Sept 2025
	\$'000	\$'000	\$'000	\$'000
Oil	99,138	52,116	16,296	42,113
Gas	161,067	43,013	79,900	25,593
Total profit for the period	260,205	95,129	96,196	67,706

	9 months ended 30 Sept 2026	9 months ended 30 Sept 2025	3 Months ended 30 Sept 2026	3 Months ended 30 Sept 2025
	\$'000	\$'000	\$'000	\$'000
Oil				
Revenue from contracts with customers				
Crude oil sales (Note 7)	2,474,261	2,004,381	839,749	711,162
Cost of sales and general and administrative expenses	(1,647,991)	(1,367,880)	(611,115)	(366,860)
Other income/(loss)	85,596	19,518	121,716	(28,145)
Operating profit before impairment	911,866	656,019	350,350	316,157
Impairment reversal/(loss)	1,507	856	(1,375)	1,224
Fair value loss	(24,153)	(16,348)	(8,871)	(6,694)
Operating profit	889,220	640,527	340,104	310,687
Finance income (Note 13)	10,058	7,862	3,640	2,524
Finance expenses (Note 13)	(119,599)	(144,939)	(35,127)	(47,822)
Profit before taxation	779,679	503,450	308,617	265,389
Income tax expense (Note 14)	(680,541)	(451,334)	(292,321)	(223,276)
Profit for the period	99,138	52,116	16,296	42,113

*Other income/(loss) in the Oil business includes foreign exchange gain and majorly changes in underlift. Note 9 provides details for the combined business.

*Impairment on trade receivables relates to oil customers (Waltersmith and Pillar).

	9 months ended 30 Sept 2026	9 months ended 30 Sept 2025	3 Months ended 30 Sept 2026	3 Months ended 30 Sept 2025
Gas	\$'000	\$'000	\$'000	\$'000
Revenue from contracts with customers				
Gas sales	165,117	139,201	63,030	44,593
Natural gas liquid sales	124,126	33,047	40,681	23,153
Cost of sales and general and administrative expenses	(125,839)	(99,136)	(37,578)	(51,939)
Other income	14,008	7,035	6,974	3,691
Operating profit before impairment	177,412	80,147	73,107	19,498
Impairment reversal/(loss)	778	(9,711)	(1,705)	(7,035)
Operating profit	178,190	70,436	71,402	12,463
Finance income (Note 13)	345	—	120	—
Share of profit/(loss) from joint venture accounted for using the equity method	24,423	(3,797)	27,564	(699)
Profit before taxation	202,958	66,639	99,086	11,764
Income tax (expense)/credit (Note 14)	(41,891)	(23,626)	(19,186)	13,829
Profit/(loss) for the period	161,067	43,013	79,900	25,593

Impairment reversal/(loss) recognised in the gas segment relate to MSN, Azura, Transcorp, Geregu 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.

	9 months ended 30 Sept 2026	9 months ended 30 Sept 2026	9 months ended 30 Sept 2026	9 months ended 30 Sept 2026	9 months ended 30 Sept 2025	9 months ended 30 Sept 2025	9 months ended 30 Sept 2025	9 months ended 30 Sept 2025
	Oil \$'000	Gas \$'000	Natural Gas Liquid \$'000	Total \$'000	Oil \$'000	Gas \$'000	Natural Gas Liquid \$'000	Total \$'000
Geographical markets								
Canada	—	—	—	—	72,935	—	—	72,935
Cote D'Ivoire	30,003	—	25,086	55,089	80,664	—	—	80,664
France	157,959	—	—	157,959	66,098	—	—	66,098
Germany	—	—	—	—	72,068	—	—	72,068
Ghana	—	—	—	—	—	—	23,410	23,410
India	107,018	—	—	107,018	414,795	—	—	414,795
Indonesia	284,110	—	—	284,110	206,116	—	—	206,116
Italy	71,561	—	—	71,561	131,665	—	—	131,665
Japan	—	—	13,984	13,984	—	—	—	—
Kenya	—	—	—	—	—	—	4,943	4,943
Malaysia	67,664	—	—	67,664	64,110	—	—	64,110
Namibia	—	—	17,192	17,192	—	—	—	—
Netherlands	232,285	—	—	232,285	168,367	—	—	168,367
Nigeria	442,493	165,117	39,660	647,270	15,759	139,201	4,694	159,654
Portugal	61,708	—	—	61,708	125,044	—	—	125,044
Singapore	321,708	—	28,204	349,912	—	—	—	—
South Africa	44,794	—	—	44,794	116,505	—	—	116,505
Spain	310,053	—	—	310,053	145,200	—	—	145,200
Turkey	—	—	—	—	85,883	—	—	85,883
Thailand	278,614	—	—	278,614	—	—	—	—
UK	—	—	—	—	61,926	—	—	61,926
Uruguay	56,867	—	—	56,867	40,794	—	—	40,794
USA	7,424	—	—	7,424	134,238	—	—	134,238
Vietnam	—	—	—	—	2,214	—	—	2,214
Revenue from contracts with customers	2,474,261	165,117	124,126	2,763,504	2,004,381	139,201	33,047	2,176,629
Geographical region								
Africa	517,290	165,117	81,938	764,345	212,928	139,201	33,047	385,176
Asia	1,059,114	—	42,188	1,101,302	687,235	—	—	687,235
Europe	833,566	—	—	833,566	856,251	—	—	856,251
Americas	64,291	—	—	64,291	247,967	—	—	247,967
Revenue from contracts with customers	2,474,261	165,117	124,126	2,763,504	2,004,381	139,201	33,047	2,176,629

