Unaudited results for the three months ended 31 March 2025

28 April 2025

Reliable energy, limitless potential

(Expressed in Nigerian Naira
and US Dollars)

Seplat Energy

Overview

Lagos and London, 28 Apr 2025: Seplat Energy PLC ("Seplat Energy" or "the Company"), a leading Nigerian independent energy Company listed on both the Nigerian Exchange and the London Stock Exchange, announces its audited results for the three months ended 31 March 2025.

Summary

Delivered robust production and cost performance during 1Q 2025, at a new scale, and firmly on track to deliver FY 2025 guidance. Strong cash position supports early repayment of $250 million reducing the RCF to $100 million, and an increase in our quarterly dividend to US$ 4.6c/share.

Operational highlights

- Production averaged 131,561 boepd up 167% from 1Q 2024 (49,258 boepd), above the midpoint of 2025 guidance (120 - 140 kboepd).
  - Onshore production contribution of 56,196 boepd, was 14% higher than 1Q 2024, and above 2025 guidance. Within this, liquids +10% and gas +21% vs 1Q 2024, following strong performance at Oben Gas Plant and first contribution from Sapele Gas Plant.
  - SEPNU production contribution of 75,365 boepd, within guidance, of which 88% crude and condensate, 4% NGL and 8% gas.
- SEPNU idle well restoration programme added c.11 kbopd gross JV production from the first 10 wells restored to production.
- Sapele Integrated Gas Plant ('SIGP') was commissioned and achieved first commercial gas sales in February 2025. Plant is delivering high quality processed gas, and condensate yields of c.2 kbopd.
- Carbon emissions intensity for Seplat onshore assets: 30.6 kg CO_2/boe (revised 1Q 2024: 31.1 kg CO_2/boe), reduction driven by lower emissions at Sapele post start-up of SIGP. End of routine flaring for onshore assets on track for H2 2025.
- Achieved more than 7.3 million man hours without Lost Time Injury (LTI), of which 2.5 million was Seplat onshore-operated assets (1Q 2024: 2.3 million man hours) and 4.8 million hours without LTI for SEPNU.

Financial highlights

- Revenue $809 million up c.350% on prior year (1Q 2024: $180 million).
- Unit production operating cost of $12.6/boe (1Q 2024: $9.5/boe), better than guidance of $14-$15/boe, due to timing of planned maintenance activities.
- Adjusted EBITDA of $401 million, up 226% on prior year (1Q 2024: $123 million).
- Cash generated from operations of $306.5 million, up materially from $16.8 million in 1Q 2024.
- Cash capital expenditure of $40.2 million (1Q 2024: $47 million). Onshore drilling activity to ramp up from 2Q 2025.
- Completed refinancing of $650 million senior notes, with newly issued notes having a 2030 maturity and priced with a coupon of 9.125%. Seplat notes were priced inside the Nigerian sovereign for the first time, reflective of established reputation in credit markets.
- Reduced gross debt by ~21% following early repayment of $250 million of RCF and $19.3 million repayment of Eland RBL.
- Balance sheet remains robust, end-March cash at bank $334.6 million (YE 2024: $469.9 million), excluding $128.9 million restricted cash.
- Net Debt at end-March of $747 million down 17% on prior quarter (YE 2024: $898 million). Pro-forma ND/EBITDA improves to 0.56x.

Dividend & Board

- 1Q 2025 declared dividend of US$ 4.6c/share, an increase on the prior quarter dividend (US$ 3.6c/share), reflecting the strength of our financial position and confidence in our outlook. The company plans to set out a revised capital allocation policy in the Capital Markets Day scheduled for September 2025.
- Mr. Bello Rabiu, Senior Independent Non-Executive Director and Mr. Babs Omotowa, Independent Non-Executive Director resigned from the Board following their appointment to the NNPC Ltd board. The Board has unanimously appointed Mrs. Bashirat Odunewu as Senior Independent Non-Executive Director.

2025 Outlook

- 2025 guidance unchanged.
  - Production guidance of 120-140 kboepd (Seplat Onshore 48-56 kboepd, SEPNU 72-84 kboepd).
  - Capex guidance $260-320 million. (Seplat Onshore $180-220 million, SEPNU $80-100 million).
  - Unit operating costs for the group are expected to be $14.0-15.0/boe.
- Capital Markets Day in September 2025 to detail our medium to long term growth ambitions.

Roger Brown, Chief Executive Officer, said:

"2025 has started positively for Seplat. As we deliver the business at a significantly enhanced scale, our focus is on the successful integration of the combined companies, and I am pleased to report that we are making good progress. It is clear that we can benefit greatly from the combined expertise of our onshore and offshore workforce.

Production has been strong, showing the benefit of the continuous drilling programme, investment in asset integrity and the availability of multiple evacuation routes. Financial performance was also strong, allowing us to be pro-active in materially reducing gross debt, maintaining low balance sheet leverage, and further strengthening our company as the near term global economic outlook becomes less predictable.

We remain conservative in our approach, but our confidence in the future trajectory for our business, combined with our strong financial position, means that we are delighted to increase our quarterly dividend to $ 4.6c/share, an 28% increase in our quarterly dividend versus 4Q 2024. Our assets are high quality, and while we will remain agile to the prevailing oil price environment, our business plan is designed to be robust at lower oil prices and our gas revenues, which are largely delinked to oil prices, provide long-term stability for the business. We are committed to our plan of growth and maximising value for our stakeholders."

Summary of performance

	$ million			₦ billion	
	Q1 2025*	Q1 2024	% change	**Q1 2025***	Q1 2024
Revenue **	**809.3**	179.8	350.0 %	**1,227.5**	268.6
Gross profit	**353.0**	42.7	726.4 %	**535.4**	63.8
EBITDA ***	**400.6**	123.3	224.9 %	**607.6**	184.2
Operating profit (loss)	**238.2**	81.9	190.7 %	**361.3**	122.4
Profit (loss) before tax	**207.4**	69.3	199.4 %	**314.6**	103.5
Profit (loss) after tax	**23.3**	(1.9)	nm	**35.4**	(2.9)
Cash generated from operations	**306.5**	16.8	1721.0 %	**464.9**	25.2
Working interest production (boepd)	**131,561**	49,258	167.1 %		
Volumes lifted (MMbbls)	**9.9**	1.8	450.0 %		
Average realised oil price ($/bbl)	**76.42**	86.17	(11.3)%		
Average realised gas price ($/Mscf)	**3.01**	3.11	(3.2)%		
LTIF	**—**	—			
CO2 emissions intensity from operated onshore assets, kg/boe	**30.6**	31.1	(1.5)%		

*Throughout results 1Q 2025 reported figures consolidate SEPNU contribution, while 1Q 2024 information relates solely to Seplat's Onshore assets
** 1Q 2025 reported revenue includes an overlift of $53.5 million, 1Q 2024 excludes an underlift of $56.4 million
*** Adjusted for non-cash items

Responsibility for publication

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

Signed:

Eleanor Adaralegbe
Chief Financial Officer

Important notice

The information contained within this announcement is unaudited and deemed by the Company to constitute inside information 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.

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About Seplat Energy

Seplat Energy PLC (Seplat) is Nigeria's leading indigenous energy company. Listed on 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.

Following the acquisition of Mobil Producing Nigeria Unlimited, Seplat Energy's enlarged portfolio consists of eleven oil and gas blocks in onshore and shallow water locations in the prolific Niger Delta region of Nigeria, which we operate with partners including the Nigerian Government and other oil producers. Furthermore, we have an operated interest in three export terminals including the Qua Iboe export terminal and Yoho FSO, as well as an operated interest in the Bonny River Terminal (BRT) NGL recovery plant. We operate two gas processing plants onshore, at Oben in OML 4 and Sapele in OML 41, and are soon to open the 300 MMscfd ANOH Gas Processing Plant in OML 53 as a joint venture with NGIC. Combined, these gas facilities augment Seplat Energy's position as a leading supplier of natural gas to the domestic power generation market.

For further information please refer to our website; https://www.seplatenergy.com/

Operating review

Group Production

Working interest production for the three months ended 31 March 2025

		Q1 2025				Q1 2024			
	Seplat WI	Crude & Condensate	Gas	NGLs	Total	Crude & Condensate	Gas	NGLs	Total
Asset	%	bopd	MMscfd	bpd	kboepd	bopd	MMscfd	bpd	kboepd
OMLs 4, 38, 41	45 %	16,291	132.0	—	39,050	15,089	109.5	—	33,961
OML 40	45 %	12,676	—	—	12,676	12,470	—	—	12,470
OML 53	40 %	2,935	—	—	2,935	1,263	—	—	1,263
OPL 283	40 %	1,535	—	—	1,535	1,564	—	—	1,564
Seplat Onshore		**33,437**	**132.0**	**—**	**56,196**	**30,386**	**109.5**	**—**	**49,258**
OMLs 67, 68, 70, 104	40 %	65,385	20.2	3,376	72,238	—	—	—	—
OML 99 (A/K Field)	9.6 %	816	13.4	—	3,127	—	—	—	—
SEPNU		**66,201**	**33.6**	**3,376**	**75,365**	**—**	**—**	**—**	**—**
Total		**99,638**	**165.6**	**3,376**	**131,561**	**30,386**	**109.5**	**—**	**49,258**

Liquid production volumes as measured at the LACT (Lease Automatic Custody Transfer) unit for OMLs 4, 38 and 41; OML 40 and OPL 283 flow station.
Gas conversion factor of 5.8 boe per scf.
Volumes stated are subject to reconciliation and may differ from sales volumes within the period.

In 1Q 2025, total crude & condensate production increased by 224% to 9.0 MMbbls, compared to the 2.8 MMbbls produced in 1Q 2024. Total gas produced during the quarter also rose 50% to 14.9 Bscf (1Q 2024: 10.0 Bscf), and we also produced 304 kbbls of NGLs in 1Q 2025. As such, aggregate production for the quarter rose 164% to 11.8 MMboe (1Q 2024: 4.5 MMboe). This reflects the transformational impact of the SEPNU consolidation and strong performance on our onshore assets. We provide more details on drivers of this performance in subsequent sections.

Average daily working interest production for the group was 131,561 boepd (1Q 2024: 49,258 boepd), slightly above the midpoint of our production guidance of 120,000 - 140,000 boepd.

Production performance in our onshore assets was strong, up 14% from the equivalent period in 2024 (1Q 2025: 56,196 boepd; 1Q 2024: 49,258 boepd), aided by a confluence of several positive catalysts including good performance of the new wells in the 2024 drilling campaign, commencement of gas production from Sapele Integrated Gas Plant (SIGP), improved gas production from Oben following turnaround maintenance, and continuation of 24-hour operations at the Trans Niger Pipeline (TNP).

Seplat Energy Producing Nigeria Unlimited (SEPNU)

Production across the offshore assets started the year in-line with expectations with daily average working interest production during 1Q 2025 of 75,365 boepd. January and February benefited from high uptime, while in March we commenced a number of planned shutdown operations to improve long term asset performance.

Across product lines, production was 88% crude and condensates, 4% NGL, and 8% gas. The Amenam-Kpono field (A/K) contributed 3.1 kboepd to average daily production of which 26% was crude and condensate and the balance gas.

During 1Q 2025 we commenced the 2025 work programme, and we are pleased to report that, after period end, we achieved 2025 budget planning sign-off with our JV partners

The programme to resume production from idle wells across the license commenced during the period. At period end, approximately 11 kboepd gross production capacity has been reinstated from the idle well restoration programme. This has been achieved from 10 idle wells, that could be accessed directly from certain existing platforms. The jack-up barge has now moved to well work activities and commenced well interventions after the period end. Combining both platform and well work barge activities, we are now targeting production restoration work on over 50 of the idle well inventory in 2025.

The East Area Project ('EAP') Inlet Gas Exchanger (IGE) replacement project will increase gross JV NGL production at EAP by 8 to 10 kboepd when operational. Fabrication of the IGE unit was completed in the OEM facility (Germany) and transported in-country. Construction works, including onshore interconnect piping fabrication and offshore installation campaign have commenced and installation is expected to complete during 3Q 2025.

Other planned maintenance activities increased during March, included a nested shutdown across three major platforms to address full function testing of critical safety devices and replacement of multiple valves, rises and piping. These activities impacted production across Crude, NGL and gas in the period. Gas sales were also impacted by a leak on third party infrastructure.

Seplat Onshore Operations Update

Western Assets

In OMLs 4, 38, & 41, working interest liquids production rose by 8% to 16,291 bopd (1Q 2024: 15,089 bopd). The growth was aided by the successful 2024 drilling campaign which helped to arrest decline on the assets and support growth. In addition, export route availability remained strong during the quarter with only two days overlapping downtime between the Amukpe-Escravos pipeline ('AEP') and Trans Forcados pipeline ('TFP') routes. While overall asset performance was strong, it was partially offset by some operational challenges on the TFP and at the Escravos Oil Terminal ('EOT'). As such, total deferments on the asset in 1Q 2025 rose to 17% (1Q 2024: 13%).

Elcrest

Production at OML 40 recorded marginal improvement, rising by 1.7% to 12,676 bopd (1Q 2024: 12,470 bopd). Well performance at OML 40 continues to remain strong while export route availability has also been a positive for production. Total deferments on OML 40 during the quarter were 22%. Elcrest recorded 0.7 million LTI free man hours in 1Q 2025.

Sibiri oil field

As communicated in our FY 2024 results, following persistent strong well performance at Sibiri, we plan to drill three wells (Sibiri-C, Sibiri-D, & Sibiri-E) at the Sibiri field in the 2025 drilling plan. Drilling of the wells will commence in 2H 2025.

Abiala oil field

In our FY 2024 results, we reported receipt of field development approval (FDP) from the Nigerian Upstream Petroleum Regulatory Commission (NUPRC) on 14th February, 2025. In the period since, we have ramped up production from all four producing strings, reaching approximately 3,500 bopd gross. By March 2025, Abiala's total production reached approximately 130,000 barrels, with the first crude export of 30,000 barrels on March 21, 2025.

In April 2025, the field was shut in as we commenced operations to switch production from the extended well test facility ('EWT') to an early production facility ('EPF'). Production is expected to resume during 2Q 2025 following installation, integration, and commissioning of the Abiala EPF. We are pleased to report that following positive initial observations, gross production potential from the two development wells is now estimated at 8,000 bopd, up from our previous estimate of 5,000 bopd. We also secured an additional storage vessel to support optimised production and evacuation from the Abiala field.

Eastern Assets

In OML 53, average daily working interest production increased by 132% to 2,935 bopd in 1Q 2025, from 1,263 bopd in 1Q 2024, due to continuous availability of the evacuation routes for the asset, principally the Trans Niger Pipeline ('TNP'). During the quarter a section of the TNP, near the Bodo-Bonny road, was impacted by attempted sabotage, however the episode caused minimal disruption to our Ohaji operations, with normal production restored within days. Total uptime for the TNP-BOT evacuation route in 1Q 2025 was 88% (1Q 2024: 0%). We also continued to supply the Waltersmith refinery during the quarter.

Production from our Jisike field continued to improve as the reliability of the Antan-Ebocha-Brass terminal route was sustained in 1Q 2025. Uptime on the route improved to 73% (1Q 2024: 29%).

In OPL 283, production was stable at 1,535 bopd (1Q 2024: 1,564 bopd).

Drilling activities

As communicated in our FY 2024 results, our 2025 drilling programme involves delivery of 13 new wells on our onshore assets (Western Assets - 7 wells; Eastern Assets - 2 wells; Elcrest - 4 wells). No wells from the 2025 plan were completed during 1Q 2025, while four are expected to complete during 2Q 2025. The 2025 well programme is expected to arrest production decline and support organic growth ambitions.

In 1Q 2025, we spudded two wells (Orogho KZGF-02 and Okporhuru-10) on OMLs 4, 38, & 41, both of which are set to be completed in May 2025. A third well is also planned on our Western asset in 2Q 2025, together, the three wells are estimated to add 3,100 bopd and 45 MMscfd gross JV production volumes.

At OML 40, implementation of the drilling programme will commence in 2Q 2025 once the rig arrives at location. Rig maintenance work is ongoing while all regulatory permits needed to commence drilling are being finalised. We plan to deliver one well in 2Q 2025.

On our Eastern assets, we are in the process of securing a land rig and obtaining the necessary regulatory permits required to commence drilling. Drilling activities are expected to start during 3Q 2025.

Offshore activity related to drilling is currently focused on planning for future drilling campaigns, including identification of potential drilling contractors and long lead items.