	9 months ended 30 Sept 2026	9 months ended 30 Sept 2026	9 months ended 30 Sept 2026	9 months ended 30 Sept 2026	9 months ended 30 Sept 2025	9 months ended 30 Sept 2025	9 months ended 30 Sept 2025	9 months ended 30 Sept 2025
	Oil \$'000	Gas \$'000	Natural Gas Liquid \$'000	Total \$'000	Oil \$'000	Gas \$'000	Natural Gas Liquid \$'000	Total \$'000
Timing of revenue recognition								
At a point in time	2,474,261	—	124,126	2,598,387	2,004,381	—	33,047	2,037,428
Over time	—	165,117	—	165,117	—	139,201	—	139,201
Revenue from contracts with customers	2,474,261	165,117	124,126	2,763,504	2,004,381	139,201	33,047	2,176,629

	3 Months ended 30 Sept 2026	3 Months ended 30 Sept 2026	3 Months ended 30 Sept 2026	3 Months ended 30 Sept 2026	3 Months ended 30 Sept 2025	3 Months ended 30 Sept 2025	3 Months ended 30 Sept 2025	3 Months ended 30 Sept 2025
	Oil \$'000	Gas \$'000	Natural Gas Liquid \$'000	Total \$'000	Oil \$'000	Gas \$'000	Natural Gas Liquid \$'000	Total \$'000
Geographical markets								
Canada	—	—	—	—	11,179	—	—	11,179
Cote D'Ivoire	—	—	25,086	25,086	30,893	—	—	30,893
France	82,165	—	—	82,165	—	—	—	—
Ghana	—	—	—	—	—	—	18,459	18,459
India	84,683	—	—	84,683	121,746	—	—	121,746
Indonesia	—	—	—	—	80,662	—	—	80,662
Italy	(1,573)	—	—	(1,573)	2,413	—	—	2,413
Namibia	—	—	28	28	—	—	—	—
Netherlands	175,174	—	—	175,174	67,929	—	—	67,929
Nigeria	234,609	63,030	15,567	313,206	3,589	44,593	4,694	52,876
Portugal	—	—	—	—	72,197	—	—	72,197
Singapore	(235)	—	—	(235)	—	—	—	—
South Africa	172	—	—	172	69,790	—	—	69,790
Spain	264,754	—	—	264,754	41,865	—	—	41,865
Turkey	—	—	—	—	83,660	—	—	83,660
UK	—	—	—	—	60,503	—	—	60,503
USA	—	—	—	—	64,736	—	—	64,736
Revenue from contracts with customers	839,749	63,030	40,681	943,460	711,162	44,593	23,153	778,908

Geographical region								
Africa	234,781	63,030	40,681	338,492	104,272	44,593	23,153	172,018
Asia	84,448	—	—	84,448	202,408	—	—	202,408
Europe	520,520	—	—	520,520	328,567	—	—	328,567
Americas	—	—	—	—	75,915	—	—	75,915
Revenue from contracts with customers	839,749	63,030	40,681	943,460	711,162	44,593	23,153	778,908

	3 Months ended 30 Sept 2026	3 Months ended 30 Sept 2026	3 Months ended 30 Sept 2026	3 Months ended 30 Sept 2026	3 Months ended 30 Sept 2025	3 Months ended 30 Sept 2025	3 Months ended 30 Sept 2025	3 Months ended 30 Sept 2025
	Oil	Gas	Natural Gas Liquid	Total	Oil	Gas	Natural Gas Liquid	Total
	\$'000	\$'000	\$'000	\$'000	\$'000	\$'000	\$'000	\$'000
Timing of revenue recognition								
At a point in time	839,749	—	40,681	880,430	711,162	—	23,153	734,315
Over time	—	63,030	—	63,030	—	44,593	—	44,593
Revenue from contracts with customers	839,749	63,030	40,681	943,460	711,162	44,593	23,153	778,908

The Group's transactions with its major customers, Shell Western, Chevron and ExxonMobil, constitute about 91% (\$2.25 billion), (9M 2025: 92%, \$1.85 billion) of the total revenue from oil segment. Also, the Group's transactions with NGML, MSN, Egbin Power and Azura constitute about 65% (\$107.07 million) (9M 2025: 72%.; \$100.9 million) of the total revenue from gas segment.

The current period data reflects location of the final buyers based on information extracted from bill of lading.

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

	9 months ended 30 Sept 2026			9 months ended 30 Sept 2025		
	Oil	Gas	Total	Oil	Gas	Total
	\$'000	\$'000	\$'000	\$'000	\$'000	\$'000
Impairment reversal/(loss) recognised during the period	1,507	778	2,285	856	(9,711)	(8,855)

	3 Months ended 30 Sept 2026			3 Months ended 30 Sept 2025		
	Oil	Gas	Total	Oil	Gas	Total
	\$'000	\$'000	\$'000	\$'000	\$'000	\$'000
Impairment (loss)/reversal recognised during the period	(1,375)	(1,705)	(3,080)	1,224	(7,035)	(5,811)

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.

Total segment assets	Oil	Gas	Total
	\$'000	\$'000	\$'000
30 September 2026	5,063,426	1,092,128	6,155,554
31 December 2025	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.