Midstream Gas business performance

During the quarter, the Company delivered 14.9 Bcf of gas, representing a 50% increase on 1Q 2024's 10.0 Bcf . The average daily working interest gas production volumes increased by 51% to 165.6 MMscfd, from 109.5 MMscfd in 1Q 2024. Consolidation of SEPNU's gas production added 33.6 MMscfd to the group's average daily working interest gas production during the quarter. On our onshore assets, average daily working interest gas production increased by 21% to 132.0 MMscfd (1Q 2024: 109.5 MMscfd). The increase was supported by commencement of production at the Sapele gas plant, gas wells coming onstream, and improved efficiency at the Oben gas plant following the 2024 turnaround maintenance activities.

2025 Domestic Gas Price Update

On 1st April, the Nigerian Midstream and Downstream Petroleum Regulatory Authority (NMDPRA) announced a downward review of gas price for Domestic Gas Delivery Obligation (DGDO) contracts for a year from April 2025, to $2.13/MMbtu, from $2.42/MMbtu previously. We continue to work with industry members to engage with the regulator to review the decision.

Sapele Gas Plant

The Sapele Gas Plant is a 90 MMscfd plant, capable of processing both Non-Associated Gas (NAG) and Associated Gas (AG) which meets export specifications and an LPG processing module which will supply LPG to the domestic market. The project will also contribute significantly to Seplat's target to end routine flaring by the end of 2025.

As previously reported the initial 30 MMscfd Mechanical Refrigeration Unit ('MRU') was completed in Q4 2024, in line with expectations. The start of commercial operations began in February 2025. Throughput has been very strong, averaging c.28 Mmscf/d high quality gas, with strong condensate recovery of c.2 kbopd gross volumes. We have seen high demand for the gas due to its specification, which augurs well for the start up on the second 60 MMscf MRU.

The second MRU, which will lift total production capacity to 90 MMscfd, is on track for completion during 2Q 2025 with sales commencing in the third quarter. The upgraded facility will produce gas that meets export specifications, and the LPG processing module will enhance the economics of the plant and eliminate routine gas flaring. During 1Q 2025 associated gas commercialisation through Sapele gas plant resulted in approximately a 30% reduction in emissions intensity at the Sapele flow station, illustrating the potential of the programme.

We note that in early 2025, Oben and Sapele gas plants combined operations has regularly exceeded 300 MMscfd on a gross JV basis, peaking at 333 MMscfd (c. 150 MMScfd net working interest) during the quarter.

ANOH Gas

AGPC continued its strong safety performance achieving a cumulative total of 15.4 million man-hours LTI free by the end of 1Q 2025. We are pleased to announce that the ANOH Gas plant construction project achieved commissioning (dry) gas Ready for Start-Up ('RFSU') milestone during the quarter, and will shortly introduce dry gas for commissioning.
Beyond the gas plant execution work, much of the focus in 1Q 2025 has been on securing alternative evacuation options, given continued delays to completion of the OB3 pipeline. During the period AGPC agreed preliminary heads of terms for delivery of gas into the export market through the Nigeria LNG ('NLNG') terminal. This will act as an interim outlet for gas monetization and work is currently ongoing to make the necessary pipeline modifications to enable gas sales to commence in 3Q 2025.

During the quarter the Incorporated Joint Venture ('IJV') partners agreed to an additional equity investment of $20 million (Seplat share; $10 million) to support final project execution costs in advance of revenue generation from production.

Ending routine flaring

Reducing the carbon intensity of our operations is a key strategic focus. Seplat has implemented its end of routine flaring ('EORF') roadmap, which includes investments across our production facilities to minimise Scope 1 & 2 greenhouse gas emissions and improve overall energy efficiency.

The carbon emissions intensity recorded on Seplat's onshore operations for the period was 30.6 kg CO2/boe, lower than the 31.1 kg CO_2/boe recorded in 1Q 2024. On a quarter-on-quarter basis, carbon emissions intensity onshore fell by 5% from 32.3 kgCO_2/boe reported in 4Q 2024. The improvement in carbon emissions intensity was driven by the completion and commencement of operations from the 30 MMscfd MRU at the Sapele gas plant. As stated above, the first module of SIGP has commenced operations and is now producing. Partial commercialisation of the associated gas flares was achieved, which resulted in a reduction of c.30% in CO_2 emissions at the Sapele flow station, versus 4Q 2024. Further reductions are expected as full injection of associated gas into Sapele gas plant is achieved later in 2025.

Other ongoing key flare-out projects include, the Western Asset Flares Out (installation of vapour recovery unit compressors), Sapele LPG Storage & Offloading Facility, Oben LPG Project and Ohaji Flares Out Project. The Company is on track to end routine flaring of gas across its onshore assets in 2H 2025.

We continue to assess the emissions and flaring regime within SEPNU and alignment with Seplat reporting methodology. The intention is to begin reporting SEPNU emissions data during 2025.

HSE Performance

The Company achieved a total of 2.5-million hours without any Lost Time Injury (LTI) on its operated onshore assets in 1Q 2025 (1Q 2024: 2.3-million hours), which reflects the Company's strong focus on safety and the dedication of its workforce to maintaining a secure work environment. The Company has achieved a cumulative 23.0-million-man hours since last LTI recorded (on 13th October 2022) across our operated onshore assets. In the period we recorded two Process Safety Tier 1 incidents of which one was related to an oil spill and one due to a gas release, and one further oil spill related Tier 2 loss of primary containment incident. Other key HSE performance metrics remain positive with no fatality, LTI, nor TRIR recorded during the quarter.

As we disclosed in our FY 2024 results, we remain on the path towards achieving ISO 45001 and 14001 standards certifications. In 1Q 2025, we progressed the stage 2 audit for ISO 45001 and expect to complete it in time to receive the certification in Q2 2025. We also completed the stage 2 regulatory audit for ISO 14001 and remain on track to achieve completion in Q2 2025. Working to achieve these certifications further demonstrates our commitment top-tier safety and environmental performance.

SEPNU recorded 4.8 million hours worked without a LTI during the period, as such SEPNU has now achieved a cumulative 14.1-million-man-hours since its last LTI.

Petroleum Industry Act (PIA) Implementation Status

In our onshore business, we have progressed the process towards securing approval to convert our onshore assets to the PIA regime. In our FY 2024 release, we communicated that delineation had been made based on principles established in section 93 of the PIA, 2021 and that the Commission has requested documentation from Seplat that would facilitate the preparation of legal transfer documents on the retained PMLs and PPLs.

We are pleased to report that post the FY 2024 results release, we have submitted to NUPRC, all relevant technical data on areas to be relinquished. We have also commenced work with the commission's recommended surveyor to standardise vertices and coordinates of the retention areas, in line with statutory requirements for boundary maps and conversion documentation. Completing this process will facilitate the preparation of legal transfer documents on the retained PMLs and PPLs.

For SEPNU, conversations are ongoing with the regulators to resume the process of conversion of the offshore assets to PIA.

Board Changes

Following their recent appointments to the Board of NNPC Limited by the President of the Federal Republic of Nigeria, Mr. Bello Rabiu, Senior Independent Non-Executive Director ('SINED') and Mr. Babs Omotowa, Independent Non-Executive Director ('INED') notified the Board of their resignations. The Board has subsequently appointed Mrs. Bashirat Odunewu as our new SINED.

Financial review

Our 1Q 2025 results represent the first complete quarter as an enlarged business, resulting in a significant step change in financial performance, with reported revenues 350% higher than in 1Q 2024. This was partially offset by weakness in Brent oil price versus the prior year, a factor which has continued after the period end. We recorded an average realised oil price of $76.42/bbl, a $1.55/bbl premium to Brent, but down 12% on prior year. Our NGL realised price of $44.8/boe was equivalent to approximately 60% of Brent. Our blended realised gas price averaged $3.01/Mscf, a 3% decrease on 1Q 2024.

Revenue

Description	Units	Reported Q1-2025	Reported Q1-2024	y/y change
Oil volumes lifted	mmbbl	9.9	1.8	450 %
NGLs volumes lifted	kbbl	138.0	—	nm
Gas sales volume	Bscf	14.9	10.0	49 %
Average realised oil price	US$/bbl	76.42	86.17	(11) %
Average Brent crude oil price	US$/bbl	74.87	81.67	(8) %
Premium (discount) to Brent	US$/bbl	1.55	4.50	(66) %
Average realised NGL price	US$/bbl	44.8	—	nm
Average realised gas price	US$/mscf	3.01	3.11	(3) %
Crude oil revenue	US$m	759.8	150.8	404 %
Gas revenue	US$m	44.5	29.0	53 %
NGLs revenue	US$m	5.0	—	nm
Total revenue	**US$m**	**809.3**	**179.8**	**350 %**
(Overlift)/underlift *	kbbls	(595)	849	nm
(Overlift)/underlift *	US$m	(53.5)	56.4	nm
Total revenue adjusted for (overlift)/underlift	**US$m**	**755.8**	**236.2**	**220 %**
Crude oil revenue adjusted for (overlift)/underlift	US$m	704.9	207.2	240 %

*Overlift/Underlift balance in the quarter comprised 672 kbbl crude oil overlift (valued at $54.9 million) and 77 kbbl NGL underlift (valued at $1.4 million).

Total revenue from oil and gas sales for 1Q 2025, rose 350% to $809.3 million from $179.8 million in 1Q 2024. Adjusting reported revenue for 1Q 2025 overlifts and 1Q 2024 underlifts, total oil and gas sales were $755.8 million ($53.5 million overlift), 220% higher than 1Q 2024's equivalent revenue figure of $236.2 million ($56.4 million underlift).

Reported crude oil revenue, rose 404% to $759.8 million in 1Q 2025 from $150.8 million in 1Q 2024. The increase in crude oil revenue reflects the full impact of the acquired SEPNU business as total crude oil volume lifted for the period rose 450% to 9.9 MMbbls in 1Q 2025, from the 1.8 MMbbls lifted in 1Q 2024. As such, despite an 11% decline in average realised oil price to $76.42/bbl in 1Q 2025 (1Q 2024: $86.17/bbl), the strong increase in volumes lifted supported crude oil revenue growth. The impact of a liquids-heavy acquired business is now reflected in the fact that crude oil revenue contributed 94% of revenues in 1Q 2025 compared to 84% in 1Q 2024.

Reported gas revenue rose by 53% to $44.5 million in 1Q 2025, compared to $29.0 million in 1Q 2024. Gas sales represented 5% of total reported revenue in 1Q 2025 (1Q 2024: 16%). The increase in gas revenue is due to higher gas sales volume of 14.9 Bscf (1Q 2024: 10.0 Bscf) which offset the impact of lower realised gas price of $3.01/Mscf (1Q 2024: $3.11/Mscf). Higher gas sales for the period reflects the impact of strong gas production growth at the Oben gas plant, beginning of commercial operations at the Sapele gas plant, and gas production from SEPNU. The lower realised gas price reflects the impact of adding SEPNU's gas sales into the portfolio. The average realised gas price for SEPNU gas was $2.42/Mscf while for our onshore assets, it was $3.18/Mscf.

The business recorded $5.0 million revenue from Natural Gas Liquids (NGLs) sales in 1Q 2025. Total NGL production volume was 304 kbbls while total NGLs lifted during the period was 138 kbbls. Average realised price was $44.79/bbl (59% of realised crude price).

Production deferment in the period was 19% onshore (1Q 2024: 22%) and 23% offshore. Onshore deferments were ahead of plan given reduced third party related downtime, while offshore was in line with plan. The group's average reconciliation loss factor for the onshore assets remained both stable and low at 3.2% in 1Q 2025, attributed to continued focus on security measures and asset integrity management.

Gross profit

Description	Units	Reported Q1-2025	Reported Q1-2024	y/y change
Non-Production Cost:				
Royalties	US$'m	130.2	50.8	156 %
Depletion, Depreciation, & Amortisation	US$'m	164.0	41.4	296 %
Others	US$'m	12.9	2.0	545 %
Production Cost:				
Crude Handling Fees	US$'m	18.8	18.9	(1) %
Barging & Trucking	US$'m	5.7	3.7	54 %
Operational & Maintenance Expenses	US$'m	124.6	20.2	517 %
Production Opex per boe	**US$/boe**	**12.6**	**9.6**	**31 %**
Cost of Sales	US$'m	456.2	137.0	233 %
Gross Profit	**US$'m**	**353.0**	**42.7**	**727 %**

In 1Q 2025, gross profit rose 727% to $353.0 million, from $42.7 million in 1Q 2024, reflecting the impact of bigger operations.

Direct operating costs, which encompass expenses related to crude-handling charges (CHC), barging/trucking, operations & maintenance, amounted to $149.1 million in 1Q 2025 (1Q 2024: $42.8 million) due to consolidation of SEPNU's production costs. On our onshore operations, total direct operating costs was $53.3 million (1Q 2024: $42.7 million), reflecting the impact of higher production on our onshore assets. For our offshore assets, total direct operating costs was $95.8 million.

Non-production costs increased by 226% to $307.2 million, made up of $130.2 million in royalties (1Q 2024: $50.8 million), $164.0 million in depreciation, depletion, and amortisation (1Q 2024: $41.4 million), and regulatory fees/levies of $12.9 million (1Q 2024: $2.0 million). The increase in group non-production costs reflect consolidation of SEPNU's costs. Across asset categories, non-production costs on our onshore assets increased to $98.3 million (1Q 2024: $94.3 million) due to higher DD&A charge for the quarter arising due to higher production volumes. On our offshore assets, total non-production costs were $208.9 million.

Considering the cost per barrel equivalent basis, our onshore assets, production opex per boe was $10.5/boe while for SEPNU, it was $14.6/boe. Our consolidated production opex per boe of $12.6/boe is lower than our 2025 guidance ($14.0/boe - $15.0/boe) largely due to timing of maintenance and workover well activities scheduled to commence later in the year.

Operating profit and Adjusted EBITDA

Description	Units	Reported Q1-2025	Reported Q1-2024	y/y change
Other Income/(Loss)	US$'m	(44.4)	65.0	nm
General and Administrative Expenses	US$'m	(64.9)	(24.1)	169.3 %
Impairment (Loss)/Reversal on Financial Assets	US$'m	(0.5)	0.7	(171.4) %
Fair Value Loss	US$'m	(5.0)	(2.4)	108.3 %
Operating Profit	US$'m	**238.2**	**81.9**	**190.8 %**
Adjusted EBITDA	US$'m	**400.6**	**123.3**	**224.9 %**

General and Administrative ('G&A') expenses amounted to $64.9 million, versus $24.1 million in 1Q 2024 further reflecting the consolidation of SEPNU. G&A cost per boe for the group was $5.5/boe. We continue to invest efforts in improving administrative efficiency in order to bring costs lower while we also limit the impact of non-recurring costs.

During the period, we recorded overlift of $53.5 million, translating to 672 kbbls, compared to underlift of $56.4 million (translating to 849 kbbls) which was adjusted for in the Other income line item in the Income statement. We also recorded foreign exchange gain of $5.9 million (1Q 2024: $6.0 million) due to optimized cash working capital management and a more stable naira this period.

Overall, we reported operating profit of $238.2 million in 1Q 2025 (29.4% margin), from $81.9 million in 1Q 2024 (45.6% margin). The increase in reported operating profit also reflects the increased scale of the business.

After adjusting for non-cash items such as impairment, fair value, and exchange gains or losses, the adjusted EBITDA for the quarter was $400.6 million (1Q 2024: $123.3 million), resulting in a margin of 49.5%.

Taxation

The income tax expense of $184.1 million (1Q 2024: $71.2 million) includes a current tax charge of $215.0 million (1Q 2024: $13.9 million) and a deferred tax credit of $30.9 million (1Q 2024: $57.3 million charge). The higher tax charge in the income statement reflects the current tax due in SEPNU. For the offshore assets, we expect the current tax charge to moderate overtime as the pool of available capital allowances increases as we increase our investments across the asset base.

Net result

Description	Units	Reported Q1-2025	Reported Q1-2024	y/y change
Profit before Tax	US$'m	207.4	69.3	199 %
Total Income tax expense:		184.1	71.2	159 %
Current Tax	US$'m	215.0	13.9	1447 %
Deferred Tax	US$'m	(30.9)	57.3	(154)%
Net Income/(Loss)	**US$'m**	**23.3**	**(1.9)**	**nm**
Profit Attributable to Holders of Equity	US$'m	20.2	1.0	1920 %
Earnings per Share	**US$c'shr**	**3.1**	**—**	**nm**

Profit before tax rose 199%, amounting to $207.4 million, compared to $69.3 million in 1Q 2024. Profit after tax for the quarter was $23.3 million, compared to a $1.9 million loss in 1Q 2024.