Total segment liabilities	Oil	Gas	Total
	\$'000	\$'000	\$'000
30 September 2026	3,755,400	579,151	4,334,551
31 December 2025	3,783,086	457,359	4,240,445

7. Revenue from contract with customers

	9 months ended 30 Sept 2026	9 months ended 30 Sept 2025	3 Months ended 30 Sept 2026	3 Months ended 30 Sept 2025
	\$'000	\$'000	\$'000	\$'000
Crude oil sales	2,474,261	2,004,381	839,749	711,162
Gas sales	165,117	139,201	63,030	44,593
Natural gas liquid sales	124,126	33,047	40,681	23,153
	2,763,504	2,176,629	943,460	778,908

The major off-takers for crude oil are Chevron, Vitol, Shell Western, and ExxonMobil. The major off-takers for gas are Azura, MSN Energy, Egbin Power, and Nigerian Gas Marketing Company. The major off-taker for natural gas liquid is ExxonMobil.

8. Cost of sales

	9 months ended 30 Sept 2026	9 months ended 30 Sept 2025	3 Months ended 30 Sept 2026	3 Months ended 30 Sept 2025
	\$'000	\$'000	\$'000	\$'000
Royalties	447,212	381,181	161,065	129,169
Depletion, Depreciation and Amortisation	438,967	340,978	156,584	23,529
Depreciation of Right of Use Assets	17,613	17,351	5,572	1,949
Crude handling fees	67,046	59,230	23,719	20,659
Nigeria Export Supervision Scheme (NESS) fee	2,994	2,000	1,261	719
Niger Delta Development Commission Levy	33,210	34,822	9,357	13,079
Barging/Trucking	20,646	20,567	6,671	7,029
Operational & Maintenance expenses	547,468	441,047	206,797	187,935
	1,575,156	1,297,176	571,026	384,068

Operational & maintenance expenses relate mainly to maintenance costs, warehouse operations expenses, security expenses, community expenses, clean-up costs, fuel supplies and catering services. The increase in operational and maintenance expense in 9M 2026 is principally driven by Yoho restoration expense of \$67 million. Included in operational and maintenance expenses is gas flare penalty of \$21.7 million (9M 2025: \$36.0 million) 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 income/(loss) - net

	9 months ended 30 Sept 2026	9 months ended 30 Sept 2025	3 Months ended 30 Sept 2026	3 Months ended 30 Sept 2025
	\$'000	\$'000	\$'000	\$'000
Underlift/(Overlift)	40,054	3,826	107,080	(38,765)
Realised gain/(loss) on foreign exchange	1,029	16,701	(9,382)	16,701
Unrealised gain/(loss) on foreign exchange	11,342	(5,306)	4,062	(7,023)
Others	47,179	11,332	26,930	4,633
	99,604	26,553	128,690	(24,454)

Underlifts and overlifts represent differences between crude oil lifted and the Group's entitlement based on its share of production. Underlifts are measured at current market value. Overlifts are measured by reference to the observable lifted price at the date of lifting. Movements during the period are recognised within other income/(loss).

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

Others include tariffs from the usage of the Group's pipeline by others.

10. General and administrative expenses

	9 months ended 30 Sept 2026	9 months ended 30 Sept 2025	3 Months ended 30 Sept 2026	3 Months ended 30 Sept 2025
	\$'000	\$'000	\$'000	\$'000
Depreciation and amortisation	3,037	25,045	1,093	7,710
Depreciation of right of use assets	11,516	14,213	3,844	4,841
Professional & Consulting Fees	16,620	20,577	7,303	11,055
Auditor's remuneration	327	265	95	116
Directors Emoluments (Executives)	2,594	2,318	1,444	728
Directors Emoluments (Non-Executives)	2,910	3,132	976	853
Employee benefits	72,857	43,817	25,361	(2,056)
Share-based benefits	52,839	15,271	26,100	5,000
Donation	30	66	3	14
Flights and other travel costs	8,503	7,422	4,679	(849)
Other general expenses	27,441	37,714	6,769	7,319
	198,674	169,840	77,667	34,731

Depreciation expenses reflect depreciation on non-field related assets.

The increase in share-based benefits expense primarily reflects the impact of a higher Company share price on the valuation of share-based awards.

Included in the other general expenses are IT\communications consumables of \$7.03 million (9M 2025: \$8.81 million), contract labour \$6.14 million (9M 2025: \$15.00 million), repairs and maintenance expenses of \$6.87 million (9M 2025: \$9.56 million) and software license/maintenance fees of \$4.89 million (9M 2025: \$2.39 million).

10.1 Below are details of non-audit services provided by the auditors:

Entity	Service	PwC office	Fees (\$'000)	Period
Seplat Energy Plc	Remuneration committee advice	PwC UK	396	2026

11. Impairment reversal/(loss)

	9 months ended 30 Sept 2026	9 months ended 30 Sept 2025	3 Months ended 30 Sept 2026	3 Months ended 30 Sept 2025
	\$'000	\$'000	\$'000	\$'000
Impairment reversal/(loss) on financial assets-net (Note 11.1)	2,285	(8,855)	(3,080)	(5,811)
	2,285	(8,855)	(3,080)	(5,811)

11.1 Impairment reversal/(loss) on financial assets - net

	9 months ended 30 Sept 2026	9 months ended 30 Sept 2025	3 Months ended 30 Sept 2026	3 Months ended 30 Sept 2025
	\$'000	\$'000	\$'000	\$'000
Impairment reversal/(loss) on:				
NUIMS receivables	—	—	—	167
NEPL receivables	1,261	161	(536)	362
Trade receivables (Gas customers)*	302	(8,766)	(2,017)	(6,182)
Contract asset	(1,051)	(83)	(711)	9
Other receivables	1,773	(167)	184	(167)
Total impairment reversal/(loss)	2,285	(8,855)	(3,080)	(5,811)