The profit attributable to equity holders of the parent Company, representing shareholders, was $20.2 million in 1Q 2025, which resulted in basic earnings per share of $0.03 for the period (1Q 2024: $0.002/share).

Cash flows from operating activities

Description	Units	Reported Q1-2025	Reported Q1-2024	y/y change
Profit before tax	US$'m	**207.4**	**69.3**	199 %
Non Cash Adjustments	US$'m	213.3	61.0	250 %
Working Capital Changes	US$'m	(114.2)	(113.4)	1 %
Pre-tax Cashflow from Operating Activities	**US$'m**	**306.5**	**16.9**	**1714%**
Cash Taxes	US$'m	(36.2)	(0.5)	7140 %
Others	US$'m	(53.7)	(1.4)	3736 %
Post-tax Cashflow from Operating Activities	**US$'m**	**216.6**	**14.9**	**1354 %**

In 1Q 2025, the Company generated pre-tax cashflow from operating activities of $306.5 million (1Q 2024: $16.9 million). The substantial improvement reflects the impact of the significantly enhanced production base, alongside relatively lower costs, partially offset by a working capital build of $114.2 million.

Net cash flow from operating activities amounted to $216.6 million in 1Q 2025, compared to $14.9 million in 1Q 2024. This figure includes cash tax payments of $36.2 million and a hedging premium of $1.7 million paid during the current period, while in the previous year, cash tax payments were $0.5 million, and the hedging premium paid was $1.4 million. Overall, the cash taxes paid represents 12% of operating cashflow. We anticipate the effective cash tax rate to increase in subsequent quarters during 2025 due to the addition of the offshore assets. Longer term, our planned investments in SEPNU via capital projects such as the East Area Project IGE will help build-up a capital allowance balance in SEPNU which will be deductible against future assessable profits.

Our onshore business continues to record strong cash call collection in 1Q 2025. During the quarter, on the NEPL/Seplat JV for OMLs 4, 38 & 41 and OML 40, we received $119.4 million in cash calls from our JV partner, bringing the receivables balance on the JV to $28.4 million (FY 2024: $41.4 million). On our NUIMS/Seplat JV for OML 53, we received $9.0 million in cash call settlement in 1Q 2025 with cash call obligations fully paid up.

For our SEPNU/NNPC JV, though we received $153.0 million for cash call settlements out of $253.0 million due for the period, the balance on the JV receivables rose to $419.0 million (FY 2024: $318.0 million). We note that we received the balance of the 2025 cash call payments post the reporting period. On the legacy cash call receivable balance, which represents approximately 75% of the total balance, we have had positive interactions with our partner to reconcile these cash calls and progress to settlement. We anticipate that we will begin to recover these balances from 4Q 2025.

Cash flows from investing activities

Description	Units	Reported Q1-2025	Reported Q1-2024	y/y change
Post-tax Cashflow from Operating Activities	**US$'m**	**216.6**	**14.9**	**1353.7 %**
Capital Expenditure	US$'m	(40.2)	(47.1)	(14.6) %
Free Cashflow	**US$'m**	**176.4**	**(32.2)**	**nm**
Additional Investment in Joint Venture	US$'m	(10.0)	—	nm
Restricted Cash	US$'m	3.3	(3.0)	nm
Others*	US$'m	3.6	17.6	(79.5) %
Net cash outflows used in investing activities	**US$'m**	**(43.3)**	**(32.5)**	**33.2 %**

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

In 1Q 2025 the total net cash outflow from investing activities was $43.3 million, an increase on the $32.5 million reported in 1Q 2024.

The cash capital expenditure on oil & gas assets during the period was $39.9 million (1Q 2024: $46.4 million), down from the prior year given limited drilling activity in the quarter. Total capex (including other fixed assets) was $40.2 million (1Q 2024: $47.1 million).

As a result of the strong operating performance in 1Q 2025, the business generated $176.4 million of free cashflow, compared to the negative free cashflow of $32.2 million generated in 1Q 2024.

During the period the Company provided an additional $10 million in equity funding to the AGPC IJV,

Cash flows from financing activities

Description	Units	Reported Q1-2025	Reported Q1-2024	y/y change
Repayments of Loans and Borrowings	US$'m	(919.3)	(19.3)	4663.2 %
Proceeds from Loans and Borrowings	US$'m	650.0	—	nm
Interest paid on Loans and Borrowings	US$'m	(36.4)	(32.2)	13.0 %
Other Finance Costs	US$'m	(5.1)	(7.4)	(31.1) %
Shares purchased for employees	US$'m	—	(8.5)	nm
Net cash outflows used in financing activities	**US$'m**	**(310.8)**	**(67.4)**	**361.1 %**

Net cash outflow from financing activities was $310.8 million, compared to an outflow of $67.4 million in 1Q 2024. The principal driver for the outflow was debt movements among the Company's principal borrowing facilities, described below. Interest charges increased 13% on the prior period due to an increase in drawn debt facilities.Other finance charges predominantly relates to repayment of leases and interest on leases. No shares were purchased for the obligations under the long-term incentive plan (1Q 2024: $8.5 million).

Debt Movements

On 21 March 2025 the Company successfully refinanced its $650 million 7.75% 144A/Reg S bond, which was set to mature in March 2026, with a new $650 million 9.125% 144A/Reg S bond maturing in April 2030. The offering was strongly over-subscribed, despite challenging market conditions. We are pleased to note that the offering, our third since 2018, priced inside the Nigerian sovereign for the first time, testament to our strong reputation in public credit markets.

Subsequent to our bond refinancing, the Company's $350 million revolving credit facility ('RCF') maturity was automatically extended to 31 December 2026. In late March, the Company took the opportunity, due to its strong cash position, to pay down $250 million of its previously fully drawn facility. As such, at 31 March 2025, $100 million was drawn under the $350 million revolving credit facility.

The $110 million Westport RBL Facility (RBL Facility) commenced amortising on 31 March 2023. The reduction in facility commitments occurs on a semi-annual basis in March and September of each year until final maturity in 2026. In March 2025, Seplat's wholly owned subsidiary, Westport (and the borrower of record under the RBL facility) paid $19.25 million in principal repayments under the RBL Facility. As at 31 March 2025, $30.25 million is now outstanding under the RBL Facility. The next reduction in commitments will be on 30 September 2025 for an amount of $19.25 million.

In total, the Company repaid approximately 21% of its outstanding gross debt during the period. There were no changes in the principal amount outstanding under the Seplat group's other facilities (including, the $300m advanced payment facility with ExxonMobil, which is fully drawn, or the $50 million Westport off-take loan, of which $11 million is outstanding). See note 22.2 for further details on debt movements during the period.

Liquidity

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

Description	Units	Principal amount Q1-2025	Reported* Q1-2025	Reported* FY-2024
Senior loan notes	US$'m	650.0	634.7	657.6
Westport Reserve Based Lending (RBL) facility	US$'m	30.3	30.4	51.1
Revolving credit facility	US$'m	100.0	102.2	351.5
Offtake facilities	US$'m	11.0	9.9	10.3
Advance payment facility	US$'m	300.0	304.5	297.0
Total borrowings	US$'m	**1,091.3**	**1,081.7**	**1,367.5**
Cash and cash equivalents (exclusive of restricted cash)	US$'m		**334.6**	**469.9**
Net Debt	US$'m		747.1	897.6
Adjusted Pro-Forma EBITDA **	US$'m		1,345.2	1,353.5
Net Debt-to-TTM EBITDA	x		0.56	0.66

* Including amortised interest and accrual for the RCF (undrawn) commitment fee
** Adjusted EBITDA 2024 represents the FY 2024 pro-forma adjusted EBITDA for Seplat and SEPNU combined, 1Q 2025 adjusted EBITDA includes pro-forma adjusted EBITDA from Seplat and SEPNU between 2Q-4Q 2024 plus 1Q 2025 adjusted EBITDA as reported.

Seplat Energy ended the period with gross debt of $1,081.6 million (YE 2024: $1,376.6 million) and cash at bank of $334.6 million (YE 2024: $469.9 million), leaving net debt at $747 million (YE 2024: $898 million). Net debt declined by 17% due to a combination of debt repayments and free cash generation during the quarter.

We continue to monitor the Net Debt-to-EBITDA ratio of the Company with a focus to keep it under 2.0x (Debt covenant - 3.0x). At the end of March 2025, proforma Net Debt-to-EBITDA ratio improved to 0.56x, from 0.66x at end 2024.

Dividend

The Board has approved a quarterly dividend of US$ 4.6 cents per share for the first quarter 2025 (subject to appropriate WHT). This is a 28% increase on 4Q 2024 core dividend, and a 53% increase on the equivalent core dividend in 1Q 2024. On the basis of maintaining this level through 2025 it will result in a total dividend of $18.4 cents per share, an 11% increase in the total dividend declared for 2024 ($16.5 cents per share). We expect to set out an updated capital allocation policy in our capital markets day scheduled for September this year.

Reporting Period	Proposed Dividend (US$ cents per share)	Announcement Date	Qualification Date (LSE)	Qualification Date (NGX)	Payment Date
Q1 2024	3.0				14. June 2024
Q2 2024	3.0				28. August 2024
Q3 2024	3.6				27. November 2024
Q4 2024	3.6	4. March 2025	9. May 2025	12. May 2025	23. May 2025
Special 2024	3.3	4. March 2025	9. May 2025	12. May 2025	23. May 2025
Total 2024	16.5				
Q1 2025	**4.6**	**28. April 2025**	**23. May 2025**	**23. May 2025**	**6. June 2025**

Hedging

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

Year to date 15.75 MMbbls have been hedged for 1Q-3Q 2025 at a weighted average premium of $0.76/bbl and a weighted average strike price of $55.0/bbl. Additional barrels are expected to be hedged for 4Q 2025 later in the year in line with our policy and as soon as the right opportunity presents especially in view of market volatility.

2025 Oil Hedges (Brent Deferred Premium Put Options)	Unit	Q1 2025	Q2 2025	Q3 2025	Q4 2025
Volumes hedged	MMbbls	5.25	5.25	5.25	
Price hedged	US$/bbl	55	55	55	
Puts cost	US$/bbl	0.44	0.97	0.87	

Credit ratings

Seplat maintains corporate credit ratings with Moody's Investor Services (Moody's), Standard & Poor's Rating Services (S&P) and Fitch Ratings (Fitch). The current corporate ratings are as follows: (i) Moody's Caa1 (positive); (ii) S&P B (stable); (iii) Fitch B (stable).

In April 2025 Fitch upgraded our corporate rating to B (previously B-). This was linked to an upgraded outlook for the Nigerian sovereign long term rating and the agency's view of a stronger business profile post the completion of the MPNU acquisition. Our ratings with S&P and Moody's were reaffirmed in April 2025 and March 2025 respectively.

Outlook

Seplat Energy's 2025 production, capex and unit operating cost guidance is maintained. Production operations performed well in the first quarter, with the benefit of ANOH gas and the impacts of the onshore drilling programme and offshore maintenance & capex activities yet to be realised. Costs, both capex and opex tracked below guidance in the first quarter, however we anticipate an increase in run rate costs in 2Q 2025 onwards as drilling activity increases onshore and the jack-up barge commences well restoration work offshore.

Production guidance

Seplat Energy's production operations were ahead of the mid-point of guidance in 1Q 2025 and was supported by strong performance in particular from the onshore assets which benefited from the performance of 2024 new wells, high uptime on Oben gas plant and contribution from Sapele IGP.

2025 production guidance reiterated at 120-140 kboepd. This includes:

- **Seplat Onshore: 48-56 kboepd.** mid-point delivers 7% growth on 2024. Production in 2025 is set to benefit from well stock delivered in 2024, plus contribution from ANOH from 2H25, Sapele Gas Plant's second MRU and the completion of the Abiala EPF. We also see growth on OML 53 oil given the resumption of 24-hour operations on the TNP.
- **SEPNU: 72-84 kboepd.** mid-point delivers 12% growth on 2024. We are targeting growth from restoration of idle wells, investment in improving reliability of the NGL facilities and other activities which will improve uptime and provide the basis for longer term growth plans.

Capex guidance

Working interest capital expenditure guidance is reiterated in the range of $260 million - $320 million.

Capex in 1Q 2025 of $40.2 million was limited to a number of smaller projects including final payments for 2024 wells and Sapele IGP construction costs. Run rate will increase in 2Q 2025 with the drilling of 4 wells and EAP IGE costs.

- **Seplat Onshore: $180 million-$220 million.** Key focus is new well stock to offset natural decline
    - Programme includes drilling 13 new wells: OMLs 4, 38 & 41: Seven, OML 53: Two, OML 40: Four. Of these, 9 are oil wells and 4 are gas wells
    - Completion of the second MRU at the Sapele IGP
    - Delivery of Oben, Amukpe, Sapele & Ohaji flares out projects
- **SEPNU: $80 million-$100 million.** Key focus on capital projects and long term planning to improve reliability, uptime and safety
    - Installation of the Inlet Gas Exchanger on the East Area Project (EAP) NGL facility
    - Long lead items for 2026+ drilling programme

Opex guidance

Unit operating costs for the Company are expected be in the range of $14.0-15.0/boe. This increase in unit operating costs versus prior years reflects increased investment in O&M activities across our offshore assets, mainly re-opening previously shut-in wells and asset integrity work required due to long term lack of investments. Our expectation continues to be that unit opex will moderate post 2025/2026 as production grows and as investment pivots towards capital projects. In 2025 the major cost items are:

- Two jack-up barges to operate across the offshore license area from early 2Q 2025, one targeting integrity works and the other working on the idle well restoration programme.

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The primary goal of the 2025 opex plan is to increase reliability and integrity offshore which will set a solid foundation from which to grow production over time. Due to the nature of the installed infrastructure offshore, the 2025 plan necessitates partial asset shut-downs, which commenced in March 2025 and will continue at certain points during the year.

Interim Consolidated Financial Statements (Unaudited)

For the three months ended 31 March 2025

(Expressed in Nigerian Naira and US Dollars)

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

For the three months ended 31 March 2025

	Notes	3 Months ended 31 March 2025 Unaudited ₦ million	3 Months ended 31 March 2024 Unaudited ₦ million	3 Months ended 31 March 2025 Unaudited $'000	3 Months ended 31 March 2024 Unaudited $'000
Revenue from contracts with customers	7	**1,227,512**	268,618	**809,267**	179,820
Cost of sales	8	**(692,079)**	(204,805)	**(456,273)**	(137,105)
Gross profit		**535,433**	63,813	**352,994**	42,715
Other (loss)/income -net	9	**(67,293)**	97,166	**(44,365)**	65,046
General and administrative expenses	10	**(98,415)**	(35,931)	**(64,884)**	(24,057)
Impairment (loss)/reversal on financial assets - net	11	**(810)**	972	**(534)**	651
Fair value (loss)	12	**(7,653)**	(3,643)	**(5,045)**	(2,439)
Operating profit		**361,262**	122,377	**238,166**	81,916
Finance income	13	**3,968**	7,003	**2,616**	4,688
Finance costs		**(49,524)**	(30,047)	**(32,650)**	(20,114)
Finance cost - net	13	**(45,556)**	(23,044)	**(30,034)**	(15,426)
Share of (loss)/profit from joint venture accounted for using the equity method		**(1,060)**	4,180	**(699)**	2,798
Profit before taxation		**314,646**	103,513	**207,433**	69,288
Income tax expense	14	**(279,262)**	(106,387)	**(184,110)**	(71,218)
Profit/(loss) for the year		**35,384**	(2,874)	**23,323**	(1,930)
Attributable to:					
Equity holders of the parent		**30,679**	1,570	**20,221**	1,045
Non-controlling interests		**4,705**	(4,444)	**3,102**	(2,975)
		35,384	(2,874)	**23,323**	(1,930)
Earnings per share for the year					
Basic earnings per share ₦/$	25	**52.14**	2.67	**0.03**	0.00
Diluted earnings per share ₦/$	25	**52.14**	2.67	**0.03**	0.00

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

	Notes	3 Months ended 31 March 2025 Unaudited ₦ million	3 Months ended 31 March 2024 Unaudited ₦ million	3 Months ended 31 March 2025 Unaudited $'000	3 Months ended 31 March 2024 Unaudited $'000
Profit/(loss) for the year		**35,384**	(2,874)	**23,323**	(1,930)
Other comprehensive income:					
Foreign currency translation difference		**2,380**	907,894	**–**	–
Other comprehensive income/(loss) for the year		**2,380**	907,894	**–**	–
Total comprehensive income/(loss) for the year (net of tax)		**37,764**	905,020	**23,323**	(1,930)
Attributable to:					
Equity holders of the parent		**33,059**	909,464	**20,221**	1,045
Non-controlling interests		**4,705**	(4,444)	**3,102**	(2,975)
		37,764	905,020	**23,323**	(1,930)

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

Interim condensed consolidated statement of financial position

For the three months ended 31 March 2025

	Notes	31 March 2025 Unaudited ₦ million	31 Dec 2024 Audited ₦ million	31 March 2025 Unaudited $'000	31 Dec 2024 Audited $'000
Assets					
Non-current assets					
Oil & gas properties	16	**4,909,655**	5,074,590	**3,195,733**	3,305,233
Other Property, plant and Equipment		**334,052**	346,574	**217,437**	225,734
Right-of-use assets		**181,634**	198,918	**118,227**	129,561
Intangible assets		**377,140**	383,257	**245,483**	249,627
Other Assets		**139,521**	139,431	**90,815**	90,815
Investment accounted for using equity method		**389,174**	374,641	**253,317**	244,015
Long-term prepayments		**42,957**	48,018	**27,961**	31,276
Deferred tax assets	14.1	**332,240**	353,954	**216,258**	230,541
Defined benefit plan	23.1	**4,341**	—	**2,825**	—
Total non-current assets		**6,710,714**	6,919,383	**4,368,056**	4,506,802
Current assets					
Inventory		**712,368**	725,565	**463,686**	472,582
Trade and other receivables	17	**1,390,617**	1,156,593	**905,162**	753,321
Prepayments		**45,719**	52,596	**29,759**	34,257
Contract assets	18	**35,243**	23,918	**22,939**	15,579
Restricted cash	20.2	**198,016**	202,983	**128,890**	132,209
Cash and cash equivalents	20	**514,097**	721,385	**334,634**	469,862
Total current assets		**2,896,060**	2,883,040	**1,885,070**	1,877,810
Asset held for sale		**18,851**	18,838	**12,270**	12,270
Total assets		**9,625,625**	9,821,261	**6,265,396**	6,396,882
Equity and liabilities					
Equity attributable to shareholders					
Issued Share Capital	21	**297**	297	**1,864**	1,864
Share Premium	21	**87,375**	87,375	**518,564**	518,564
Share Based Payment Reserve	21	**24,370**	15,558	**42,557**	36,747
Treasury shares	21	**(3,570)**	(3,570)	**(5,609)**	(5,609)
Capital Contribution		**5,932**	5,932	**40,000**	40,000
Retained Earnings		**349,692**	319,013	**1,253,349**	1,233,128
Foreign currency translation reserve		**2,395,631**	2,393,251	**2,233**	2,233
Non-controlling interest		**15,832**	11,127	**18,781**	15,679
Total shareholder's equity		**2,875,559**	2,828,983	**1,871,739**	1,842,606
Non-current liabilities					
Interest bearing loans and borrowings	22	**1,485,068**	1,409,480	**966,642**	918,036
Lease liabilities		**87,482**	88,530	**56,943**	57,663
Provision for decommissioning obligation		**1,211,266**	1,194,818	**788,422**	778,221
Deferred tax liability	14.1	**1,547,351**	1,615,677	**1,007,183**	1,052,339
Defined benefit plan	23.1	**—**	76,900	**—**	50,087
Total non-current liabilities		**4,331,167**	4,385,405	**2,819,190**	2,856,346
Current liabilities					
Interest bearing loans and borrowings	22	**176,642**	690,270	**114,977**	449,593
Lease liabilities		**23,981**	24,415	**15,610**	15,902
Derivative financial liability	19	**11,150**	6,073	**7,258**	3,955
Trade and other payables	24	**1,731,588**	1,684,706	**1,127,091**	1,097,297
Other provisions		**5,090**	5,088	**3,313**	3,314
Current tax liabilities		**470,448**	196,321	**306,218**	127,869
Total current liabilities		**2,418,899**	2,606,873	**1,574,467**	1,697,930
Total liabilities		**6,750,066**	6,992,278	**4,393,657**	4,554,276
Total shareholders' equity and liabilities		**9,625,625**	9,821,261	**6,265,396**	6,396,882

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

The financial statements of Seplat Energy Plc and its subsidiaries (The Group) for the three months ended 31 March 2025 were authorised for issue in accordance with a resolution of the Directors on 28 April 2025 and were signed on its behalf by:

U. U. Udoma	**R.T Brown**	**E. Adaralegbe**
FRC/2013/NBA/00000001796	FRC/2014/PRO/DIR/00000017939	FRC/2017/ICAN/006/00000017591
Chairman	Chief Executive Officer	Chief Financial Officer
28 April 2025	28 April 2025	28 April 2025

Interim condensed consolidated statement of changes in equity

For the three months ended 31 March 2025

	Issued Share Capital	Share Premium	Share Based Payment Reserve	Treasury shares	Capital Contribution	Retained Earnings	Foreign Currency Translation Reserve	Non-controlling interest	Total Equity
	₦ million	₦ million	₦ million	₦ million	₦ million	₦ million	₦ million	₦ million	₦ million
At 1 January 2024	**297**	**90,138**	**12,255**	**(1,612)**	**5,932**	**230,708**	**1,251,127**	**23,790**	**1,612,635**
Profit for the year	–	–	–	–	–	1,570	–	(4,444)	(2,874)
Other comprehensive (loss)/income	–	–	–	–	–	–	907,894	–	907,894
Total comprehensive income for the year	**–**	**–**	**–**	**–**	**–**	**1,570**	**907,894**	**(4,444)**	**905,020**
Transactions with owners in their capacity as owners:									
Share based payments	–	–	7,091	–	–	–	–	–	7,091
Shares re-purchased	–	–	–	(12,697)	–	–	–	–	(12,697)
Total	**–**	**–**	**7,091**	**(12,697)**	**–**	**–**	**–**	**–**	**(5,606)**
At 31 March 2024 (unaudited)	**297**	**90,138**	**19,346**	**(14,309)**	**5,932**	**232,278**	**2,159,021**	**19,346**	**2,512,049**
At 1 January 2025	**297**	**87,375**	**15,558**	**(3,570)**	**5,932**	**319,013**	**2,393,251**	**11,127**	**2,828,983**
Profit for the period	**–**	**–**	**–**	**–**	**–**	**30,679**	**–**	**4,705**	**35,384**
Other comprehensive (loss)/ income	**–**	**–**	**–**	**–**	**–**	**–**	**2,380**	**–**	**2,380**
Total comprehensive income for the year	**–**	**–**	**–**	**–**	**–**	**30,679**	**2,380**	**4,705**	**37,764**
Transactions with owners in their capacity as owners:									
Share based payments	**–**	**–**	**8,812**	**–**	**–**	**–**	**–**	**–**	**8,812**
Total	**–**	**–**	**8,812**	**–**	**–**	**–**	**–**	**–**	**8,812**
At 31 March 2025 (unaudited)	**297**	**87,375**	**24,370**	**(3,570)**	**5,932**	**349,692**	**2,395,631**	**15,832**	**2,875,559**

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

	Issued Share Capital	Share Premium	Share Based Payment Reserve	Treasury shares	Capital Contribution	Retained Earnings	Foreign Currency Translation Reserve	Non-controlling interest	Total
	$'000	$'000	$'000	$'000	$'000	$'000	$'000	$'000	$'000
At 1 January 2024	**1,864**	**520,431**	**34,515**	**(4,286)**	**40,000**	**1,173,450**	**2,816**	**24,237**	**1,793,027**
Profit for the year	–	–	–	–	–	1,045	–	(2,975)	(1,930)
Total comprehensive income for the year	**–**	**–**	**–**	**–**	**–**	**1,045**	**–**	**(2,975)**	**(1,930)**
Transactions with owners in their capacity as owners:									
Share based payments	–	–	4,747	–	–	–	–	–	4,747
Share repurchased	–	–	–	(8,500)	–	–	–	–	(8,500)
Total	**–**	**–**	**4,747**	**(8,500)**	**–**	**–**	**–**	**–**	**(3,753)**
At 31 March 2024 (unaudited)	**1,864**	**520,431**	**39,262**	**(12,786)**	**40,000**	**1,174,495**	**2,816**	**21,262**	**1,787,344**
At 1 January 2025	**1,864**	**518,564**	**36,747**	**(5,609)**	**40,000**	**1,233,128**	**2,233**	**15,679**	**1,842,606**
Profit for the period	**–**	**–**	**–**	**–**	**–**	**20,221**	**–**	**3,102**	**23,323**
Other Comprehensive income	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**–**
Total comprehensive income/(loss) for the period	**–**	**–**	**–**	**–**	**–**	**20,221**	**–**	**3,102**	**23,323**
Transactions with owners in their capacity as owners:									
Share based payments	**–**	**–**	**5,810**	**–**	**–**	**–**	**–**	**–**	**5,810**
Total	**–**	**–**	**5,810**	**–**	**–**	**–**	**–**	**–**	**5,810**
At 31 March 2025 (unaudited)	**1,864**	**518,564**	**42,557**	**(5,609)**	**40,000**	**1,253,349**	**2,233**	**18,781**	**1,871,739**

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

Seplat Energy

Interim condensed consolidated statement of cash flows

For the three months ended 31 March 2025

	Notes	3 Months ended 31 March 2025 Unaudited ₦ million	3 Months ended 31 March 2024 Unaudited ₦ million	3 Months ended 31 March 2025 Unaudited $'000	3 Months ended 31 March 2024 Unaudited $'000
Cash flows from operating activities					
Cash generated from operations	15	**464,919**	25,153	**306,504**	16,832
Tax paid		**(54,903)**	(748)	**(36,196)**	(501)
Contribution to plan assets		**(78,884)**	–	**(52,006)**	–
Hedge premium paid		**(2,644)**	(2,159)	**(1,743)**	(1,445)
Net cash inflows from operating activities		**328,488**	22,246	**216,559**	14,886
Cash flows from investing activities					
Payment for acquisition of oil and gas properties		**(60,459)**	(69,262)	**(39,859)**	(46,366)
Additional investment in Joint venture		**(15,168)**	–	**(10,000)**	–
Proceeds from the disposal of oil and gas properties		**–**	3,043	**–**	2,037
Payment for acquisition of other property, plant and equipment		**(575)**	(1,070)	**(379)**	(716)
Deposit for asset held for Sale		**1,517**	–	**1,000**	–
Receipts from other asset		**–**	16,277	**–**	10,896
Restricted Cash		**5,034**	(4,468)	**3,319**	(2,991)
Interest received		**3,968**	7,003	**2,616**	4,688
Net cash outflows used in investing activities		**(65,683)**	(48,477)	**(43,303)**	(32,452)
Cash flows from financing activities					
Repayments of loans and borrowings		**(1,394,337)**	(28,769)	**(919,250)**	(19,259)
Proceeds from loans and borrowings		**985,933**	–	**650,000**	–
Shares purchased for employees		**–**	(12,697)	**–**	(8,500)
Interest paid on lease liability		**(3,766)**	(442)	**(2,483)**	(296)
Lease payment - principal portion		**(3,451)**	(7,444)	**(2,275)**	(4,983)
Payments of other financing charges*		**(467)**	(3,183)	**(308)**	(2,131)
Interest paid on loans and borrowings		**(55,238)**	(48,164)	**(36,417)**	(32,242)
Net cash inflows/(outflows) used in financing activities		**(471,326)**	(100,699)	**(310,733)**	(67,411)
Net (decrease)/increase in cash and cash equivalents		**(208,521)**	(126,930)	**(137,477)**	(84,977)
Cash and cash equivalents at beginning of the year		**721,385**	404,825	**469,862**	450,109
Effects of exchange rate changes on cash and cash equivalents		**1,233**	194,064	**2,249**	(29,328)
Cash and cash equivalents at end of the period	20	**514,097**	471,959	**334,634**	335,804

*Other financing charges of $0.3 million, ₦0.5 billion (2024: $2.1 million, ₦ 3.2 billion) relate to commitment fees and other transaction costs incurred on interest bearing loans and borrowings ($350 million Revolving Credit Facility, $300 million Advance Payment Facility, $110 million Reserved Based Lending Facility and $50 million Junior Facility).

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

Notes to the interim condensed consolidated financial statements

For the three months ended 31 March 2025

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: 16a Temple Road (Olu Holloway), Ikoyi, 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 27 March 2013, the Group incorporated a subsidiary, MSP Energy Limited. The Company was incorporated for oil and gas exploration and production.

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

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

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

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

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

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

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

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

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

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

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

Wester Ord Oil & Gas (Nigeria) Limited, who also became an indirect subsidiary of the Group acquired a 40% stake in a licence, Ubima, in 2014 via a joint operations agreement. The principal activity of Wester Ord Oil & Gas (Nigeria) Limited is exploration and production of oil and gas. In 2022, Wester Ord Oil and Gas (Nigeria) divested it's 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 5 July 2022, the Group incorporated a subsidiary, Turnkey Drilling Services Limited. The Company was incorporated for the purpose of drilling chemicals, material supply, directional drilling, drilling support services and exploration services.

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

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

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

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

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

Subsidiary	Date of incorporation	Country of incorporation and place of business	Percentage holding	Principal activities	Nature of holding
Eland Oil & Gas Limited	28 August 2009	United Kingdom	100%	Holding company	Direct
Eland Oil & Gas (Nigeria) Limited	11 August 2010	Nigeria	100%	Oil and Gas Exploration and Production	Indirect
Elcrest Exploration and Production Nigeria Limited	6 January 2011	Nigeria	45%	Oil and Gas Exploration and Production	Indirect
Westport Oil Limited	8 August 2011	Jersey	100%	Financing	Indirect
Brineland Petroleum Limited	18 February 2013	Nigeria	49%	Dormant	Indirect
MSP Energy Limited	27 March 2013	Nigeria	100%	Oil and Gas exploration and production	Direct
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
Turnkey Drilling Services Limited	5 July 2022	Nigeria	100%	Drilling services	Direct
Seplat Energy Investment Limited	07 August , 2024	Nigeria	100%	Oil and Gas exploration and production	Direct
Seplat Energy Producing Nigeria Unlimited	19 December , 2024	Nigeria	100%	Oil and Gas exploration and production	Direct

2. Significant changes in the current accounting period

There are no significant changes in the business during the current reporting period ending 31 March 2025.

3. Summary of significant accounting policies

3.1 Introduction to summary of significant accounting policies

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

3.2 Basis of preparation

The consolidated financial statements of the Group for the three months ended 31 March 2025 have been prepared in accordance with International Financial Reporting Standards ("IFRS") and interpretations issued by the IFRS Interpretations Committee (IFRS IC). The financial statements comply with IFRS 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 United States Dollars, and all values are rounded to the nearest million (₦ million) and thousand ($'000) respectively, except when otherwise indicated.

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

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

3.3 New and amended standards adopted by the Group

The Group applied for the first-time certain standards and amendments, which are effective for annual periods beginning on or after 1 January 2025. The Group has not early adopted any other standard, interpretation or amendment that has been issued but is not yet effective.

a) Lack of exchangeability - Amendments to IAS 21

The amendments to IAS 21 The Effects of Changes in Foreign Exchange Rates specify how an entity should assess whether a currency is exchangeable and how it should determine a spot exchange rate when exchangeability is lacking. The amendments also require disclosure of information that enables users of its financial statements to understand how the currency not being exchangeable into the other currency affects, or is expected to affect, the entity's financial performance, financial position and cash flows.

The amendments are effective for annual reporting periods beginning on or after 1 January 2025. When applying the amendments, an entity cannot restate comparative information.

The amendments did not have a material impact on the Group's 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) Amendments to IFRS 10 and IAS 28: Selection or contribution of assets between an investor or joint venture

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.

b) IFRS 18 - Presentation and Disclosure in Financial Statements

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

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

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

c) 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.