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

12. Fair value loss

	9 months ended 30 Sept 2026	9 months ended 30 Sept 2025	3 Months ended 30 Sept 2026	3 Months ended 30 Sept 2025
	\$'000	\$'000	\$'000	\$'000
Hedge premium expenses	(18,118)	(10,434)	(4,508)	(3,039)
Fair value loss on derivatives (Note 19)	(6,035)	(5,914)	(4,363)	(3,655)
	(24,153)	(16,348)	(8,871)	(6,694)

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

13. Finance income/(cost)

	9 months ended 30 Sept 2026	9 months ended 30 Sept 2025	3 Months ended 30 Sept 2026	3 Months ended 30 Sept 2025
	\$'000	\$'000	\$'000	\$'000
Finance Income				
Interest income on fixed deposit	10,058	7,862	3,640	2,524
Interest income on other financial assets at amortised cost	345	–	120	–
Finance Income	10,403	7,862	3,760	2,524
Finance Charges				
Interest on loans and borrowings	(86,823)	(110,764)	(24,309)	(36,426)
Interest on lease liabilities	(3,753)	(6,241)	(1,138)	(2,084)
Unwinding of discount on provision for decommissioning	(29,023)	(27,934)	(9,680)	(9,312)
	(119,599)	(144,939)	(35,127)	(47,822)
Finance cost - net	(109,196)	(137,077)	(31,367)	(45,298)

Finance costs decreased due to lower gross debt in the period.

14. Taxation

The major components of income tax expense for the period ended 30 September 2026 and 2025 are:

	9 months ended 30 Sept 2026	9 months ended 30 Sept 2025	3 Months ended 30 Sept 2026	3 Months ended 30 Sept 2025
	\$'000	\$'000	\$'000	\$'000
Current tax:				
Current tax expense on profit for the period	672,568	456,842	227,862	110,537
Education Tax	–	15,919	–	4,657
NASENI Levy	–	1,529	–	736
Police Levy	–	33	–	15
Development levy	56,659	–	25,805	–
Total current tax	729,227	474,323	253,667	115,945
Deferred tax:				
Deferred tax (credit)/expense to profit or loss (Note 14.1)	(6,795)	637	57,840	93,502
Total tax expense in statement of profit or loss	722,432	474,960	311,507	209,447
Total tax charged for the period	722,432	474,960	311,507	209,447
Effective tax rate	74 %	83 %	76 %	76 %

In accordance with IAS 34: Interim Financial Reporting, income tax expense for the interim period has been determined using the estimated weighted average annual effective income tax rate expected for the full financial year. This estimate is reviewed at each interim reporting date and adjusted, where necessary, to reflect changes in the expected annual tax rate.

Income tax expense for the Group is analysed by Oil segment - 9 months ended \$680.5 million (9M 2025: \$451.3 million); 3 months ended \$292.3 million (3M 2025: \$223.3 million) and Gas Segment - 9 months ended \$41.9 million (9M 2025: \$23.6 million); 3 months ended \$19.2 million (3M 2025: (\$13.8 million)).

The Group has applied the provisions of the Nigeria Tax Act 2025 which became effective in January 2026 and require Education Tax, the NASENI Levy, and the Police Trust Fund Levy to be consolidated into Development Levy.

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	Balance as at 30 Sept 2026
	\$'000	\$'000	\$'000	\$'000
Deferred tax assets	201,762	(47,292)	–	154,470
Deferred tax liabilities	(1,213,860)	54,087	–	(1,159,773)
	(1,012,098)	6,795	–	(1,005,303)

	Balance as at 1 January 2025	(Charged) /credited to profit or loss	Credited to other comprehensive income	Balance as at 30 Sept 2025
	\$'000	\$'000	\$'000	\$'000
Deferred tax assets	230,541	(7,534)	–	223,007
Deferred tax liabilities	(1,052,339)	6,897	–	(1,045,442)
	(821,798)	(637)	–	(822,435)

In line with the requirements of IAS 12, the Group offset the deferred tax assets against the deferred tax liabilities arising from similar transactions.

15. Computation of cash generated from operations

	Notes	9 months ended 30 Sept 2026 \$'000	9 months ended 30 Sept 2025 \$'000
Profit before tax		982,637	570,089
Adjusted for:			
Depletion, depreciation and amortisation		442,004	366,023
Depreciation of right-of-use asset		29,129	31,564
Impairment (reversal)/loss on financial assets	11.1	(2,285)	8,855
Interest income	13	(10,403)	(7,862)
Interest expense on bank loans	13	86,823	110,764
Interest on lease liabilities	13	3,753	6,241
Unwinding of discount on provision for decommissioning	13	29,023	27,934
Fair value loss on derivatives	12	6,035	5,914
Hedge premium expenses	12	18,118	10,434
Unrealised foreign exchange (gain)/loss	9	(11,342)	5,306
Share-based payment expenses	8 & 10	69,645	15,271
Share of (profit)/loss from joint venture		(24,423)	3,797
Defined benefit plan	24.1	(166)	(4,702)
Changes in working capital: (excluding the effects of exchange differences)			
Trade and other receivables		(174,889)	151,145
Inventories		(25,949)	10,474
Prepayments		11,596	31,632
Contract assets		(19,673)	(33,885)
Trade and other payables		69,074	86,380
Cash generated from operations		1,478,707	1,395,374

16. Oil and gas properties

During the nine months ended 30 September 2026, the Group acquired oil and gas properties amounting to \$168.7 million (Dec 2025: \$261 million).

17. Trade and other receivables

	30 Sept 2026 \$'000	31 Dec 2025 \$'000
Financial instruments		
Trade receivables (Note 17.1)	314,142	134,822
NEPL receivables (Note 17.2)	61,613	84,540
NUIMS receivables (Note 17.3)	105,613	201,662
Receivables from ANOH (Note 17.5)	24,479	3,504
Other receivables (Note 17.4)	60,236	37,629
Non-financial instruments		
Other receivables (Note 17.4)	5,987	2,066
Underlift	57,777	5,297
Advances to suppliers-others	9,308	6,412
	639,155	475,932

17.1 Trade receivables

Included in the trade receivables are:

	30 Sept 2026 \$'000	31 Dec 2025 \$'000
Geregu	5,657	12,517
Waltersmith	–	2,624
Sapele Power	9,373	8,813
NGMC	2,046	260
MSN ENERGY	21,825	15,120
Pillar	15,727	9,229
Shell Western	41,852	32,634
Azura	14,888	2,522
Transcorp Power	6,186	4,896
Ardoxa Plc	14,666	–
TotalEnergies	2,189	–
NAOC JV	1,751	–
ExxonMobil	214,584	82,074
Others - crude injectors	2,070	353
Impairment allowance	(38,672)	(36,220)
Total	314,142	134,822

Reconciliation of trade receivables

	30 Sept 2026 \$'000	31 Dec 2025 \$'000
Balance as at 1 January	171,042	369,337
Additions during the period	2,491,822	2,506,976
Receipt for the period	(2,313,301)	(2,708,183)
Exchange difference	3,251	2,912
Gross carrying amount	352,814	171,042
Less: Impairment allowance	(38,672)	(36,220)
Balance as at	314,142	134,822

Reconciliation of impairment allowance on trade receivables

	30 Sept 2026 \$'000	31 Dec 2025 \$'000
Loss allowance as at 1 January	36,220	20,930
(Decrease)/increase in loss allowance	(302)	14,329
Revaluation impact	2,754	961
Loss allowance as at	38,672	36,220

17.2 NEPL receivables

The outstanding cash calls due to Seplat from its JOA partner, NEPL is \$64.11 million (Dec 2025: \$88.21 million).

Reconciliation of NEPL receivables

	30 Sept 2026 \$'000	31 Dec 2025 \$'000
Balance as at 1 January	88,211	44,260
Addition during the period	226,279	383,360
Receipts during the period	(254,957)	(342,160)
Exchange difference	4,581	2,751
Gross carrying amount	64,114	88,211
Less: impairment allowance	(2,501)	(3,671)
Balance as at	61,613	84,540

Reconciliation of impairment allowance on NEPL receivables

	30 Sept 2026 \$'000	31 Dec 2025 \$'000
Loss allowance as at 1 January	3,671	2,826
(Decrease)/increase in loss allowance	(1,261)	1,195
Foreign exchange revaluation impact	91	(350)
Loss allowance as at	2,501	3,671

17.3 NUIMS receivables

The outstanding cash calls due to Seplat from its JOA partner, NUIMS is \$105.61 million(Dec 2025: \$201.7 million).

Reconciliation of NUIMS receivables

	30 Sept 2026 \$'000	31 Dec 2025 \$'000
Balance as at 1 January	201,662	296,075
Addition during the period	822,298	1,057,959
Receipts during the period	(920,441)	(1,156,852)
Exchange difference	2,094	4,480
Balance as at	105,613	201,662

17.4 Other receivables

Reconciliation of other receivables

	30 Sept 2026 \$'000	31 Dec 2025 \$'000
Balance as at 1 January	99,659	119,118
Addition during the period	36,810	6,978
Receipts for the period	(13,999)	(27,571)
Exchange difference	1,875	1,134
Gross carrying amount	124,345	99,659
Less: impairment allowance	(58,122)	(59,964)
Balance as at	66,223	39,695

Other receivables include receivables from third-party injectors (tariff income) of \$12.3 million (Dec 2025: \$11.8 million), employee receivables of \$6.1 million, receivable from All Grace for Ubima Disposal of \$16.9 million (Dec 2025: \$17.4 million), receivable from Naptha for Abiala Marginal field of \$1.3 million (Dec 2025: \$2.9 million).

Reconciliation of impairment allowance on other receivables

	30 Sept 2026 \$'000	31 Dec 2025 \$'000
Loss allowance as at 1 January	59,964	58,258
Decrease in loss allowance	(1,773)	(1,349)
Foreign exchange revaluation impact	(69)	3,055
Loss allowance as at	58,122	59,964

17.5 Receivables from joint venture (ANOH)

	30 Sept 2026 \$'000	31 Dec 2025 \$'000
Balance as at 1 January	6,542	4,724
Additions during the period	21,175	1,677
Receipts for the period	(635)	–
Exchange difference	435	141
Gross carrying amount	27,517	6,542
Less: impairment allowance	(3,038)	(3,038)
Balance as at	24,479	3,504

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

	30 Sept 2026 \$'000	31 Dec 2025 \$'000
Loss allowance as at 1 January	3,038	3,038
Increase/(decrease) in loss allowance	–	–
Loss allowance as at	3,038	3,038

18. Contract assets

	30 Sept 2026 \$'000	31 Dec 2025 \$'000
Revenue on gas sales	25,256	12,058
Revenue on oil sales	16,481	9,974
Impairment allowance on contract assets	(2,800)	(1,717)
	38,937	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, Egbin Power, AGPC, Waltersmith, Shell Western and Chevron, 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 payment 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. Upon obtaining gas receipt certificates, bill of lading and other reconciliation documents with the respective customers/offtakers, after which invoices are issued, the respective balances are 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:

	30 Sept 2026 \$'000	31 Dec 2025 \$'000
Balance as at 1 January	22,032	15,745
Additions during the period	461,533	423,433
Amount billed during the period	(441,726)	(418,419)
Foreign exchange revaluation impact	(102)	1,273
Gross contract assets	41,737	22,032
Impairment allowance	(2,800)	(1,717)
Balance as at	38,937	20,315

Reconciliation of impairment allowance on contract assets

	30 Sept 2026 \$'000	31 Dec 2025 \$'000
Loss allowance as at 1 January	1,717	166
Increase in loss allowance during the period	1,051	1,551
Exchange difference	32	–
Loss allowance as at	2,800	1,717

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. Derivative financial assets and liabilities are presented as current to the extent they are expected to be realised or 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

	30 Sept 2026 \$'000	31 Dec 2025 \$'000
Opening Balance	12,090	–
Hedge expense	(18,130)	–
Premium paid	15,930	12,090
Balance as at	9,890	12,090

19.2 Derivative financial liabilities

	30 Sept 2026 \$'000	31 Dec 2025 \$'000
Opening Balance	(6,299)	(3,955)
Unrealized fair value loss	(6,035)	(2,562)
Prior year premium paid	–	218
Balance as at	(12,334)	(6,299)

19.3 For cashflow purposes:

	30 Sept 2026 \$'000	31 Dec 2025 \$'000
Prior period premium paid	–	218
Hedge premium prepaid	9,890	12,090
Current period hedge expense paid	6,040	19,006
	15,930	31,314

During the period ended 30 September 2026, the Group entered into economic crude oil hedge contracts with an average strike price of \$51/bbl (Dec 2025: \$50/bbl) for 18 million barrels (Dec 2025: 5.25 million barrels) at a cost of \$22.50 million (Dec 2025: \$7.05 million)

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.

	30 Sept 2026 \$'000	31 Dec 2025 \$'000
Fixed deposits	26	24
Cash at bank	557,074	332,547
Gross cash and cash equivalents	557,100	332,571
Impairment allowance	(245)	(245)
Net cash and cash equivalents	556,855	332,326

20.1 Reconciliation of impairment allowance on cash and cash equivalents

	30 Sept 2026 \$'000	31 Dec 2025 \$'000
Loss allowance as at 1 January	245	245
Increase/ (decrease) in loss allowance	–	–
Loss allowance as at	245	245

20.2 Restricted cash

	30 Sept 2026 \$'000	31 Dec 2025 \$'000
Restricted cash	129,209	126,351
	129,209	126,351

20.3 Movement in restricted cash

	30 Sept 2026 \$'000	31 Dec 2025 \$'000
Opening balance	126,351	132,209
Increase/(decrease) in restricted cash	2,858	(5,858)
Closing balance	129,209	126,351

Included in the restricted cash is \$120.9 million (Dec 2025: \$119.5 million), which relates to SEPNU's decommissioning and abandonment deposit of \$103.3 million (Dec 2025: \$103.34 million), as well as the host community fund of \$17.6 million (Dec 2025: \$16.2 million). SEPNU's decommissioning and abandonment deposit has been classified as current because it is held under a one-year letter of credit facility.

Also included in the restricted cash balance is \$2.8 million (Dec 2025: \$2.4 million) and \$4.4 million (Dec 2025: \$3.4 million) 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 (Dec 2025: \$0.6 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 (Dec 2025: \$0.4 million) for unclaimed dividend.

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

21. Other financial assets at amortised cost

	30 Sep 2026 \$'000	31 Dec 2025 \$'000
Opening Balance	—	—
Addition	2,833	—
Interest Income	345	—
Repayment	(355)	—
Exchange Difference	76	—
Gross carrying amount	2,899	—
Impairment allowance	—	—
Net carrying amount	2,899	—

Split into:

	30 Sep 2026 \$'000	31 Dec 2025 \$'000
Current	738	—
Non-current	2,161	—
	2,899	—

During the period, Seplat West Limited entered into a debt settlement agreement with Geregu Power PLC for outstanding gas sales receivables. As part of the settlement, and in line with the Presidential Power Sector Debt Reduction Programme, the company received NBET Finance Company PLC Series I (Tranche B) Bonds with a face value of ₦3.87 billion, bearing interest at 17.50% per annum and maturing in January 2033. The bonds have been recognised at amortised cost in accordance with the Group's accounting policy in Note 3.22.

22. Share capital

22.1 Authorised and issued share capital

	30 Sept 2026 \$'000	31 Dec 2025 \$'000
Authorised ordinary share capital		
599,944,561 (Dec 2025: 599,944,561) ordinary shares denominated in Naira of 50 kobo per share	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	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.