3.5 Basis of consolidation

i. Subsidiaries

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

The consolidated financial information comprises the financial statements of the Company and its subsidiaries as at 31 March 2025. Control is achieved when the Group is exposed, or has rights, to variable returns from its involvement with the investee and has the ability to affect those returns through its power over the investee. Specifically, the Group controls an investee if and only if the Group has:

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

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

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

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

ii. Change in the ownership interest of subsidiary

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

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

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

iii. Disposal of subsidiary

Where the Group disposes a subsidiary, it:

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

iv. Joint arrangements

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

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

v. Associates

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

vi. Equity method

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

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

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

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

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

vii. Changes in ownership interest

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

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

viii. Accounting for loss of control

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

- deconsolidates the assets (including goodwill), liabilities and non-controlling interest (including attributable other comprehensive income) of the former subsidiary from the consolidated financial position;
- any retained interest (including amounts owed by and to the former subsidiary) in the entity is remeasured to its fair value, with the change in carrying amount recognised in profit or loss. This fair value becomes the initial carrying amount for the purposes of subsequently accounting for the retained interest as an associate or a joint venture;
- any amounts previously recognised in other comprehensive income in respect of that entity are accounted for as if the Group had directly disposed of the related assets or liabilities. This may mean that amounts previously recognised in other comprehensive income are reclassified to profit or loss or transferred directly to retained earnings if required by other IFRSs;
- the resulting gain or loss, on loss of control, is recognised together with the profit or loss from the discontinued operation for the period before the loss of control; and
- the gain or loss on disposal will comprise of the gain or loss attributable to the portion disposed of and the gain or loss on remeasurement of the portion retained. The latter is disclosed separately in the notes to the financial statements. If the ownership interest in a joint venture is reduced but joint control or significant influence is retained, only a proportionate share of the amounts previously recognised in other comprehensive income is reclassified to profit or loss where appropriate.

ix. Non-controlling interest

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

x. Goodwill

Goodwill on acquisitions of subsidiaries is included in intangible assets. Goodwill is not amortised, but it is tested for impairment annually, or more frequently if events or changes in circumstances indicate that it might be impaired and is carried at cost less accumulated impairment losses. Gains and losses on the disposal of an entity include the carrying amount of goodwill relating to the entity sold. Goodwill is allocated to cash-generating units for the purpose of impairment testing. The allocation is made to those cash-generating units or groups of cash-generating units that are expected to benefit from the business combination in which the goodwill arose.

ix. Gain on bargain purchase

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

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

3.6 Functional and presentation currency

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

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

i. Transaction and balances

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

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

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

ii. Group companies

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

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

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

3.7 Oil and gas accounting

i. Pre-licensing costs

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

ii. Exploration license cost

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

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

iii. Acquisition of producing assets

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

iv. Exploration and evaluation expenditures

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

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

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

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

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

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

v. Development expenditures

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

3.8 Revenue recognition (IFRS 15)

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

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

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

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

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 two types of products, oil and gas. 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

Production and field facilities are depreciated on a unit-of-production basis over the estimated 1P reserves for its onshore assets and proved developed reserves shallow offshore assets. Gas plant is depreciated on a straight-line basis over its useful lives. Assets under construction are not depreciated. 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. 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 10.4%. After the commencement date, the amount of lease liabilities is increased to reflect the accretion of interest and reduced for the lease payments made. In addition, the carrying amount of lease liabilities is remeasured if there is a modification, a change in the lease term, a change in the in-substance fixed lease payments or a change in the assessment to purchase the underlying asset. The lease term refers to the contractual period of a lease.

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

3.12 Borrowing costs

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

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

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

3.13 Finance income and costs

Finance income

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

Finance costs

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

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

3.14 Impairment of non-financial assets

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

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

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

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

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

Impairment – exploration and evaluation assets

Exploration and evaluation assets are tested for impairment once commercial reserves are found before they are transferred to oil and gas assets, or whenever facts and circumstances indicate impairment. An impairment loss is recognised for the amount by which the exploration and evaluation assets' carrying amount exceeds their recoverable amount. The recoverable amount is the higher of the exploration and evaluation assets' fair value less costs to sell and their value in use.

Impairment – proved oil and gas production properties

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

3.15 Cash and cash equivalents

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

3.16 Inventories

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

3.17 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.

3.18 Other asset

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

3.19 Segment reporting

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

The Board of directors has appointed a Senior leadership team to assess the financial performance and position of the Group and makes strategic decisions. The Senior leadership team consist of Chief Executive Officer; Chief Financial Officer; Chief Operating Officer; Director New Energy; Technical Director; Managing Director, Seplat West; Managing Director, Seplat East; Managing Director, Elcrest Exploration and Production Limited; Director Legal; Director, Corporate Services; Director, External Affairs and Social Performance, Managing Director, ANOH Gas Processing Company (AGPC); Director , Strategy, Planning and Business Development, MD of Seplat Energy Producing Nigeria Unlimited (SEPNU). See further details in note 6.

3.20 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

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

All the Group's financial assets as at 31 March 2025 satisfy the conditions for classification at amortised cost under IFRS 9 except for derivatives which are classified at fair value through profit or loss.

The Group's financial assets include trade receivables, NEPL receivables, NUIMS receivables, other receivables, cash and bank balances and derivatives. 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 liabilities

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. The Group's financial liabilities include trade and other payables and interest-bearing loans and borrowings.

b) Impairment of financial assets

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

The Group applies the simplified approach or the three-stage general approach to determine impairment of receivables depending on their respective nature. The simplified approach is applied for trade receivables and contract assets while the general approach is applied to NEPL receivables, NUIMS receivables, other receivables and cash and bank balances.

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

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

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

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

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

c) Significant increase in credit risk and default definition

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

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

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

d) Write off policy

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

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

The Group may write - off financial assets that are still subject to enforcement activity. The outstanding contractual amounts of such assets written off during the year ended 31 March 2025 was Nil (2024: Nil).

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

e) Derecognition

Financial assets

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

Financial liabilities

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

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

f) Modification

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

g) Offsetting of financial assets and financial liabilities

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

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

h) Derivatives

The Group uses derivative financial instruments such as forward exchange contracts to hedge its foreign exchange risks as well as put options to hedge against its oil price risk. However, such contracts are not accounted for as designated hedges. Derivatives are initially recognised at fair value on the date a derivative contract is entered and subsequently remeasured to their fair value at the end of each reporting period. Any gains or losses arising from changes in the fair value of derivatives are recognised within operating profit in the statement of profit or loss for the period. An analysis of the fair value of derivatives is provided in Note 5, Financial risk Management.

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

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

i) Fair value of financial instruments

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

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

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

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

3.21 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.

3.22 Treasury shares

Own equity instruments that are reacquired (treasury shares) are recognised at cost and deducted from equity. No gain or loss is recognised in profit or loss on the purchase, sale, issue or cancellation of the Group's own equity instruments. Any difference between the carrying amount and the consideration, if reissued, is recognised in the share premium.

3.23 Earnings per share and dividends

Basic EPS

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

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.

3.24 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 gratuity plan, which 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 calculated annually by independent actuaries. The liability or asset recognised in the statement of financial position in respect of the defined benefit plan is the present value of the defined benefit obligation at the end of the reporting period less the fair value of plan assets (if any). The present value of the defined benefit obligation is determined by discounting the estimated future cash outflows using government bonds.

Remeasurements gains and losses, arising from changes in financial and demographic assumptions and experience adjustments, are recognised immediately in the statement of financial position with a corresponding debit or credit to retained earnings through other comprehensive income in the period in which they occur. 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

3.25 Provisions

Provisions are recognised when

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

Provisions are not recognised for future operating losses. In measuring the provision:

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

Decommissioning

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

Provisions are measured at the present value of management's best estimates of the expenditure required to settle the present obligation at the end of the reporting period. The discount rate used to determine the present value is a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability. The increase in the provision due to the passage of time is recognised as a finance cost. The corresponding amount is capitalised as part of the oil and gas properties and is amortised on a unit-of-production basis as part of the depreciation, depletion and amortisation charge. Any adjustment arising from the estimated cost of the restoration and abandonment cost is capitalised, while the charge arising from the accretion of the discount applied to the expected expenditure is treated as a component of finance costs.

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

3.26 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.

3.27 Income taxation

i. Current income tax

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

ii. Deferred tax

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

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

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

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

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

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

iii. Uncertainty over income tax treatments

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

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

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

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

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

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

3.28 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.

3.29 Share based payments

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

a) Equity-settled transactions

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

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

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

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

4. Significant accounting judgements, estimates and assumptions

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

4.1 Judgements

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

i. OMLs 4, 38 and 41

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

ii. Deferred tax asset

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

iii. Foreign currency translation reserve

The Group has used the CBN rate to translate its Dollar currency to its Naira presentation currency. Management has determined that this rate is available for immediate delivery. If the rate was 10% higher or lower, revenue in Naira would have increased/decreased by ₦40.4 billion (2021: ₦29 billion). See Note 47 for the applicable translation rates.

iv. Consolidation of Elcrest

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

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

v. Revenue recognition

Performance obligations

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

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

Significant financing component

The Group has entered into an advance payment contract with Mercuria for future crude oil to be delivered. The Group has considered whether the contract contains a financing component and whether that financing component is significant to the contract, including both of the following;

a) The difference, if any, between the amount of promised consideration and cash selling price and;

b) The combined effect of both the following:

- The expected length of time between when the Group transfers the crude to Mercuria and when payment for the crude is received and;
- The prevailing interest rate in the relevant market.

The advance period is greater than 12 months. In addition, the interest expense accrued on the advance is based on a comparable market rate. Interest expense has therefore been included as part of finance cost.

Transactions with Joint Operating arrangement (JOA) partners

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

vi. Exploration and evaluation assets

The accounting for exploration and evaluation ('E&E') assets require management to make certain judgements and assumptions, including whether exploratory wells have discovered economically recoverable quantities of reserves. Designations are sometimes revised as new information becomes available. If an exploratory well encounters hydrocarbon, but further appraisal activity is required in order to conclude whether the hydrocarbons are economically recoverable, the well costs remain capitalised as long as sufficient progress is being made in assessing the economic and operating viability of the well. Criteria used in making this determination include evaluation of the reservoir characteristics and hydrocarbon properties, expected additional development activities, commercial evaluation and regulatory matters. The concept of 'sufficient progress' is an area of judgement, and it is possible to have exploratory costs remain capitalised for several years while additional drilling is performed or the Group seeks government, regulatory or partner approval of development plans.

vii. 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 operating decision maker, consists of the chief financial officer, the Vice President (Finance), the Director (New Energy) and the financial reporting manager. See further details in note 6.

viii. 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 carried 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 used the higher of the fair value less cost to dispose and the value in use in determining the recoverable amount of the cash-generating unit. In determining the value, the Group uses a forecast of the annual net cash flows over the life of proved plus probable reserves, production rates, oil and gas prices, future costs (excluding (a) future restructurings to which the entity is not yet committed; or (b) improving or enhancing the asset's performance) and other relevant assumptions based on the year-end Competent Persons Report (CPR). The pre-tax future cash flows are adjusted for risks specific to the forecast and discounted using a pre-tax discount rate which reflects both current market assessment of the time value of money and risks specific to the asset.

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

vi. Useful life of other property, plant and equipment

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

vii. Income taxes

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

viii. Impairment of financial assets

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

ix. Intangible assets

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

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

x. Inventories

The net realisable value of crude oil and refined products is based on the estimated selling price in the ordinary course of business, less the estimated costs of completion and the estimated costs necessary to make the sale.

5. Financial risk management

5.1 Financial risk factors

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

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

5.1.1 Credit risk

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

a) Risk management

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

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

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

Estimation uncertainty in measuring impairment loss

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

Significant unobservable inputs

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

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

	Effect on profit before tax	Effect on other components of equity before tax	Effect on profit before tax	Effect on other components of equity before tax
	31 March 2024	31 March 2024	31 March 2024	31 March 2024
Increase/decrease in loss given default	₦ million	₦ million	$'000	$'000
+10%	(104)	—	(158)	—
-10%	104	—	158	—

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

	Effect on profit before tax	Effect on other components of equity before tax	Effect on profit before tax	Effect on other components of equity before tax
	31 March 2024	31 March 2024	31 March 2024	31 March 2024
Increase/decrease in probability of default	₦ million	₦ million	$'000	$'000
+10%	(109)	—	(166)	—
-10%	109	—	166	—

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

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

Increase/decrease in forward looking macroeconomic indicators	Effect on profit before tax	Effect on other components of equity before tax	Effect on profit before tax	Effect on other components of equity before tax
	31 March 2024	31 March 2024	31 March 2024	31 March 2024
	₦ million	₦ million	$'000	$'000
+10%	(37)	—	(57)	—
-10%	37	—	57	—

5.1.2 Liquidity risk

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

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

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

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

'31 March 2024	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	7.75%	35,990	71,784	949,543	—	1,057,317
Variable interest rate borrowings						
The Mauritius Commercial Bank Ltd	8% + SOFR	22,977	16,271	—	—	39,248
Stanbic IBTC Bank Plc	8% + SOFR	23,457	16,608	—	—	40,065
Standard Bank of South Africa	8% + SOFR	13,404	9,490	—	—	22,894
First City Monument Ltd (FCMB)	8% + SOFR	5,984	4,237	—	—	10,221
Shell Western Supply & Trading Limited	10.5% + SOFR	2,571	2,571	18,031	—	23,173
Total variable interest borrowings		68,393	49,177	18,031	—	135,601
Other non-derivatives						
Trade and other payables**		524,302	—	—	—	524,302
Lease liability		1,578	22,147	—	—	23,725
		525,880	22,147	—	—	548,027
Total		630,263	143,108	967,574	—	1,740,944

31 March 2025	Effective interest rate %	Less than 1 year $'000	1 – 2 year $'000	2 – 3 years $'000	3 – 5 years $'000	Total $'000
Non-derivatives						
Fixed interest rate borrowings						
650 million Senior notes	9.125%	59,313	59,313	59,313	768,625	946,564
Variable interest rate borrowings						
The Mauritius Commercial Bank Ltd	8% + SOFR	11,486	—	—	—	11,486
Stanbic IBTC Bank Plc	8% + SOFR	11,726	—	—	—	11,726
Standard Bank of South Africa	8% + SOFR	6,700	—	—	—	6,700
First City Monument Ltd (FCMB)	8% + SOFR	2,991	—	—	—	2,991
Shell Western Supply & Trading Limited	10.5% + SOFR	1,692	12,692	—	—	14,384
350 million Seplat RCF						
Citibank N.A. London	5% + SOFR+CAS	278	3,067	—	—	3,345
Nedbank Limited, London Branch	5% + SOFR+CAS	1,251	13,800	—	—	15,051
Stanbic Ibtc Bank Plc	5% + SOFR+CAS	1,390	15,333	—	—	16,723
RMB International (Mauritius) Limited	5% + SOFR+CAS	1,807	19,933	—	—	21,740
The Mauritius Commercial Bank Ltd	5% + SOFR+CAS	1,251	13,800	—	—	15,051
JP Morgan Chase Bank, N.A London	5% + SOFR+CAS	834	9,200	—	—	10,034
Standard Chartered Bank	5% + SOFR+CAS	834	9,200	—	—	10,034
Zenith Bank Plc	5% + SOFR+CAS	417	4,600	—	—	5,017
Zenith Bank (UK) Limited	5% + SOFR+CAS	556	6,133	—	—	6,689
United Bank for Africa Plc	5% + SOFR+CAS	417	4,600	—	—	5,017
First City Monument Bank Limited	5% + SOFR+CAS	556	6,133	—	—	6,689
BP	5% + SOFR+CAS	139	1,533	—	—	1,672
$300 million Advance Payment Facility (ADF)						
ExxonMobil Financing	5% + SOFR + CAS	29,153	29,153	329,153	—	387,460
Total variable interest borrowings		73,478	149,177	329,153	—	551,809
Other non-derivatives						
Trade and other payables[2]		1,127,091	—	—	—	1,127,091
Lease liability		15,610	—	—	—	15,610
		1,142,701	—	—	—	1,142,701
Total		1,275,492	208,490	388,466	768,625	2,641,073

'31 March 2024	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	7.75%	25,607	51,075	675,607	—	752,289
Variable interest rate borrowings						
The Mauritius Commercial Bank Ltd	8% + SOFR	16,349	11,576	—	—	27,925
Stanbic IBTC Bank Plc	8% + SOFR	16,690	11,817	—	—	28,507
Standard Bank of South Africa	8% + SOFR	9,537	6,752	—	—	16,289
First City Monument Ltd (FCMB)	8% + SOFR	4,258	3,015	—	—	7,273
Shell Western Supply & Trading Limited	10.5% + SOFR	1,829	1,829	12,829	—	16,487
Total variable interest borrowings		48,663	34,989	12,829	—	96,481
Other non-derivatives						
Trade and other payables**		373,044	—	—	—	373,044
Lease liability		1,123	15,758	—	—	16,881
		374,167	15,758	—	—	389,925
Total		448,437	101,822	688,698	—	1,238,695

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

Seplat Energy

5.1.3 Fair value measurements

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

	Carrying amount		Fair value	
	31 March 2025	31 Dec 2024	**31 March 2025**	31 Dec 2024
	₦ million	₦ million	**₦ million**	₦ million
Financial assets measured at amortised cost				
Trade and other receivables*	**1,355,166**	1,149,130	**1,355,166**	1,149,130
Contract asset	**35,243**	23,919	**35,243**	23,919
Cash and cash equivalents	**514,097**	721,385	**514,097**	721,385
	1,904,506	1,894,434	**1,904,506**	1,894,434
Financial liabilities				
Interest bearing loans borrowings	**1,663,453**	2,099,748	**1,671,975**	2,080,360
Trade and other payables**	**1,580,488**	1,615,528	**1,580,488**	1,615,528
	3,243,941	3,715,276	**3,252,463**	3,695,888
Financial liabilities at fair value				
Derivative financial instruments (Note 19)	**(11,150)**	(6,073)	**(11,150)**	(6,073)
	(11,150)	(6,073)	**(11,150)**	(6,073)

	Carrying amount		Fair value	
	31 March 2025	31 Dec 2024	**31 March 2025**	31 Dec 2024
	$'000	$'000	**$'000**	$'000
Financial assets at amortised cost				
Trade and other receivables*	**882,088**	748,463	**882,088**	748,463
Contract Asset	**22,940**	15,579	**22,940**	15,579
Cash and cash equivalents	**334,879**	470,107	**334,879**	470,107
	1,239,907	1,234,149	**1,239,907**	1,234,149
Financial liabilities				
Interest bearing loans and borrowings	**1,081,619**	1,367,629	**1,088,302**	1,355,001
Trade and other payables**	**1,028,743**	1,052,243	**1,028,743**	1,052,243
	2,110,362	2,419,872	**2,117,045**	2,407,244
Financial liabilities at fair value				
Derivative financial instruments (Note 19)	**(7,258)**	(3,955)	**(7,258)**	(3,955)
	(7,258)	(3,955)	**(7,258)**	(3,955)

1. Trade and other receivables exclude Geregu Power, Sapele Power and NGMC VAT receivables, cash advances and advance payments. In determining the fair value of the interest-bearing loans and borrowings, non-performance risks of the Group as at year-end were assessed to be insignificant.
2. Trade and other payables (excluding non-financial liabilities such as provisions, taxes, 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.