22.2 Movement in total equity attributable to owners of the parent

	Number of shares Shares	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	Total \$'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	–	–	–	–	–	–	254,970	–	254,970
Dividend paid	–	–	–	–	–	–	(175,844)	–	(175,844)
Vested shares during the period	–	–	(48,675)	(22,230)	70,905	–	–	–	–
PAYE tax remitted on vested shares	–	–	–	–	(35,906)	–	–	–	(35,906)
Transfer to share-based payment liability	–	–	–	(10,212)	–	–	–	–	(10,212)
Share based payments	–	–	–	10,569	–	–	–	–	10,569
Share repurchased	–	–	–	–	(69,470)	–	–	–	(69,470)
Closing balance as at 30 Sept 2026	599,944,561	1,868	511,696	21,088	(103,821)	40,000	1,327,419	2,887	1,801,137

	Number of shares Shares	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	Total \$'000
Opening balance as at 1 January 2025	588,444,561	1,864	518,564	36,747	(5,609)	40,000	1,228,817	2,233	1,822,616
Profit for the period	–	–	–	–	–	–	160,143	–	160,143
Other comprehensive loss	–	–	–	–	–	–	(468)	654	186
Dividend paid	–	–	–	–	–	–	(140,199)	–	(140,199)
Share based payments	–	–	–	24,066	–	–	–	–	24,066
Vested shares during the year	–	–	–	(17,852)	17,852	–	–	–	–
PAYE tax remitted on vested shares	–	–	–	–	(8,861)	–	–	–	(8,861)
Share repurchased	–	–	–	–	(30,921)	–	–	–	(30,921)
Shares issued	11,500,000	4	41,807	–	(41,811)	–	–	–	–
Closing balance as at 31 December 2025	599,944,561	1,868	560,371	42,961	(69,350)	40,000	1,248,293	2,887	1,827,030

22.3 Employee share-based payment scheme

As at 30 Sept 2026, the Group had 29,575,922 shares (Dec 2025: 49,999,973 shares), comprising 6,918,200 equity-settled awards and 22,657,722 cash-settled awards, which were 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 nine months ended 30 Sept 2026, 22,229,727 shares were vested (Dec 2025: 13,342,715 shares).

22.4 Treasury shares

This relates to shares purchased from the market or issued by the company to fund the Group's Long-Term Incentive Plan. The programme commenced from 1 March 2021 and are held by the Trustees under the Trust for the benefit of the Group's employee beneficiaries covered under the Trust.

23. Interest-bearing loans and borrowings

23.1 Reconciliation of interest-bearing loans and borrowings

Below is the reconciliation of interest-bearing loans and borrowings for 30 September 2026:

	Borrowings within 1 year \$'000	Borrowings above 1 year \$'000	Total \$'000
Balance as at 1 January 2026	72,568	933,028	1,005,596
Interest accrued	86,823	–	86,823
Principal paid	(200,000)	–	(200,000)
Interest repayment	(81,428)	–	(81,428)
Other financing charges	(19,245)	–	(19,245)
Transfers	210,293	(210,293)	–
Carrying amount as at 30 Sept 2026	69,011	722,735	791,746

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

	Borrowings within 1 year \$'000	Borrowings above 1 year \$'000	Total \$'000
Balance as at 1 January 2025	449,593	918,036	1,367,629
Additions	–	628,246	628,246
Interest accrued	140,558	–	140,558
Principal paid	(1,030,250)	–	(1,030,250)
Interest repayment	(100,587)	–	(100,587)
Transfers	613,254	(613,254)	–
Carrying amount as at 31 Dec 2025	72,568	933,028	1,005,596

*Transfers represent the reclassification from non-current to current as contractual cash flows become due within the next 12 months as a result of the passage of time.

Other financing charges include term loan arrangement and commitment fees, annual bank charges, technical bank fee, agency fee and analytical services in connection with annual service charge. These costs do not form an integral part of the effective interest rate. As a result, they are not included in the measurement of the interest-bearing loan.

23.2 Amortised cost of borrowings

	30 Sept 2026 \$'000	31 Dec 2025 \$'000
\$650 million Senior notes – March 2025	637,515	649,707
\$80 million Senior reserve-based lending (RBL) facility	55,178	53,507
\$300 million Advance Payment Facility	99,053	302,382
	791,746	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 at the time of issuance. The \$650 million bond issuance was used exclusively to redeem the maturing \$650 million note, with transaction costs covered from the Group's cash reserves. The amortised cost for the senior notes as at the reporting period is \$637.52 million (Dec 2025: \$649.7 million) 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. Current drawdown under the financing is \$55.25 million, which is below the committed level of \$80 million for the period up to and including 30 June 2027. The amortised cost for the senior notes as at the reporting period is \$55.18 million (Dec 2025: \$53.5 million).

\$400 million Revolving credit facility

The RCF was refinanced to \$400 million on January 31, 2026. All in pricing improved to SOFR + 4.5% from SOFR + 5.26% (including a credit adjustment spread). The facility is no longer amortising and includes a bullet repayment at final maturity, with maturity extended to 30 September 2029, i.e., maturing before the \$650 million senior notes. The facility is currently fully undrawn.

\$300 million Advance payment facility

The \$300 million APF was closed in December 2024 to provide financing for the completion of the MPNU acquisition. The facility was fully drawn; however, the Group has repaid and cancelled \$200M under the APF in May and June 2026. The current outstanding drawdown amount is \$100 million.

The APF 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 and matures in December 2027. The amortised cost for the APF as at the reporting period is \$99.05 million (Dec 2025: \$302.3 million).

24. Employee benefit obligation

24.1 Defined benefit plan

During the reporting period, the defined benefit plan was presented as a net defined benefit liability of \$0.93 million, (Dec. 2025: \$2.7 million).

	30 Sept 2026	Movement	31 Dec 2025
	\$'000	\$'000	\$'000
Net defined benefit assets/(liabilities) recognised in the financial position			
Present value of defined benefit obligation	69,048	(788)	69,836
Fair value of plan assets	(68,114)	(998)	(67,116)
	934	(1,786)	2,720

	30 September 2026
	\$'000
Movement during the period for the defined benefit assets/(liabilities):	
Income on plan asset (note 15)	166
Charged to receivables	1,620
	1,786

25. Trade and other payables

	30 Sept 2026	31 Dec 2025
	\$'000	\$'000
Financial Instruments		
Trade payables	491,640	515,704
Accruals and other payables	373,172	322,512
Non-Financial Instruments		
Share-based payment liability (Note 25.1)	71,538	2,250
NDDC levy	25,740	12,483
Royalties payable	66,318	59,937
	1,028,408	912,886

Split into:

	30 Sept 2026	31 Dec 2025
	\$'000	\$'000
Current	981,960	912,886
Non-current *	46,448	—
	1,028,408	912,886

Included in accruals and other payables are field accruals of \$227.6 million (Dec 2025: \$101.8 million), balance received for asset held for sale of \$9.9 million (Dec 2025: \$9.9 million) and other vendor payables of \$135.62 million (Dec 2025: \$210 million).

Royalties payable include accruals in respect of crude oil and gas production for which payment is outstanding at the end of the period.

* Non-current portion relates to share-based payment liability due after 12 months.

25.1. Share-based payment liability

The Group has granted share-based awards to employees that will be settled in cash. These awards comprise the 2024 LTIP, 2025 LTIP and 2026 LTIP. Awards granted under these LTIP schemes to employees below Board level will be settled in cash and have a three year vesting period. Share-based payment liability represents the Group's obligation in respect of these cash-settled LTIP awards granted to employees below Board level.

	30 Sep 2026	31 Dec 2025
	\$'000	\$'000
Opening balance	2,250	–
Additions	59,076	2,250
Transfer from share-based payment reserve *	10,212	–
Closing balance	71,538	2,250

* During the period, the terms of the 2024 LTIP were changed such that awards granted to employees below Board level, which were previously classified as equity-settled, will now be settled in cash. The modification took effect on 1 January 2026 and affected 12.49 million unvested awards. Following the modification, a cash-settled share-based payment liability was recognised in accordance with IFRS 2. The modification resulted in a transfer of \$10.2 million from share based payment reserve to share based payment liability and an incremental fair value expense of \$22.9 million, which has been recognised as share-based payment expense during the reporting period. The fair value of the share-based liability was subsequently remeasured at 30 September 2026 using a binomial valuation model.

26. 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 during 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.

	9 months ended 30 Sept 2026	9 months ended 30 Sept 2025	3 Months ended 30 Sept 2026	3 Months ended 30 Sept 2025
	\$'000	\$'000	\$'000	\$'000
Profit attributable to Equity holders of the parent	254,970	92,084	95,502	68,481
Profit/(loss) attributable to Non-controlling interests	5,235	3,045	694	(775)
Profit for the period	260,205	95,129	96,196	67,706

	Shares '000	Shares '000	Shares '000	Shares '000
Weighted average number of ordinary shares in issue	599,945	591,001	599,945	591,001
Weighted average number of ordinary shares adjusted for the effect of dilution	599,945	591,001	599,945	591,001

	\$	\$	\$	\$
Basic earnings per share for the period				
Basic earnings per share	0.42	0.16	0.16	0.12
Diluted earnings per share	0.42	0.16	0.16	0.12
Profit used in determining basic/diluted earnings per share	254,970	92,084	95,502	68,481

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.

27. Proposed dividend

For the third quarter ended 30 September 2026, the Group's directors declared an interim dividend of 19 cents per share, consisting of core dividend of 5 cents per share and special dividend of 14 cents per share. (Dec 2025: a final dividend of 5 cents per share and a special dividend of 3.3 cents per share).

28. 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 21.07% 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 following are details of transactions and balances with related parties. The terms of these transactions are at arm's length.

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 revolving credit facility ('RCF'), which remained undrawn as at the reporting date. UBA also provides a \$978 thousand customs bond for operational cargo clearance for an annual fee of 0.15%. At the end of the reporting period, the Group held balances of \$90.1 million 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 \$2.3 million. As at the reporting date, amounts due from Transcorp Power Limited was \$6.2 million.

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 \$771 thousand. The Group had an outstanding payable balance of \$23 thousand with Transcorp Hotels Plc as at the reporting date.

Shareholders of the parent company

Vaaris Resources JVCo Limited: Following the sale of TotalEnergies EP Nigeria Limited's (TEPNG) non-operated interest in the Renaissance JV (formerly SPDC) licences to Vaaris, Seplat consented, through a Deed of Novation, to Vaaris replacing TEPNG under the ANOH Unitization and Unit Operating Agreement (UUOA), to which the Renaissance JV is a party. Vaaris is controlled by Platform Petroleum, a shareholder of Seplat. No transactions or outstanding balances arose from the arrangement.

Entities controlled by Directors of the Company

Vaaris Resources JVCo Limited: Mr Kazeem Raimi, a Non-Executive Director of Seplat PLC, is also a director of Vaaris, which replaced TEPNG under the ANOH Unitization and Unit Operating Agreement (UUOA) pursuant to a Deed of Novation consented to by Seplat during the period. No transactions or outstanding balances arose from the arrangement.

29. Commitments and contingencies

29.1 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 30 Sept 2026 is \$338.82 million, (Dec 2025: \$275.75 million). The contingent liability for the year 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.

30. Events after the reporting period

There are no other events which could have had a material effect on the financial position of the Group as at 30 September 2026 and its financial performance for the period then ended that have not been adequately provided for or disclosed in these financial statements.