5.1.4 Fair Value Hierarchy

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

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

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

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

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

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

The valuation process

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

6. Segment reporting

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

For the year ended 31 March 2025, revenue from the gas segment of the business constituted 6% (2024: 16%) of the Group's revenue. Management is committed to continued growth of the gas segment of the business, including through increased investment to establish additional offices, create a separate gas business operational management team and procure the required infrastructure for this segment of the business. The gas business is positioned separately within the Group and reports directly to the (chief operating decision maker). As the gas business segment's revenues, results and cash flows are largely independent of other business units within the Group, it is regarded as a separate segment.The result is two reporting segments, Oil and Gas. There were no inter segment sales during the reporting periods under consideration, therefore all revenue was from external customers.

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

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

6.1 Segment profit disclosure

	3 Months ended 31 March 2025	3 Months ended 31 March 2024	**3 Months ended 31 March 2025**	3 Months ended 31 March 2024
	₦ million	₦ million	**$'000**	$'000
Oil	**(4,770)**	73,521	**(3,151)**	49,218
Gas	**40,154**	(76,395)	**26,474**	(51,148)
Total profit for the period	**35,384**	(2,874)	**23,323**	(1,930)

	3 Months ended 31 March 2025	3 Months ended 31 March 2024	**3 Months ended 31 March 2025**	3 Months ended 31 March 2024
Oil	**₦ million**	₦ million	**$'000**	$'000
Revenue from contracts with customers				
Crude oil sales (Note 7)	**1,152,510**	225,336	**759,821**	150,846
Cost of sales and general and administrative expenses	**(780,052)**	(236,376)	**(514,276)**	(158,235)
Other (loss)/income	**(68,437)**	192,182	**(45,119)**	128,652
Operating profit before impairment	**304,021**	181,142	**200,426**	121,263
Impairment reversal	**426**	972	**281**	651
Operating profit	**304,447**	182,114	**200,707**	121,914
Finance income (Note 13)	**3,968**	7,003	**2,616**	4,688
Finance expenses (Note 13)	**(49,524)**	(30,047)	**(32,649)**	(20,114)
Fair value loss	**(7,652)**	(3,643)	**(5,045)**	(2,440)
Profit/(loss) before taxation	**251,239**	155,427	**165,629**	104,048
Income tax expense (Note 14)	**(256,009)**	(81,906)	**(168,780)**	(54,830)
(Loss)/profit for the period	**(4,770)**	73,521	**(3,151)**	49,218

Other income in the Oil business includes foreign exchange gain/(losses) and changes in underlift/overlift. In current period we recorded an overlift position compared to the underlift position in the prior period.

Gas	3 Months ended 31 March 2025 ₦ million	3 Months ended 31 March 2024 ₦ million	3 Months ended 31 March 2025 $'000	3 Months ended 31 March 2024 $'000
Revenue from contracts with customers				
Gas sales	**67,492**	43,282	**44,496**	28,974
Natural gas liquid	**7,510**	–	**4,951**	–
Cost of sales and general and administrative expenses	**(10,443)**	(4,371)	**(6,884)**	(2,926)
Other income/(losses)	**1,142**	(95,006)	**754**	(63,606)
Operating profit/(loss) before impairment	**65,701**	(56,105)	**43,317**	(37,559)
Impairment losses	**(1,236)**	—	**(815)**	—
Operating profit/(loss)	**64,465**	(56,096)	**42,502**	(37,559)
Share of (loss)/profit from joint venture accounted for using the equity method	**(1,060)**	4,180	**(699)**	2,798
Profit/(loss) before taxation	**63,405**	(51,907)	**41,803**	(34,760)
Income tax expense (Note 14)	**(23,251)**	(24,479)	**(15,329)**	(16,388)
Profit/(loss) for the period	**40,154**	(76,395)	**26,474**	(51,148)

During the reporting period, impairment reversal recognised in the oil segment relate to trade receivables and other receivables (Pillar, Pan Ocean, Oghareki, Summit, NEPL and NUIMS). Impairment losses recognised in the gas segment relates to Geregu Power, Sapele Power and NGMC. See Note 11 for further details.

Other income on the gas segment relates to foreign exchange gains or losses. The other income/(loss) in gas segment was negatively impacted by volatility in Naira exchange to the USD in 2024, but the exchange rate has moderated in 2025 giving rise to exchange gain.

The increase in the cost of sales and general and administrative expenses in the oil and gas segment is driven mostly by the consolidation of the acquired business SEPNU.

6.1.1 Disaggregation of revenue from contracts with customers

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

	3 Months ended 31 March 2025 Oil ₦ million	3 Months ended 31 March 2025 Gas ₦ million	3 Months ended 31 March 2025 Natural Gas Liquid ₦ million	3 Months ended 31 March 2025 Total ₦ million	3 Months ended 31 March 2025 Oil $'000	3 Months ended 31 March 2025 Gas $'000	3 Months ended 31 March 2025 Natural Gas Liquid $'000	3 Months ended 31 March 2025 Total $'000
Geographical markets								
Nigeria	8,697	67,491	—	76,188	5,732	44,496	—	50,228
Portugal	80,159	—	—	80,159	52,846	—	—	52,846
Uruguay	61,877	—	—	61,877	40,794	—	—	40,794
Cote D'Ivoire	75,493	—	—	75,493	49,771	—	—	49,771
Vietnam	3,358	—	—	3,358	2,214	—	—	2,214
India	130,219	—	—	130,219	85,850	—	—	85,850
France	5,520	—	—	5,520	3,639	—	—	3,639
Turkey	3,372	—	—	3,372	2,223	—	—	2,223
Netherlands	152,346	—	—	152,346	100,438	—	—	100,438
South Africa	68,230	—	—	68,230	44,983	—	—	44,983
Indonesia	84,885	—	—	84,885	55,962	—	—	55,962
Germany	109,314	—	—	109,314	72,068	—	—	72,068
Italy	105,391	—	—	105,391	69,481	—	—	69,481
Malaysia	95,386	—	—	95,386	62,886	—	—	62,886
USA	104,941	—	—	104,941	69,185	—	—	69,185
Spain	61,164	—	—	61,164	40,324	—	—	40,324
UK	2,158	—	—	2,158	1,423	—	—	1,423
Ghana	—	—	7,511	7,511	—	—	4,952	4,952
Revenue from contracts with customers	1,152,510	67,491	7,511	1,227,512	759,819	44,496	4,952	809,267

	3 Months ended 31 March 2025	3 Months ended 31 March 2025	3 Months ended 31 March 2025	3 Months ended 31 March 2025	3 Months ended 31 March 2025	3 Months ended 31 March 2025	3 Months ended 31 March 2025	3 Months ended 31 March 2025
	Oil	Gas	Natural Gas Liquid	Total	Oil	Gas	Natural Gas Liquid	Total
	₦ million	₦ million	₦ million	₦ million	$'000	$'000	$'000	$'000
Timing of revenue recognition								
At a point in time	**1,152,510**	**—**	**7,511**	**1,160,021**	**759,819**	**—**	**4,952**	**764,771**
Over time	**—**	**67,491**	**—**	**67,491**	**—**	**44,496**	**—**	**44,496**
Revenue from contracts with customers	**1,152,510**	**67,491**	**7,511**	**1,227,512**	**759,819**	**44,496**	**4,952**	**809,267**

	3 Months ended 31 March 2024	3 Months ended 31 March 2024	3 Months ended 31 March 2024	3 Months ended 31 March 2024	3 Months ended 31 March 2024	3 Months ended 31 March 2024
	Oil	Gas	Total	Oil	Gas	Total
	₦ million	₦ million	₦ million	$'000	$'000	$'000
Geographical markets						
Nigeria	29,031	43,282	72,313	19,433	28,974	48,407
Cote D'Ivoire	49,581	—	49,581	33,191	—	33,191
Netherlands	4,021	—	4,021	2,692	—	2,692
South Africa	19,748	—	19,748	13,220	—	13,220
Spain	28,648	—	28,648	19,178	—	19,178
UK	94,307	—	94,307	63,132		63,132
Revenue from contracts with customers	**225,336**	**43,282**	**268,618**	**150,846**	**28,974**	**179,820**

	3 Months ended 31 March 2024	3 Months ended 31 March 2024	3 Months ended 31 March 2024	3 Months ended 31 March 2024	3 Months ended 31 March 2024	3 Months ended 31 March 2024
	Oil	Gas	Total	Oil	Gas	Total
	₦ million	₦ million	₦ million	$'000	$'000	$'000
Timing of revenue recognition						
At a point in time	225,336	—	225,336	150,846	28,974	179,820
Over time	—	43,282	43,282	—	—	—
Revenue from contracts with customers	**225,336**	**43,282**	**268,618**	**150,846**	**28,974**	**179,820**

The Group's transactions with its major customers, Shell Western, Chevron, and ExxonMobil, constitute about 85% ($754 million, ₦1.1 trillion) of the total revenue from oil segment and the Group as a whole. Also, the Group's transactions with Geregu Power, Sapele Power, NGMC, MSNE and Azura ($41.8 million, ₦64 billion) accounted for most of the revenue from gas segment.

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

	3 Months ended 31 March 2025			3 Months ended 31 March 2024		
	Oil	Gas	Total	Oil	Gas	Total
	₦ million	₦ million	₦ million	₦ million	₦ million	₦ million
Impairment (losses)/reversal recognised during the year	**426**	**(1,236)**	**(810)**	972	–	972

	3 Months ended 31 March 2025			3 Months ended 31 March 2024		
	Oil	Gas	Total	Oil	Gas	Total
	$'000	$'000	$'000	$'000	$'000	$'000
Impairment (losses)/reversal recognised during the year	**281**	**(815)**	**(534)**	651	–	651
			–			

6.2 Segment assets

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

	Oil	Gas	Total	Oil	Gas	Total
Total segment assets	₦ million	₦ million	₦ million	$'000	$'000	$'000
31 March 2025	**8,483,354**	**1,142,271**	**9,625,625**	**5,521,883**	**743,513**	**6,265,396**
31 December 2024	2,458,176	595,278	3,053,454	5,695,489	701,393	6,396,882

6.3 Segment liabilities

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

	Oil	Gas	Total	Oil	Gas	Total
Total segment liabilities	₦ million	₦ million	₦ million	$'000	$'000	$'000
31 March 2025	**6,140,769**	**609,297**	**6,750,066**	**3,997,061**	**396,596**	**4,393,657**
31 December 2024	1,069,025	371,794	1,440,819	4,173,248	381,028	4,554,276

7. Revenue from contract with customers

	3 Months ended 31 March 2025	3 Months ended 31 March 2024	**3 Months ended 31 March 2025**	3 Months ended 31 March 2024
	₦ million	₦ million	**$'000**	$'000
Crude oil sales	**1,152,510**	225,336	**759,820**	150,846
Gas sales	**67,492**	43,282	**44,496**	28,974
Natural gas liquid	**7,510**	–	**4,951**	–
	1,227,512	268,618	**809,267**	179,820

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

8. Cost of Sales

	3 Months ended 31 March 2025	3 Months ended 31 March 2024	**3 Months ended 31 March 2025**	3 Months ended 31 March 2024
	₦ million	₦ million	**$'000**	$'000
Royalties	**197,531**	75,879	**130,227**	50,795
Depletion, Depreciation and Amortisation	**234,338**	61,895	**154,493**	41,434
Depreciation of Right of Use Assets	**14,489**	–	**9,552**	–
Crude handling fees	**28,588**	28,294	**18,847**	18,941
Nigeria Export Supervision Scheme (NESS) fee	**–**	291	**–**	195
Niger Delta Development Commission Levy	**19,565**	2,750	**12,899**	1,841
Barging/Trucking	**8,641**	5,478	**5,697**	3,667
Operational & Maintenance expenses	**188,927**	30,218	**124,558**	20,232
	692,079	204,805	**456,273**	137,105

Operational & maintenance expenses relates mainly to maintenance costs, warehouse operations expenses, security expenses, community expenses, clean-up costs, fuel supplies and catering services. Also included in operational and maintenance expenses is gas flare penalty of $13.2 million, ₦20.0 billion (Q1 2024: $4.2 million, ₦6.2 billion). The Group is working through projects in the onshore business to end routine flaring and a significant amount of these costs are expected to reduce in 2025.

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

9. Other (loss)/income - net

	3 Months ended 31 March 2025	3 Months ended 31 March 2024	3 Months ended 31 March 2025	3 Months ended 31 March 2024
	₦ million	₦ million	**$'000**	$'000
(Overlifts)/Underlift	**(81,199)**	84,300	**(53,533)**	56,433
Gain on foreign exchange	**8,997**	8,967	**5,932**	6,003
Tariffs	**2,787**	3,702	**1,837**	2,478
Others	**2,123**	197	**1,399**	132
	(67,292)	97,166	**(44,365)**	65,046

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

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

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

Others represents other income, joint venture billing interest and joint venture billing finance fees.

10. General and administrative expenses

	3 Months ended 31 March 2025	3 Months ended 31 March 2024	3 Months ended 31 March 2025	3 Months ended 31 March 2024
	₦ million	₦ million	**$'000**	$'000
Depreciation and amortisation	**13,267**	2,698	**8,747**	1,807
Depreciation of right of use assets	**2,760**	1,822	**1,819**	1,220
Professional & Consulting Fees	**5,593**	3,332	**3,687**	2,231
Auditor's remuneration	**59**	212	**39**	142
Directors Emoluments (Executives)	**1,133**	2,099	**747**	1,405
Directors Emoluments (Non - Executives)	**1,492**	1,536	**984**	1,028
Employee benefits	**33,881**	16,977	**22,337**	11,364
Share-based benefits	**8,812**	7,091	**5,810**	4,747
Donation	**54**	38	**35**	26
Flights and other travel costs	**5,606**	1,744	**3,696**	1,168
Other general expenses	**25,758**	(1,618)	**16,983**	(1,081)
	98,415	35,931	**64,884**	24,057

Included in the other general expenses are security expenses of $5.43 million, ₦8,232.46 million (Q1 2024: $0.82 million, ₦122 million), dues and subscription of $1.58 million, ₦2,395 million (Q1 2024: $0.21 million, ₦314 million), IT expenses of $5.31 million, ₦8,055 million (Q1 2024: $0.26 million, ₦40 million), Contract labour expenses of $4.09 million, ₦6 billion (Q1 2024: $1.02 million, ₦1.53 billion) among others.

Professional and consulting fees increase in the current period is largely attributable to the payment of 2025 depository fees.

The increase in the general and administrative expenses is driven by the consolidation of the acquired business SEPNU.

11. Impairment (loss)/reversal

	3 Months ended 31 March 2025	3 Months ended 31 March 2024	3 Months ended 31 March 2025	3 Months ended 31 March 2024
	₦ million	₦ million	**$'000**	$'000
Impairment (losses)/reversal on financial assets-net (Note 11.1)	**(810)**	972	**(534)**	651
	(810)	972	**(534)**	651

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

	3 Months ended 31 March 2025 ₦ million	3 Months ended 31 March 2024 ₦ million	3 Months ended 31 March 2025 $'000	3 Months ended 31 March 2024 $'000
Impairment losses/(reversal) on:				
NUIMS receivables	**–**	80	**–**	54
NEPL receivables	**426**	892	**281**	597
Trade receivables (Geregu power, Sapele Power and NGMC)	**(1,236)**	–	**(815)**	–
Total impairment loss/(reversal)	**(810)**	972	**(534)**	651

12. Fair value (loss)

	3 Months ended 31 March 2025 ₦ million	3 Months ended 31 March 2024 ₦ million	3 Months ended 31 March 2025 $'000	3 Months ended 31 March 2024 $'000
Hedge premium expenses	**(3,470)**	(2,420)	**(2,288)**	(1,620)
Fair value (loss) on derivatives (Note 19)	**(4,183)**	(1,223)	**(2,758)**	(819)
	(7,653)	(3,643)	**(5,045)**	(2,439)

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

13. Finance income/(cost)

	3 Months ended 31 March 2025 ₦ million	3 Months ended 31 March 2024 ₦ million	3 Months ended 31 March 2025 $'000	3 Months ended 31 March 2024 $'000
Finance Income				
Interest income	**3,968**	7,003	**2,616**	4,688
Finance Charges				
Interest on bank loan	**(30,283)**	(27,603)	**(19,965)**	(18,478)
Interest on lease liabilities	**(3,766)**	(442)	**(2,483)**	(296)
Unwinding of discount on provision for decommissioning	**(15,475)**	(2,002)	**(10,202)**	(1,340)
	(49,524)	(30,047)	**(32,650)**	(20,114)
Finance cost - net	**(45,556)**	(23,044)	**(30,034)**	(15,426)

Finance income represents interest on short-term fixed deposits.

The capitalisation rate used to determine the amount of borrowing costs to be capitalised is the weighted average interest rate applicable to the Group's general borrowings denominated in dollars during the year, in this case 9.13% (Q1 2024: 7.56%). The amount capitalised during the year is Nil (Q1 2024: $1.03 million, ₦1.54 billion).

14. Taxation

The major components of income tax expense for the years ended 31 December 2025 and 2024 are:

	3 Months ended 31 March 2025	3 Months ended 31 March 2024	**3 Months ended 31 March 2025**	3 Months ended 31 March 2024
	₦ million	₦ million	**$'000**	$'000
Current tax:				
Current tax expense on profit for the year	**313,987**	18,047	**207,004**	12,081
Education Tax	**12,102**	2,513	**7,979**	1,682
NASENI Levy	**–**	264	**–**	177
Police Levy	**–**	4	**–**	3
Total current tax	**326,089**	20,828	**214,983**	13,943
Deferred tax:				
Deferred tax expense in profit or loss (Note 14.1)	**(46,828)**	85,558	**(30,873)**	57,275
Total tax expense in statement of profit or loss	**279,261**	106,386	**184,110**	71,218
Total tax charged for the period	**279,261**	106,386	**184,110**	71,218
Effective tax rate	**89 %**	103 %	**89 %**	103 %

14.1 Deferred tax

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

	Balance as at 1 January 2025	**(Charged) / credited to profit or loss**	**Credited to other comprehensive income**	**Exchange difference**	**Balance as at 31 March 2025**
	₦ million	**₦ million**	**₦ million**	**₦ million**	**₦ million**
Deferred tax assets	353,954	**(21,665)**	**—**	**(49)**	**332,240**
Deferred tax liabilities	(1,615,677)	**68,493**	**—**	**(168)**	**(1,547,351)**
	(1,261,723)	**46,828**	**—**	**(217)**	**(1,215,111)**

	Balance as at 1 January 2025	**(Charged) /credited to profit or loss**	**Credited to other comprehensive income**	**Balance as at 31 March 2025**
	$'000	**$'000**	**$'000**	**$'000**
Deferred tax assets	230,541	**(14,283)**	**—**	**216,258**
Deferred tax liabilities	(1,052,339)	**45,156**	**—**	**(1,007,183)**
	(821,798)	**30,873**	**—**	**(790,925)**

15. Computation of cash generated from operations

	Notes	31 March 2025 ₦ million	31 March. 2024 ₦ million	31 March 2025 $'000	31 March. 2024 $'000
Profit before tax		**314,646**	103,513	**207,433**	69,288
Adjusted for:					
Depletion, depreciation and amortisation		**247,606**	64,594	**163,241**	43,241
Depreciation of right-of-use asset		**17,248**	1,822	**11,371**	1,220
Impairment losses on financial assets	11.1	**810**	(972)	**534**	(651)
Interest income	13	**(3,967)**	(7,003)	**(2,616)**	(4,688)
Interest expense on bank loans	13	**30,283**	27,603	**19,965**	18,478
Interest on lease liabilities	13	**3,767**	442	**2,483**	296
Unwinding of discount on provision for decommissioning	13	**15,475**	2,002	**10,202**	1,340
Unrealised fair value loss on derivatives financial instrument	12	**4,183**	1,223	**2,758**	819
Realised fair value loss on derivatives	12	**3,470**	2,420	**2,288**	1,620
Unrealised foreign exchange (gain)	9	**(8,997)**	(8,967)	**(5,932)**	(6,003)
Share based payment expenses		**8,812**	7,091	**5,810**	4,747
Share of loss/(profit) from joint venture		**1,060**	(4,180)	**699**	(2,798)
Defined benefit plan		**3,792**	5,027	**2,500**	3,365
Changes in working capital: (excluding the effects of exchange differences)					
Trade and other receivables		**(231,125)**	13,720	**(152,375)**	9,184
Inventories		**13,494**	2,433	**8,896**	1,629
Prepayments		**11,851**	4,986	**7,813**	3,338
Contract assets		**(11,164)**	(117)	**(7,360)**	(78)
Trade and other payables		**43,675**	(190,484)	**28,794**	(127,515)
Net cash from operating activities		**464,919**	25,153	**306,504**	16,832

16 Oil and gas properties

During the three months ended 31 March 2025, the Group acquired assets amounting to ₦57 billion, $38 million (Dec 2024: ₦362.8 billion, $245.2 million)

17. Trade and other receivables

	31 March 2025 ₦ million	31 Dec 2024 ₦ million	31 March 2025 $'000	31 Dec 2024 $'000
Trade receivables (Note 17.1)	**578,983**	534,917	**376,865**	348,407
Nigerian Petroleum Development Company (NPDC) receivables (Note 17.2)	**43,643**	63,615	**28,407**	41,434
NUIMS receivables (Note 17.3)	**616,212**	454,571	**401,097**	296,075
Underlift	**17,629**	–	**11,475**	–
Advances to suppliers-others	**17,820**	7,461	**11,599**	4,859
Receivables from ANOH (Note 17.5)	**3,207**	2,589	**2,087**	1,686
Other receivables (Note 17.4)	**113,123**	93,440	**73,632**	60,860
	1,390,617	1,156,593	**905,162**	753,321

17.1 Trade receivables

Included in the trade receivables are:

	31 March 2025 ₦ million	31 Dec 2024 ₦ million	31 March 2025 $'000	31 Dec 2024 $'000
Geregu	**17,994**	18,001	**11,712**	11,725
Waltersmith	**5,523**	8,079	**3,595**	5,262
Sapele Power	**11,520**	11,271	**7,499**	7,341
NGMC	**3,130**	1,274	**2,037**	830
MSN ENERGY	**33,437**	25,526	**21,764**	16,626
Pillar	**11,925**	7,634	**7,762**	4,972
Shell Western	**48,311**	50,503	**31,446**	32,894
Chevron Nigeria Limited	**120,877**	–	**78,680**	
Azura	**18,213**	3,359	**11,855**	2,188
Transcorp Power	**3,178**	2,555	**2,069**	1,665
Exxon Mobil	**334,444**	438,326	**217,692**	285,495
Others	**3,817**	522	**2,484**	339
Impairment allowance	**(33,386)**	(32,134)	**(21,731)**	(20,930)
Total	**578,983**	534,917	**376,864**	348,407

Reconciliation of trade receivables

	31 March 2025 ₦ million	31 Dec 2024 ₦ million	31 March 2025 $'000	31 Dec 2024 $'000
Balance as at 1 January	**567,051**	107,871	**369,337**	119,939
Additions during the year	**1,236,067**	1,703,543	**804,566**	1,109,569
Receipt for the year	**(1,175,389)**	(1,393,036)	**(774,904)**	(941,444)
Acquired from business combination	**–**	141,601	**–**	92,229
Exchange difference	**(15,359)**	7,072	**(403)**	(10,956)
Gross carry amount	**612,370**	567,051	**398,596**	369,337
Less: Impairment allowance	**(33,386)**	(32,134)	**(21,731)**	(20,930)
Balance as at	**578,983**	534,916	**376,865**	348,407

Reconciliation of impairment allowance on trade receivables

	31 March 2025 ₦ million	31 Dec 2024 ₦ million	31 March 2025 $'000	31 Dec 2024 $'000
Loss allowance as at 1 Jan	**32,134**	15,130	**20,930**	16,822
Increase in loss allowance	**1,236**	14,137	**815**	9,554
Revaluation impact	**(21)**	–	**(14)**	(5,446)
Exchange difference	**37**	2,867	**–**	–
Loss allowance as at	**33,386**	32,134	**21,731**	20,930

17.2 NEPL receivables

The outstanding cash calls due to Seplat from its JOA partner, NEPL is ₦43.6 billion (Dec 2024: ₦112.1 billion) $28.4million (Dec. 2024: $124.6 million).

Reconciliation of NEPL receivables

	31 March 2025 ₦ million	31 Dec 2024 ₦ million	31 March 2025 $'000	31 Dec 2024 $'000
Balance as at 1 January	**67,954**	116,421	**44,260**	129,444
Addition during the year	**162,510**	495,804	**105,779**	322,932
Receipts during the year	**(181,151)**	(601,059)	**(119,428)**	(406,209)
Exchange difference	**(1,759)**	56,788	**342**	(1,907)
Gross carrying amount	**47,554**	67,954	**30,953**	44,260
Less: impairment allowance	**(3,911)**	(4,339)	**(2,546)**	(2,826)
Balance as at	**43,643**	63,615	**28,407**	41,434

Reconciliation of impairment allowance on NEPL receivables

	31 March 2025 ₦ million	31 Dec 2024 ₦ million	31 March 2025 $'000	31 Dec 2024 $'000
Loss allowance as at 1 January	**4,339**	4,367	**2,826**	4,856
Decrease in loss allowance	**(426)**	(2,473)	**(281)**	(1,671)
Foreign exchange revaluation impact	**—**	—	**1**	(359)
Exchange difference	**(2)**	2,445	**–**	–
Loss allowance as at period end	**3,911**	4,338	**2,546**	2,826

17.3 NUIMS receivables

Reconciliation of NUIMS receivables

	31 March 2025 ₦ million	31 Dec 2024 ₦ million	31 March 2025 $'000	31 Dec 2024 $'000
Balance as at 1 January	**454,571**	19,099	**296,075**	21,236
Addition during the year	**407,302**	386,723	**265,116**	251,884
Receipts during the year	**(243,442)**	(246,960)	**(160,495)**	(166,901)
Acquired on business combination	**–**	300,562	**–**	196,189
Exchange difference	**(2,220)**	(4,853)	**401**	(6,333)
Gross carrying amount	**616,211**	454,571	**401,097**	296,075
Balance as at 31 March	**616,211**	454,571	**401,097**	296,075

Reconciliation of impairment allowance on NUIMS receivables

	31 March 2025 ₦ million	31 Dec 2024 ₦ million	31 March 2025 $'000	31 Dec 2024 $'000
Loss allowance as at 1 January	**–**	684	**–**	761
Increase/(decrease) in loss allowance during the period	**–**	(1,126)	**–**	(761)
Exchange difference	**–**	442	**–**	–
Loss allowance as at	**–**	–	**–**	–

17.4 Other receivables

Reconciliation of other receivables

	31 March 2025 ₦ million	31 Dec 2024 ₦ million	31 March 2025 $'000	31 Dec 2024 $'000
Balance as at 1 January	**173,107**	74,727	**119,118**	83,086
Addition during the year	**26,437**	49,908	**17,208**	38,875
Receipts for the year	**(11,824)**	(16,491)	**(7,795)**	(11,145)
Acquired from business combination	**–**	6,583	**–**	4,297
Exchange difference	**14,902**	58,380	**3,356**	4,005
Gross carrying amount	**202,622**	173,107	**131,887**	119,118
Less: impairment allowance	**(89,498)**	(79,667)	**(58,255)**	(58,258)
Balance as at period end	**113,124**	93,440	**73,632**	60,860

Other receivables includes receivables from 3rd party injectors (tariff income) of $9.7 million, ₦14.9 billion, employee receivables of $11.2 million, ₦17.2 billion, sundry receivables of $24.7 million, ₦37.9 billion, advances to Belema for OML 55 crude evacuation of $3.7 million, ₦5.6 billion, receivable from All Grace for Ubima Disposal of $15.2 million, ₦23.3 billion, receivable from Naptha for Abiala Marginal field of $2.6 million, ₦4. billion and Pillar Cash Call of $6.53 million, ₦10 billion.

Reconciliation of impairment allowance on other receivables

	31 March 2025 ₦ million	31 Dec 2024 ₦ million	31 March 2025 $'000	31 Dec 2024 $'000
Loss allowance as at 1 January	**79,666**	48,564	**58,258**	53,996
Increase in loss allowance during the period	**–**	9,711	**–**	6,563
Foreign exchange revaluation impact	**(5)**	—	**(3)**	(2,301)
Exchange difference	**9,837**	21,391	**–**	–
Loss allowance as at	**89,498**	79,666	**58,255**	58,258

17.5 Receivables from joint venture (ANOH)

Receivables from joint venture (ANOH)	31 March 2025 ₦ million	31 Dec 2024 ₦ million	31 March 2025 $'000	31 Dec 2024 $'000
Balance as at 1 January	**7,252**	5,992	**4,724**	6,662
Additions during the year	**559**	775	**364**	505
Receipts for the year	**–**	(616)	**–**	(416)
Exchange difference	**64**	1,101	**38**	(2,027)
Gross carrying amount	**7,875**	7,252	**5,126**	4,724
Less: Impairment reversal/(charge)	**(4,667)**	(4,664)	**(3,038)**	(3,038)
Balance as at period end	**3,208**	2,588	**2,088**	1,686

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

	31 March 2025 ₦ million	31 Dec 2024 ₦ million	31 March 2025 $'000	31 Dec 2024 $'000
Loss allowance as at 1 January	**4,664**	5,427	**3,038**	6,034
Increase in loss allowance during the period	**–**	(4,433)	**–**	(2,996)
Exchange difference	**3**	3,670	**–**	–
Loss allowance as at	**4,667**	4,664	**3,038**	3,038

18. Contract assets

	31 March 2025 ₦ million	31 Dec 2024 ₦ million	31 March 2025 $'000	31 Dec 2024 $'000
Revenue on gas sales	**1,428**	12,622	**929**	8,221
Revenue on oil sales	**34,070**	11,551	**22,176**	7,524
Impairment loss on contract assets	**(255)**	(255)	**(166)**	(166)
	35,243	23,918	**22,939**	15,579

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

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

18.1 Reconciliation of contract assets

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

	31 March 2025 ₦ million	31 Dec 2024 ₦ million	31 March 2025 $'000	31 Dec 2024 $'000
Balance as at 1 January	**24,173**	7,496	**15,745**	8,334
Additions during the period	**35,083**	167,015	**23,129**	112,872
Amount billed during the year	**(23,877)**	(156,049)	**(15,742)**	(105,461)
Foreign exchange revaluation impact	**(41)**	–	**(27)**	–
Exchange difference	**160**	5,711	**–**	–
Gross revenue on gas and oil	**35,498**	24,173	**23,105**	15,745
Impairment charge	**(255)**	(255)	**(166)**	(166)
Balance as at 31 March	**35,243**	23,918	**22,939**	15,579

19. Derivative financial instruments

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

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

	31 March 2025 ₦ million	31 Dec 2024 ₦ million	31 March 2025 $'000	31 Dec 2024 $'000
Opening Balance	**(6,073)**	(1,444)	**(3,955)**	(1,606)
Realised fair value (Note12)	**5,670**	1,836	**3,738**	1,241
Prior year premium paid	**330**	540	**218**	365
Premium Accrued	**(1,157)**	(322)	**(764)**	(217)
Unrealised fair value (Note12)	**(9,852)**	(5,531)	**(6,495)**	(3,738)
Exchange difference	**(69)**	(1,152)	**–**	–
	(11,151)	(6,073)	**(7,258)**	(3,955)

In Q1 2025, the Group entered into economic crude oil hedge contracts with an average strike price of ₦83,425, $55/bbl (Dec. 2024: ₦81,382, $55/bbl) for 3 million barrels (Dec. 2024: 3 million barrels) at a cost of ₦6.9 billion, $4.6 million (Dec. 2024: ₦ 7.6 billion, $4.9 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.

	31 March 2025 ₦ million	31 Dec 2024 ₦ million	31 March 2025 $'000	31 Dec 2024 $'000
Short-term fixed deposits	**62,090**	202,123	**40,415**	131,649
Cash at bank	**452,384**	519,638	**294,464**	338,458
Gross cash and cash equivalents	**514,474**	721,761	**334,879**	470,107
Loss allowance	**(377)**	(376)	**(245)**	(245)
Net cash and cash equivalents	**514,097**	721,385	**334,634**	469,862

20.1 Reconciliation of impairment allowance on cash and cash equivalents

	31 March 2025 ₦ million	31 Dec 2024 ₦ million	31 March 2025 $'000	31 Dec 2024 $'000
Loss allowance as at 1 January 2025	**376**	221	**245**	246
Increase/ (decrease) in loss allowance during the period	**–**	–	**–**	(1)
Exchange difference	**–**	155	**–**	–
Loss allowance as at	**377**	376	**245**	245

20.2 Restricted cash

	31 March 2025 ₦ million	31 Dec 2024 ₦ million	31 March 2025 $'000	31 Dec 2024 $'000
Restricted cash	**198,016**	202,983	**128,890**	132,209
	198,016	202,983	**128,890**	132,209

20.3 Movement in restricted cash

	31 March 2025 ₦ million	31 Dec 2024 ₦ million	31 March 2025 $'000	31 Dec 2024 $'000
Opening balance	**202,983**	24,311	**132,209**	27,031
(Decrease)/increase in restricted cash	**(5,034)**	155,630	**(3,319)**	105,178
Exchange difference	**67**	23,042	**–**	–
Closing balance	**198,016**	202,983	**128,890**	132,209

Included in the restricted cash is ($104.1 million, ₦159.9billion), which relates to SEPNU's decommissioning and abandonment deposit, as well as the host community fund.

Also Included in the restricted cash balance is ($2.4 million, ₦3.7 billion) and ($21.4 million, ₦32.9 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 $0.5 million, ₦0.8 billion is included in the restricted cash balance as at the end of the reporting period.

Also included in the restricted cash balance is $0.4 million, ₦0.6 billion for unclaimed dividend.

The movement in the restricted cash during the period is driven by the outflow from the host community fund.

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

21. Share capital

21.1 Authorised and issued share capital

	31 March 2025 ₦ million	31 Dec 2024 ₦ million	31 March 2025 $'000	31 Dec 2024 $'000
Authorised ordinary share capital				**–**
588,444,561 ordinary shares denominated in Naira of 50 kobo per share	**297**	297	**1,864**	1,864
Issued and fully paid				
588,444,561 (Dec. 2024: 588,444,561) issued shares denominated in Naira of 50 kobo per share	**297**	297	**1,864**	1,864

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

21.2 Movement in share capital and other reserves

	Number of shares Shares	Issued share capital ₦ million	Share premium ₦ million	Share based payment reserve ₦ million	Treasury shares ₦ million	Total ₦ million
Opening balance as at 1 January 2025	**588,444,561**	**297**	**87,375**	**15,558**	**(3,570)**	**99,660**
Additions to share based during the period	**–**	**–**	**–**	**–**	**–**	**–**
Vested shares during the period	**–**	**–**	**–**	**–**	**–**	**–**
Forfeited shares	**–**	**–**	**–**	**–**	**–**	**–**
PAYE tax withheld on vested shares	**–**	**–**	**–**	**–**	**–**	**–**
Share based payments	**–**	**–**	**–**	**8,813**	**–**	**8,813**
Share repurchased	**–**	**–**	**–**	**–**	**–**	**–**
Closing balance as at 31 March 2025	**588,444,561**	**297**	**87,375**	**24,371**	**(3,570)**	**108,473**

	Number of shares	Issued share capital	Share premium	Share based payment reserve	Treasury shares	Total
	Shares	$'000	$'000	$'000	$'000	$'000
Opening balance as at 1 January 2025	**588,444,561**	**1,864**	**518,564**	**36,747**	**(5,609)**	**551,566**
Additions to share based during the period	–	–	–	–	–	–
Vested shares during the period	–	–	–	–	–	–
Forfeited shares	–	–	–	–	–	–
PAYE tax withheld on vested shares	–	–	–	–	–	–
Share based payments	–	–	–	5,810	–	5,810
Share repurchased	–	–	–	–	–	–
Closing balance as at 31 March 2025	**588,444,561**	**1,864**	**518,564**	**42,557**	**(5,609)**	**557,376**

21.3 Employee share-based payment scheme

As at 31 March 2025, the Group had 53,305,512 shares (Dec 2024: 53,305,512 shares). which are yet to fully vest. These shares have been assigned to certain employees and senior executives in line with its share-based incentive scheme. During the three months ended 31 March 2025, no new shares were vested (Dec 2024: 17,567,776 shares).

22. Interest bearing loans and borrowings

22.1 Reconciliation of interest bearings loans and borrowings

Below is the reconciliation on interest bearing loans and borrowings for Q1 2025:

	Borrowings within 1 year	Borrowings above 1 year	Total	Borrowings within 1 year	Borrowings above 1 year	Total
	₦ million	₦ million	₦ million	$'000	$'000	$'000
Balance as at 1 January 2025	**690,270**	**1,409,480**	**2,099,750**	**449,593**	**918,036**	**1,367,629**
Additions	**–**	**–**	**–**	**–**	**–**	**–**
Interest accrued	**30,283**	**–**	**30,283**	**19,965**	**–**	**19,965**
Borrowing cost capitalized	**–**	**–**	**–**	**–**	**–**	**–**
Principal paid	**(1,394,335)**	**–**	**(1,394,335)**	**(919,250)**	**–**	**(919,250)**
Interest repayment	**(55,238)**	**–**	**(55,238)**	**(36,417)**	**–**	**(36,417)**
Other financing charges	**(467)**	**–**	**(467)**	**(308)**	**–**	**(308)**
Proceeds from loan financing	**985,932**	**–**	**985,932**	**650,000**	**–**	**650,000**
Transfers	**(73,726)**	**73,726**	**–**	**(48,606)**	**48,606**	**–**
Exchange differences	**(6,077)**	**1,862**	**(4,215)**	**–**	**–**	**–**
Carrying amount as at 31 March 2025	**176,642**	**1,485,068**	**1,661,710**	**114,977**	**966,642**	**1,081,619**

Below is the reconciliation on interest bearing loans and borrowings for 31 December 2024:

	Borrowings within 1 year	Borrowings due above 1 year	Total	Borrowings within 1 year	Borrowings above 1 year	Total
	₦ million	₦ million	₦ million	$'000	$'000	$'000
Balance as at 1 January 2024	80,265	599,434	679,699	89,244	666,487	755,731
Additions	517,888	443,904	961,792	350,000	300,000	650,000
Interest accrued	118,896	–	118,896	80,352	–	80,352
Borrowing cost capitalized	5,985	–	5,985	4,045	–	4,045
Principal paid	(56,981)	–	(56,981)	(38,509)	–	(38,509)
Interest repayment	(92,504)	–	(92,504)	(62,516)	–	(62,516)
Other financing charges	(31,775)	–	(31,775)	(21,474)	–	(21,474)
Transfers	71,692	(71,692)	–	48,451	(48,451)	–
Exchange differences	76,804	437,834	514,638	–	–	–
Carrying amount as at 31 Dec 2024	690,270	1,409,480	2,099,750	449,593	918,036	1,367,629

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.

22.2 Amortised cost of borrowings

	31 March 2025	31 Dec 2024	31 March 2025	31 Dec 2024
	₦ million	₦ million	$'000	$'000
Senior loan notes	**973,341**	1,009,628	**634,689**	657,601
Revolving loan facilities	**15,143**	15,868	**9,856**	10,335
Reserve based lending (RBL) facility	**46,682**	78,522	**30,386**	51,143
$350 million RCF	**156,984**	539,722	**102,181**	351,537
$300 million Advance Payment Facility	**469,560**	456,010	**304,507**	297,013
	1,661,710	2,099,750	**1,081,619**	1,367,629

$650 million Senior notes – April 2030

On 21 March 2025, the Group refinanced the $650m notes due 2026 with a new $650m issuance maturing in 2030 — ahead of the 2026 notes becoming current in April 2025. The redemption of the 2026 notes was carried out through a combination of a tender offer and a call option. On March 18, 2025, $567.5m (87.3%) of the total principal was tendered and settled on March 21, 2025, while the remaining $82.5m (12.7%) was redeemed via the par call option on April 1, 2025. The newly issued $650m notes due in 2030 carry a coupon rate of 9.125%, reflecting prevailing global market volatility. The amortised cost for the senior notes as at the reporting period is $633.6 million, ₦1,082 billion (Dec. 2024: $657.6 million, ₦1,009 billion) although the principal is $650 million.

$110 million Senior reserve-based lending (RBL) facility – March 2021

The Group through its subsidiary Westport on 28 November 2018 entered into a five-year loan agreement with interest payable semi-annually. The RBL facility has an initial contractual interest rate of 8% + USD LIBOR, now SOFR (Secured Overnight Financing Rate), which came into effect in August 2023 and a final settlement date of March 2026. The original facility of $90 million was increased to $ 100 million on 4 February in 2020 and then again to $110 million on 24 May 2021.

The RBL is secured against the Group's producing assets in OML 40 via the Group's shares in Elcrest, and by way of a debenture which creates a charge over certain assets of the Group, including its bank accounts. The available facility is capped at the lower of the available commitments and the borrowing base. At the 2025 Spring redetermination which was finalized in early April, the technical and modelling bank calculated a borrowing base of $53.12 million. Following the March 2025 principal repayment the current available commitment level is $30.25m which is fully drawn down.

$50 million Reserved based lending (RBL) facility – July 2021

In July 2021, the Group through its subsidiary Westport raised a $50 million offtake facility also secured on Elcrest's assets, including OML 40, in addition to the Senior Reserved Based Lending Facility. The offtake facility has a 6-year tenor, maturing in 2027. The principal outstanding is $11 million, with the facility size having reduced to $40 million as at 31 March 2025.The margin is 2% over the then-prevalent senior margin (resulting in a margin of SOFR, including the CAS, plus 10%). LIBOR rates were replaced by the financial institutions to Secured Overnight Financing Rate (SOFR) plus a credit adjustment spread (CAS) in August 2023.

$350 million Revolving credit facility

The $350m Seplat RCF was amended and restated on 20 August 2024. The facility has a bullet repayment and incurs a total interest of SOFR (incl. CAS) + 5% margin. Due to the refinancing of the $650m notes that occurred on 21 March 2025, the final maturity of the RCF was automatically extended to 31 December 2026 from 30 June 2025, an extension of 18 months. The RCF was fully drawn for the completion of the MPNU transaction in December 2024. $250m was prepaid on 31 March 2025, leaving $100m outstanding. The amortised cost for the RCF as at the reporting period is $102.2 million, ₦157.0 billion (Dec. 2024: $351.5 million, ₦539.7 billion).

$300 million Advance payment facility

On 6 December 2024, Seplat Energy Offshore Limited entered into an up to $300m Advance Payment Facility ("APF") with ExxonMobil Financial Investment Company Limited, a fully owned subsidiary of ExxonMobil. The APF can be used for general corporate purposes and was used to provide financing in the completion of the MPNU acquisition.

The security package of the APF covers shares in Seplat Energy Offshore Limited ("SEOL") and Seplat Energy Investment Limited ("SEIL"), as well as, security over the onshore collection account and the offshore proceeds account, and an assignment by way of security of SEPNU's rights as seller under the offtake agreement.

The APF is currently fully drawn and will bear interest at a rate of the aggregate of Term SOFR (including a credit adjustment spread of 0.25% per annum) plus 5% per annum. This is the same pricing as our RCF.

Financial covenants under the APF include a forward-looking DSCR of 1.20x, with a cure period of 30 business days.

The amortised cost for the APF as at the reporting period is $306 million, ₦470 billion (Dec. 2024: $297 million, ₦456 billion) although the principal is $300 million. Final maturity is three years following the date of the agreement, i.e., December 2027.

23. Employee benefit obligation

23.1 Defined benefit plan

During the reporting period, the defined benefit plan was presented as a net plan asset of $2.8 million, ₦4.3 billion compared to a net defined benefit liability of (Dec. 2024: $50.1 million, ₦76.9 billion) as at year end. This change in position is due to the consolidation of SEPNU's financials where the defined benefit asset stood at $8.4 million, ₦12.8 billion as at the end of the current period.

24. Trade and other payables

	31 March 2025 ₦ million	31 Dec 2024 ₦ million	31 March 2025 $'000	31 Dec 2024 $'000
Trade payable	**537,157**	562,913	**349,640**	366,642
Accruals and other payables	**816,412**	865,971	**531,396**	564,032
NDDC levy	**23,776**	11,715	**15,476**	7,630
Royalties payable	**203,149**	174,932	**132,231**	113,938
Overlift	**151,094**	69,174	**98,348**	45,055
	1,731,588	1,684,705	**1,127,091**	1,097,297

Included in accruals and other payables are field accruals of $84.8 million, ₦130.2 billion (Dec. 2024: $96.3 million, ₦147.8 billion), deposit received for asset held for sale of $9.5 million, ₦14.6 billion ((Dec. 2024: $8.5 million, ₦12.6 billion) and other vendor payables of $78.9 million, ₦121.2 billion (Dec. 2024: $459..2 million, ₦705.6 billion). Royalties payable include accruals in respect of crude oil and gas production for which payment is outstanding at the end of the period.

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

25. Earnings per share (EPS)

Basic

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

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 year plus all the dilutive potential ordinary shares (arising from outstanding share awards in the share-based payment scheme) into ordinary shares.

	31 March 2025	31 March 2024	**31 March 2025**	31 March 2024
	₦ million	₦ million	**$'000**	$'000
Profit attributable to Equity holders of the parent	**30,679**	1,570	**20,221**	1,045
(Loss)/Profit attributable to Non-controlling interests	**4,705**	(4,444)	**3,102**	(2,975)
Profit for the year	**35,384**	(2,874)	**23,323**	(1,930)

	Shares '000	Shares '000	**Shares '000**	Shares '000
Weighted average number of ordinary shares in issue	**588,445**	588,445	**588,445**	588,445
Outstanding share based payments (shares)	**–**	–	**–**	–
Weighted average number of ordinary shares adjusted for the effect of dilution	**588,445**	588,445	**588,445**	588,445

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

Basic earnings per share for the period	**₦**	₦	**$**	$
Basic earnings per share	**52.14**	2.67	**0.03**	0.00
Diluted earnings per share	**52.14**	2.67	**0.03**	0.00
Profit used in determining basic/diluted earnings per share	**30,679**	1,570	**20,221**	1,045

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

26. Proposed dividend

For the three months ended 31 March 2025, the Group's directors proposed an interim dividend of 4.6 cents per share for the reporting period (Q1 2024: 3.0 cents per share)

27. Related party relationships and transactions

There was no related party transactions in the period.

28. Commitments and contingencies

28.1 Contingent liabilities

The Group is involved in a number of legal suits as defendant. The estimated value of the contingent liabilities for the year ended 31 March 2025 is ₦387 million, $0.252 million (Dec 2024: ₦724 million, $0.471 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.

29. Events after the reporting period

There was no event after the reporting period which could have a material effect on the disclosures and the financial position of the Group as at 31 March 2025 and on its profit or loss and other comprehensive income for the period ended.

30. Exchange rates used in translating the accounts to Naira

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

	Basis	31 March 2025 N/$	31 March 2024 N/$	31 Dec. 2024 N/$
Property, plant & equipment – opening balances	Historical rate	**1535.32**	899.39	899.39
Property, plant & equipment – additions	Average rate	**1,516.82**	1,405.47	1,479.68
Property, plant & equipment - closing balances	Closing rate	**1,536.32**	1405.47	1535.32
Current assets	Closing rate	**1,536.32**	1405.47	1535.32
Current liabilities	Closing rate	**1,536.32**	1405.47	1535.32
Equity	Historical rate	**Historical**	Historical	Historical
Income and Expenses:	Overall Average rate	**1,516.82**	1,493.81	1,479.68